Draft
Environmental Impact Report

SCH# 2022030180

Volume 2

Appendix A - K

CARBON TERRAVAULT I (KERN COUNTY)

by California Resources Corporation *(PP22405)*

Zone Change Case No. 5, Map No. 119
Zone Change Case No. 4, Map No. 120
Conditional Use Permit No. 13, Map No. 118
Conditional Use Permit No. 14, Map No. 118
Conditional Use Permit No. 5, Map No. 119
Conditional Use Permit No. 6, Map No. 119
Conditional Use Permit No. 3, Map No. 120
Conditional Use Permit No. 2, Map No. 138

Kern County
Planning and Natural Resources Department
Bakersfield, California

December 2023

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Appendix A - K

CARBON TERRAVAULT I (KERN COUNTY)

by California Resources Corporation *(PP22405)*

Zone Change Case No. 5, Map No. 119
Zone Change Case No. 4, Map No. 120
Conditional Use Permit No. 13, Map No. 118
Conditional Use Permit No. 14, Map No. 118
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Conditional Use Permit No. 6, Map No. 119
Conditional Use Permit No. 3, Map No. 120
Conditional Use Permit No. 2, Map No. 138

Kern County
Planning and Natural Resources Department
Bakersfield, California

December 2023

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Appendix A
Notice of Preparation/Initial Study

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A.1 Notice of Preparation/Initial Study

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Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 **TTY Relay 1-800-735-2929**
Email: planning@kerncounty.com
Web Address: http://kernplanning.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

DATE: March 4, 2022

TO: See Attached Mailing List

FROM: Kern County Planning and Natural Resources Department
Attn: Cindi Hoover
2700 "M" Street, Suite 100
Bakersfield, CA 93301
(661)862-8629; hooverc@kerncounty.com

SUBJECT: NOTICE OF PREPARATION (NOP) OF A DRAFT ENVIRONMENTAL IMPACT REPORT (EIR) FOR THE CARBON TERRAVAULT 1 (CTV 1) CARBON CAPTURE AND SEQUESTRATION PROJECT BY CALIFORNIA RESOURCES CORPORATION (CRC)

The Kern County Planning and Natural Resources Department as Lead Agency (per CEQA Guidelines Section 15062) has determined that preparation of an Environmental Impact Report (per CEQA Guidelines 15161) is necessary for the proposed project identified below. The Planning and Natural Resources Department solicits the views of your agency as to the scope and content of the environmental information which is germane to your agency's statutory responsibilities in connection with the proposed project. Your agency may need to use the EIR prepared by our agency when considering your permit or other approval of the project.

You are invited to view the NOP and submit written comments regarding the content of the environmental information in connection with the proposed project should you wish to do so. Due to the limits mandated by State law, your response must be received by **April 4, 2022 at 5:00 p.m**. Comments on the scope and content of the EIR can be submitted to the Kern County Planning and Natural Resources Department at the address shown above or to hooverc@kerncounty.com. A Scoping Meeting will be held on **Friday, March 18, 2021 at 1:30 p.m.**

PROJECT TITLE: Carbon TerraVault 1 (CTV 1) by California Resources Corporation (PP22405); PLN21-01378: ZCC No. 5, Map No. 118; ZCC No. 5, Map No. 119; ZCC No. 4, Map No. 120; CUP No. 13, Map No. 118; CUP No. 5, Map No. 119; CUP No. 3, Map No. 120

PROJECT LOCATION: Central Valley portion of unincorporated Kern County, West side of Elk Hills Road and north Side of Skyline Road, within the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield (pop. 413,098), approximately 8.5 miles from the City of Taft (pop 8945) and approximately 4 miles from the unincorporated community of Buttonwillow (pop. 1443), also being located within within section 12 of Township 30 South, Range 22 East, sections 7, 8, 17, 18, 22, 25, 26, 27, 35 and 36 of Township 30 South, Range 23 East, and section 31 Township 30 South, Range 24 East, Mount Diablo Base and Meridian (MDBM), County of Kern, State of California.

PROJECT DESCRIPTION: The proposed project is a Conditional Use Permit for a 5,332.34 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells and related improvements for storage of Carbon Dioxide (CO_2). The project, Carbon TerraVault 1 (CTV 1), is a wholly

owned subsidiary of California Resources Corporation, the applicant for the project. The project comprises the following area:

Table 1: Project Assessor Parcel Numbers, Existing General Plan Designation, Existing Zoning Classification, Proposed Zone Classification, Acreage

APN	Map No.	Zoning	GP Designation	Sec/T/R	Acreage	Ag. Preserve
157-060-02 PTN	118	A (Exclusive Agriculture)	8.4 Mineral and Petroleum	12/ 30 S/R 22 E	159.50	Ag. Preserve 3 Inclusion: Yes
158-040-07	119	A (Exclusive Agriculture)	8.3 Extensive Agriculture; 8.3/2.1 Extensive Agriculture and Seismic Hazard	7/ 30 S/R 23 E	42.95	Ag. Preserve 3 Inclusion: Yes
158-040-06	119	A-1 (Limited Agriculture)	8.4 Mineral and Petroleum	8/30 S/R 23 E	641.20	
158-070-02	119	A-1 (Limited Agriculture)	8.3 Extensive Agriculture	17/ 30 S/R 23 E	156.44	
158-070-03 PTN	119	A-1 (Limited Agriculture)	8.4 Mineral and Petroleum	17/ 30 S/R 23 E	154.38	
158-070-01 PTN	119	A-1 (Limited Agriculture)	8.4 Mineral and Petroleum	18/ 30 S/R 23 E	319.06	
158-080-06 PTN	119	A-1 (Limited Agriculture)	8.4 Mineral and Petroleum	22/ 30 S/R 23 E	160.89	
158-090-03 PTN	119	A-1 (Limited Agriculture)	8.3 Extensive Agriculture	25/ 30 S/R 23 E	340.82	

158-090-02	119	A-1 (Limited Agriculture)	8.4 Mineral and Petroleum	26/ 30 S/R 23 E	637.78	
158-090-01	119	A-1 (Limited Agriculture)	8.4 Mineral and Petroleum	27/ 30 S/R 23 E	637.54	
158-090-19	119	A (Exclusive Agriculture)	8.4 Mineral and Petroleum; 8.3/2.1 Extensive Agriculture & Seismic Hazard	35/ 30 S/R 23 E	637.89	Ag. Preserve 3 Inclusion: Yes
158-090-04	119	A (Exclusive Agriculture)	8.4 Mineral and Petroleum	36/ 30 S/R 23 E	683.74	Ag. Preserve 3 Inclusion: Yes
159-280-07 PTN	120	A-1 (Limited Agriculture)	8.4 Mineral and Petroleum; 8.4/2.4 Extensive Agriculture/ Steep Slope	31/ 30 S/R 24 E	160.15	
				Total Acres	5,332.34	

The proposed project site is located within the Elk Hills Oil Field which comprises approximately 75 square miles (47,800-acre) complex with surface and mineral rights privately held by CRC in the San Joaquin Valley of unincorporated Kern County. The surrounding area is comprised of agricultural fields, both active and fallow, and other existing oilfields. They include the Midway – Sunset Oil Field, McKittrick Oilfield and Cymric Oil Field. Skyline Road is closed to public entry and is the southern boundary of the project. Skyline Road connects to Elk Hills Road, which connects the town of Taft, to the south, with Buttonwillow to the north. California Resource Corporation's gated and guarded entrance to the field is located at the western intersection of Skyline Drive and Elk Hills Road.

The proposed project would take local industrial sources of CO_2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project. Potential sources and locations of sources will be specifically identified and analyzed to the extent legally required by CEQA in the Draft EIR. The CO_2 would then be injected into identified geographically confined reservoirs for storage in perpetuity. This area has been identified as a location suitable for such storage and a potential to provide a contribution to the goals of California for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter (https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/). The project, as proposed, has the capacity for up to 48 million metric tons of estimated storage and capable of sequestrating over 1.5 million metric tons of CO_2 per year.

Implementation of the project would require permits from the Federal Environmental Protection Agency (EPA) for four (4) to six (6) Class VI injection wells in compliance with the UIC program Class VI geologic

sequestration regulations. Location of the proposed Class VI injection wells will be within the proposed CUP boundary of 5,332.34 acres. All employee facilities needed to manage the project will be provided by the existing Elk Hills oil field facilities.

Implementation of the project as proposed includes the following requests:

- Zone Change Case (ZCC No. 5, Map No. 118; ZCC No. 5, Map No. 119; ZCC No 4, Map No. 120); : From A-1 (Limited Agriculture) to A (Exclusive Agriculture) on approximately 3,208 acres; and
- Issuance of three (3) Conditional Use Permits (CUP No. 13, Map No. 118; CUP No. 5, Map 119; CUP No. 3, Map No. 120) to allow for the construction and operation of a 5,332.34-acre carbon capture and sequestration field and accessory infrastructure with a CO_2 storage capacity of 48 million metric tons, within the A (Exclusive Agriculture) Zone District. Carbon Capture and Sequestration (CCS) has been determined to be a storage operation and not a manufacturing operation and under the Kern County Zoning Ordinance, Section 19.08.085. And under the authority of Section 19.06.020. Storage of CCS in either existing formations or tanks is an allowed use with a Conditional Use Permit (CUP) in the following districts:
    - A District (Exclusive Agriculture)
    - M-2 District (Medium Industrial)
    - M-3 (Heavy Industrial)

Documents can be viewed online at: https://kernplanning.com/planning/notices-of-preparation/

Signature: 
Name: Cindi Hoover, Supervising Planner

Carbon TerraVault1
ZCC 5, Map 119; CUP 5, Map 119

City of Arvin
P.O. Box 548
Arvin, CA 93203

Bakersfield City Planning Dept
1715 Chester Avenue
Bakersfield, CA 93301

Bakersfield City Public Works Dept
1501 Truxtun Avenue
Bakersfield, CA 93301

California City Planning Dept
21000 Hacienda Blvd.
California City, CA 93515

Delano City Planning Dept
P.O. Box 3010
Delano, CA 93216

City of Maricopa
P.O. Box 548
Maricopa, CA 93252

City of McFarland
401 West Kern Avenue
McFarland, CA 93250

City of Ridgecrest
100 West California Avenue
Ridgecrest, CA 93555

City of Shafter
336 Pacific Avenue
Shafter, CA 93263

City of Taft
Planning & Building
209 East Kern Street
Taft, CA 93268

City of Tehachapi
Attn: John Schlosser
115 South Robinson Street
Tehachapi, CA 93561-1722

City of Wasco
764 E Street
Wasco, CA 93280

Los Angeles Co Reg Planning Dept
320 West Temple Street
Los Angeles, CA 90012

San Bernardino Co Planning Dept
385 North Arrowhead Avenue, 1st Floor
San Bernardino, CA 92415-0182

Inyo County Planning Dept
P.O. Drawer "L"
Independence, CA 93526

Santa Barbara Co Resource Mgt Dept
123 East Anapamu Street
Santa Barbara, CA 93101

Tulare County Planning & Dev Dept
5961 South Mooney Boulevard
Visalia, CA 93291

Kings County Planning Agency
1400 West Lacey Blvd, Bldg 6
Hanford, CA 93230

U.S. Bureau of Land Management
Caliente/Bakersfield
3801 Pegasus Drive
Bakersfield, CA 93308-6837

Federal Aviation Administration
Western Reg Office/
777 South Aviation Boulevard
Suite 150
El Segundo, CA 90245

San Luis Obispo Co Planning Dept
Planning and Building
976 Osos Street
San Luis Obispo, CA 93408

U. S. Fish & Wildlife Service
Division of Ecological Services
2800 Cottage Way #W-2605
Sacramento, CA 95825-1846

North West Kern Resource Cons Dist
5080 California Avenue, Suite 150
Bakersfield, CA 93309

Ventura County RMA Planning Div
800 South Victoria Avenue, L1740
Ventura, CA 93009-1740

U.S. Dept of Agriculture/NRCS
5080 California Avenue, Ste 150
Bakersfield, CA 93309-0711

California Air Resources Board
Stationary Resource Division
P.O. Box 2815
Sacramento, CA 95812

Federal Communications Comm
18000 Studebaker Road, #660
Cerritos, CA 90701

California Dept of Conservation
Geologic Energy Management Division
801 K Street, MS 20-20, Sacramento,
CA 95814

California Natural Resources Agency
Secretary Wade Crowfoot
715 P Street 20th Floor
Sacramento, CA 95814

California Air Resources Board
Industrial Strategic Division
Matthew Bohill, Chief
P.O. Box 2815
Sacramento, CA 95812

Caltrans/Dist 6
Planning/Land Bank Bldg.
P.O. Box 12616
Fresno, CA 93778

Caltrans/
Division of Aeronautics, MS #40
P.O. Box 942873
Sacramento, CA 94273-0001

Environmental Protection Agency
Region IX Office
75 Hawthorn Street
San Francisco, CA 94105

California Dept of Conservation
Geologic Energy Management Division
4800 Stockdale Highway, Ste 108
Bakersfield, CA 93309

California State University
Bakersfield - Library
9001 Stockdale Highway
Bakersfield, CA 93309

So. San Joaquin Valley Arch Info Ctr
California State University of Bkfd
9001 Stockdale Highway
Bakersfield, CA 93311

California Fish & Wildlife
1234 East Shaw Avenue
Fresno, CA 93710

California Regional Water Quality
Control Board/Central Valley Region
1685 E Street
Fresno, CA 93706-2020

California Dept of Conservation
Director's Office
801 "K" Street, MS 24-01
Sacramento, CA 95814-3528

California Energy Commission
Attn: Commissioner Douglas
715 P Street
Sacramento, CA 95814

California Public Utilities Commission
Attn: President Alice Reynolds
505 Van Ness Avenue
San Francisco, CA 94102

California Energy Commission
715 P Street
Sacramento, CA 95814

Cal Environmental Protection Agency/
Dept of Toxic Substances Control, Reg 1
Attn: Dave Kereazis, Permit Div - CEQA
8800 Cal Center Drive, 2nd Floor
Sacramento, CA 95826

California Dept of Water Resources
San Joaquin Dist.
3374 East Shields Avenue, Room A-7
Fresno, CA 93726

California State Geological Survey
Attm: Steve Bohlan
801 K Street MS 12-30, 801 K St MS 12-30, Sacramento, CA 95814

California Dept of Toxic Substance Control
Environmental Protection Agency
1515 Tollhouse Road
Clovis, CA 93612

California Dept of Water Resources
Div. Land & Right-of-Way
P.O. Box 942836
Sacramento, CA 94236

Kern County Public Works Department/
Building & Development/Development Review

Kern County Airports Department

Kern County Public Works Department/
Building & Development/Floodplain

Kern County Public Works Department/
Building & Development/Survey

Kern County
Env Health Services Department

Kern County Fire Dept
Aaron Duncan, Fire Chief

Kern County Sheriff's Dept
Administration

Kern County Library/Beale
Local History Room

Kern County Library/Beale
Andie Sullivan

Kern County Fire Dept
Kain Linville, Fire Marshall

Kern County Public Works Department/Operations &
Maintenance/Regulatory Monitoring & Reporting

Kern County Library
Buttonwillow Branch
116 Buttonwillow Avenue
Buttonwillow, CA 93206

Kern County Library
Taft Branch
27 Emmons Park Drive
Taft, CA 93268

McKittrick School Dist
P.O. Box 277
McKittrick, CA 93251

Kern High School Dist
5801 Sundale Avenue
Bakersfield, CA 93309

Kern County Water Agency
P.O. Box 58
Bakersfield, CA 93302-0058

San Joaquin Valley
Air Pollution Control District
1990 East Gettysburg Avenue
Fresno, CA 93726

Kern Audubon Society
Attn: Frank Bedard, Chairman
4124 Chardonnay Drive
Bakersfield, CA 93306

Defenders of Wildlife
980 - 9th Street, Suite 1730
Sacramento, CA 95814

Sierra Club/Kern Kaweah Chapter
P.O. Box 3357
Bakersfield, CA 93385

Torres Martinez Desert Cahuilla Indians
Attn: Michael Mirelez, Cultural
Resources Coordinator
P.O. Box 1160
Thermal, CA 92274

Twenty-Nine Palms Band of Mission Indians
Attn: Anthony Madrigal Jr., Tribal Grants
Administrator
46-200 Harrison Place
Coachella, CA 92236

Buttonwillow Union School Dist
42600 Highway 58
Buttonwillow, CA 93206

Kern County Superintendent of Schools
Attention School District Facility Services
1300 - 17th Street
Bakersfield, CA 93301

West Side Rec & Parks Dist
P.O. Box 1406
Taft, CA 93268

West Side Mosquito
Abatement Dist.
P.O. Box 205
Taft, CA 93268

Center on Race, Poverty
& the Environment
Attn: Marissa Alexander
1999 Harrison Street – Suite 650
San Francisco, CA 94612

Native American Heritage Council
of Kern County
3401 Aslin Street
Bakersfield, CA 93312

Southern California Gas Co
35118 McMurtrey Avenue
Bakersfield, CA 93308-9477

Verizon California, Inc.
Attention Engineering Department
520 South China Lake Boulevard
Ridgecrest, CA 93555

San Manuel Band of Mission Indians
Attn: , Cultural Resources Analyst
26569 Community Center Drive
Highland, CA 92346

Tejon Indian Tribe
Attn: Collin Rambo, Cultural Resource
Management Technician
1731 Hasti Acres Dr., Suite 108
Bakersfield, CA 93309

Taft Union High School Dist
701 - 7th Street
Taft, CA 93268

Elk Hills School Dist
P.O. Box 129
Tupman, CA 93276

Rosedale-Rio Bravo Water Dist
P.O. Box 20820
Bakersfield, CA 93390-0820

Buttonwillow Rec & Parks Dist
P.O. Box 434
Buttonwillow, CA 93206-9320

Buttonwillow County Water Dist
P.O. Box 874
Buttonwillow, CA 93206

Center on Race, Poverty
& the Environmental/
CA Rural Legal Assistance Foundation
1012 Jefferson Street
Delano, CA 93215

Pacific Gas & Electric Co
Land Projects
650 "O" Street, First Floor
Fresno, CA 93760-0001

Southern California Gas Co
Transportation Dept
9400 Oakdale Avenue
Chatsworth, CA 91313-6511

Tejon Indian Tribe
Kathy Morgan, Chairperson
1731 Hasti-acres Drive, Suite 108
Bakersfield, CA 93309

Twenty-Nine Palms Band of Mission Indians
Attn: Darrell Mike, Tribal Chairman
46-200 Harrison Place
Coachella, CA 92236

LIUNA
Attn: Danny Zaragoza
2201 "H" Street
Bakersfield, CA 93301

JB Energy Partners
Andrew Bremner
P.O. Box 82515
Bakersfield, CA 93308

QK Inc,
Chris Mynk
5080 California Ave. Suite 220
Bakersfield, CA 93309

Aera
Attn: Cindy Pollard
10000 Ming Avenue
Bakersfield, CA 93311

LINN Energy, LLC
5201 Truxtun Avenue, Suite 100
Bakersfield, CA 93309

Halliburton
Attn: Steve Pruett
34722 Seventh Standard Road
Bakersfield, CA 93314

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2131 Mars Court
Bakersfield, CA 93308

Naftex Operating Company
P.O. Box 308
Edison, CA 93220

San Joaquin Refining
3129 Standard Street
Bakersfield, CA 93308

Ensign
7001 Charity Avenue
Bakersfield, CA 93308

Lozeau Drury LLP
1939 Harrison Street, Suite 150
Oakland, CA 94612

Livermore Lab Foundation
c/o UC Office of Institutional Advancement
1111 Franklin Street
Oakland, CA 94607

Chevron, USA
9525 Camino Media
Bakersfield, CA 93311

Exxon/Mobil Production Company
Attn: Troy Tranquada
12000 Calle Real
Goleta, CA 93117

Hathaway, LLC
Attn: Chad Hathaway
P.O. Box 81385
Bakersfield, CA 93380

Macpherson Oil Company
P.O. Box 5368
Bakersfield, CA 93388

Venoco, Inc.
Attn: Ian Livett
6267 Carpentaria Avenue, Suite 100
Carpentaria, CA 93013

Mt Poso CoGen Company, LLC
100 Wilshire Boulevard, Suite 800
Santa Maria, CA 90401

Tricor Refining, LLC
1134 Manor Street
Bakersfield, CA 93308

Key Energy Services, Inc.
5080 California Avenue
Bakersfield, CA 93309

Adams, Broadwell, Joseph & Cardozo
Attention: Janet M. Laurain
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080

WZI, Inc.
1717 - 28th Street
Bakersfield, CA 93301

Stanford University
Energy Resources Engineering
Center of Carbon Storage
367 Panama Street
Stanford, CA 94305

CIPA
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1200 Discovery Drive, Suite 100
Bakersfield, CA 93309

IOPA
Attn: Les Clark
4520 California Avenue, Suite 230
Bakersfield, CA 93309

WSPA
Attn: Suzanne Noble
1518 Mill Rock Way, Suite 103
Bakersfield, CA 93311

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7724 East Panama Lane
Bakersfield, CA 93307

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1600 Norris Road
Bakersfield, CA 93309

GE Energy
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Tehachapi, CA 93561

Hess Corporation
1675 Chester Avenue
Bakersfield, CA 93301

PCL Industrial Services
1500 Union Avenue
Bakersfield, CA 93307

PLCL Plus Int'l, Inc.
12418-B Rosedale Highway
Bakersfield, CA 93312

Vintage Production California
9600 Ming Avenue, Suite 300
Bakersfield, CA 93311

Sturgeon Services Int'l
3511 Gilmore Avenue
Bakersfield, CA 93308

Sturgeon Services Int'l
3511 Gilmore Avenue
Bakersfield, CA 93308

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5001 California Avenue, Suite 211
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Weatherford Completions
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5060 California Avenue, Suite 1150
Bakersfield, CA 93309

Total Western
2811 Fruitvale Avenue
Bakersfield, CA 93308

Baker Hughes
3901 Fanucchi Way
Shafter, CA 93263

Golden Gate University School of Law
Environmental Law and Justice Clinic,
Attn: Lucas Williams, Susann Bradford
536 Mission Street
San Francisco, CA 94105

Schlumberger Oilfield Services
2157 Mohawk Street
Bakersfield, CA 93308

Nabors Completion & Production
3651 Pegasus Drive, Suite 101
Bakersfield, CA 93308

California State University Bakersfield
Dr. Lynette Zelezny, Ph.D., M.B.A.
President
Mail Stop: 33BCD
9001 Stockdale Highway
Bakersfield, CA 93311

Center for Biological Diversity
Ann K. Brown
Open Government Coordinator
P.O. Box 11374
Portland, OR 97211-0974

Kern Economic Development Corp
Richard Chapman, President & CEO
2700 M Street, Suite 200,
Bakersfield, CA 93301

Dolores Huerta Foundation
Dolores Huerta, President
P.O. Box 2087
Bakersfield, CA 93303

Dolores Huerta Foundation
Camila Chavez, Executive Director
P.O. Box 2087
Bakersfield, CA 93303

Kern Community College District
Dr. Sonya Christian, Chancellor
2100 Chester Avenue
Bakersfield, CA 93301

Kern Community College District
Bonita Steele, Ed. D
Director, Programs and Program Development
2100 Chester Avenue
Bakersfield, CA 93301

City of Bakersfield
Mayor Karen Goh
Office of the Mayor
1501 Truxtun Avenue
Bakersfield, CA 93301

Governor's Office of Business and Economic Development
Dee Dee Myers, Senior Advisor & Director
1325 J Street, 18th Floor
Sacramento, CA 95814

California Natural Resources Agency
Wade Crowfoot, Secretary for Natural Resources
715 P Street, 20th Floor
Sacramento, CA 95814

California Workforce Development Board
Tim Rainey, Executive Director
800 Capitol Mall, Suite 1022
Sacramento, CA 95814

California State Senate
Senator Melissa Hurtado, 14th District
State Capitol
Sacramento, CA 95814

Large Scale Solar Association
Shannon Eddy, Executive Director
2501 Portola Way
Sacramento, CA 95818

Kern County Farm Bureau
Patty Poire, Board President
1800 30th Street, Suite 390
Bakersfield, CA 93301

Kern County Farm Bureau
Romeo Agbalog, Executive Director
1800 30th Street, Suite 390
Bakersfield, CA 93301

Employers' Training Resource
Teresa Hitchcock, Assistant CAO
1600 East Belle Terrace
Bakersfield, CA 93307

Greater Bakersfield Chamber of Commerce
Nick Ortiz, President & CEO
1725 Eye Street
Bakersfield, CA 93301

International Brotherhood of Electrical Workers
Brian Holt, Business Manager/Financial Secretary
3921 Sillect Avenue
Bakersfield, CA 93308

Tejon Indian Tribe
Octavio Escobedo, Tribal Chair
P.O. Box 640
Arvin, CA 93203

Building Trades Council
Kern, Inyo, & Mono Counties, AFL-CIO
John Spaulding, Executive Secretary
200 West Jeffrey Street
Bakersfield, CA 93305-2434

Public Policy Institute of California
PPIC Water Policy Center
Ellen Hanak, Vice President, Senior Fellow, and Director
500 Washington Street, Suite 600
San Francisco, CA 94111

Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
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Fax: (661) 862-8601 **TTY Relay 1-800-735-2929**
Email: planning@kerncounty.com
Web Address: http://kernplanning.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

DATE: March 4, 2022

TO: Surrounding Property Owners within 1,000 Feet of Project Boundary; and, Interested Parties

FROM: Kern County Planning and Natural Resources Department
2700 "M" Street, Suite 100
Bakersfield, CA 93301

SUBJECT: Notice of Preparation of an Environmental Impact Report – Carbon TerraVault 1 by California Resources Corporation (PP22405)

Dear Sir or Madam:

The Kern County Planning and Natural Resources Department has determined that preparation of an Environmental Impact Report (EIR) is necessary for the proposed project identified below. The purpose of this letter is to notify interested parties and surrounding property owners within 1,000 feet of the project boundaries of this determination. A copy of the Initial Study/Notice of Preparation (IS/NOP) prepared for this proposed project is available for viewing at the following Kern County website:

https://kernplanning.com/planning/notices-of-preparation/

The purpose of the IS/NOP is to describe the proposed project, specify the project location, and to identify the potential environmental impacts of the project so that Responsible Agencies and interested persons can provide a meaningful response related to potential environmental concerns that should be analyzed in the Environmental Impact Report.

You are invited to view the NOP and submit written comments regarding the scope and content of the environmental information in connection with the proposed project should you wish to do so. Due to the limits mandated by State law, your response must be received by **April 4, 2022 at 5:00 p.m**. Comments can be submitted to the Kern County Planning and Natural Resources Department at the address shown above or to hooverc@kerncounty.com. A Scoping meeting will be held on **Friday, March 18, 2022 at 1:30 p.m.**, at the address listed above.

Please be advised that any comments received after the dates listed above will still be included in the public record for this project and made available to decision makers when this project is scheduled for consideration at a public hearing. Please also be advised that you will receive an additional notice in the mail once a public hearing date is scheduled for this project. You will also be provided additional opportunities to submit comments at that time.

PROJECT TITLE: Carbon TerraVault 1 (CTV 1) by California Resources Corporation (PP22405); PLN21-01378: ZCC No. 5, Map No. 119; CUP No. 5, Map No. 119

PROJECT LOCATION: Central Valley portion of unincorporated Kern County, west side of Elk Hills Road and north side of Skyline Road, within the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield, approximately 8.5 miles from the City of Taft, and approximately 4 miles from the unincorporated community of Buttonwillow, also being located within sections 7, 8, 9, 10, 13, 15, 16, 17,

18, and 26 of Township 30 South, Range 23 East, Mount Diablo Base and Meridian (MDBM), County of Kern, State of California.

PROJECT DESCRIPTION: The proposed project is a Conditional Use Permit for a 5,745.44 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells, and related improvements for storage of Carbon Dioxide (CO_2). The project, Carbon TerraVault 1 (CTV 1), is a wholly owned subsidiary of California Resources Corporation, the applicant for the project.

Implementation of the project as proposed includes the following requests:

a) Zone Change Case # 5, Map 119:From A-1 (Limited Agriculture) to A (Exclusive Agriculture) on approximately 4,465 acres; and

b) Issuance of Conditional Use Permit #5, Map 119 to allow for the construction and operation of a 5,745.44-acre carbon capture and sequestration field and accessory infrastructure with a CO_2 storage capacity of 48 million metric tons, within the A (Exclusive Agriculture) Zone District. Carbon Capture and Sequestration (CCS) has been determined to be a storage operation under the Kern County Zoning Ordinance, Section 19.08.085 and Section 19.06.020. Therefore, CCS in either existing formations or tanks is an allowed use with a Conditional Use Permit (CUP) in the following districts:

   - A District (Exclusive Agriculture)
   - M-2 District (Medium Industrial)
   - M-3 (Heavy Industrial)

Should you have any questions regarding this project, or the Initial Study/Notice of Preparation, please feel free to contact me at (661) 862-8629 or hooverc@kerncounty.com

Sincerely,

Cindi Hoover, Supervising Planner
Advanced Planning Division

Attachments: Figure 2 – Local Vicinity Map

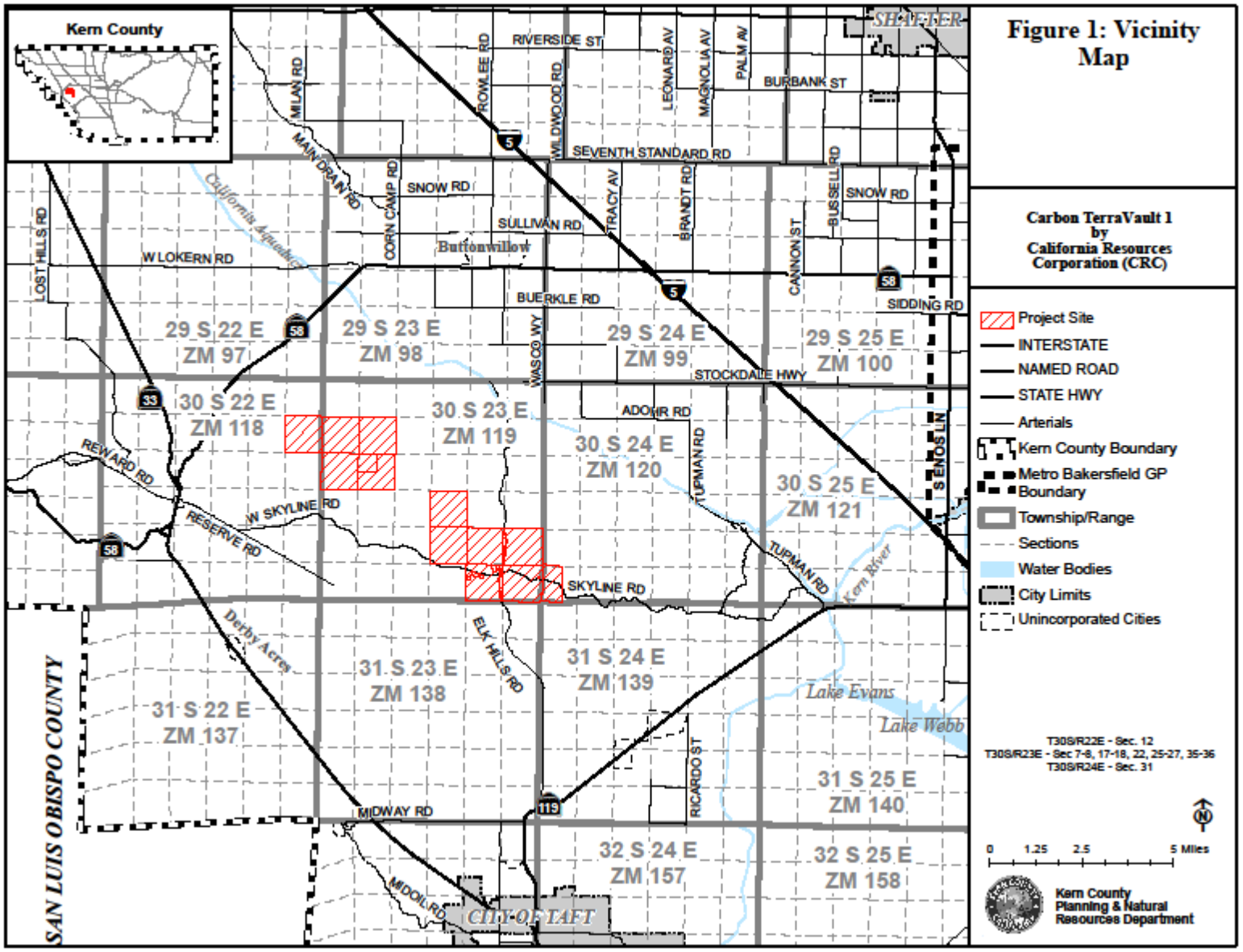

Figure 1: Regional Vicinity Map

Carbon TerraVault 1 Project

Carbon TerraVault1
ZCC 5, Map 119; CUP 5, Map 119
APN Labels

158 010 06 00 1
CENTER FOR NATURAL LANDS MANAGEMENT
27258 VIA INDUSTRIA # B
TEMECULA CA 92590-3751

158 090 16 00 4
ELK HILLS POWER LLC
PO BOX 27570
HOUSTON TX 77227-7570

158 010 23 00 0
BALDERAS REV TR
18053 ERWIN ST
ENCINO CA 91316-7116

158 080 09 00 1
CALIFORNIA RESOURCES ELK
272000 TOURNEY RD STE 200
SANTA CLARITA CA 91355-4910

157 010 02 00 2
CHEVRON USA INC
P O BOX 1392
BAKERSFIELD CA 93302-1392

158 010 07 00 4
GARRARD MELODY
PO BOX 4456
PALM SPRINGS CA 92263-4456

157 060 02 00 7
CALIFORNIA RESOURCES ELK HILLS LLC
27200 TOURNEY RD STE 200
SANTA CLARITA CA 91355-4910

158 040 07 00 3
CHEVRON USA INC
PO BOX 1392
BAKERSFIELD CA 93302-1392

158 010 05 00 8
MILLER MELVIN E & JACQULYN TRS
2872 STANBRIDGE AV
LONG BEACH CA 90815-1059

Notice of Completion & Environmental Document Transmittal

Mail to: State Clearinghouse, P. O. Box 3044, Sacramento, CA 95812-3044 (916) 445-0613
For Hand Delivery/Street Address: 1400 Tenth Street, Sacramento, CA 95814

SCH # _____

Project Title: Carbon TerraVault 1 by California Resources Corporation (CRC)

Lead Agency: Kern County Planning and Natural Resources Department — Contact Person: Cindi Hoover

Mailing Address: 2700 "M" Street Suite 100 — Phone: (661) 862-8629

City: Bakersfield — Zip: 93301 — County: Kern

Project Location: County: Kern — City/Nearest Community: City of Taft, Community of Buttonwillow

Cross Streets: Skyline Road and Elk Hills Road — Zip Code: 93251

Lat. / Long.: 35° 19.51567' N, 119° 31.11937' W — Total Acres: 5,745.44

Assessor's Parcel No.: Multi — Section: Multi — Twp.: 30 S — Range: 23 E — Base: MDB&M

Within 2 Miles: State Hwy #: 58 W — Waterways: California Aqueduct

Airports: Elk Hills – Buttonwillow Airport — Railways: N/A — Schools: N/A

Document Type:

CEQA: ☒ NOP ☐ Early Cons ☐ Neg Dec ☐ Mit Neg Dec ☐ Draft EIR ☐ Supplement/Subsequent EIR (Prior SCH No.) _____ ☐ Other _____

NEPA: ☐ NOI ☐ EA ☐ Draft EIS ☐ FONSI

Other: ☐ Joint Document ☐ Final Document ☐ Other _____

Local Action Type:

☐ General Plan Update ☐ General Plan Amendment ☐ General Plan Element ☐ Community Plan
☐ Specific Plan ☐ Master Plan ☐ Planned Unit Development ☐ Site Plan
☒ Rezone ☐ Prezone ☒ Use Permit ☐ Land Division (Subdivision, etc.)
☐ Annexation ☐ Redevelopment ☐ Coastal Permit ☐ Other:

Development Type:

☐ Residential: Units _____ Acres _____
☐ Office: Sq.ft. _____ Acres _____ Employees _____
☐ Commercial: Sq.ft. _____ Acres _____ Employees _____
☐ Industrial: Sq.ft. _____ Acres _____ Employees _____
☐ Educational _____
☐ Recreational _____
☐ Water Facilities: Type _____ MGD _____
☐ Transportation: Type _____
☐ Mining: Mineral _____
☐ Power: Type _____ MW _____
☐ Waste Treatment: Type _____ MGD _____
☐ Hazardous Waste: Type _____
☒ Other: Carbon Capture and Sequestration

Project Issues Discussed in Document:

☒ Aesthetic/Visual
☒ Agricultural Land
☒ Air Quality
☒ Archeological/Historical
☒ Biological Resources
☐ Coastal Zone
☒ Drainage/Absorption
☒ Economic/Jobs
☐ Fiscal
☒ Flood Plain/Flooding
☒ Forest Land/Fire Hazard
☒ Geologic/Seismic
☒ Minerals
☒ Noise
☒ Population/Housing Balance
☒ Public Services/Facilities
☒ Recreation/Parks
☒ Schools/Universities
☒ Septic Systems
☒ Sewer Capacity
☒ Soil Erosion/Compaction/Grading
☒ Solid Waste
☒ Toxic/Hazardous
☒ Traffic/Circulation
☒ Vegetation
☒ Water Quality
☒ Water Supply/Groundwater
☒ Wetland/Riparian
☒ Wildlife
☒ Growth Inducing
☒ Land Use
☒ Cumulative Effects
☒ Other GHG, Wildfire, Tribal Cultural Resources, Energy

Present Land Use/Zoning/General Plan Designation: Oil and Gas Exploration and Production/*Zoning:* A (Exclusive Agriculture); A-1 (Limited Agriculture)/*General Plan:* 8.3 (extensive Agriculture); 8.3/2.1 (Extensive Agriculture & Seismic Hazard); 8.4 (Mineral and Petroleum)

Project Description: The Carbon TerraVault 1 Project, as proposed by California Resources Corporation would develop an approximate 5,745 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells, and related improvements for storage of Carbon Dioxide (CO_2). The proposed project would take local industrial sources of CO_2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project. Potential sources and locations of sources will be specifically identified and analyzed to the extent legally required by CEQA in the Draft EIR. The CO_2 would then be injected into identified geographically confined reservoirs for storage in perpetuity. This area has been identified as a location suitable for such storage and a potential to provide a contribution to the goals of California for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter. The project, as proposed, has the capacity for up to 40 million metric tons of estimated storage and capable of sequestrating over 1 million metric tons of CO_2 per year.

Reviewing Agencies Checklist

Lead Agencies may recommend State Clearinghouse distribution by marking agencies below with and "**X**".
If you have already sent your document to the agency please denote that with an "**S**".

S	Air Resources Board	X	Office of Emergency Services
	Boating & Waterways, Department of		Office of Historic Preservation
	California Highway Patrol		Office of Public School Construction
X	CalFire		Parks & Recreation
S	Caltrans District # 6		Pesticide Regulation, Department of
S	Caltrans Division of Aeronautics		Public Utilities Commission
	Caltrans Planning (Headquarters)	S	Regional WQCB # Central
	Central Valley Flood Protection Board	S	Resources Agency
	Coachella Valley Mountains Conservancy		S.F. Bay Conservation & Development Commission
	Coastal Commission		San Gabriel & Lower L.A. Rivers and Mtns Conservancy
	Colorado River Board		San Joaquin River Conservancy
S	Conservation, Department of		Santa Monica Mountains Conservancy
	Corrections, Department of		State Lands Commission
	Delta Protection Commission		SWRCB: Clean Water Grants
	Education, Department of	X	SWRCB: Water Quality
S	Energy Commission		SWRCB: Water Rights
S	Fish & Game Region # Fresno		Tahoe Regional Planning Agency
	Food & Agriculture, Department of	S	Toxic Substances Control, Department of
	General Services, Department of	S	Water Resources, Department of
	Health Services, Department of		
	Housing & Community Development		Other _____
	Integrated Waste Management Board		Other _____
X	Native American Heritage Commission		

Local Public Review Period (to be filled in by lead agency)

Starting Date March 4, 2022 Ending Date April 4, 2022

Lead Agency (Complete if applicable):

Consulting Firm: _____
Address: _____
City/State/Zip: _____
Contact: _____
Phone: _____

Applicant: _____
Address: _____
City/State/Zip: _____
Phone _____

Signature of Lead Agency Representative: /s/ **Date:** 03/04/2022

Cindi Hoover, Supervising Planner

Authority cited: Section 21083, Public Resources Code. Reference: Section 21161, Public Resources Code.

NOTICE OF PREPARATION/INITIAL STUDY CHECKLIST

Carbon TerraVault 1 Project
by California Resources Corporation

Zone Classification Change No. 5, Map No. 118
Zone Classification Change No. 5, Map No. 119
Zone Classification Change No. 4, Map No. 120
Conditional Use Permit No. 13, Map No. 118
Conditional Use Permit No. 5, Map No. 119
Conditional Use Permit No. 3, Map No. 120

PLN21-01378
(PP22405)

LEAD AGENCY:

Kern County Planning and Natural Resources Department
2700 M Street, Suite 100
Bakersfield, CA 93301-2370

Contact: Cindi Hoover
(661) 862-8629
hooverc@kerncounty.com

March 2022

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INTRODUCTION

Pursuant to the California Environmental Quality Act (CEQA), the Kern County Planning and Natural Resources Department (County) will initiate the preparation of an Environmental Impact Report (EIR) for the Carbon TerraVault 1 Carbon Capture and Sequestration Project in the unincorporated area of western Kern County, California.

Project Description

Project Location

The proposed Carbon TerraVault 1 Carbon Capture and Sequestration Project (proposed project) is a proposal by Carbon TerraVault 1, LLC (CRC) (project proponent) to construct and operate a carbon capture and sequestration (CCS) field on approximately 5,332 acres of privately owned land. The CCS field would include four to six injection wells and associated infrastructure, capable of storing approximately 48 million metric tons of Carbon Dioxide (CO_2) within identified geographically confined reservoirs.

The project site is located in the Central Valley portion of unincorporated Kern County, on the west side of Elk Hills Road and the north side of Skyline Road, within the administrative boundary of the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield (pop. 413,098) , approximately 8.5 miles from the City of Taft (pop 8945), and approximately 4 miles from the unincorporated community of Buttonwillow (pop. 1443), also being located within Sections 7,8,9,10,13,15,16,17,18,26 of Township 30 South, Range 23 East, Mount Diablo Base and Meridian (MDBM), County of Kern, State of California. Please see *Figure 1: Regional Vicinity Map.*

The project site is made up of ten (10) privately owned parcels totaling approximately 5,332 acres of land, predominately developed with oil and gas production and accessory facilities and infrastructure. Please see *Figure 2: Existing Parcel Map.* The total study area for this project includes the entirety of the confined reservoir proposed for CO_2 sequestration.

Primary access to the project site would be via existing access at the western intersection of Skyline Drive and Elk Hills Road. The access road connects to a network of existing dirt roads within the field, depending on the final locations of the injection wells and accessory facilities and infrastructure new internal access roads may be constructed. These new roads would most likely be compacted dirt roads as well. Please see *Figure 3: Aerial Photograph.*

Environmental Setting

The proposed project is located on approximately 5,332acres of privately-owned land located in the south-western extent of Kern County, California. Portions of the project site is located within the boundaries of Agricultural Preserve No. 3, however none of the parcels are currently subject to a Williamson Act Land Use Contract. The project is in the administrative boundary of the Elk Hills Oil Field and the United States Geological Survey (USGS) Elk Hills and West Elk Hills 7.5-minute topographical quadrangle. Development in the area surrounding the project site is predominantly oil and gas production and agricultural.

The project site is within the San Joaquin Valley Air Basin, under the regulatory authority of the San Joaquin Valley Air Pollution Control District. The Federal Emergency Management Agency (FEMA) delineates flood hazard areas on its Flood Insurance Rate Maps (FIRMs). According to the FIRMs for the project area, the project site is designated Flood Zone X; which indicates the site is outside of the 0.2% annual chance floodplain.

The project site is not designated by the California Department of Conservation (DOC) as Prime Farmland, Farmland of Statewide Importance, or Unique Farmland. The project site is designated *Urban Built-Up Land* and *Vacant or Disturbed Land*. Please see *Figure 4: Important Famland.* There is land designated as Non-Prime Farmland, which is subject to a Williamson Act land Use Contract, immediately adjacent to the west of the project site. Please see *Figure 5: Williamson Act Land*

The project site is not within a mineral recovery area, however seven parcels are within designated mineral and petroleum resource site designated by the Kern County General Plan. The project site is not located within the County's NR (Natural Resources) or PE (Petroleum Extraction) Zone Districts. *Table 1: Project Assessor Parcel Numbers, Existing Map Codes, Existing* Zoning, *and Acreage*, below identifies the individual parcels, their respective assessor parcel numbers (APN), acreages, and existing general plan and zoning designations. Please see *Figure 6: Existing General Plan Designations*, and *Figure 7: Existing Zoning Classifications*.

Table 1: Project Assessor Parcel Numbers, Existing Map Codes, Existing Zoning, and Acreage

APN	Existing Map Code Designation	Existing Zoning	Proposed Zoning	Section/Township / Range	Acres	Agricultural Preserve Inclusion
157-060-02	8.4	A	A	12/30 S/R 22 E	159.50*	Ag Preserve No. 3
158-040-07	8.3/2.1	A	A	7/ 30 S/R 23 E	642.85	Ag Preserve No. 3
158-040-06	8.4	A-1	A	8/30 S/R 23 E	641.20	
158-070-02	8.3	A-1	A	17/30 S/R 23 E	156.44	
158-070-03	8.4	A-1	A	17/ 30 S/R 23 E	154.38*	
158-070-01	8.4	A-1	A	18/ 30 S/R 23 E	319.06*	
158-080-06	8.4	A-1	A	22/ 30 S/R 23 E	160.89*	
158-090-03	8.3	A-1	A	25/ 30 S/R 23 E	340.82*	
158-090-02	8.4	A-1	A	26/ 30 S/R 23 E	637.78	
158-090-01	8.4	A-1	A	27/ 30 S/R 23 E	637.54	
158-090-19	8.4; 8.3/2.1	A	A	35/ 30 S/R 23 E	637.89	Ag. Preserve 3
158-090-04	8.4	A	A	36/ 30 S/R 23 E	683.74	Ag Preserve 3
159-280-07	8.4	A-1	A	31/ 30 S/R 24 E	160.15*	
Project Totals					5,332.34	

* = Represents a portion of total APN acreage.

General Plan Map Code:

8.3 = Extensive Agriculture (Min. 20 Acre Parcel Size)
8.4 = Mineral and Petroleum
2.1 = Seismic Hazard Overlay
2.4 = Steep Slope Overlay

Zone Designation:

A = Exclusive Agriculture
A-1 = Limited Agriculture

Surrounding Land Uses

Table 2, Existing Project Site and Surrounding Properties, Existing Land Use, General Plan Map Code Designations, and Zoning, identifies the existing land use, the existing general plan land use designation, and the existing zoning for each of the two parcels within the project site. Additionally, such conditions are described for adjacent lands to the north, east, south, and west of the project site.

Table 2: Existing Project Sites and Surrounding Properties, Existing Land Use, General Plan Map Code Designations, and Zoning

Location	Existing Land Use	Existing General Plan Map Code Designations	Existing Zoning
Project Site	**Oil and Gas Exploration and Production**	**8.3 (Extensive Agriculture; 8.3/ 2.1 (Extensive Agriculture Seismic Hazard Overlay) 8.4 (Mineral and Petroleum)**	**A (Exclusive Agriculture) A-1 (Limited Agriculture)**
North	Oil and Gas Exploration and Production; Oil and Gas Ancillary Services Undeveloped Private Lands; Elk Hills/Buttonwillow Airport Landing	8.3 (Extensive Agriculture); 8.3/2.1 (Extensive Agriculture and Seismic Hazard); 8.4 (Mineral and Petroleum); 1.1 (State or Federal Land)	A (Exclusive Agriculture); A-1 (Limited Agriculture); PL RS MH (Platted Lands, Residential Suburban Combining, Mobile home Combining); AH (Exclusive Agriculture, Airport Approach Height Combining)
South	Oil and Gas Exploration and Production	8.4 (Mineral and Petroleum)	A-1 (Limited Agriculture)
East	Oil and Gas Exploration and Production	8.3 (Extensive Agriculture); 8.4 (Mineral and Petroleum)	A (Exclusive Agriculture); A-1 (Limited Agriculture); A-1 H (Limited Agriculture, Airport Approach Height Combining)
West	Oil and Gas Exploration and Production	8.3 (Extensive Agriculture); 8.3/2.1 (Extensive Agriculture and Seismic Hazard); 8.4 (Mineral and Petroleum)	A (Exclusive Agriculture)

Existing land use in the vicinity of the project site generally includes oil and gas exploration and production and agricultural lands. The sensitive receptor closest to the project site is the rural residence approximately 1 mile to the south of the project site. Lost Hills Wonderful Park, a local park, is located approximately 14 miles southeast of the project site. The closest schools to the site are the McKittrick Elementary School and the Buttonwillow Elementary School, located approximately 4.5 miles southwest and north, respectively, of the project site. The Elk Hills Elementary is located approximately 6 miles east of the project site.

The proposed project would be served by the Kern County Sheriff's Department for law enforcement and public safety services, with the closest substation being the Taft Area Substation, located at 315 N. Lincoln Street. Fire protection and emergency medical services would be provided by the Kern County Fire Department, with the closest station being Fire Station #25, located at 100 Mirasol Avenue, and Kern County Emergency Medical Services for medical care and emergency services.

The nearest public airport to the project site is the Elk Hills - Buttonwillow Airport located adjacent to the northeast corner of the project. The portion of the project site is located within Zone C of the Elk Hills-Buttonwillow Airport Land Use Compatibility Plan (ALUCP).

Project Description

Project Overview

The proposed project is a Conditional Use Permit for a 5,332.34 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells and related improvements for storage of Carbon Dioxide (CO_2). The project, Carbon TerraVault 1 (CTV 1), is a wholly owned subsidiary of California Resources Corporation, the applicant for the project. The project comprises the area shown in *Table 1: Project Assessor Parcel Numbers, Existing Map Codes, Existing* Zoning, *and Acreage, above.*

The proposed project site is located within the Elk Hills Oil Field which comprises an approximately 75- square mile (47,800 acre) complex, with surface and mineral rights privately held by CRC, in the San Joaquin Valley of unincorporated Kern County. The surrounding area is comprised of agricultural fields, both active and fallow, and other existing oilfields. They include the Midway – Sunset Oil Field, McKittrick Oilfield and Cymric Oil Field. Skyline Road is closed to public entry and is the southern boundary of the project. Skyline Road connects to Elk Hills Road, which connects the town of Taft, to the south, with Buttonwillow to the north. California Resource Corporation's gated and guarded entrance to the field is located at the western intersection of Skyline Drive and Elk Hills Road

The proposed project would take local industrial sources of CO_2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project. The CO_2 would then be injected into identified geographically confined reservoirs for storage in perpetuity. This area has been identified as a location suitable for such storage and a potential to provide a contribution to the goals of California for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter. (https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/). The project, as proposed, has the capacity for up to 48 million metric tons of estimated storage and capable of sequestrating in excess of 1.5 million metric tons of CO_2 per year.

Implementation of the project would require permits from the Federal Environmental Protection Agency (EPA) for up to six (6) Class VI injection wells in compliance with the UIC program Class VI geologic sequestration regulations. Location of the proposed Class VI injection wells will be within the proposed CUP boundary of 5,332.34 acres. All employee facilities needed to manage the project will be provided by the existing Elk Hills oil field facilities.

Implementation of the project as proposed includes the following requests:

- Zone Classification Change (ZCC No. 5, Map No. 118; ZCC No. 5, Map No. 119; ZCC No. 4, Map No. 120) from A-1 (limited Agriculture) Zone District to A (Exclusive Agriculture) Zone District on approximately 3,208 acres. See *Figure 8: Proposed Zoning Classification*

- Conditional Use Permit (CUP No. 13, Map No. 118; CUP No. 5, Map No. 119; CUP No. 3, Map No. 120) to allow for the construction and operation of a Carbon capture and sequestration field, within the A (Exclusive Agriculture) Zone District. Carbon Capture and Sequestration (CCS) has been determined to be a storage operation under the Kern County Zoning Ordinance, Section 19.08.085 and Section 19.06.020. Therefore, CCS in either existing formations or tanks is an allowed use with a Conditional Use Permit (CUP) in the following districts:

    - A District (Exclusive Agriculture)
    - M-2 District (Medium Industrial)
    - M-3 (Heavy Industrial)

Project Objectives

The project proponent had defined the following objectives for the project:

- Construct and operate a permanent underground storage facility for up to 48 million tons of Carbon Dioxide (CO_2) in an economically feasible manner.
- Contribute to California Resources Corporation (CRC) adopted goals of Full-Scope Net Zero emission for Scope 1, 2 and 3 emissions by 2045.
- Support California's Executive Order B-55-18 for Carbon neutrality by 2045 and net negative emissions thereafter.
- Site and design the project in an environmentally responsible manner consistent with current Kern County guidelines.
- To promote economic development and bring living-wage jobs to the region throughout the life of the proposed project.

Proposed Discretionary Actions/Required Approvals

The Kern County Planning and Natural Resources Department as the Lead Agency (per CEQA Guidelines Section 15052) for the proposed project has discretionary responsibility for the proposed project. To implement this project, the project proponent may need to obtain discretionary and ministerial permits/approvals including, but not limited to, the following:

Federal

- Environmental Protection Agency Underground Injection Control – Class VI Permit
- U.S. Fish and Wildlife Service (USFWS) Section 10 Incidental Take Permit and Habitat Conservation Plan (if required)
- United States Army Corps of Engineers Section 404 Permit (if required)

State

- California Department of Fish and Wildlife (CDFW)
    - Section 2081 Permit (State-listed endangered species) (if required)
- Central Valley Water Quality Control Board (RWQCB)
    - Waste Discharge Requirements
    - Regional Water Quality Certification (401 Permit) (if required)
    - National Pollution Discharge Elimination System (NPDES) Construction General Permit
    - General Construction Stormwater Permit (Preparation of a SWPPP) (if required)
- California Department of Transportation (Caltrans)
    - Right-of-Way Encroachment Permit (if required)
    - Permit for Transport of Oversized Loads (if required)

Local

- **Kern County**
    - Certification of Final Environmental Impact Report
    - Adoption of Mitigation Monitoring and Reporting Program
    - Adoption of 15091 Findings of Fact and 15093 Statement of Overriding Considerations
    - Approval of Zone Classification Change
    - Approval of Conditional Use Permits
    - Approval of Kern County Grading (if required)
    - Approval of Kern County Building Permits
    - Approval of Kern County Encroachment Permits (if required)
    - Approval of Fire Safety Plan
- **San Joaquin Valley Air Pollution Control District**
    - Approval of Fugitive Dust Control Plan
    - Authority to Construct (ATC)
    - Permit to Operate (PTO)

The preceding discretionary actions/approvals are potentially required and do not necessarily represent a comprehensive list of all possible discretionary permits/approvals required. Other additional permits or

approvals from responsible agencies may be required for the proposed project.

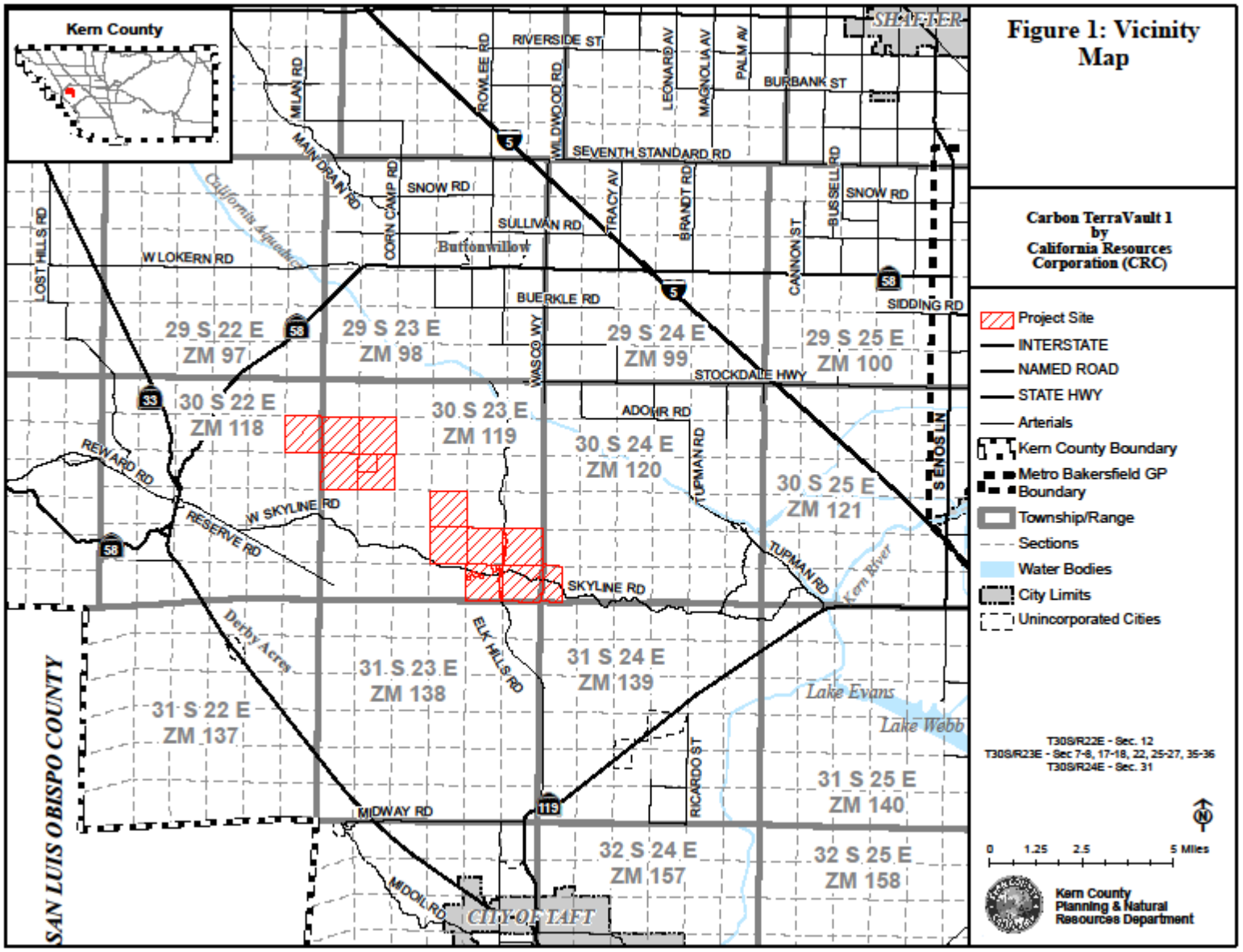


Figure 1: Regional Vicinity Map

Carbon TerraVault 1 Project

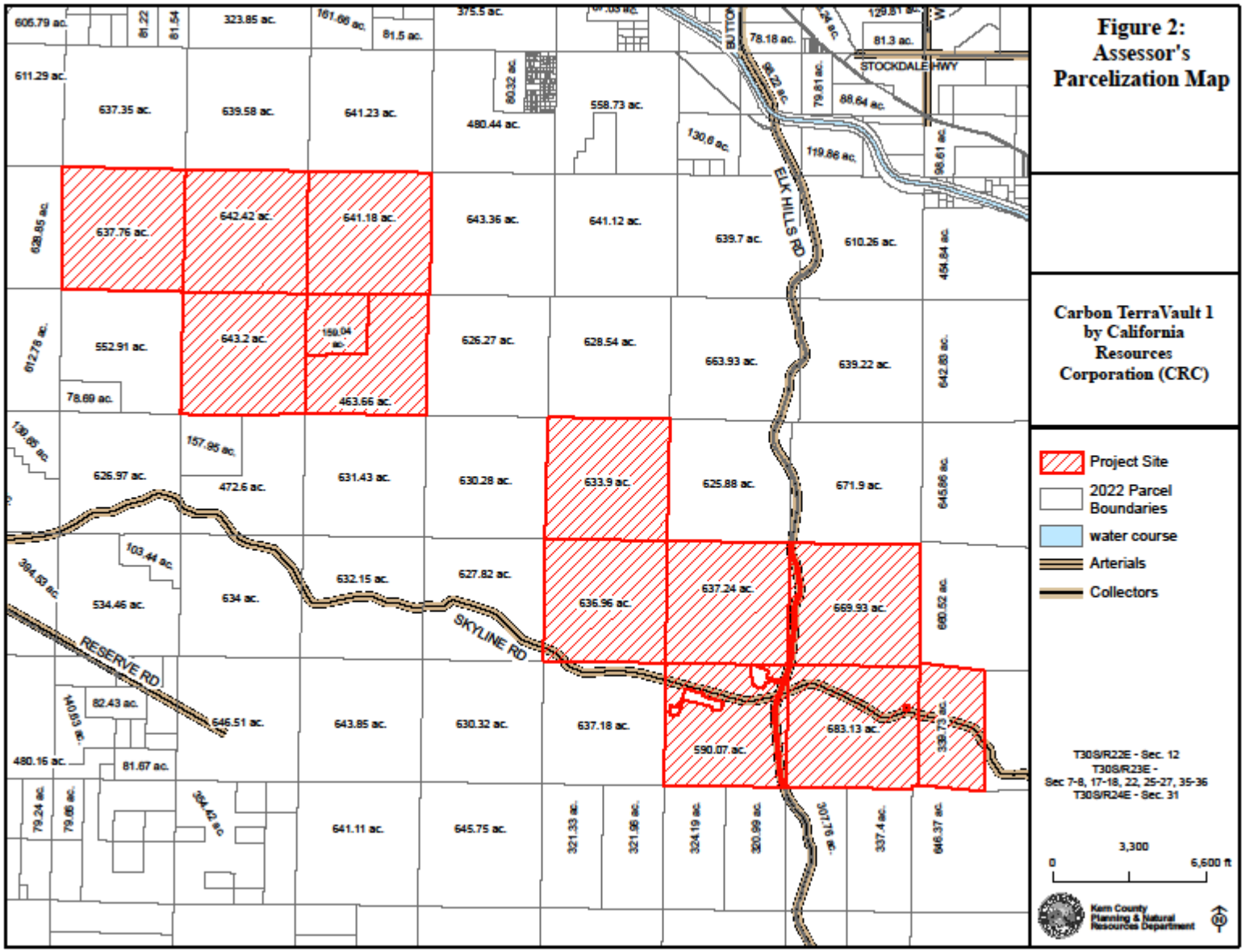
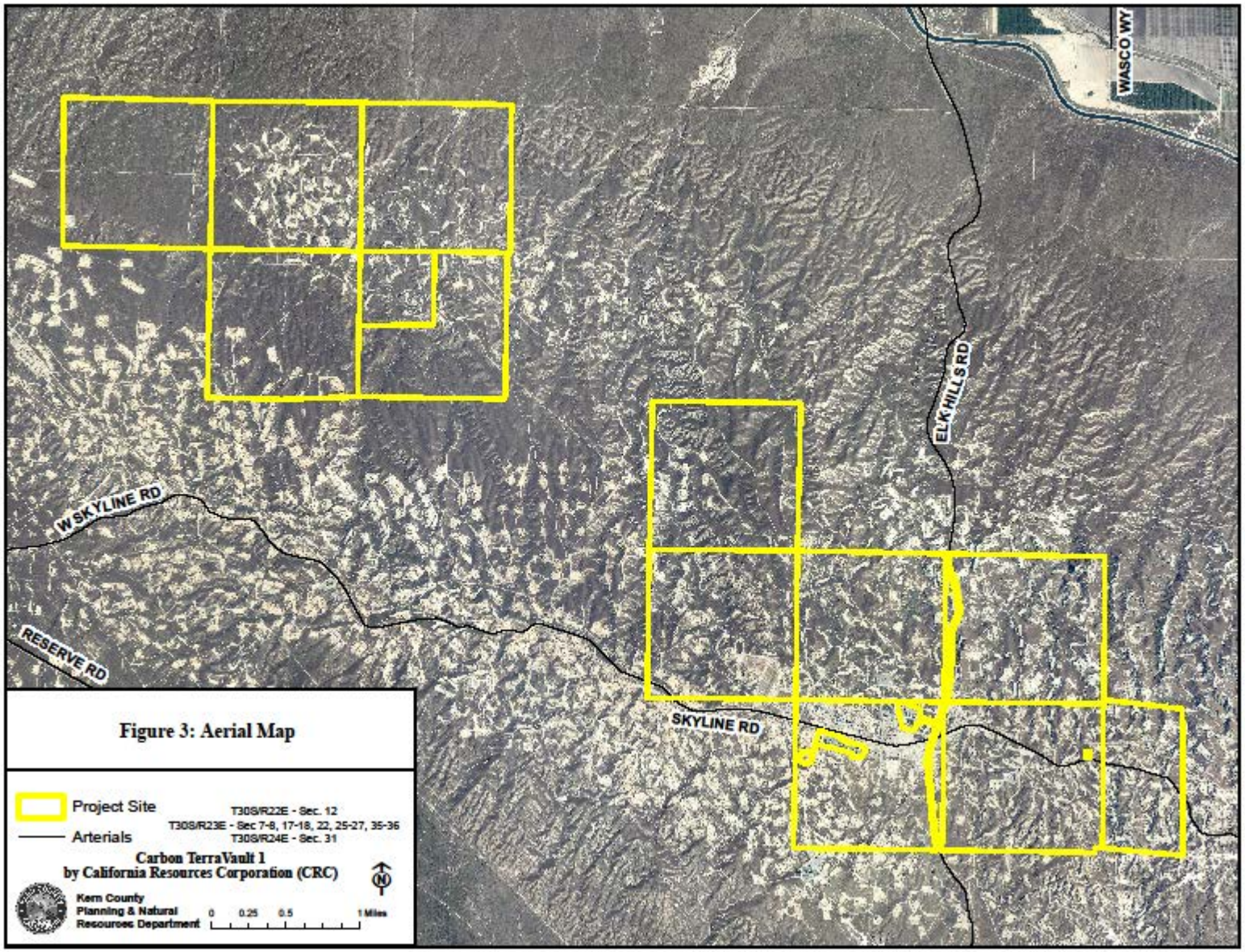


Figure 2: Existing Parcel Map


WASCO WY
ELK HILLS RD
W SKYLINE RD
RESERVE RD
SKYLINE RD
Figure 3: Aerial Map
Project Site
Arterials
T30S/R22E - Sec. 12
T30S/R23E - Sec 7-8, 17-18, 22, 25-27, 35-36
T30S/R24E - Sec. 31
Carbon TerraVault 1
by California Resources Corporation (CRC)
Kern County
Planning & Natural
Resources Department
0 0.25 0.5 1 Miles

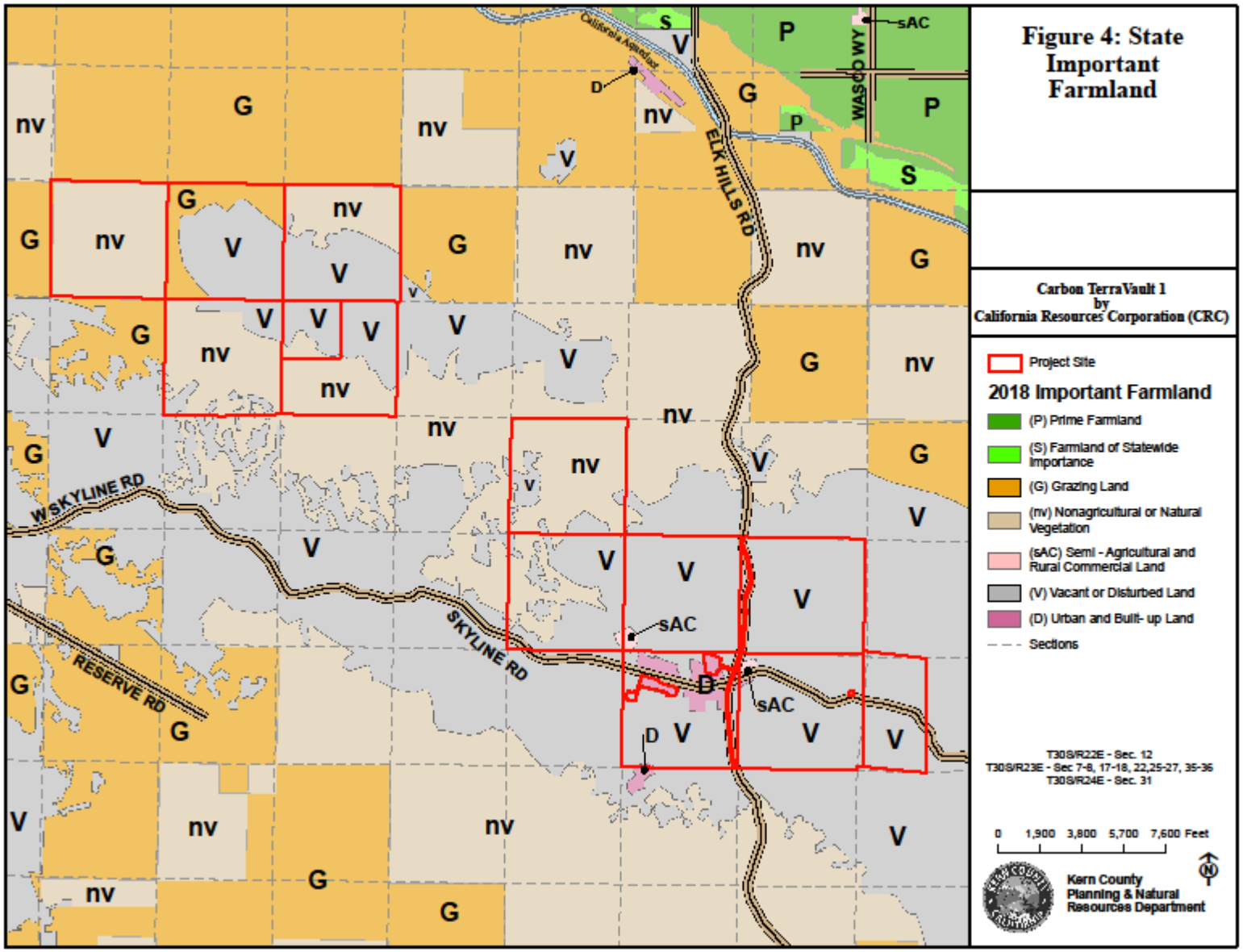


Figure 4: Important Farmland

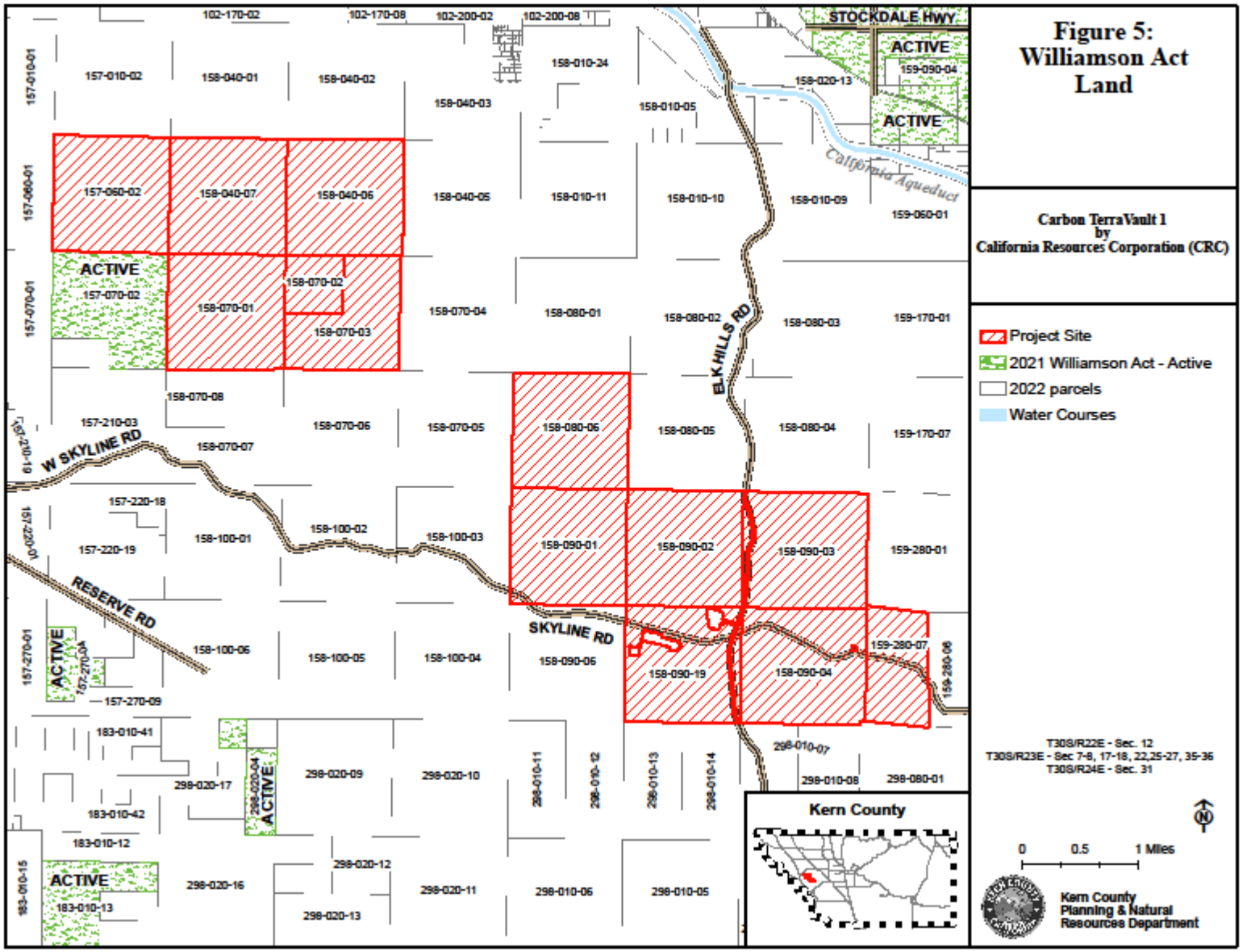


Figure 5: Williamson Act Land

Carbon TerraVault 1 Project

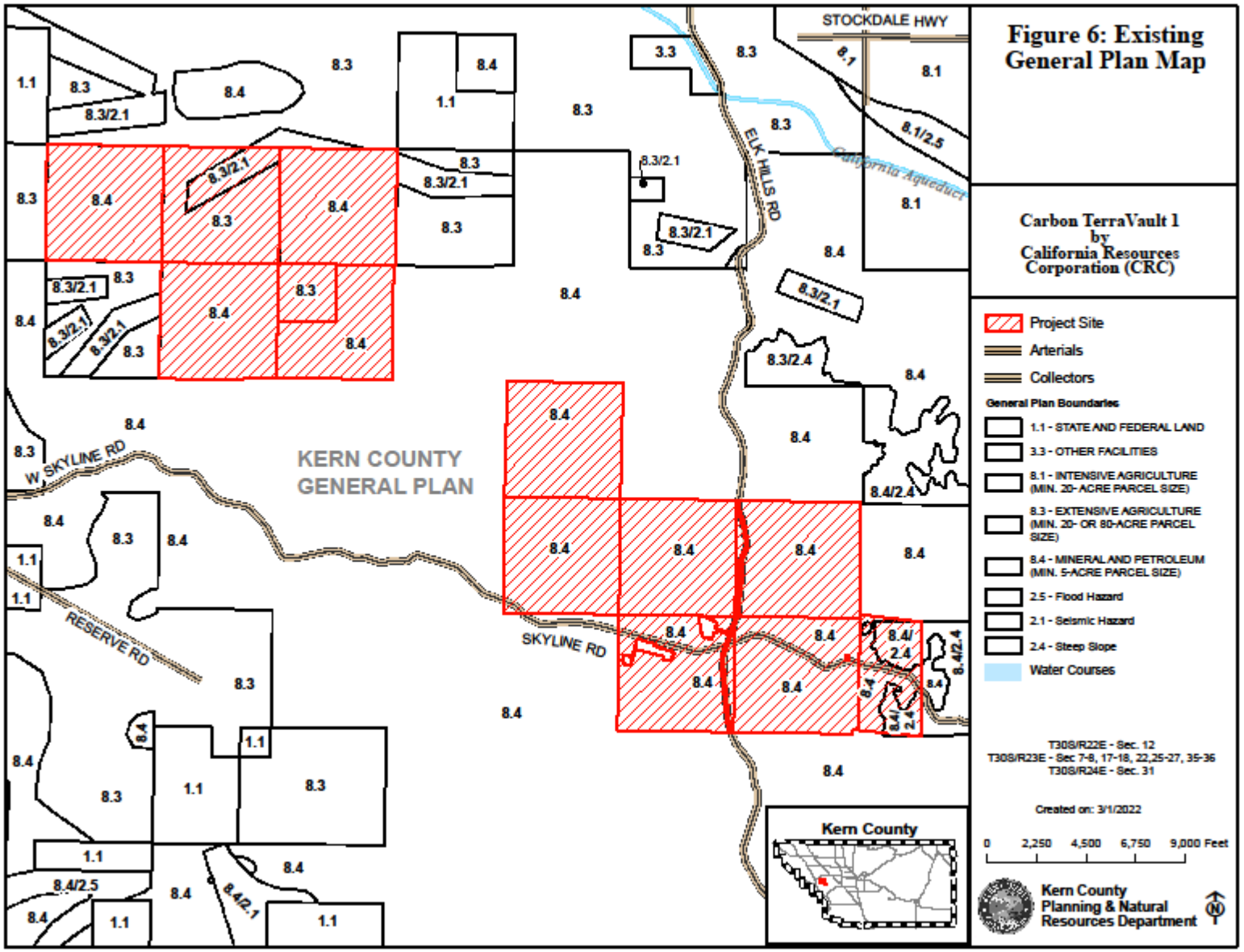


Figure 6: Existing General Plan Designation

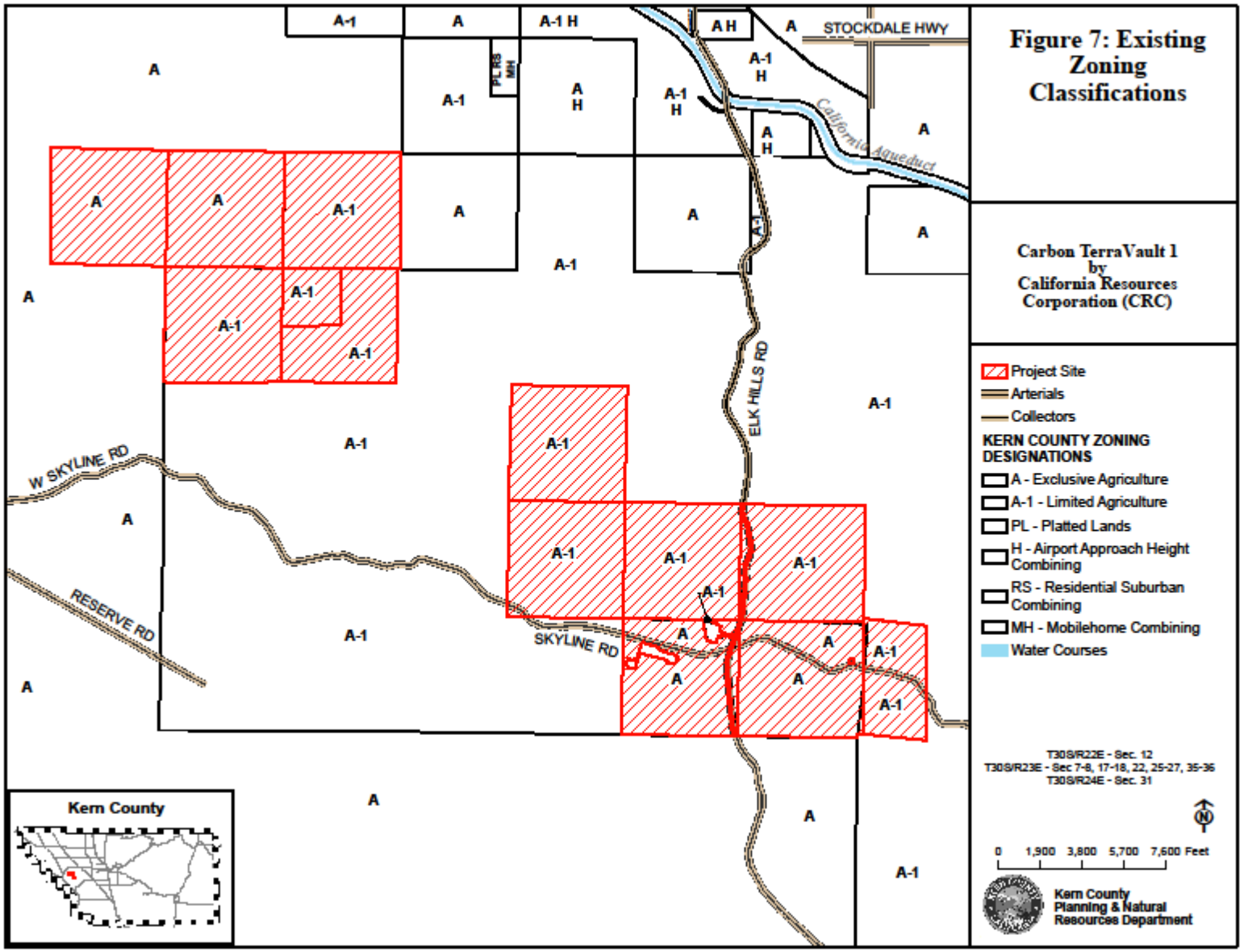


Figure 7: Existing Zoning Classifications

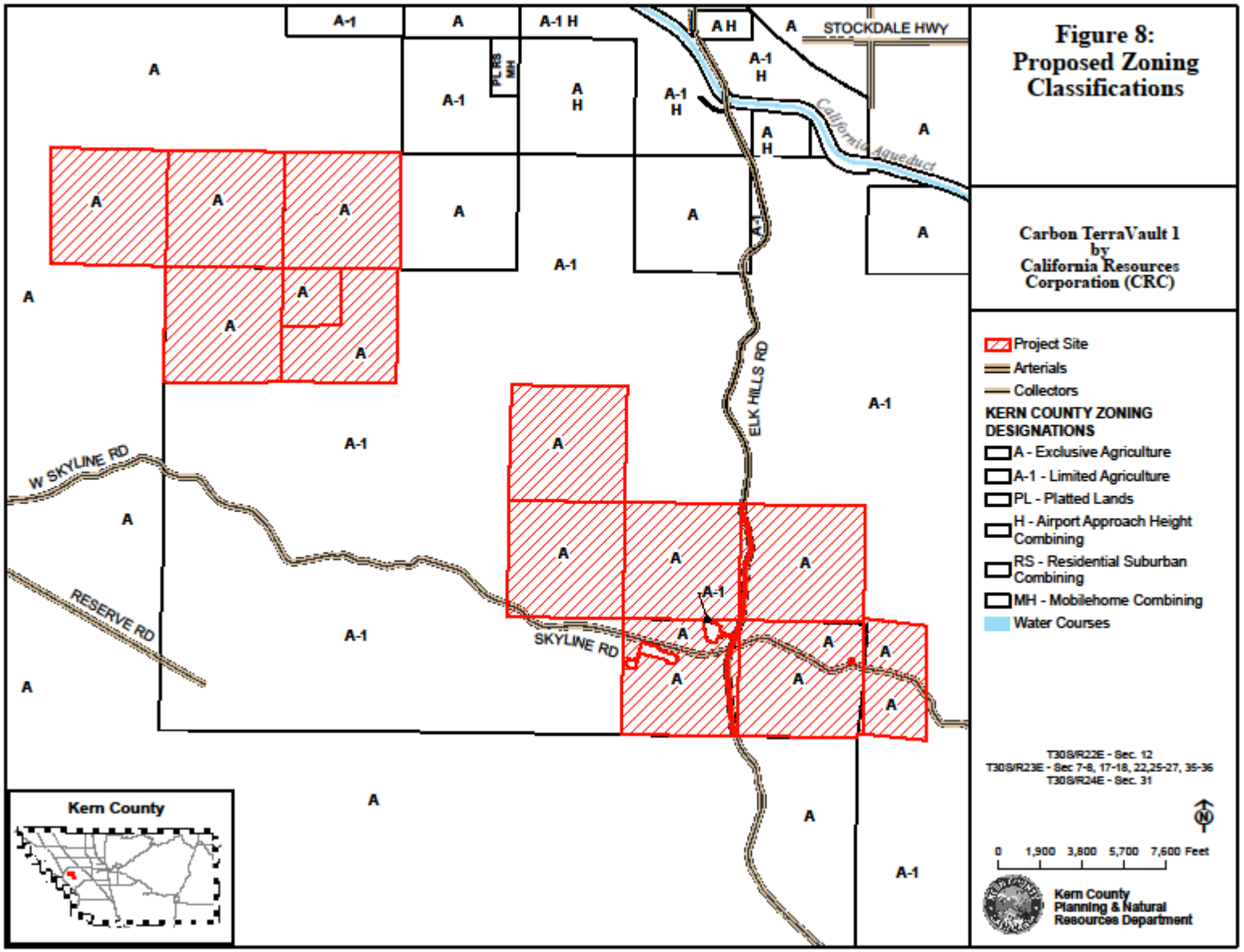


Figure 8: Proposed Zoning Classifications

KERN COUNTY
ENVIRONMENTAL CHECKLIST FORM

Environmental Factors Potentially Affected:

The environmental factors checked below would be potentially affected by this project, involving at least one impact that is a Potentially Significant Impact" as indicated by the checklist on the following pages.

☒ Aesthetics	☒ Agriculture/Forestry	☒ Air Quality
☒ Biological Resources	☒ Cultural Resources	☒ Energy
☒ Geology / Soils	☒ Greenhouse Gas Emissions	☒ Hazards & Hazardous Materials
☒ Hydrology / Water Quality	☒ Land Use /Planning	☒ Mineral Resources
☒ Noise	☒ Population / Housing	☒ Public Services
☒ Recreation	☒ Transportation	☒ Tribal Cultural Resources
☒ Utilities / Service Systems	☒ Wildfire	☒ Mandatory Findings of Significance

DETERMINATION.

On the basis of this initial evaluation:

☐ I find that the proposed project COULD NOT have a significant effect on the environment, and a NEGATIVE DECLARATION will be prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will not be a significant effect in this case because revisions in the project have been made by or agreed to by the project proponent. A MITIGATED NEGATIVE DECLARATION will be prepared.

☒ I find that the proposed project MAY have a significant effect on the environment, and an ENVIRONMENTAL IMPACT REPORT is required.

☐ I find that the proposed project MAY have a "potentially significant impact" or "potentially significant unless mitigated" impact on the environment, but at least one effect (a) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and (b) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENT IMPACT REPORT (EIR) is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier EIR or NEGATIVE DECLARATION pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier EIR or NEGATIVE DECLARATION, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Signature	March 4, 2022 Date
Cindi Hoover Printed Name	Supervising Planner Title

Evaluation of Environmental Impacts:

(1) A brief explanation is required for all answers except "No Impact" answers that are adequately supported by the information sources a Lead Agency cites in the parentheses following each question. A "No Impact" answer is adequately supported if the referenced information sources show that the impact simply does not apply to projects like the one involved (e.g., the project falls outside a fault rupture zone). A "No Impact" answer should be explained where it is based on project-specific factors as well as general standards (e.g., the project will not expose sensitive receptors to pollutants, based on a project-specific screening analysis).

(2) All answers must take account of the whole action involved, including off-site as well as on-site, cumulative as well as project-level, indirect as well as direct, and construction as well as operational impacts.

(3) Once the Lead Agency has determined that a particular physical impact may occur, then the checklist answers must indicate whether the impact is potentially significant, less than significant with mitigation, or less than significant. "Potentially Significant Impact" is appropriate if there is substantial evidence that an effect may be significant. If there are one or more "Potentially Significant Impact" entries when the determination is made, an Environmental Impact Report (EIR) is required.

(4) Negative Declaration: "Less Than Significant With Mitigation Incorporated" applies where the incorporation of mitigation measures has reduced an effect from "Potentially Significant Impact" to a "Less Than Significant Impact." The Lead Agency must describe the mitigation measure and briefly explain how they reduce the effect to a less than significant level.

(5) Earlier analyses may be used where, pursuant to the tiering, program EIR, or other CEQA process, an effect has been adequately analyzed in an earlier EIR or Negative Declaration, Section 15063(c)(3)(D). In this case, a brief discussion should identify the following:

(a) Earlier Analysis Used. Identify and state where they are available for review.

(b) Impacts Adequately Addressed. Identify which effects from the above checklist where within the scope of and adequately analyzed in an earlier document pursuant to applicable legal standards, and state whether such effects were addressed by mitigation measures based on the earlier analysis.

(c) Mitigation Measures. For effects that are "Less Than Significant With Mitigation Measures Incorporated," describe the mitigation measures which were incorporated or refined from the earlier document and the extent to which they address site-specific conditions for the project.

(6) Lead Agencies are encouraged to incorporate into the checklist references to information sources for potential impacts (e.g., general plans, zoning ordinances). Reference to a previously prepared or outside document should, where appropriate, include a reference to the page or pages where the statement is substantiated.

(7) Supporting Information Sources: A source list should be attached, and other sources used or individuals contacted should be cited in the discussion.

(8) The adopted guidelines state " This is only a suggested form, and lead agencies are free to use different formats; however, Lead Agencies should normally address the questions from this checklist that are relevant to a project's environmental effects in whatever format is selected. "Kern County has adopted this format and included all questions from Appendix G.

(9) The explanation of each issue should identify:

(a) The significance criteria or threshold, if any, used to evaluate each question; and

(b) The mitigation measure identified, if any, to reduce the impact to less than significance.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
I. AESTHETICS.				
Would the project:				
a) Have a substantial adverse effect on a scenic vista?	☒	☐	☐	☐
b) Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☒	☐
c) In nonurbanized areas, substantially degrade the existing visual character or quality of public views of the site and its surroundings? (Public views are those that are experienced from publicly accessible vantage points) If the project is in an urbanized area, would the project conflict with applicable zoning and other regulations governing scenic quality?	☒	☐	☐	☐
d) Create a new source of substantial light or glare which would adversely affect daytime or nighttime views in the area?	☒	☐	☐	☐

RESPONSES:

a)–d) The proposed project is located within the Elk Hills Oil Field which is heavily developed with oil wells and associated infrastructure. The aesthetic features of the existing visual environment in the area are varied with agricultural and oil production/extraction equipment dominating the landscape. As such, there are no unique aesthetic features, identified scenic vistas, or designated scenic highways in the project vicinity. According to the California Department of Transportation's (Caltrans') California Scenic Highway Mapping System, the closest section of highway that would be eligible for State Scenic Highway designation are portions of State Routes 14 and 58 which are located many miles to the east of the project site within the desert region of the county. Portions of the project site may be visible from public roads or other publically accessible vantage points, however as stated previously the project site is currently dominated by oil and gas production facilities and associated infrastructure. The proposed project would introduce four to six CO_2 injection wells into the viewshed, however these would not be easily distinguishable in the viewshed from public roads or public vantage points. The proposed project would likely introduce new lighting features during construction and operations, similar to those currently existing within the project site, however the project would be required to conform to the Kern County Dark Skies Ordinance which would require the minimum lighting possible for safety, as well as shielding of light fixtures and a downward orientation to eliminate light spillover. Because oil and gas production activities and associated infrastructure, which are visually similar to the proposed project, currently dominate the existing

viewshed and no scenic vistas have been identified in the project area, impacts on aesthetic resources are anticipated to be less than significant. However, because the project will introduce a new source of light or glare, and because the project site is located in a non-urban area and may be visible from publicly accessible vantage points, potential impacts to aesthetic resources will be analyzed in the Environmental Impact Report.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
II. AGRICULTURE AND FOREST RESOURCES. Would the project:				
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to nonagricultural use?	☐	☐	☐	☒
b) Conflict with existing zoning for agricultural use, or Williamson Act contract?	☒	☐	☐	☐
c) Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code section 12220(g)) or timberland (as defined in Public Resources Code section 4526) or timberland zoned Timberland Production (as defined by Government Code Section 51104 (g),	☐	☐	☐	☒
d) Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☐	☒
e) Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to nonagricultural use or conversion of forest land to non-forest use?	☒	☐	☐	☐
f) Result in the cancellation of an open space contract made pursuant to the California Land Conservation Act of 1965 or Farmland Security Zone Contract for any parcel of 100 or more acres (Section 15206(b)(3) Public Resources Code?	☒	☐	☐	☐

RESPONSES:

a)-f) The proposed project currently has a zone classification of A (exclusive Agriculture) and A-1 (Limited Agriculture), however is not designated Prime or Unique Farmland or Farmland of Statewide Importance pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, nor is any portion of the project site subject to the California Land Conservation Act of 1965 (Williamson Act Land Use Contract) or Farmland Security Zone Contract. The project site is not designated Timberland or forest land and as no Timberland or Forestland is in the project vicinity would not conflict with existing zoning for, or cause rezoning of land designated as Timberland or forest land to non-forest use. However, land adjacent to the project site is subject to a Williamson Act Land Use Contract and is designated non-prime

farmland pursuant to the Farmland Mapping and Monitoring Program. Portions of the project site are located with Agricultural Preserve number 3. Due to the project site's zone classification of A (Exclusive Agriculture) and adjacent land that is subject to a Williamson Act Land Use Contract, impacts to agricultural resources will be analyzed in the Environmental Impact report.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
III. AIR QUALITY.				
The significance criteria established by the applicable Air pollution control district shall be relied upon to make the following determinations. Would the project:				
a) Conflict with or obstruct implementation of the applicable air quality plan?	☒	☐	☐	☐
b) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is nonattainment under an applicable federal or state ambient air quality standard? Specifically, would implementation of the project (in a specific location) exceed any of the following adopted thresholds:				
i. San Joaquin Valley Unified Air Pollution Control District:				
<u>Operational and Area Sources</u>				
Reactive Organic Gases (ROG) 10 tons per year.	☒	☐	☐	☐
Oxides of Nitrogen (NO_x) 10 tons per year.	☒	☐	☐	☐
Particulate Matter (PM_{10}) 15 tons per year.	☒	☐	☐	☐
<u>Stationary Sources as determined by District Rules</u>				
Severe Nonattainment 25 tons per year.	☒	☐	☐	☐
Extreme Nonattainment 10 tons per year.	☒	☐	☐	☐

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
III. AIR QUALITY. (Continued)				
ii. Eastern Kern Air Pollution Control District.				
Operational and Area Sources				
Reactive Organic Gases (ROG) 25 tons per year.	☐	☐	☐	☒
Oxides of nitrogen (NO_x) 25 tons per year.	☐	☐	☐	☒
Particulate Matter (PM_{10}) 15 tons per year.	☐	☐	☐	☒
Stationary Sources - determined by District Rules 25 tons per year.	☐	☐	☐	☒
c) Expose sensitive receptors to substantial pollutant concentrations?	☒	☐	☐	☐
d) Result in other emissions (such as those leading to odors) adversely affecting a substantial number of people.	☒	☐	☐	☐

RESPONSES:

a) The project would be located within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD), in the San Joaquin Valley Air Basin (SJVAB). The SJVAB is classified by the State as a severe nonattainment area with respect to the 1-hour ozone standard as well as a nonattainment area for the State standards pertaining to particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2 ½ microns ($PM_{2.5}$). In addition, the SJVAB is classified as an extreme nonattainment area for the Federal 8-hour ozone standard, a nonattainment area for the Federal $PM_{2.5}$ standard, and an attainment/maintenance area for the Federal carbon monoxide (CO) and PM_{10} standards.

Project construction activities would generate ozone precursor (i.e., oxides of nitrogen [NOX] and reactive organic compounds [ROC]) emissions as well as CO, $PM_{2.5}$, and PM_{10} emissions that could result in significant impacts on regional air quality. Emissions sources would include heavy equipment used for excavation and grading, cranes, drilling rigs and on-road motor vehicles for equipment and material deliveries as well as construction workers' vehicles. Long-term maintenance and operational activities are other emissions sources. Grading and activities on unpaved roads would contribute to fugitive PM_{10} and $PM_{2.5}$ emissions. This impact is potentially significant. Further analysis of air quality impacts is warranted to determine whether the project

would conflict with or obstruct implementation of the applicable plans for attainment and, if so, the reasonable and feasible mitigation measures that could be adopted to reduce such impacts. These issues will be evaluated in the EIR.

b) The project is located within the jurisdictional boundaries of SJVAPCD. The SJVAB is classified by the State as a severe nonattainment area with respect to the 1-hour ozone standard as well as a nonattainment area for the State standards pertaining to PM10 and PM2.5. In addition, the SJVAB is classified as an extreme nonattainment area for the Federal 8-hour ozone standard, a nonattainment area for the Federal PM2.5 standard, and an attainment/maintenance area for the Federal CO and PM10 standards.

SJVAPCD rules and regulations would apply to all project activities within the SJVAPCD. Construction and operational emissions will be analyzed in the EIR as well as long-term operational emissions. Some construction personnel may commute from outside the SJVAB. Cumulative contributions of emissions to the SJVAB are considered potentially significant and will be evaluated further in the EIR.

c)-d) The project site is located within the administrative boundary of the Elk Hills Oil Field. There are no schools or hospitals located with the vicinity of the project site, however, the project site is located approximately 8.5 miles north of the City of Taft and approximately 4 miles west of the unincorporated community of Buttonwillow, additionally there may be sparse, rural residences located within the project vicinity. The closest disadvantaged community to the project site is the unincorporated community of Buttonwillow (population 1,445). California Environmental Protection Agency's "CalEnviroScreen 4.0" ranks Buttonwillow and the City of Taft as communities in the state, heavily impacted from pollution and other health and socio-economic indicators.

Therefore, impacts on sensitive receptors are potentially significant and further analysis is warranted to determine whether the project would expose sensitive receptors to substantial pollutant concentrations or a substantial number of people to other emissions, and, if so, the reasonable and feasible mitigation measures that could be adopted to reduce such impacts. These issues will be evaluated in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
IV. BIOLOGICAL RESOURCES. Would the project:				
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations or by the California Department of Fish and Wildlife or U.S. Fish and Wildlife Service?	☒	☐	☐	☐
b) Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, regulations, or by the California Department of Fish and Wildlife or U.S. Fish and Wildlife Service?	☒	☐	☐	☐
c) Have a substantial adverse effect on federally protected wetlands (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☒	☐	☐	☐
d) Interfere substantially with the movement of any native resident or migratory fish or wildlife species, or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☒	☐	☐	☐
e) Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☒	☐	☐	☐
f) Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☒	☐	☐	☐

RESPONSES:

a)–f) The proposed Project site is located in the south-western portion of the San Joaquin Valley which hosts a variety of sensitive resources including several listed as threatened or endangered at the

state or federal level. Several conservation programs or mitigation requirements have been approved or proposed to comply with State and federal Endangered Species laws including the issuance of incidental take coverage through habitat conservation plans, federal Section 7 Consultations, Biological Opinions and mitigation measures that are a part of CEQA and NEPA environmental documents.

The proposed project would allow the construction of four to six Class VI injection wells, ancillary infrastructure and facilities, and the injection and storage of up to 48 million metric tons of CO_2 on approximately 5,332 acres.

Impacts could result from activities related to construction of injection and/or monitoring wells or from continued activities related to injection of CO_2 and maintenance of the injection wells and ancillary facilities. These impacts are considered potentially significant and will be discussed in the EIR. The EIR will assess impacts on known resources including protected wetlands, riparian areas and streams; impacts on resources that may occur in the future (e.g., foraging or nesting raptors); and impacts on landscape-level resources, such as wildlife corridors that could provide interconnectivity between existing higher value habitats. The EIR will also evaluate potential conflicts with regulatory policies or procedures for protection of biological resources.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact

V. CULTURAL RESOURCES.

Would the project:

a) Cause a substantial adverse change in the significance of a historical resource as defined in CEQA Guidelines Section 15064.5?	☒	☐	☐	☐
b) Cause a substantial adverse change in the significance of an archaeological resource pursuant to CEQA Guidelines § 15064.5?	☒	☐	☐	☐
c) Disturb any human remains, including those interred outside of dedicated cemeteries?	☒	☐	☐	☐

RESPONSES:

a)–c) The potential for impacts on historical and prehistoric resources is considered potentially significant. Therefore, the EIR will more thoroughly address this issue. The EIR will set forth research criteria and report content needed to enable an evaluation of resource occurrence and possible significant impacts on sensitive historic and prehistoric cultural resources.

VI. ENERGY. Would the project:

a)	Result in potentially significant environmental impact due to wasteful, inefficient or unnecessary consumption of energy resources, during project construction or operation?	☒	☐	☐	☐
b)	Conflict with or obstruct a state or local plan for renewable energy or energy efficiency?	☒	☐	☐	☐

RESPONSES:

a)-b) Construction of the proposed project would involve on-site energy demand and consumption related to use of oil in the form of gasoline and diesel fuel for construction worker vehicle trips, hauling and materials delivery truck trips, and operation of off-road construction equipment. In addition, diesel-fueled portable generators may be necessary to provide additional electricity demands for temporary on-site lighting, welding, and for supplying energy to areas of the sites where energy supply cannot be met via a hookup to the existing electricity grid. Ongoing injection activities would result in energy consumption for the duration of the project. Additionally, perpetual storage of CO_2 within confined reservoirs would most likely be passive and would not require the use of energy, however ongoing monitoring activities could result in energy consumption. Impacts related to the consumption of energy resources and the potential for the project to obstruct a state or local plan for renewable energy or energy efficiency will be analyzed in the Environmental Impact Report.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
VII . GEOLOGY AND SOILS. Would the project:				
a) Directly or indirectly cause potential substantial adverse effects, including the risk of loss, injury, or death involving:				
i. Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault? Refer to Division of Mines and Geology Special Publication 42.	☐	☐	☒	☐
ii. Strong seismic ground shaking?	☒	☐	☐	☐
iii. Seismic-related ground failure, including liquefaction?	☒	☐	☐	☐
iv. Landslides?	☐	☐	☒	☐
b) Result in substantial soil erosion or the loss of topsoil?	☒	☐	☐	☐
c) Be located on a geologic unit or soil that is unstable, or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, sub-sidence, liquefaction, or collapse?	☒	☐	☐	☐
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (19914), creating substantial risks to life or property?	☒	☐	☐	☐
e) Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater?	☐	☐	☒	☐
f) Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature.	☒	☐	☐	☐

RESPONSES:

a)–f) Due to the location of active faults in the general region, strong seismic ground shaking could occur at the project site, resulting in damage to above and below ground structures and other site improvements if not properly designed to withstand strong ground shaking. Adherence to applicable regulations would minimize the potential impacts associated with the proposed project.

A geotechnical investigation of the project site may be conducted to determine the physical characteristics of the underlying soils and geologic formations and to identify if any unstable conditions exist that could be exacerbated by proposed construction activities. The results of these investigations will be provided in the EIR.

The above listed project impacts will be further evaluated in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
VIII GREENHOUSE GAS EMISSIONS. Would the project:				
a) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?	☒	☐	☐	☐
b) Conflict with any applicable plan, policy or regulation of an agency adopted for the purpose of reducing the emissions of greenhouse gases?	☒	☐	☐	☐

RESPONSES:

a)–b) Greenhouse gas (GHG) emissions emitted by human activity are implicated in global climate change or global warming. The principal GHGs are CO_2, methane (CH_4), NO_X, ozone, water vapor, and fluorinated gases. The temporary construction activities associated with the proposed project, which would involve operation of heavy off-road equipment, on-road trucks (for deliveries and hauling), and construction worker commute trips, would generate GHGs through exhaust emissions. However, the proposed project is expected to capture traditional sources of CO_2 emissions that have historically been emitted into the environment. As such, the provision of carbon capture and sequestration in perpetuity by the proposed project would reduce GHG emissions and is anticipated to offset GHGs that would otherwise be emitted by traditional sources. The project's GHG emissions generated during construction of the project and the potential GHG offsets resulting from operation of the project, as well as any potential conflicts with any applicable plan, policy or regulation will be identified and quantified in the EIR. Additionally, the project's potential GHG impacts and the potential GHG offsets resulting from operation of the project will be examined in the EIR, with respect to the objectives of statewide programs to reduce GHGs associated with energy generation.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
IX. HAZARDS AND HAZARDOUS MATERIALS. Would the project:				
a) Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials?	☒	☐	☐	☐
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?	☒	☐	☐	☐
c) Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within 1/4 mile of an existing or proposed school?	☒	☐	☐	☐
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code § 65962.5 and, as a result, would it create a significant hazard to the public or the environment?	☒	☐	☐	☐
e) For a project located within the adopted Kern County Airport Land Use Compatibility Plan, would the project result in a safety hazard or excessive noise for people residing or working in the project area?	☒	☐	☐	☐
f) Impair implementation of, or physically interfere with, an adopted emergency response plan or emergency evacuation plan?	☒	☐	☐	☐
g) Expose people or structures, either directly or indirectly, to a significant risk of loss, injury, or death involving wildland fires?	☒	☐	☐	☐

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
IX HAZARDS AND HAZARDOUS MATERIALS. (Continued)				
h) Would implementation of the project generate vectors (flies, mosquitoes, rodents, etc.) or have a component that includes agricultural waste? Specifically, would the project exceed the following qualitative threshold: The presence of domestic flies, mosquitoes, cockroaches, rodents, and/or any other vectors associated with the project is significant when the applicable enforcement agency determines that any of the vectors:				
i. Occur as immature stages and adults in numbers considerably in excess of those found in the surrounding environment; and	☐	☐	☒	☐
ii. Are associated with design, layout, and management of project operations; and	☐	☐	☒	☐
iii. Disseminate widely from the property; and	☐	☐	☒	☐
iv. Cause detrimental effects on the public health or well-being of the majority of the surrounding population.	☐	☐	☒	☐

RESPONSES:

a)-e) The proposed CO_2 capture and storage activities could create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials; create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment. A small portion of the proposed project site is located within Zone C, as identified in the Elk Hills – Buttonwillow Airport Land Use Compatibility Plan (ALUCP). These impacts are considered potentially significant and will be further analyzed in the Environmental Impact Report.

The project is not anticipated to emit hazardous emissions or involve handling hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school, however the nearest schools are Buttonwillow Elementary and McKittrick Elementary, which are approximately 4.5 miles from the project site and Elk Hills Elementary, which is approximately 6.5 miles from the project site. Because the project proposes the transport of CO_2

by pipeline, truck, and/or rail, CO_2 could pass within one quarter mile of a school(s) during transport. Therefore, impacts are potentially significant and will be further analyzed in the Environmental Impact Report.

f) The project would generate construction trips, worker construction and maintenance trips, and CO_2 transport trips. The potential for roadway lane closures also exists, which could temporarily affect an emergency response or evacuation plan. This impact is considered potentially significant and will be addressed in the EIR.

g) According to the California Department of Forestry and Fire Protection (CalFire), Kern County Fire Hazards Severity Zone Maps for the Local Responsible Areas, the project site is classified as State Responsibility Area (SRA) Moderate (Calfire 2021). Moderate zones are typically wildland supporting areas of low fire frequency and relatively modest fire behavior. The proposed project would comply with all applicable wildland fire management plans and policies established by CalFire, and Kern County Fire Department. Accordingly, the project is not expected to expose people or structures to a significant risk of loss, injury, or death involving wildland fires. Nonetheless, potential impacts involving wildfires will be discussed in the EIR--please refer to the responses to the Checklist topic concerning Wildfire, later in this Initial Study.

h)i.-iv. Project construction and injection/storage activities are not expected to result in the generation of vectors (flies, mosquitoes, rodents, etc.) or have a component that includes agricultural waste. However, this issue will be addressed in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
X HYDROLOGY AND WATER QUALITY. Would the project:				
a) Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or ground water quality?	☒	☐	☐	☐
b) Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin?	☒	☐	☐	☐
c) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would:	☒	☐	☐	☐
i) result in a substantial erosion or siltation on – or off-site	☒	☐	☐	☐
ii) substantially increase the rate or amount of surface runoff in a manner which would result in flooding on-or offsite;	☒	☐	☐	☐
iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or	☒	☐	☐	☐
iv) impede or redirect flood flows ?	☒	☐	☐	☐
d) In flood hazard, tsunami, seiche zones, risk release of pollutants due to project inundation?	☐	☐	☐	☒
e) Conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan?	☒	☐	☐	☐

RESPONSES:

a) The construction of injection wells and ancillary facilities could potentially fail to comply with water quality standards or waste discharge requirements. The potential to create substantial erosion and siltation or violate any water quality standards or waste discharge requirements is considered significant and will be discussed in the EIR.

b) The construction of injection wells and ancillary facilities could potentially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level. This impact is considered potentially significant and will be addressed in the EIR.

c) The construction of injection wells and ancillary facilities could potentially result in alteration of drainage patterns and lead to substantial erosion and siltation. The potential to create substantial erosion and siltation is considered significant and will be discussed in the EIR.

The construction of injection wells and ancillary facilities and production facilities could potentially result in alteration of drainage patterns and lead to flooding. The potential to create flooding is considered significant and will be discussed in the EIR.

There are no stormwater drainage systems in the agricultural areas under consideration. It is not considered likely that future oil and gas exploration and production activities would create or contribute sufficient runoff water such that the capacity of existing stormwater drainage systems would be exceeded. Nonetheless, this impact is considered potentially significant and will be addressed in the EIR.

d) None of the injection well construction or storage activities occurs or would occur in locations where tsunamis, mudflows or seiche-related inundation would occur. This impact is considered no impact; however it will be discussed further in the EIR.

e) The proposed project is located with the San Joaquin Valley Groundwater Basin, in the Kern County sub-basin. The construction of injection wells and ancillary facilities could potentially deplete groundwater supplies or interfere substantially with groundwater recharge such that it would conflict with or obstruct implementation of a water quality control plan, the State Groundwater Management Act, or a Groundwater Sustainability Plan (GSP) as adopted by the West Kern Water District Groundwater Sustainability Agency (GSA). This impact is considered potentially significant and will be analyzed in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XI. LAND USE AND PLANNING. Would the project:				
a) Physically divide an established community?	☐	☐	☐	☒
b) Cause a significant environmental impact due to a conflict with any land use plan, policy or regulation adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☒	☐

RESPONSES:

a) Construction of injection wells and CO_2 capture and storage activities are not expected to result in the division of established communities. There would be no impact.

b) The impacts of the proposed project and potential conflicts with County ordinances and policies, or regulation adopted for the purpose of avoiding or mitigating an environmental effect are not expected to be significant; however they will be addressed in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XII. MINERAL RESOURCES. Would the project:				
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☒	☐	☐	☐
b) Result in the loss of availability of a locally important mineral resource recovery site delineated on a local general plan, specific plan, or other land use plan?	☒	☐	☐	☐

RESPONSES:

a)–b) The proposed project is located within the administrative boundary of the Elk Hills Oilfield, however the project site is not a designated mineral resource zone. The project could potentially result in the loss of availability of a known mineral resource of value to the region and the residents of the state. Impacts to mineral resources will be addressed further in the Environmental Impact Report.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XIII. NOISE. Would the project result in:				
a) Generation of a substantial temporary or permanent increase in the ambient noise levels in the vicinity of the project in excess of standards established in the local general plan or noise ordinance or applicable standards of other agencies?	☒	☐	☐	☐
b) Generation of, excessive ground borne vibration or ground borne noise levels?	☒	☐	☐	☐
c) A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?	☒	☐	☐	☐
d) For a project located within the Kern County Airport Land Use Compatibility Plan, would the project expose people residing or working in the project area to excessive noise levels?	☒	☐	☐	☐

RESPONSES:

a)–c) Construction activities, including injection well pad preparation, drilling, completion and testing of new injection wells, construction of necessary infrastructure, and general maintenance activities could result in temporary or periodic increases in noise and groundborne vibration. The Kern County General Plan Noise Element sets a 65-decibel limit on exterior noise levels from stationary sources (i.e., non- transportation sources) at sensitive receptors. The Noise Control Ordinance in the Kern County Code (Section 8.36.020 et seq.) prohibits a variety of nuisance noises. Construction-related noise is regulated by means of a limitation on the hours of construction activity for projects located within 1,000 feet of an occupied residential dwelling. In such cases, construction is prohibited between the hours of 9 p.m. and 6 a.m. on weekdays and 9 p.m. and 8 a.m. on weekends. The project proponent would adhere to the provisions of Kern County Ordinance Section 8.36.020. Nonetheless, the project could expose persons to or generate noise levels in excess of established standards. This impact is considered potentially significant and will be discussed further in the EIR.

d) A small portion of the project site is located within Zone C of the Elk Hills- Buttonwillow Airport Land Use Compatibility Plan. Depending on the final location of injection wells the project could potentially expose people residing or working in the project area to excessive noise levels. This impact is considered potentially significant and will be further addressed in the Environmental Impact Report

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XIV. POPULATION AND HOUSING. Would the project:				
a) Induce substantial unplanned population growth in an area, either directly (for example, by proposing new homes and businesses) or indirectly (for example, through extension of roads or other infrastructure)?	☒	☐	☐	☐
b) Displace substantial numbers of existing people or housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☒

RESPONSES:

a)-b) Construction of the proposed project and ongoing storage, maintenance and monitoring activities could provide new employment opportunities consistent with adopted Kern County General Plan goals, plans, and policies. If temporary housing should be necessary, it is expected that accommodations would be available in the nearby communities. While the proposed project is not expected to induce substantial population growth in Kern County, displace a substantial number of existing homes or people, or necessitate the construction of replacement housing elsewhere, these issues will be evaluated in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XV. PUBLIC SERVICES. Would the project **:**				
a) Result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times, or to other performance objectives for any of the public services:				
Fire Protection?	☒	☐	☐	☐
Police Protection?	☒	☐	☐	☐
Schools?	☒	☐	☐	☐
Parks?	☒	☐	☐	☐
Other Public Facilities?	☒	☐	☐	☐

RESPONSES:

a)i. - v. The demand for fire protection, police protection, schools, parks and other public facilities could be affected by the proposed project. Impacts on public services are considered potentially significant and will be addressed in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XVI. RECREATION.				
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☒	☐	☐	☐
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities which might have an adverse physical effect on the environment?	☐	☐	☐	☒

RESPONSES:

a)–b) The project would not include the construction or expansion of new recreational facilities. However, an increase in population that might result from an influx of workers and the associated increase in the use of parks or recreational facilities could require the expansion of recreational facilities. This impact is considered potentially significant and will be evaluated in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XVII. TRANSPORTATION AND TRAFFIC Would the project:				
a) Conflict with a program, plan, ordinance, or policy addressing the circulation system, including transit, roadway, bicycle and pedestrian facilities?	☒	☐	☐	☐
b) Conflict or be inconsistent with CEQA Guidelines § 15064.3 (b)	☒	☐	☐	☐
c) Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous inter-sections) or incompatible uses (e.g., farm equipment)?	☐	☐	☒	☐
d) Result in inadequate emergency access?	☒	☐	☐	☐

RESPONSES:

a) There are no dedicated pedestrian or bicycle facilities in the immediate vicinity of the project site or along the surrounding roadways. Due to the rural nature of the project area, pedestrian and bicycle traffic is limited. The project is not located along an existing bus route and few bus stops exist on roadways that are likely to be used during construction and operation of the proposed project.

Further analysis in the EIR is required to determine whether construction traffic could disrupt normal traffic flows or otherwise conflict with the County's roadway performance policies and programs.

b) CEQA Guidelines section 15064.3, subdivision (b) was adopted in December 2018 by the California Natural Resources Agency. These revisions to the CEQA Guidelines criteria for determining the significance of transportation impacts are primarily focused on projects within transit priority areas and shift the focus from driver delay to reduction of vehicular greenhouse gas emissions through creation of multimodal networks, and creation of a mix of land uses that can facilitate fewer and shorter vehicle trips. Vehicle miles traveled (VMT) is a measure of the total number of miles driven for various purposes and is sometimes expressed as an average per trip or per person. Construction traffic would be temporary and would not permanently affect VMT characteristics in this part of Kern County or elsewhere. Long-term, operational traffic related to the CO_2 storage, maintenance, and monitoring activities would be limited. It is not known where the employees would live or how long their commuting trips would be but is assumed that they would commute from nearby communities. According to technical guidance issued by the Office of Planning and Research, projects generating less than 110 or fewer daily vehicle trips may be presumed to have a less than significant impact involving VMT. Further analysis of the operational VMT characteristics of the project is required to determine whether the project is considered a "low-VMT" project due to small daily traffic volumes alone, or whether more extensive analysis is warranted. An assessment of the project's VMT characteristics will be provided in the EIR, to ensure consistency with state and local guidance.

c) No new roadway design or features (i.e., sharp curves, dangerous intersections, or other hazardous features) that could result in transportation-related hazards or safety concerns are anticipated. The project injection wells and other infrastructure and facilities would be set back from roadways as required by the Kern County Zoning Ordinance. The types and numbers of vehicles utilized during injection well construction and for storage, maintenance, and monitoring activities would be similar to existing activities in the vicinity and therefore would not likely be incompatible. Given these considerations, significant impacts related to increased hazards are not anticipated to occur; however, additional analysis will be included in the EIR.

d) The project would generate construction trips and the potential for roadway lane closures exists during construction of ancillary infrastructure and during transport of CO_2 to the site, which could temporarily increase the daily traffic volumes on local roadways and at intersections. It is anticipated that emergency access would be maintained at all times, and appropriate detours would be provided, as necessary. Nonetheless, impacts related to emergency access are considered potentially significant and will be addressed in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XVIII. TRIBAL CULTURAL RESOURCES. Would the project:				
a) Would the project cause a substantial adverse change in the significance of a tribal cultural resource, defined in Public Resources Code § 21074 as either a site, feature, place, cultural landscape that is geographically defined in terms of the size and scope of the landscape, sacred place, or object with cultural value to a California Native American tribe, and that is:				
i) Listed or eligible for listing in the California Register of Historical Resources, or in a local register of historical resources defined in Public Resources Code section 5020.1 (k) or	☒	☐	☐	☐
ii) A resource determined by the lead agency, in its discretion and supported by substantial evidence, to be significant pursuant to criteria set forth in subdivision (c) of Public Resources Code section 5024.1. In applying the criteria set forth in subdivision (c) of Public Resource Code section 5024.1, the lead agency shall consider the significance of the resource to a California Native America tribe.	☒	☐	☐	☐

RESPONSES:

a)i.-ii. The proposed project site is currently highly disturbed with oil and gas production and ancillary infrastructure, however because the injection well sites may not be on previously disturbed land there is a potential for tribal cultural resources to exist on-site and on surrounding lands. Therefore, the proposed project has the potential to impact tribal cultural resources during injection well pad constructions and drilling as well as during the construction of ancillary infrastructure. All tribes with possible cultural affiliation and interest within the project area will be notified pursuant to the requirements of Assembly Bill 52, and consultation with the potentially affected tribes will occur, as appropriate, between the County and the tribes. Further evaluation in the EIR is warranted to identify potential impacts to tribal cultural resources and to formulate avoidance or mitigation measures, if applicable.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XIX. UTILITIES AND SERVICE SYSTEMS. Would the project:				
a) Require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects?	☒	☐	☐	☐
b) Have sufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years?	☒	☐	☐	☐
c) Result in a determination by the waste water treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☐	☐	☒	☐
d) Generate solid waste in excess of state or local standards, or in excess of the capacity of local infrastructure, or otherwise impair the attainment of solid waste reduction goals?	☒	☐	☐	☐
e) Comply with federal, State, and local management and reduction statutes and regulations related to solid waste	☒	☐	☐	☐

RESPONSES:

a) The proposed project would not require or result in the relocation or construction of new or expanded municipal wastewater facilities, and no connection to a public wastewater system is required or proposed. Impacts would be less than significant in this regard; however, further analysis in the EIR will be provided. The proposed project does not require expanded or new storm drainage facilities because the proposed project is not anticipated to generate a significant increase in the amount of impervious surfaces that would increase runoff during storm events. The proposed project is not anticipated to result in a significant increase in water demand/use; however, water will be needed for dust suppression and injection well drilling. Impacts associated with construction of the electrical lines and telecommunication lines will be evaluated in the EIR.

Impacts would be potentially significant and further analysis in the EIR is warranted.

b) Water consumption during construction would primarily be used for dust-suppression purposes. Water is anticipated to be obtained from existing on-site wells. A water supply assessment will be completed for the project to analyze potential water sources and potential impacts to water supplies.

This potentially significant impact will be addressed further in the EIR.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XX. WILDFIRE. If located in or near state responsibility areas or lands classified as very high fire hazard severity zones, would the project:				
a) Substantially impair an adopted emergency response plan or emergency evacuation plan?	☒	☐	☐	☐
b) Due to slope, prevailing winds, or other factors, exacerbate wildfire risks, and thereby expose project occupants to pollutant concentrations from a wildfire or the uncontrolled spread of a wildfire?	☒	☐	☐	☐
c) Require the installation or maintenance of associated infrastructure (such as roads, fuel breaks, emergency water sources, power lines or other utilities) that may exacerbate fire risk or that may result in temporary or ongoing impacts to the environment?	☒	☐	☐	☐
d) Expose people or structures to significant risks, including downslope or downstream flooding or landslides, as a result of runoff, post-fire slope instability, or drainage changes?	☒	☐	☐	☐

RESPONSES:

a)-d) According to the California Department of Forestry and Fire Protection (CalFire), Kern County Fire Hazards Severity Zone Maps, the project site is located within a Moderate Fire Hazard Severity Zone in a State Responsibility Area. Therefore, the potential for wildfire on the project site exists. The site is located in a rural area with limited population, primarily developed with oil and gas production facilities and agricultural land. The project site is not identified for any purpose in an adopted emergency evacuation plan to address wildfires or other types of emergencies. Further analysis of prevailing winds is required to determine if there are periodic high winds that could influence the spreading and velocity of wildfires. Adherence to applicable regulations would reduce wildfire ignitions and prevent the spread of wildfires. The proposed project involves the development of a carbon capture and sequestration facility. The proposed project would include the construction of injection wells, internal roads, power transmission lines, and ancillary infrastructure including CO_2 transport pipelines.

Issues (and Supporting Information Sources):	Potentially Significant Impact	Less Than Significant With Mitigation Incorporation	Less Than Significant Impact	No Impact
XXI. MANDATORY FINDINGS OF SIGNIFICANCE.				
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, substantially reduce the number or restrict the range of a rare or endangered plant or animal, or eliminate important examples of the major periods of California history or prehistory?	☒	☐	☐	☐
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.)	☒	☐	☐	☐
c) Does the project have environmental effects which will cause substantial adverse effects on human beings, either directly or indirectly?	☒	☐	☐	☐

RESPONSES:

a) The EIR's biological, cultural, and tribal cultural resources sections will discuss specific project impacts on plants and wildlife including avian species and impacts to cultural and tribal cultural resources. The document will also evaluate the project's contribution to cumulative biological, cultural and tribal cultural resources impacts and propose mitigation that will reduce the impacts to less than significant levels, where feasible.

b) The project has the potential to contribute to cumulatively significant air quality, biological resources, cultural resources, tribal cultural resources, greenhouse gas emissions, traffic, and wildfire impacts. Such impacts could occur during the construction phases and/or as a result of the fully built and operational project. The EIR will evaluate the project's contribution to cumulative impacts in these and other areas.

c) The Project could potentially result in environmental effects that have adverse impacts on human beings, either directly or indirectly. These impacts will be fully addressed in the EIR.

A.2 Comment Letters

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From:	Whitmore, Stephanie A.
To:	Lee, Annie
Cc:	Smith, Michael
Subject:	FW: Carbon TerraVault 1 NOP Comments
Date:	Tuesday, April 5, 2022 10:25:50 AM
Attachments:	CTV 1 NOP - Comment Tracking Table.docx 03.06.22_Mark.pdf 03.07.22_2022030180_NAHC Comment.cleaned.pdf 03.09.22_PW Floodplain_NoP EIR Carbon Terra Vault (002).docx 03.15.22_S. Reid_CRC"s Carbon Capture Project at Elk Hills.pdf 03.23.22_EHS_Draft EIR - Carbon Terra Vault 1 by California Resources Corporation ZM 5 CUP 5 Map 119 (002).docx 03.26.22_Caltrans District 6_KER-58-R23.781 NOP DEIR Carbon Terravault Ltr (002).pdf 03.29.22_SOS.pdf 04.02.22_Kern AudubonCarbon Terravault 1 Project NOP April 2 2022.pdf 04.04.22_PW Survey_NPEIR Carbon Terra Vault 1 by California Resources Corp - PP22405.pdf 04.04.22_SJVAPCD comment letter NOP DEIR Carbon Terravault 20220282.pdf 04.04.22_Sierra Club NOP comments for Kern CCS project (002).pdf CCS letter to CARB from SCC__Attachment to NOP Comment Letter.pdf 04.04.22_CBD_Elk Hills CCS Scoping Comments from CBD CVAQC CCEJN (002).pdf image001.png

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From: Cindi Hoover <hooverc@kerncounty.com>
Sent: Tuesday, April 5, 2022 8:43 AM
To: Lorelei Oviatt <Loreleio@kerncounty.com>; Whitmore, Stephanie A. <Stephanie.Whitmore@wsp.com>
Cc: Smith, Michael <Michael.D.Smith@wsp.com>
Subject: Carbon TerraVault 1 NOP Comments

Good morning,

The Carbon TerraVault 1 NOP comment period ended yesterday at 5:00 pm. We received a total of 12 comments which I have attached to this email along with a tracking table. CBD submitted a USB with PDF documents of all of their references which will need to be included in Appendix A of the DEIR. I will send those to the WSP team via file sharing once we get an FTP or Sharepoint set up. Please let me know if you believe you are missing any comments or have trouble opening any of the PDF documents.

Stephanie and Michael - I will send the Scoping Meeting Agenda and Summary in a separate email.

No comments were provided during the Scoping Meeting.

Warmest regards,

***Cindi Hoover**, Division Chief*
Plan Development and Special Projects Division
Kern County
Planning and Natural Resources Dept.
2700 M Street, Ste 100
Bakersfield CA 93301
ph (661) 862-8629
fax (661) 862-8601
email: hooverc@kerncounty.com

August 16, 2021

Liane Randolph, Chair
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

RE: Sierra Club California Comments on Scoping Plan Workshop - Engineered Carbon Removal Technical Workshop on August 2, 2021

Dear Chair Randolph and Members of the Board:

Sierra Club California, on behalf of our over 500,000 members and supporters in California, appreciates the opportunity to comment on the California Air Resources Board's (CARB) Scoping Plan Technical Workshop on Engineered Carbon Removal.

We are concerned that CARB is moving forward on advancing carbon capture, utilization and storage (CCUS) technologies at a pace that fails to take into account input from environmental and environmental justice organizations. The Scoping Plan workshop that took place on August 2, 2021 gave the impression that CARB has already decided that engineered carbon removal technologies will be the solution to achieving our climate targets. CARB is required to take into consideration input from the Environmental Justice Advisory Council (EJAC).[1] Yet, the workshop made it clear that CARB is not effectively doing so as one EJAC member commented "[It] feels like someone has already decided that this is the right solution and now it's being announced."

During the workshop, members from the EJAC raised critical concerns regarding CCUS technologies. Sierra Club California shares these concerns and is concerned that CARB is catering to industry over the environment by leaning on these technologies when there are extreme risks associated with them as well as better, cleaner pathways. We urge CARB to consider the following:

I. Climate change strategies should prioritize the health and safety of environmental justice communities.

CARB must take into consideration that CCUS technologies will not reduce air pollutants aside from CO_2 and will not address the harms of fossil fuel pollution that are felt by environmental justice

[1] The California Global Warming Solutions Act of 2006 (AB 32; Stats. 2006, ch. 488).

communities. In fact, research has shown that these technologies can increase co-pollutants at the source.[2]

Any increase in air pollutants in environmental justice communities is unacceptable. California has some of the worst air quality in the world. Often low-income communities and communities of color suffer the brunt of the harms of local air pollution, which CCUS does not mitigate. Many of these communities are located nearby fossil fuel plants so they are disproportionately exposed to a greater amount of air pollution. As a result, they suffer from higher levels of pollution-associated illnesses. Because CCUS focus is on capturing carbon before it enters the atmosphere as opposed to reducing or removing other toxic air pollutants, it fails to address the air quality and public health problems faced by environmental justice communities.

As EJAC members stated during the workshop, these communities are already treated as "sacrifice zones". CCUS will be used to extend the life of fossil fuel operations, including its harmful impacts on environmental justice communities. In addition, the process of CCUS itself will rely on fossil fuels to power it, resulting in more negative impacts.

The state must prioritize protecting these communities and relieving them of the poor air quality and public health impacts they are experiencing. In order to prioritize the health and safety of environmental justice communities, CARB should focus its time and resources on strategies that promote the development of clean energy resources and phasing out fossil fuel production.

II. The risks associated with these technologies must be balanced against the cost

Many CCUS technologies have not been proven to be feasible or economic at scale and have only seen limited use or use that permits climate and public health harmful activities such as enhanced oil recovery (EOR).

One EJAC member noted during the workshop that, financially, the investment in this technology is risky - some facilities have failed or not resulted in significant carbon reductions while others were only profitable because the CO_2 was used for EOR.[3] In fact, CCUS technologies have been shown to only contain a fraction of source emissions since fossil fuels release pollutants at every stage of their lifecycle (extraction, refining, transport, use, and disposal).[4] Reports have shown that the 28 existing CCUS facilities currently operating have a capacity to capture 0.1 percent of fossil fuel emissions (and the vast majority of the captured carbon is being used to produce more oil).[5]

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[2] Jacobson, Mark Z., *The health and climate impacts of carbon capture and direct air capture*, Energy Environ. Sci. (2019), available at https://web.stanford.edu/group/efmh/jacobson/Articles/Others/19-CCS-DAC.pdf

[3] *Id.*

[4] Drugmand, D. & Muffett, C., *Confronting the Myth of Carbon-Free Fossil Fuels: Why Carbon Capture is Not a Climate Solution,* CIEL (2021), available at https://www.ciel.org/wp-content/uploads/2021/07/Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf [hereinafter "CIEL, Why Carbon Capture is Not a Climate Solution"].

[5] *Id.*

Most of these technologies are very expensive with little payoff, costing hundreds of dollars to remove just one ton of carbon dioxide.[6] CARB's own presentation showed how expensive these technologies will be ($190/200 per ton) as compared to natural and working land strategies ($11 per ton). To put this in further context, in 2018 we released 37 billion tons of CO_2. That means removing a year's worth of carbon using these technologies at an average price of $200 per ton, would cost around $7.4 trillion dollars.[7]

Considering that the research is still unclear and undetermined as to what the risks associated with these technologies will be, is the cost worth it? Science reports have stated that these technologies will have to be monitored over the next 100 years. However, we have seen that our state has failed to monitor the current fossil fuel industry which has resulted in devastating leaks, spills, and gas explosions. The 2018 IPCC report cautioned against technologies such as CCUS given "concerns about storage safety and cost" and the "non-negligible risk of carbon dioxide leakage from geological storage and the carbon dioxide transport infrastructure."[8]

Bottom line, we don't know the wide-ranging effects these technologies may have. As we've seen with anthropogenic climate change, when humans alter the atmosphere at a global scale, unexpected consequences occur. Therefore, we recommend that CARB focus on cleaner, safer alternatives for reaching our climate goals.

III. The state must focus on reducing anthropogenic emissions including phasing out fossil fuel production and reaching 100% clean, renewable energy resources

It is essential that we prioritize climate change mitigation and transitioning to clean, renewable energy as soon as possible.[9] Any carbon removal technologies or practices should be implemented as a last resort and in addition to, rather than instead of, anthropogenic carbon emissions reductions.

Clean energy resources have additional benefits that these technologies do not have such as reducing non-CO_2 air pollutants caused by fossil combustion as well as eliminating the risks of oil spills, oil fires, gas leaks or gas explosions.[10] Transitioning to clean, renewable alternatives seems the most efficient pathway for achieving reductions especially considering CCUS does not remove carbon from the atmosphere but only prevents *some* emissions caused by the fossil fuel activities from reaching the atmosphere.[11] Reports state that "[CCUS] masks the harmful carbon emissions from the

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[6] Sabine Fuss et al., *Negative emissions - Part 2: Costs, potentials and side effects*, Environ. Res. Lett. 13 (2018), available at https://iopscience.iop.org/article/10.1088/1748-9326/aabf9f/pdf.
[7] Kelly Levin, *New Global CO2 Emissions Numbers Are In. They're Not Good*, WRI (Dec. 5, 2018), https://www.wri.org/insights/new-global-co2-emissions-numbers-are-theyre-not-good.
[8] IPCC, Summary for Policymakers in IPCC, Global Warming of 1.5°C: An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty (2018).
[9] *Id.*
[10] Jacobson, supra note 1.
[11] CIEL: Why Carbon Capture is Not a Climate Solution, supra note 2.

underlying source, enabling that source to continue operation rather than being replaced altogether, while creating additional risks, impacts, and costs associated with the [CCUS] infrastructure."[12]

We cannot allow the prospect of these technologies to delay fossil fuel elimination. It's healthier, cheaper, and safer to limit pollution at the source, transition to clean, renewable energy sources, and enhance nature based solutions.[13] Studies have shown that replacing fossil fuels with clean energy resources such as wind or solar will not only result in more CO_2 emission reductions than relying on CCUS equipment, but it will also result in reductions in air pollution emissions and doesn't have the added costs and risks associated with CCUS.[14]

Experts have stated that "Carbon capture is a polluting technology because it doesn't reduce air pollutants aside from CO_2, and all the [other pollutants] go up because of the fact that you need more energy to run carbon capture equipment. . .There is no reason for it, except to distract us and waste money."[15] These technologies are delaying the state from transitioning away from fossil fuels and will provide the fossil fuel industry with a license to continue polluting.[16] Technologies like CCUS that allow the fossil fuel industry to continue business as usual should not be permitted.

IV. Conclusion

The Intergovernmental Panel on Climate Change's The Sixth Assessment Report (August 2021) makes it clear that we must rapidly stop new CO_2 emissions from entering the atmosphere. It is imperative that we do not allow technologies like CCUS to become an excuse to continue creating new pollution.

Considering the risks, costs, and negative impacts on environmental justice communities, we urge CARB to slow down and direct its focus and resources on strategies that encourage the development of clean, renewable energy and phasing out fossil fuel production. Those pathways are guaranteed to result in reductions in climate emissions, air pollutants, and other harmful impacts from fossil fuel activities.

Sincerely,



Lauren Cullum
Policy Advocate

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[12] *Id.*
[13]CIEL: Why Carbon Capture is Not a Climate Solution, supra note 2.
[14] Jacobson, supra note 1.
[15]CIEL: Why Carbon Capture is Not a Climate Solution, supra note 2; Hutchins, M., The Weekend Read: Looking at the energy transition's bigger picture (July 10, 2021) (featuring Mark Jacobson), https://www.pv-magazine.com/2021/07/10/the-weekend-read-looking-at-the-energy-transitions-bigger-picture/ (stating "The correct idea of electrifying everything and supplying that electricity through wind, water, solar, and storage has really hit the mainstream now. But still a lot of effort and money is being spent on appeasing the fossil fuels industry with carbon capture and related technologies……").
[16] CIEL: Why Carbon Capture is Not a Climate Solution, supra note 2.

Cindi Hoover

From: Mark H. <mark.realtor1@gmail.com>
Sent: Sunday, March 6, 2022 9:24 PM
To: Cindi Hoover
Subject: CCS in Bakersfield

CAUTION: This email originated from outside of the organization. Do not click links, open attachments, or provide information unless you recognize the sender and know the content is safe.

Hello,

With respect to the CCS projects that will be approved in Bakersfield, for any operator, I would like to know

1. How CO2 will remain in the ground, and not seep above the approved zone due to wells that do not have cement behind casing, and therefore creating a seeping barrier. Will all wells identified for a specific zone be analyzed (maybe cement bond logs?) and correctly remediated? What about wells that were abandoned using non-current standards such that they do not have cement on top of the CO2 storage zone?

2. Bakersfield operators do not have a subsidence mitigation plan. Due to depletion, historical wells have deformed and lost their integrity and therefore the cement seal may not be sealing any more. How will operators correct for this?

3. There is numerous literature documenting that cement degrades under influence of CO2. Although the rate of degradation is dependent on multiple factors, there is a well documented risk of the cement integrity being lost over time. How will regulators de-risk this?

We have 'orphan' oil wells in Bakersfield. We have to make sure there are no "ponzi scheme" sequestration credits.

Thank you for your help.

Mark

NATIVE AMERICAN HERITAGE COMMISSION

GOVERNOR'S OFFICE OF PLANNING AND RESEARCH
Mar 11 2022
STATE OF CALIFORNIA

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NAHC HEADQUARTERS
1550 Harbor Boulevard
Suite 100
West Sacramento,
California 95691
(916) 373-3710
nahc@nahc.ca.gov
NAHC.ca.gov

March 7, 2022

Cindi Hoover
Kern County Planning and Natural Resources Department
2700 "M" Street Suite 100
Bakersfield, CA 93301

Re: 2022030180, Carbon TerraVault 1 by California Resources Corporation (CRC) Project, Kern County

Dear Ms. Hoover:

The Native American Heritage Commission (NAHC) has received the Notice of Preparation (NOP), Draft Environmental Impact Report (DEIR) or Early Consultation for the project referenced above. The California Environmental Quality Act (CEQA) (Pub. Resources Code §21000 et seq.), specifically Public Resources Code §21084.1, states that a project that may cause a substantial adverse change in the significance of a historical resource, is a project that may have a significant effect on the environment. (Pub. Resources Code § 21084.1; Cal. Code Regs., tit.14, §15064.5 (b) (CEQA Guidelines §15064.5 (b)). If there is substantial evidence, in light of the whole record before a lead agency, that a project may have a significant effect on the environment, an Environmental Impact Report (EIR) shall be prepared. (Pub. Resources Code §21080 (d); Cal. Code Regs., tit. 14, § 5064 subd.(a)(1) (CEQA Guidelines §15064 (a)(1)). In order to determine whether a project will cause a substantial adverse change in the significance of a historical resource, a lead agency will need to determine whether there are historical resources within the area of potential effect (APE).

CEQA was amended significantly in 2014. Assembly Bill 52 (Gatto, Chapter 532, Statutes of 2014) (AB 52) amended CEQA to create a separate category of cultural resources, "tribal cultural resources" (Pub. Resources Code §21074) and provides that a project with an effect that may cause a substantial adverse change in the significance of a tribal cultural resource is a project that may have a significant effect on the environment. (Pub. Resources Code §21084.2). Public agencies shall, when feasible, avoid damaging effects to any tribal cultural resource. (Pub. Resources Code §21084.3 (a)). **AB 52 applies to any project for which a notice of preparation, a notice of negative declaration, or a mitigated negative declaration is filed on or after July 1, 2015.** If your project involves the adoption of or amendment to a general plan or a specific plan, or the designation or proposed designation of open space, on or after March 1, 2005, it may also be subject to Senate Bill 18 (Burton, Chapter 905, Statutes of 2004) (SB 18). **Both SB 18 and AB 52 have tribal consultation requirements**. If your project is also subject to the federal National Environmental Policy Act (42 U.S.C. § 4321 et seq.) (NEPA), the tribal consultation requirements of Section 106 of the National Historic Preservation Act of 1966 (154 U.S.C. 300101, 36 C.F.R. §800 et seq.) may also apply.

The NAHC recommends consultation with California Native American tribes that are traditionally and culturally affiliated with the geographic area of your proposed project as early as possible in order to avoid inadvertent discoveries of Native American human remains and best protect tribal cultural resources. Below is a brief summary of portions of AB 52 and SB 18 as well as the NAHC's recommendations for conducting cultural resources assessments.

Consult your legal counsel about compliance with AB 52 and SB 18 as well as compliance with any other applicable laws.

AB 52

AB 52 has added to CEQA the additional requirements listed below, along with many other requirements:

1. Fourteen Day Period to Provide Notice of Completion of an Application/Decision to Undertake a Project: Within fourteen (14) days of determining that an application for a project is complete or of a decision by a public agency to undertake a project, a lead agency shall provide formal notification to a designated contact of, or tribal representative of, traditionally and culturally affiliated California Native American tribes that have requested notice, to be accomplished by at least one written notice that includes:

- **a.** A brief description of the project.
- **b.** The lead agency contact information.
- **c.** Notification that the California Native American tribe has 30 days to request consultation. (Pub. Resources Code §21080.3.1 (d)).
- **d.** A "California Native American tribe" is defined as a Native American tribe located in California that is on the contact list maintained by the NAHC for the purposes of Chapter 905 of Statutes of 2004 (SB 18). (Pub. Resources Code §21073).

2. Begin Consultation Within 30 Days of Receiving a Tribe's Request for Consultation and Before Releasing a Negative Declaration, Mitigated Negative Declaration, or Environmental Impact Report: A lead agency shall begin the consultation process within 30 days of receiving a request for consultation from a California Native American tribe that is traditionally and culturally affiliated with the geographic area of the proposed project. (Pub. Resources Code §21080.3.1, subds. (d) and (e)) and prior to the release of a negative declaration, mitigated negative declaration or Environmental Impact Report. (Pub. Resources Code §21080.3.1(b)).

- **a.** For purposes of AB 52, "consultation shall have the same meaning as provided in Gov. Code §65352.4 (SB 18). (Pub. Resources Code §21080.3.1 (b)).

3. Mandatory Topics of Consultation If Requested by a Tribe: The following topics of consultation, if a tribe requests to discuss them, are mandatory topics of consultation:

- **a.** Alternatives to the project.
- **b.** Recommended mitigation measures.
- **c.** Significant effects. (Pub. Resources Code §21080.3.2 (a)).

4. Discretionary Topics of Consultation: The following topics are discretionary topics of consultation:

- **a.** Type of environmental review necessary.
- **b.** Significance of the tribal cultural resources.
- **c.** Significance of the project's impacts on tribal cultural resources.
- **d.** If necessary, project alternatives or appropriate measures for preservation or mitigation that the tribe may recommend to the lead agency. (Pub. Resources Code §21080.3.2 (a)).

5. Confidentiality of Information Submitted by a Tribe During the Environmental Review Process: With some exceptions, any information, including but not limited to, the location, description, and use of tribal cultural resources submitted by a California Native American tribe during the environmental review process shall not be included in the environmental document or otherwise disclosed by the lead agency or any other public agency to the public, consistent with Government Code §6254 (r) and §6254.10. Any information submitted by a California Native American tribe during the consultation or environmental review process shall be published in a confidential appendix to the environmental document unless the tribe that provided the information consents, in writing, to the disclosure of some or all of the information to the public. (Pub. Resources Code §21082.3 (c)(1)).

6. Discussion of Impacts to Tribal Cultural Resources in the Environmental Document: If a project may have a significant impact on a tribal cultural resource, the lead agency's environmental document shall discuss both of the following:

- **a.** Whether the proposed project has a significant impact on an identified tribal cultural resource.
- **b.** Whether feasible alternatives or mitigation measures, including those measures that may be agreed to pursuant to Public Resources Code §21082.3, subdivision (a), avoid or substantially lessen the impact on the identified tribal cultural resource. (Pub. Resources Code §21082.3 (b)).

7. Conclusion of Consultation: Consultation with a tribe shall be considered concluded when either of the following occurs:

a. The parties agree to measures to mitigate or avoid a significant effect, if a significant effect exists, on a tribal cultural resource; or

b. A party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached. (Pub. Resources Code §21080.3.2 (b)).

8. Recommending Mitigation Measures Agreed Upon in Consultation in the Environmental Document: Any mitigation measures agreed upon in the consultation conducted pursuant to Public Resources Code §21080.3.2 shall be recommended for inclusion in the environmental document and in an adopted mitigation monitoring and reporting program, if determined to avoid or lessen the impact pursuant to Public Resources Code §21082.3, subdivision (b), paragraph 2, and shall be fully enforceable. (Pub. Resources Code §21082.3 (a)).

9. Required Consideration of Feasible Mitigation: If mitigation measures recommended by the staff of the lead agency as a result of the consultation process are not included in the environmental document or if there are no agreed upon mitigation measures at the conclusion of consultation, or if consultation does not occur, and if substantial evidence demonstrates that a project will cause a significant effect to a tribal cultural resource, the lead agency shall consider feasible mitigation pursuant to Public Resources Code §21084.3 (b). (Pub. Resources Code §21082.3 (e)).

10. Examples of Mitigation Measures That, If Feasible, May Be Considered to Avoid or Minimize Significant Adverse Impacts to Tribal Cultural Resources:

a. Avoidance and preservation of the resources in place, including, but not limited to:

i. Planning and construction to avoid the resources and protect the cultural and natural context.

ii. Planning greenspace, parks, or other open space, to incorporate the resources with culturally appropriate protection and management criteria.

b. Treating the resource with culturally appropriate dignity, taking into account the tribal cultural values and meaning of the resource, including, but not limited to, the following:

i. Protecting the cultural character and integrity of the resource.

ii. Protecting the traditional use of the resource.

iii. Protecting the confidentiality of the resource.

c. Permanent conservation easements or other interests in real property, with culturally appropriate management criteria for the purposes of preserving or utilizing the resources or places.

d. Protecting the resource. (Pub. Resource Code §21084.3 (b)).

e. Please note that a federally recognized California Native American tribe or a non-federally recognized California Native American tribe that is on the contact list maintained by the NAHC to protect a California prehistoric, archaeological, cultural, spiritual, or ceremonial place may acquire and hold conservation easements if the conservation easement is voluntarily conveyed. (Civ. Code §815.3 (c)).

f. Please note that it is the policy of the state that Native American remains and associated grave artifacts shall be repatriated. (Pub. Resources Code §5097.991).

11. Prerequisites for Certifying an Environmental Impact Report or Adopting a Mitigated Negative Declaration or Negative Declaration with a Significant Impact on an Identified Tribal Cultural Resource: An Environmental Impact Report may not be certified, nor may a mitigated negative declaration or a negative declaration be adopted unless one of the following occurs:

a. The consultation process between the tribes and the lead agency has occurred as provided in Public Resources Code §21080.3.1 and §21080.3.2 and concluded pursuant to Public Resources Code §21080.3.2.

b. The tribe that requested consultation failed to provide comments to the lead agency or otherwise failed to engage in the consultation process.

c. The lead agency provided notice of the project to the tribe in compliance with Public Resources Code §21080.3.1 (d) and the tribe failed to request consultation within 30 days. (Pub. Resources Code §21082.3 (d)).

The NAHC's PowerPoint presentation titled, "Tribal Consultation Under AB 52: Requirements and Best Practices" may be found online at: http://nahc.ca.gov/wp-content/uploads/2015/10/AB52TribalConsultation_CalEPAPDF.pdf

SB 18

SB 18 applies to local governments and requires local governments to contact, provide notice to, refer plans to, and consult with tribes prior to the adoption or amendment of a general plan or a specific plan, or the designation of open space. (Gov. Code §65352.3). Local governments should consult the Governor's Office of Planning and Research's "Tribal Consultation Guidelines," which can be found online at: https://www.opr.ca.gov/docs/09_14_05_Updated_Guidelines_922.pdf.

Some of SB 18's provisions include:

1. Tribal Consultation: If a local government considers a proposal to adopt or amend a general plan or a specific plan, or to designate open space it is required to contact the appropriate tribes identified by the NAHC by requesting a "Tribal Consultation List." If a tribe, once contacted, requests consultation the local government must consult with the tribe on the plan proposal. **A tribe has 90 days from the date of receipt of notification to request consultation unless a shorter timeframe has been agreed to by the tribe.** (Gov. Code §65352.3 (a)(2)).
2. No Statutory Time Limit on SB 18 Tribal Consultation. There is no statutory time limit on SB 18 tribal consultation.
3. Confidentiality: Consistent with the guidelines developed and adopted by the Office of Planning and Research pursuant to Gov. Code §65040.2, the city or county shall protect the confidentiality of the information concerning the specific identity, location, character, and use of places, features and objects described in Public Resources Code §5097.9 and §5097.993 that are within the city's or county's jurisdiction. (Gov. Code §65352.3 (b)).
4. Conclusion of SB 18 Tribal Consultation: Consultation should be concluded at the point in which:
    a. The parties to the consultation come to a mutual agreement concerning the appropriate measures for preservation or mitigation; or
    b. Either the local government or the tribe, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached concerning the appropriate measures of preservation or mitigation. (Tribal Consultation Guidelines, Governor's Office of Planning and Research (2005) at p. 18).

Agencies should be aware that neither AB 52 nor SB 18 precludes agencies from initiating tribal consultation with tribes that are traditionally and culturally affiliated with their jurisdictions before the timeframes provided in AB 52 and SB 18. For that reason, we urge you to continue to request Native American Tribal Contact Lists and "Sacred Lands File" searches from the NAHC. The request forms can be found online at: http://nahc.ca.gov/resources/forms/.

NAHC Recommendations for Cultural Resources Assessments

To adequately assess the existence and significance of tribal cultural resources and plan for avoidance, preservation in place, or barring both, mitigation of project-related impacts to tribal cultural resources, the NAHC recommends the following actions:

1. Contact the appropriate regional California Historical Research Information System (CHRIS) Center (http://ohp.parks.ca.gov/?page_id=1068) for an archaeological records search. The records search will determine:
    a. If part or all of the APE has been previously surveyed for cultural resources.
    b. If any known cultural resources have already been recorded on or adjacent to the APE.
    c. If the probability is low, moderate, or high that cultural resources are located in the APE.
    d. If a survey is required to determine whether previously unrecorded cultural resources are present.

2. If an archaeological inventory survey is required, the final stage is the preparation of a professional report detailing the findings and recommendations of the records search and field survey.
    a. The final report containing site forms, site significance, and mitigation measures should be submitted immediately to the planning department. All information regarding site locations, Native American human remains, and associated funerary objects should be in a separate confidential addendum and not be made available for public disclosure.

b. The final written report should be submitted within 3 months after work has been completed to the appropriate regional CHRIS center.

3. Contact the NAHC for:

a. A Sacred Lands File search. Remember that tribes do not always record their sacred sites in the Sacred Lands File, nor are they required to do so. A Sacred Lands File search is not a substitute for consultation with tribes that are traditionally and culturally affiliated with the geographic area of the project's APE.

b. A Native American Tribal Consultation List of appropriate tribes for consultation concerning the project site and to assist in planning for avoidance, preservation in place, or, failing both, mitigation measures.

4. Remember that the lack of surface evidence of archaeological resources (including tribal cultural resources) does not preclude their subsurface existence.

a. Lead agencies should include in their mitigation and monitoring reporting program plan provisions for the identification and evaluation of inadvertently discovered archaeological resources per Cal. Code Regs., tit. 14, §15064.5(f) (CEQA Guidelines §15064.5(f)). In areas of identified archaeological sensitivity, a certified archaeologist and a culturally affiliated Native American with knowledge of cultural resources should monitor all ground-disturbing activities.

b. Lead agencies should include in their mitigation and monitoring reporting program plans provisions for the disposition of recovered cultural items that are not burial associated in consultation with culturally affiliated Native Americans.

c. Lead agencies should include in their mitigation and monitoring reporting program plans provisions for the treatment and disposition of inadvertently discovered Native American human remains. Health and Safety Code §7050.5, Public Resources Code §5097.98, and Cal. Code Regs., tit. 14, §15064.5, subdivisions (d) and (e) (CEQA Guidelines §15064.5, subds. (d) and (e)) address the processes to be followed in the event of an inadvertent discovery of any Native American human remains and associated grave goods in a location other than a dedicated cemetery.

If you have any questions or need additional information, please contact me at my email address: Cameron.Vela@nahc.ca.gov.

Sincerely,

Cameron Vela

Cameron Vela
Cultural Resources Analyst

cc: State Clearinghouse

Office Memorandum

KERN COUNTY

To: Planning and Natural Resources Department
Cindi Hoover

Date: March 9, 2022

From: Public Works Department
Floodplain Management Section
Kevin Hamilton, by Brian Blase

Phone: (661) 862-5098
Email: BlaseB@kerncounty.com

Subject: Notice of Preparation of Environmental Impact Report
Carbon Terra Vault 1 by California Resources Corporation (PP22405)

From the information supplied, we have no comments or recommendations regarding the above project.

Cindi Hoover

From: Stephen Reid <dacite.plug@outlook.com>
Sent: Tuesday, March 15, 2022 4:44 PM
To: Cindi Hoover
Subject: CRC's Carbon Capture Project at Elk Hills

CAUTION: This email originated from outside of the organization. Do not click links, open attachments, or provide information unless you recognize the sender and know the content is safe.

Hello,

I got this email address from the Bakersfield Californian article about the planned environmental study at Elk Hills. I followed the link to the additional information, and was left with some questions. Has CRC provided more detailed information on the petroleum reservoirs that will receive the CO2? More specifically, information on reservoir pressure, data to support volumetric estimates, or vertical and lateral seal competencies? Seems like these are important questions to answer before designing the environmental review contents. Is there a CRC document that may be review by the public that may hold some of the answers to these questions?

Thank you.

Stephen Anthony Reid, PG

Sent from Mail for Windows

KERN COUNTY
Public Health Services
DEPARTMENT

BRYNN CARRIGAN
DIRECTOR

KRISTOPHER LYON, MD
HEALTH OFFICER

2700 M STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301-2370 661-862-8740 WWW.KERNPUBLICHEALTH.COM

INTEROFFICE MEMORANDUM

To: Cindi Hoover, Supervising Planner Date: March 23, 2022
From: Dayana Torres, EHS
Subject: Draft EIR - Carbon Terra Vault 1 by California Resources Corporation, ZM 5, CUP 5, Map 119

The Kern County Environmental Health Division has reviewed the above referenced project. This Division has the local regulatory authority to enforce state regulations and local codes as they relate to waste discharge, water supply requirements, and other items that may affect the health and safety of the public or that may be detrimental to the environment.

The design of the project or the type of improvement is not likely to cause serious public health problems; therefore, this Division has no comments or recommendations and does not wish to impose any conditions on the subject project.

California Department of Transportation

DISTRICT 6 OFFICE
1352 WEST OLIVE AVENUE | P.O. BOX 12616 | FRESNO, CA 93778-2616
(559) 981-7066 | FAX (559) 488-4195 | TTY 711
www.dot.ca.gov

March 24, 2022

06-KER-58-R23.781
NOP DEIR
CARBON TERRAVAULT
GTS #: #36250

SENT VIA EMAIL

Ms. Cindi Hoover, Planner II
Kern County Planning and Natural Resources
2700 M Street, Suite 100
Bakersfield, CA 93301

Dear Ms. Hoover:

Thank you for the opportunity to review the Notice of Preparation of Draft Environmental Impact Report for the Carbon Terravault 1 Carbon Capture and Sequestration Project. The proposed project is a Conditional Use Permit for a 5,332.34-acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells and related improvements for storage of Carbon Dioxide (CO2). The project site is located on the West side of Elk Hills Road and north Side of Skyline Road, within the Elk Hills Oil Field in Kern County.

The mission of Caltrans is to provide a safe and reliable transportation network that serves all people and respects the environment. The **Local Development Review (LDR) process** reviews land use projects and plans through the lenses of our mission and state planning priorities of infill, conservation, and travel-efficient development. To ensure a safe and efficient transportation system, we encourage early consultation and coordination with local jurisdictions and project proponents on all development projects that utilize the multimodal transportation network.

Caltrans provides the following comments consistent with the State's smart mobility goals that support a vibrant economy and sustainable communities:

1. A traffic control permit may be required during the construction phase if large construction vehicles and equipment will use the State Highway System. These large vehicles travel at slow speeds, potentially requiring warning signs and traffic control. **Please call the Caltrans Encroachment Permit Office District 6: 1352 W. Olive, Fresno, CA 93778, at (559) 383-5047 or (559) 383-5235** to submit a traffic control permit.

2. Prior to an encroachment permit application submittal, the project proponent is required to schedule a "Pre-Submittal" meeting with District 6 Encroachment Permit Office. To schedule this meeting, please call the Caltrans Encroachment Permit Office - District 6: 1352 W. Olive, Fresno, CA 93778, **at (559) 383-5047 or (559) 383-5235.**

3. Please review the permit application **- required document checklist at:** https://forms.dot.ca.gov/v2Forms/servlet/FormRenderer?frmid=TR0402&distpath=MAOTO&brapath=PERM.

4. Please **also** review the permit application **- processing checklist at:** https://dot.ca.gov/-/media/dot-media/programs/traffic-operations/documents/encroachment-permits/tr-0416-applicable-review-process-checklist.pdf.

If you have any other questions, please call Lupita Mendoza, Associate Transportation Planner at (559) 981-7066.

Sincerely,

Lorena Mendibles

LORENA MENDIBLES, Chief
Transportation Planning – South

Kern County
Superintendent of Schools

Office of Mary C. Barlow ...advocates for children

March 14, 2022

Kern County Planning Department
Attn: Cindy Hoover
2700 M Street, Suite 100
Bakersfield, CA 93301

Our File No.: CO22-0027

RE: **DEVELOPER FEES FOR**: NOP Draft EIR for the Carbon Terravault Carbon Capture and Sequestration Project; Map No. 118-12, 119-7, 8, 17, 18, 22 ,25-27, 35, 36 & 120-31
(West side of Elk Hills Rd. and north side of Skyline Rd, within the Elk Hills Oil Field)

Dear Ms. Hoover,

This office represents the Buttonwillow and Kern High School Districts with regard to the imposition of developer fees, and appreciates the opportunity to respond on behalf of these districts regarding the proposed project. This letter is limited to addressing the possible effects which the project might have on school facilities created by students attributable to the project. It is not intended to address other possible environmental concerns which might be identified by the district(s) after reviewing it.

Please note: this project is also within the boundaries of the Elk Hills, Taft and McKittrick School Districts. This project should be reviewed by these districts for comment.

It is our determination that the above mentioned project proposing a Zone Change from A-1 (Limited Agriculture) to A (Exclusive Agriculture) and three Conditional Use Permits to allow for the construction and operation of a 5,332.34-acre carbon capture and sequestration field and accessory infrastructure with a CO2 storage capacity of 48 million metric tons, within the A Zone District will have no significant effects on either of these district's facilities so long as statutory school facilities fees, if any, are collected as required by law and that no further mitigation measures regarding school facilities are necessary. However, in the event that further general plan amendments and/or zone changes are proposed for this property which would permit denser development, the districts could be significantly impacted and additional mitigation measures would perhaps be required.

Thank you for the opportunity to comment on the project. Should you have any questions, or if we can be of any further assistance in this matter, please contact me at 636-4599, or through e-mail at anwatson@kern.org.

Sincerely,

MAR 22 2022

Kern County Planning & Natural Resources Dept.

Mary C. Barlow
County Superintendent of Schools

awatson

Andrea Watson, Specialist
School District Facility Services

ALW
cc: District(s)

Kern Audubon Society
Attn: Franklin Bedard
P.O. Box 3581
Bakersfield, CA 93385
mbedard@bak.rr.com

April 2, 2022 *submitted electronically*

Cindi Hoover, Supervising Planner
Kern County Planning and Natural Resources Department
2700 "M" Street, Suite 100
Bakersfield, CA 93301
hooverc@kerncounty.com

Subject: **Notice of Preparation of a Draft Environmental Impact Report**
The Carbon Terravault 1 (CTV 1) Carbon Capture and Sequestration Project by California Resources Corporation (CRC)

Dear Ms Hoover:

The Kern Audubon Society (KAS), an interested party, received a notice of availability concerning a Notice of Preparation (NOP) for a Draft Environmental Impact Report (DEIR) from the Kern County Planning and Natural Resources Department (County) for the above referenced Project pursuant to the California Environmental Quality Act (CEQA) and CEQA Guidelines.

Thank you for the opportunity to provide comments concerning the scope and content of the environmental analysis of the Project that may affect the diverse California wildlife within the Project's footprint and its cumulative impacts in the region.

The DEIR for the proposed 5,332.34 acre project located in the Central Valley Region of unincorporated Kern County, within the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield, approximately 8.5 miles from the City of Taft, and approximately 4 miles from the unincorporated community of Buttonwillow should identify and evaluate potential adverse impacts to protected species that may utilize the disturbed and undeveloped scrub areas proposed for the Project activities. The developed and undeveloped areas within the Elk Hills Oil Field have potential to support San Joaquin kit

fox, Blunt-nosed leopard lizard, American badger, San Joaquin antelope squirrel, Tipton kangaroo rat, Giant kangaroo rat, Western burrowing owl, Swainson's hawk, Golden eagle, and loggerhead shrike. As the proposed project is to be sited within the existing Elk Hills Oil Production area, KAS hopes to see the Project utilize the already disturbed portions of the area while minimizing disturbances to existing native ground and vegetation.

The biological site evaluation should be performed by qualified biological consultants using the appropriate survey protocols as established by both state and federal wildlife agencies. It is imperative that all biological surveys be performed during the appropriate time of year to discern species presence for this eco-region. Species presence or absence can be influenced by seasonal drought conditions so it is imperative that surveys be performed during years exhibiting average winter precipitation.

KAS appreciates the opportunity to comment on the NOP for the CTV 1 Project DEIR and to assist the County in identifying Project impacts on sensitive biological resources endemic to this region of Kern County.

Sincerely,

Franklin Bedard
Conservation Chair
Kern Audubon Society

April 4, 2022

Kern County Planning and Natural Resources Department
Cindi Hoover
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Re: Notice of Preparation of a Draft Environmental Impact Report for the Carbon Terravault 1 Carbon Capture and Sequestration Project by California Resources Corporation

To the Kern County Planning and Natural Resources Department:

The Center for Biological Diversity and Central Valley Air Quality Coalition submit comments on the Notice of Preparation ("NOP") of an Environmental Impact Report for the Carbon TerraVault 1 Carbon Capture and Sequestration Project by California Resources Corporation (the "project"). The proposed project involves transporting "local industrial sources" of carbon dioxide ("CO_2") to four to six injection wells in the Elk Hills oilfield that have the capacity to store 48 million metric tons of CO_2 at a rate of more than 1.5 million metric tons per year.

Our organizations disagree with the premise that carbon capture and sequestration ("CCS") projects should play a role in achieving our state's goal of reaching near-zero emissions by midcentury in order to limit global warming to 1.5°C. CCS is a false solution that diverts attention and resources from clean renewable energy. In order to decarbonize, we must stop permitting projects that further entrench fossil fuels. Storing carbon underground in an oilfield prolongs the life of the field and the life of whatever industrial facility the carbon is sourced from. Instead of approving carbon storage, the County should phase out fossil fuel development to prevent catastrophic climate change and environmental injustice.

If the County continues to consider the project, as explained in detail below, it must adequately define the project and analyze the potential impacts to the environment in detail. Without more information about the source of carbon, method of transportation, location of the project, and timeline, the community and County decisionmakers will not be able to assess all of the environmental impacts. Storing carbon underground can contaminate drinking water, trigger earthquakes, and result in dangerous carbon leaks. And the County must pay special attention to the risks here, where the project applicant says it will store CO_2 "in perpetuity." Unless the company posts a bond, submits a long-term monitoring plan, and provides other assurances that it will have the financial resources to find and fix leaks, the County is taking a gamble that the recently-bankrupt California Resources Corporation ("CRC") will be around to clean up any future problems. Much more detail is required in the Environmental Impact Report ("EIR"), and the County should deny the requested conditional use permit.

I. The Kern County Planning Department Should Provide the Public with 90 Days for Comment and at Least Two Hearings on the Draft EIR.

While we recognize that the present comment period is on the NOP for the EIR, for the

reasons described below, we urge the County to offer at least 90 days for public comment on the draft Carbon TerraVault EIR.[1] The County should also hold at least two public hearings once the draft EIR is available.[2] We also request that the County translate the EIR and other key documents—including press releases, summaries, and presentations—into Spanish, Punjabi and any other language translation requested by county residents. In light of the significant Spanish- and Punjabi- speaking populations near the proposed project site and throughout Kern County, the County should also provide Spanish, Punjabi, or other language interpretation requested at any public meetings.

First, to our knowledge, the Carbon TerraVault analysis will be the first EIR ever prepared for a carbon sequestration and storage project. The novelty of this project type necessitates that the public and decisionmakers—who have no experience reviewing CCS projects under the California Environmental Quality Act ("CEQA")—be given more time to review the impacts and proposed mitigation.

Second, carbon sequestration projects produce an array significant public safety and environmental impacts, such as groundwater contamination, dangerous releases of compressed CO_2, earthquakes, and air pollution.[3] The public needs more than 30 days to review an EIR discussing such a wide array of significant impacts that could result from deployment of technology that is new to the state.

Third, the proposed project location is near highly-impacted, vulnerable, and overburdened residents of the San Joaquin Valley who care deeply about their communities' wellbeing and future economic development. The input, questions, and perspectives of those who will be most affected by the proposed projects must be heard, and allowing only 30 days for review and comment on the EIR—or requiring residents to seek a comment extension and wait for an answer—does not serve this purpose. In addition, there is widespread and growing concern over CCS from community, environmental justice, and other groups across the state and country.[4] It is likely that many who are outside the Valley will want to take a close look at the draft EIR and provide the County with input, concerns, and questions.

For these reasons, it is imperative that the County provide at least 90 days for public comment throughout the CEQA process, hold at least two hearings on the draft EIR, and translate all materials and hearings.

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[1] Cal. Code Regs. tit. 14, § 15087(d) (directing that the public be given "*at least* 30 days" for comment).
[2] *Id.* § 15087(i).
[3] Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells – Final Rule, 75 Fed. Reg. 77230, 77234 (Dec. 10, 2010) (to be codified at 40 C.F.R. Pts 124, 144, 145, 146, 147); Miss. Emergency Mgmt. Agency, *Pipeline Ruptures in Yazoo County, Dozens Rushed to the Hospital*, Miss. Emergency Mgmt. Agency, Feb. 23, 2020, https://www.msema.org/news/pipe-ruptures-in-yazoo-county-dozens-hospitalized/; Vinca, A. et al., Bearing the Cost of Stored Carbon Leakage, 6 Frontiers in Energy Rese. Art. 40 (2018), https://www.frontiersin.org/articles/10.3389/fenrg.2018.00040/full; Zoback, Mark D. et al., Earthquake triggering and large-scale geologic storage of carbon dioxide, 109 PNAS 10164 (2012), https://www.pnas.org/content/109/26/10164.
[4] The 1,500 member-organizations of Climate Action Network ("CAN") International adopted a shared position statement stating that the members "do[] not consider currently envisioned CCS applications as proven sustainable climate solutions." Climate Action Network, Position: Carbon Capture, Storage, and Utilization, Climate Action Network Int'l at 6 (2021), https://climatenetwork.org/resource/can-position-carbon-capture-storage-and-utilisation/. In July 2021, over 500 organizations sent an open letter to lawmakers calling on them to reject CCS as a "dangerous distraction." Center for International Environmental Law, Letter Re: Carbon capture is not a climate solution (July 19, 2021), https://www.ciel.org/wp-content/uploads/2021/07/CCS-Letter_FINAL_US-1.pdf.

II. Instead of Creating Carbon Storage, the County Must End Fossil Fuel Development to Prevent Catastrophic Climate Change and Halt Further Environmental Injustices.

From the outset, we reject the premise that CCS is a necessary—or even appropriate—approach to addressing the climate crisis and pollution burdens borne by frontline communities. Further, the proposed project *itself* will emit greenhouse gases ("GHGs"), even if it purports to capture and store other sources' climate-harming emissions. As such, the proposed project is inconsistent with California's goals to reduce emissions and protect vulnerable residents.

CCS is a false climate solution championed by polluting industries—such as the biomass and fossil fuel industries—to enable business-as-usual operations, all while diverting resources from the needed transition to clean, cheaper renewable energy. In fact, CCS is *not* required under Intergovernmental Panel on Climate Change pathways to limit temperature rise to 1.5°C and avert climate catastrophe.[5] At the state level, CCS is also not necessary for California to achieve its climate goals, and deploying CCS would be inconsistent with state orders directing that policies and programs undertaken to achieve carbon neutrality must "improve air quality and support the health and economic resiliency of . . . particularly low-income and disadvantaged communities."[6]

After billions of dollars of investment and decades of development, CCS projects around the world have consistently failed to meet their GHG emission reduction promises. In July 2021, Chevron, operator of Australia's only commercial-scale CCS project, admitted that its self-described "world's biggest CCS project" failed to meet its five-year target of sequestering 80% CO_2,[7] instead only sequestering 30%.[8] In the U.S., CCS equipment on the Petra Nova coal-fired powerplant in Texas achieved only a 50% CO_2 capture rate,[9] before being shut down indefinitely for being uneconomic. And these real-world failures of CCS projects do not even take into account the *lifecycle* emissions of CCS projects. One Stanford study of the lifecycle emissions

[5] The IPCC-modeled pathway with the best chance of keeping warming at or below the target of 1.5°C makes no use of fossil fuels with carbon capture and storage (CCS) or bioenergy with carbon capture and storage (BECCS). IPCC, Summary for Policymakers in Global Warming of 1.5°C: An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty (2018) [hereinafter IPCC SR1.5] at 14, Section C.1.1., Figure SPM 3b (Pathway 1); *see also* IPCC SR1.5, at Ch. 2.3.3 and Table 2.SM.12. *See also* Center for International Environmental Law, Confronting the Myth of Carbon Free Fossil Fuels at 2, https://www.ciel.org/wp-content/uploads/2021/07/Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf [hereinafter *CIEL CCS Report*].

[6] State of California, Executive Department, Executive Order B-55-18 (2018), https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

[7] Mazengarb, Michael, *Chevron admits failure of $3 billion CCS facility in Western Australia*, Inst. For Energy Econ. & Fin. Analysis (July 19, 2021), https://ieefa.org/chevron-admits-failure-of-3-billion-ccs-facility-in-western-australia/.

[8] Milne, Peter, *Chevron's five years of Gorgon carbon storage failure could cost $230 million*, Sydney Morning Herald, Nov. 11, 2021, https://www.smh.com.au/environment/climate-change/chevron-s-five-years-of-gorgon-carbon-storage-failure-could-cost-230-million-20211110-p597uf.html; Morton, Adam, *'A shocking failure': Chevron criticized for missing carbon capture target at WA gas project*, Guardian, July 18, 2021, https://www.theguardian.com/environment/2021/jul/20/a-shocking-failure-chevron-criticised-for-missing-carbon-capture-target-at-wa-gas-project.

[9] Schlissel, David, *IEEFA op-ed: Reality of carbon capture not even close to proponents' wishful thinking*, Inst. For Energy Econ. & Fin. Analysis (Aug. 8, 2019), https://ieefa.org/reality-of-carbon-capture-not-even-close-to-proponents-wishful-thinking/.

associated with Petra Nova CCS project found that "the [CCS] equipment captured the equivalent of only 10-11% of the emissions they produced, averaged over 20 years."[10]

When the lifecycle GHG impacts of carbon capture and storage are taken into account, any purported climate benefits evaporate. For one, carbon capture is incredibly energy intensive, reducing the net GHG benefits.[11] Second, there is always a risk that CO_2 transported via pipeline, rail, or truck, and then stored underground, could leak back to the atmosphere.[12] Researchers estimate that a minor leakage of stored CO_2 could reduce the benefit of CCS by up to 35%.[13] Third, lifecycle studies of CCS projects show that CCS "reduces only a small fraction of carbon emissions, and it usually increases air pollution."[14] A Stanford study recommended replacing fossil fuels with renewables such as wind or solar, rather than encouraging and investing in CCS.[15]

Because CCS is commonly used to perpetuate the fossil fuel industry, these investments prolong the transition to renewable energy. It is estimated that over 80% of global captured carbon is used to increase oil production through "enhanced oil recovery."[16] CCS can further entrench fossil fuels even if carbon is not used to directly recover more oil. For example, Carbon TerraVault's application to the Environmental Protection Agency ("EPA") for a Class VI permit mentions that the CO_2 for the Carbon TerraVault project may be sourced from the Elk Hills 550 MW gas power plant.[17] This power plant supplies electricity for the Elk Hills oilfield, including to power enhanced oil recovery and other injection and production activities.[18] Investment in the gas plant could incentivize CRC to keep the plant (and the extraction it enables) running beyond its otherwise useful life. The extraction of gas itself is also a major source of GHGs *beyond* what

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[10] Jacobson, Mark Z., The health and climate impacts of carbon capture and direct air capture, 12 Energy Envt. Sci. 3567 (2019), https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b/unauth#!divAbstract. This research also considered the social cost of carbon capture—in other words, the resulting air pollution, potential health problems, economic costs and overall contributions to climate change—and concluded that these costs are similar to or higher than a fossil fuel plant *without* carbon capture, meaning "it is always better to use the renewable electricity instead to replace coal or natural gas electricity or to do nothing." *Id.*

[11] Butler, Clark, Carbon Capture and Storage Is About Reputation, Not Economics, Inst. For Energy Econ. & Fin. Analysis at 4 (2020), https://ieefa.org/wp-content/uploads/2020/07/CCS-Is-About-Reputation-Not-Economics_July-2020.pdf.

[12] The 2015-16 Aliso Canyon natural gas blowout released over 97,000 metric tons of methane, effectively doubling the Los Angeles basin's methane emission rate. Conley. S. et al., Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA, 351 Science 1317 (2016), https://science.sciencemag.org/content/351/6279/1317.

[13] Vinca, A. et al., Bearing the Cost of Stored Carbon Leakage, 6 Frontiers in Energy Res. Art. 40 (2018), https://www.frontiersin.org/articles/10.3389/fenrg.2018.00040/full.

[14] Jacobson, Mark Z., The health and climate impacts of carbon capture and direct air capture, 12 Energy Envt. Sci. 3567 (2019), https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b/unauth#!divAbstract.

[15] *Id.* ("There is a lot of reliance on carbon capture in theoretical modeling, and by focusing on that as even a possibility, that diverts resources away from real solutions. It gives people hope that you can keep fossil fuel power plants alive. It delays action. In fact, carbon capture and direct air capture are always opportunity costs.").

[16] Garcia Freites, S & C. Jones, A Review of the Role of Fossil Fuel-Based Carbon Capture and Storage in the Energy System, Tyndall Centre (2021), https://www.research.manchester.ac.uk/portal/files/184755890/CCS_REPORT_FINAL_v2_UPLOAD.pdf. Expanding EOR in the United States could result in an additional 400,000 barrels per day oil production by 2035, which would directly lead to as much as 50.7 million metric tons of net CO2 emissions annually. Oil Change International, Expanding Subsidies for CO2-Enhanced Oil Recovery: A Net Loss for Communities, Taxpayers, and the Climate (2017), https://priceofoil.org/content/uploads/2017/10/45q-analysis-oct-2017-final.pdf.

[17] Carbon TerraVault 1, EPA Class VI Application, Attachment A: Class VI Permit Application Narrative for Elk Hills A1-S2 Storage at 1 (2020).

[18] California Resources Corporation, Elk Hills Field, https://crc.com/our-business/where-we-operate/san-joaquin-basin/elk-hills-field (last visited Mar. 31, 2022).

comes out of the stack. These lifecycle emissions of gas are simply not captured for potential storage.

Carbon TerraVault alternatively mentions that CO_2 could come from "renewable diesel refineries, and/or other sources in the EHOF area." This could lead to restart and entrenchment of facilities that will emit GHG emissions along with harmful air pollution. For example, a CCS project proposed in Mendota would restart an idle biomass plant that was a major source of local air pollution. Generally, power plants and industries that sequester CO_2 are energy-intensive, using 15 to 25% more energy to produce the same amount of power as a conventional plant, and emitting more air pollution, including fine particulate matter, ammonia, hazardous volatile organic compounds, and other toxic pollutants that threaten the health of nearby communities.[19]

Finally, the Carbon Terravault project will *itself* be an emitter of GHGs from activities such as carbon transportation, compression, and injection, meaning the claims that the project will somehow be GHG neutral or negative are simply untrue.

III. More Information is Required to Properly Describe the Project and Analyze its Impacts Under CEQA.

The NOP does not adequately describe the project. The EIR must include a much more detailed description to enable decision-making that considers environmental consequences and environmental characteristics.[20] Under CEQA, a project description must represent the "whole of an action" to be undertaken by the lead agency; "an accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity."[21] Moreover, the project description and analysis must include "future action" that is "a reasonably foreseeable consequence of the initial project" and would "be significant in that it will likely change the scope or nature of the initial project or its environmental effects."[22]

Most critically, the EIR must include detailed information about the source of CO_2 for the project, how that CO_2 will be transported to the injection wells, and the timeline for injection. The NOP merely states that "[t]he proposed project would take local industrial sources of CO_2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project."[23] This is insufficient. Courts have routinely held that EIRs must include information about the associated transportation method and its impacts.[24] The location and form of these project components will dictate environmental impacts and their significance. For instance, the applicant notes that, depending on the transportation option, CO_2 could pass within one quarter mile of a school during transport.[25] Transporting compressed CO_2 so close to a school raises a host of concerns about clean-up risks in the event of an accident. For example,

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[19] European Environment Agency, *Carbon capture and storage could also impact air pollution* https://www.eea.europa.eu/highlights/carbon-capture-and-storage-could (last modified Nov. 23, 2020).
[20] Cal. Code Regs. tit. 14 § 15124.
[21] *San Joaquin Raptor/Wildlife Rescue Ctr. v. Cnty of Stanislaus*, 27 Cal. App. 4th 713, 730 (1994).
[22] *Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.*, 47 Cal. 3d 376, 396 (1988), as modified on denial of reh'g (Jan. 26, 1989).
[23] Kern County Planning and Natural Resources Department, Notice of Preparation of Draft Environmental Impact Report for the Carbon TerraVault 1 Carbon Capture and Sequestration Project by California Resources Corporation (Mar. 4, 2022) at 4 [hereinafter *Elk Hills NOP*].
[24] *See, e.g., Santiago County Water Dist. v County of Orange* (1981) 118 Cal.App.3d 818, 830 (EIR for a sand and gravel mine that failed to describe or analyze the construction of water pipelines that would be needed for mining operations); *Whitman v Board of Supervisors* (1979) 88 Cal.App.3d 397, 414 (EIR for an exploratory oil well should have analyzed the impacts associated with a proposed oil pipeline).
[25] Elk Hills NOP at 35.

an enhanced oil recovery field in Wyoming leaked and spewed carbon into the atmosphere next to a public school, with air pollution so severe that it took almost the entire school year to return the premises to safety.[26] The EIR must provide the precise location and boundaries of the ancillary facilities and the facilities must be detailed on a map.[27]

In prior communications between CRC and Kern County, the County has indicated that "[t]ransport of CO2 by pipeline is covered by Kern County Oil and Gas Ordinance and related [Supplemental Recirculated Environmental Impact Report ("SREIR")] (2020/2021) and requires an Oil and Gas Conformity Review permit for construction and operation."[28] While new CO_2 pipelines certainly should get a permit before construction and operation, Kern County will not be able to rely on the SREIR for an analysis of the pipeline's impacts. If upheld, the SREIR "addresses County jurisdictional activities that occur as ancillary activities *in support of oil and gas production* in these areas, including, for example, electric transmission lines, pipelines, and access roads."[29] CRC has not explained how a CO_2 pipeline transporting carbon to be stored long term in the oil field would support oil and gas production, so should not be able to defer to the SREIR to escape analysis of pipeline impacts..

Similarly, as noted in Section II, the source of carbon has major implications for air pollution impacts and for the overall greenhouse gas emissions that will result from the project. It is "reasonably foreseeable" that CRC's project will restart sources of emissions or extend the life of emissions sources that would otherwise close in the next few decades.

Additional aspects of the project that must be better defined in the EIR include:

- The number and location of injection wells[30]
- The injection rate[31]
- The properties of the carbon to be injected[32]
- Whether new wells will be drilled or existing wells Class II will be converted to Class VI wells

[26] Kusnetz, Nicholas, *Exxon Touts Carbon Capture as a Climate Fix, but Uses It to Maximize Profit and Keep Oil Flowing,* Inside Climate News, Sept. 27, 2020, https://insideclimatenews.org/news/27092020/exxon-carbon-capture/.

[27] Cal. Code Regs. Tit. 14 §15124(a).

[28] Oviatt, Lorelei, to File, Determination on Zoning Classification for Carbon Capture and Sequestration Section 19.08.085 Alternative to Determination of Similar Use (June 21, 2021).

[29] Kern County Oil and Gas Draft SREIR, Project Description (2020), https://psbweb.co.kern.ca.us/UtilityPages/Planning/EIRS/OG_SREIR/aVol1/Oil_Gas_SREIR_Oct%202020_Vol%201_03.0_Project%20Description.pdf at 3-13.

[30] Project location is particularly important for identifying potentially-impacted species and historic sites. In response to CRC's application for a parallel Class VI injection permit, the Environmental Protection Agency ("EPA") has requested that CRC provide more information about species and sites with the help of a wildlife consultant and archaeologist. Albright, David, U.S. EPA, Letter to Travis Hurst, Carbon TerraVault 1, LLC, re: Underground Injection Control Permit Application Technical Review (Dec. 15, 2021).

[31] *See* U.S. EPA, Evaluation of Operating Procedures in Carbon TerraVault's Monterey Formation A1-A2 Permit Application (Jan. 11, 2022) at 6 ("the range of proposed daily injection rates allow for the exceedance of the modeled storage capacity. The applicant should reconcile this inconsistency and provide an updated range of daily CO2 injection rates that satisfies the modeled CO2 storage capacity.")

[32] EPA has asked for more information about fluid properties for the CO_2 injectate used in the computational modeling, including but not limited to viscosity, density, salinity, and fluid compressibility. U.S. EPA, Evaluation of the AoR Delineation Modeling Approach in Carbon TerraVault's Monterey Formation A1-A2 Class VI Permit Application (Jan. 11, 2022) at 9.

- The quantity, location, and impact of the construction of "new internal access roads"[33]
- The project duration[34]

Other aspects of the project description need to be better supported. For example, the EIR should include a carbon migration monitoring and emergency response plan, among other information to support the assertion that carbon will truly be stored "in perpetuity"[35] An analysis of how the planned activities will support jobs and for what length of time should also be provided in consideration of the project objective to "promote economic development and bring living-wage jobs to the region throughout the life of the proposed project."[36]

IV. The County Must Take a Hard Look at the Environmental Impacts of the Project.

The NOP rightly finds that the project has the potential to contribute to significant impacts across almost every environmental issue considered. A thorough assessment of the project's water quality, habitat and wildlife, environmental justice and public health, seismicity, climate change, and other impacts is necessary in achieving the informed decision-making process that affords the fullest protection of communities and the environment. As discussed below, CRC's submissions so far to EPA in the parallel Class VI injection well permit process show that the company has not provided sufficient information about impacts. The EIR must fill in these project analysis gaps.

A. Water quality impacts

Kern County currently faces severe water pollution,[37] and the project threatens to make the problem worse if carbon migrates from the injection sites.

EPA has already noted that CRC needs to provide more water quality information. It has asked the company to review water quality data from existing monitoring wells,[38] document that wells in the field are engineered to ensure protection of drinking water and withstand land subsidence,[39] provide details on the potential for corrosion of injection wells,[40] establish baseline water quality for the overlying Etchegoin/San Joaquin Formations and the Tulare Formation prior to injection,[41] and include more information about post-injection monitoring.[42] This information should also be included in the EIR to help the public and Kern County understand the potential water pollution impacts.

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[33] Elk Hills NOP at 1.
[34] EPA has noted inconsistencies in the project descriptions submitted for Class VI permits; the application indicates injection could happen over a period of 15 or 5 years. U.S. EPA, Evaluation of the AoR Delineation Modeling Approach in Carbon TerraVault's Monterey Formation A1-A2 Class VI Permit Application (Jan. 11, 2022) at 6.
[35] Elk Hills NOP at 35.
[36] *Id.* at 5.
[37] *King & Gardiner Farms, LLC v. Cty. of Kern*, 45 Cal. App. 5th 814, 833, 259 Cal. Rptr. 3d 109, 125 (2020), *as modified on denial of reh'g* (Mar. 20, 2020).
[38] U.S. EPA, Evaluation of the AoR Delineation Modeling Approach in Carbon TerraVault's Monterey Formation A1-A2 Class VI Permit Application (Jan. 11, 2022) at 12.
[39] *Id.* at 11; U.S. EPA, Evaluation of Construction and Plugging Procedures for Injection Well 355-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project (Feb. 3, 2022) at 4-5.
[40] U.S. EPA, Evaluation of Construction and Plugging Procedures for Injection Well 355-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project (Feb. 3, 2022) at 4.
[41] U.S. EPA, Site Characterization Evaluation of the Carbon TerraVault (CTV) Class VI A1-A2 Permit Application (Dec. 15, 2021) at 6.
[42] U.S. EPA, Evaluation of Proposed Testing and Monitoring Activities at Carbon TerraVault's Monterey Formation A1-A2 Class VI Project (Jan. 11, 2022) at 10-11.

B. Habitat and wildlife impacts

The project's construction and operation of the injection wells and other project components, including transportation and carbon capture, will impact biological resources in the Elk Hills area.

Under the California Endangered Species Act, all state agencies "shall seek to conserve endangered species and threatened species."[43] And, "state agencies should not approve projects as proposed which would jeopardize the continued existence of any endangered species or threatened species . . . if there are reasonable and prudent alternatives available."[44] The federal Endangered Species Act[45] also affords protections to imperiled species in the Elk Hills Oil Field area. The area of the project overlaps with the habitats of numerous federally managed species and habitats.[46]

Table 1 displays the rare, special, threatened, and endangered species that are found in the area around Elk Hills—specifically in the U.S. Geologic Survey quadrangles—and that therefore must be considered in the EIR. Of course, the EIR also must consider impacts to species that will be impacted by ancillary transportation activities and by any activities to source the carbon that are not currently in existence.

Table 1. *Threatened, Endangered and Sensitive Animals, Plants, and Plant Communities of the Elk Hills Area (threatened and endangered species are bolded).*

Common Name	***Scientific Name***	***Federal/State***
	Plants	
Horn's milk-vetch	*Astragalus hornii var. hornii*	*S/1B.1*
heartscale	*Atriplex cordulata var. cordulata*	*S/1B.2*
California jewelflower	***Caulanthus californicus***	***FE/SE, 1B.1***
Lemmon's jewelflower	*Caulanthus lemmonii*	*S/1B.2*
recurved larkspur	*Delphinium recurvatum*	*S/1B.2*
Kern mallow	***Eremalche parryi ssp. kernensis***	***FE/1B.2***
Temblor buckwheat	*Eriogonum temblorense*	*S/1B.2*
Tejon poppy	*Eschscholzia lemmonii ssp. kernensis*	*S/1B.1*
Coulter's goldfields	*Lasthenia glabrata ssp. coulteri*	*S/1B.1*
pale-yellow layia	*Layia heterotricha*	*S/1B.1*
Munz's tidy-tips	*Layia munzii*	*S/1B.2*
Jared's pepper-grass	*Lepidium jaredii ssp. jaredii*	*S/1B.2*
showy golden madia	*Madia radiata*	*S/1B.1*
San Joaquin woollythreads	***Monolopia congdonii***	***FE/1B.2***
	Plant Communities	
Valley Saltbush Scrub	*Valley Saltbush Scrub*	*--/WL*
	Insects	
Crotch bumble bee	*Bombus crotchii*	*--/WL*
Kern primrose sphinx moth	***Euproserpinus euterpe***	***FT/--***
Morrison's blister beetle	*Lytta morrisoni*	*--/WL*

[43] Cal. Fish & Game Code § 2055, et seq.
[44] *Id.* § 2053.
[45] 7 U.S.C. § 136; 16 U.S.C. § 1531 et seq.
[46] U.S. Fish & Wildlife Service, Information for Planning and Conservation (IPaC) database, available at https://ecos.fws.gov/ipac/ (last visited on Mar. 22, 2022).

Amphibians		
western spadefoot	*Spea hammondii*	*S/SSC*
Reptiles		
Temblor legless lizard	*Anniella alexanderae*	*--/SSC*
Bakersfield legless lizard	*Anniella grinnelli*	*--/SSC*
California legless lizard	*Anniella spp.*	*--/SSC*
California glossy snake	*Arizona elegans occidentalis*	*--/SSC*
blunt-nosed leopard lizard	***Gambelia sila***	***FE/SE, FP***
San Joaquin coachwhip	*Masticophis flagellum ruddocki*	*--/SSC*
Birds		
burrowing owl	*Athene cunicularia*	*S/SSC*
mountain plover	*Charadrius montanus*	*S/SSC*
Le Conte's thrasher	*Toxostoma lecontei*	*S/SSC*
California condor	***Gymnogyps californianus***	***FE/SE, FP***
Mammals		
Nelson's (San Joaquin) antelope squirrel	***Ammospermophilus nelsoni***	***S/CT***
giant kangaroo rat	***Dipodomys ingens***	***FE/SE***
short-nosed kangaroo rat	*Dipodomys nitratoides brevinasus*	*S/SSC*
Tipton kangaroo rat	***Dipodomys nitratoides nitratoides***	***FE/SE***
western mastiff bat	*Eumops perotis californicus*	*S/SSC*
Tulare grasshopper mouse	*Onychomys torridus tularensis*	*S/SSC*
American badger	*Taxidea taxus*	*--/SSC*
San Joaquin kit fox	***Vulpes macrotis mutica***	***FE/ST***

Federal Designation

FE—Federally listed as endangered
FT—Federally listed as threatened.
S—BLM Sensitive Species.

State Designation

CE—State listed as endangered.
CT—State listed as threatened. Species that although not presently threatened in California with extinction are likely to become endangered in the foreseeable future.
SSC—California Department of Fish and Wildlife's "Species of Special Concern." Species with declining populations in California.
WL—Watch List
1B.1—Plant rare, threatened or endangered in Cal. and elsewhere, and very threatened in CA.
1B.2—Plant rare, threatened or endangered in Cal. and elsewhere, and fairly threatened in CA.

Data from California Natural Diversity Database – accessed March 2022

In its review of CRC's Class VI application, EPA has noted that the company needs to provide more information about species near the oilfield, recommending that CRC: use the Fish and Wildlife Service's project planning tool to map out the project area and do a search for potential or threatened endangered species within the project area, provide a report of the results of that search, and hire a Wildlife Consultant to provide additional analysis.[47] CRC should follow EPA's recommendations in preparing the EIR as well.

[47] Albright, David, U.S. EPA, Letter to Travis Hurst, Carbon TerraVault 1, LLC, re: Underground Injection Control Permit Application Technical Review (Dec. 15, 2021).

C. Air quality and environmental justice impacts

Kern County must consider how the environmental and public health burdens of the project might disproportionately impact certain vulnerable and historically-harmed populations.[48]

The proposed project location is described as the Elk Hills Oil Field, "approximately 26 miles from the City of Bakersfield (pop. 413,098), approximately 8.5 miles from the City of Taft (pop. 8,945) and approximately 4 miles from the unincorporated community of Buttonwillow (pop. 1,443)."[49] These communities are designated as "disadvantaged" by the California EPA because they fall within the top 25% scoring areas from CalEnviroScreen—the higher the score, the higher the level of pollution burden relative to other California census tracts.[50] The census tract where the Elk Hills oilfield is consistently scores in the top CalEnviroScreen percentiles due to extreme concentration of industry pollution, with high levels of cumulative impacts to air, water, and soil contamination, coupled with health burdens and socioeconomic disadvantages. It is currently in the 97th percentile for pollution burden.[51]

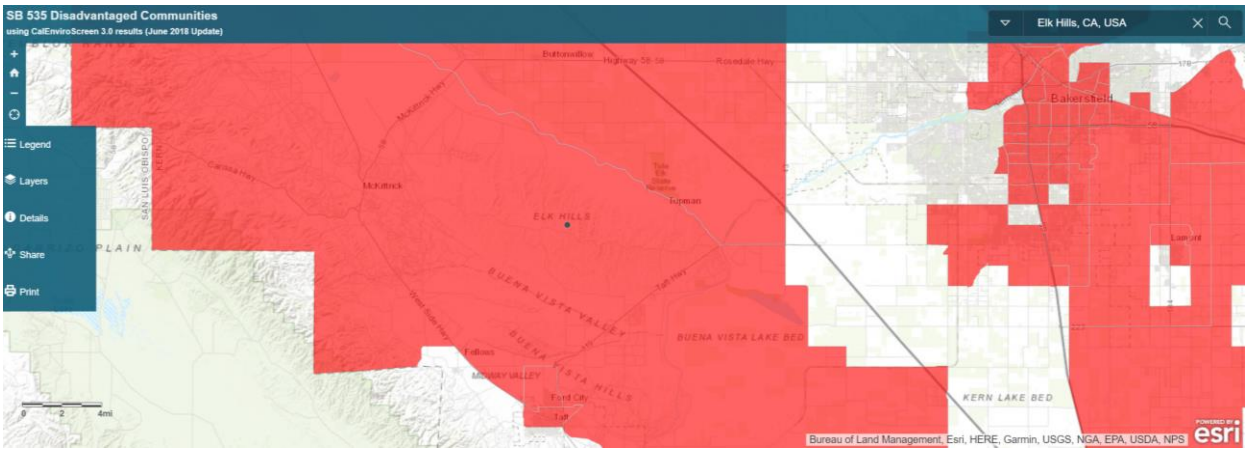

Figure 1: SB 535 Disadvantaged Communities in the Vicinity of Elk Hills Oilfield

More broadly, Kern County, Taft, and Buttonwillow have a high percentage of residents of color, that are linguistically isolated, and that have less than a high school education. Taft is in the 85 percentile or greater in the categories of linguistic isolation, low income, and less than a high school education.[52] Further, the residents of Taft are in the 90th population percentile or greater for several of EPA's Environmental Justice Indexes, including ozone and particulate matter 2.5, as compared to the U.S.[53] 84% of the residents of Buttonwillow, an unincorporated community just four miles from the project, are people of color.[54]

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[48] State of California, Department of Justice, Environmental Justice at the Local and Regional Level Legal Background (May 8, 2012), https://oag.ca.gov/sites/all/files/agweb/pdfs/environment/ej_fact_sheet_final_050712.pdf.
[49] Elk Hills NOP at 1.
[50] California Office of Environmental Health Hazard Assessment, *SB 535 Disadvantaged Communities*, https://oehha.ca.gov/calenviroscreen/sb535 (last visited Mar. 23, 2022).
[51] California Office of Environmental Health Hazard Assessment, *SB 535 Disadvantaged Communities Map*, Census Tract 6029003304, https://oehha.ca.gov/calenviroscreen/sb535 (last visited Mar. 23, 2022).
[52] U.S. EPA, *EJSCREEN Mapper*, https://ejscreen.epa.gov/mapper/ (last visited Mar. 21, 2022) (socioeconomic indicators tab once Taft / FIPS 060290035001 is selected).
[53] *Id.* (environmental justice indices tab once Taft / FIPS 060290035001 is selected).
[54] *Id.* (socioeconomic indicators tab once Buttonwillow / FIPS 060290037001 is selected).

It is critical that the EIR address the environmental justice impacts of the project and incorporate mitigation measures to address the high levels of pollution and emissions at sensitive receptors surrounding the project. The analysis and mitigation measures should also focus on the communities surrounding the facility that will source the carbon for the project and where compressed carbon will pass through on its way to the Elk Hills oilfield. According to the American Lung Association, Bakersfield ranked 3rd for 24-hour particle pollution out of 216 cities, 2nd for high ozone days out of 226 cities, and 1st for annual particle pollution out of 199 cities.[55] The EIR should therefore pay special attention to the air impacts associated with sourcing the carbon for the project and transporting it given the already dangerous air quality of Kern County.

The White House Environmental Justice Advisory Council has called CCS projects a "type[] of project that will *not* benefit a community," noting that "it would be unreasonable to have any climate investment working against historically harmed communities."[56] Simply because a project is touted as a climate solution does not mean the County can assume it will benefit nearby disadvantaged communities.

D. Seismicity impacts

California is one of the most seismically active states in the U.S. and earthquakes pose a risk in the project area. For example, a U.S. Department of Energy Draft Environmental Impact Statement from the time when Elk Hills was a Naval Petroleum Reserve discusses at length risks posed by seismicity.[57] That EIS confirms that Elk Hills is in a seismically active region that has generated structurally significant earthquakes in recent times, including earthquakes on the Big Pine, San Andreas, and White Wolf faults.[58] These three faults have all produced earthquakes with magnitudes exceeding 7.5 in the last 125 years.[59] The most recent of these was a magnitude 7.7 earthquake on the White Wolf Fault in 1952,[60] which is approximately 24 miles southeast of Elk Hills—close enough for effects of such an earthquake to be felt in Elk Hills. In fact, in response to the 1952 White Wolf earthquake, sanding occurred in some 30 wells.[61]

Studies link CO_2 injection to earthquakes.[62] For example, a 2012 study concluded that large-scale geologic storage of CO_2 carries has a "high probability" of triggering earthquakes, finding that "[b]ecause even small- to moderate-sized earthquakes threaten the seal integrity of

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[55] American Lung Association, *Report Cards Metropolitan Statistical Areas: Bakersfield, CA*, https://www.lung.org/research/sota/city-rankings/msas/bakersfield-ca (last visited Mar. 21, 2022).
[56] WHEJAC, Interim Final Recommendations at 55, 58 (May 13, 2021), https://www.epa.gov/sites/default/files/2021-05/documents/whejac_interim_final_recommendations_0.pdf (emphasis original).
[57] U.S. Department of Energy, Draft EIS, Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills) (DOE 1978), Kern County, California (June 1978), https://play.google.com/books/reader?printsec=frontcover&output=reader&id=4AYxAQAAMAAJ&pg=GBS.SL5-PA18.
[58] *Id.* at E-12-13.
[59] *Id.* at E-13.
[60] *Id.*
[61] *Id.* at E-15.
[62] Zoback, Mark D. and & Steven M. Gorelick, "Earthquake triggering and large-scale geologic storage of carbon dioxide," 109 PNAS 10164 (2012), https://doi.org/10.1073/pnas.1202473109; Gan, Wei & Cliff Frohlich, Gas injection may have triggered earthquakes in the Cogdell oil field, Texas, 110 *PNAS* 18786 (2013), https://doi.org/10.1073/pnas.1311316110; Foulger, Gillian R. et al., Global review of human-induced earthquakes, 178 Earth-Science Reviews 438 (2018), https://doi.org/10.1016/j.earscirev.2017.07.008; Sano, Yuji et al., Groundwater anomaly related to CCS-CO2 injection and the 2018 Hokkaido Eastern Iburi Earthquake in Japan, 8 Frontiers in Earth Science 611010 (2020), https://doi.org/10.3389/feart.2020.611010.

CO_2 repositories, in this context, large-scale CCS is a risky, and likely unsuccessful, strategy for significantly reducing greenhouse gas emissions."[63] A 2013 study found a strong correlation between earthquakes and CO_2 injection for enhanced oil recovery.[64] A 2016 study linked wastewater injection in the Tejon Oil Field in Kern County to a September 2005 earthquake swarm of three $M \geq 4$ events near the White Wolf Fault, signaling that this fault is sensitive to injection.[65] The San Andreas Fault is even closer to the Elk Hills oilfield than the White Wolf Fault, at approximately 14 miles to the southwest.[66]

According to EPA, CRC still has not provided basic information about the seismic monitoring network it will use and data that will inform the baseline,[67] where faults terminate,[68] and circumstances in which an earthquake would trigger a need to reevaluate the area of review to track carbon plume migration.[69] EPA recommends that CRC describe how the project:

> has a geologic system *free of known faults and fractures* and capable of receiving and containing the volumes of CO2 proposed to be injected; will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events; will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and poses a low risk of inducing a felt seismic event.[70]

Given EPA's request for further assurance that the project is free of known faults, Kern County should reconsider the determination that the project is likely to have a "less than significant impact" related to causing potential substantial adverse effects involving "rupture of a known earthquake fault."[71] The full range of seismic impacts should be evaluated in an EIR, particularly given the evidence that injection activities have been linked to earthquakes.

E. Forest land loss impacts

Kern County must consider whether the project will lead to loss or conversion of forest land, which may occur if CRC sources its carbon from a biomass facility. The NOP indicates that the project will not "[r]esult in the loss of forest land or conversion of forest land to non-forest use,"[72] presumably due to the project's location outside of forest land. However, this impact determination is not possible until the source of the carbon is identified. As noted in section VIII, several CCS potential projects in California propose to convert woody biomass to gas or

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[63] Zoback, Mark D. & Steven M. Gorelick, Earthquake triggering and large-scale geologic storage of carbon dioxide, 109 PNAS 10164 (2012), https://doi.org/10.1073/pnas.1202473109.
[64] Gan, Wei & Cliff Frohlich, Gas injection may have triggered earthquakes in the Cogdell oil field, Texas, 110 *PNAS* 18786 (2013), https://doi.org/10.1073/pnas.1311316110.
[65] Goebel, T.H.W. et al., Wastewater Disposal and Earthquake Swarm Activity at the Southern End of the Central Valley, California, 43 Geophysical Res. Letters 1092 (2016).
[66] U.S. EPA, Site Characterization Evaluation of the Carbon TerraVault (CTV) Class VI A1-A2 Permit Application (Dec. 15, 2021) at 7-8.
[67] U.S. EPA, Evaluation of Proposed Testing and Monitoring Activities at Carbon TerraVault's Monterey Formation A1-A2 Class VI Project (Jan. 11, 2022) at 13; U.S. EPA, Evaluation of Construction and Plugging Procedures for Injection Well 355-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project (Feb. 3, 2022) at 6.
[68] U.S. EPA, Site Characterization Evaluation of the Carbon TerraVault (CTV) Class VI A1-A2 Permit Application (Dec. 15, 2021) at 3.
[69] U.S. EPA, Evaluation of the AoR Delineation Modeling Approach in Carbon TerraVault's Monterey Formation A1-A2 Class VI Permit Application (Jan. 11, 2022) at 13.
[70] U.S. EPA, Site Characterization Evaluation of the Carbon TerraVault (CTV) Class VI A1-A2 Permit Application (Dec. 15, 2021) at 8.
[71] Elk Hills NOP at 30.
[72] *Id.* at 21.

electricity while sequestering carbon. If CRC gets its carbon from a biomass facility, this could lead to forest loss if the biomass is sourced from cutting forests. In California, forest-sourced biomass consumed in biomass plants includes whole trees and stemwood and there is no requirement that forests cut down for biomass energy be allowed to regrow. Even if new forests are regrown, there is no guarantee that new forests will be allowed to grow large enough to sequester as much carbon as the older, complex, carbon-rich forests that were cut. Research shows that it takes many decades to more than a century, if ever, for new trees to grow large enough to capture the carbon that was released.[73] The impacts from the sourced carbon must be evaluated in an EIR.

F. Climate change impacts

CEQA requires that EIRs consider a project's reasonably foreseeable indirect impacts on the environment,[74] which includes indirect GHG emission impacts. An environmental review must evaluate these impacts to the extent doing so is feasible and the effects are not speculative.[75] CEQA Guidelines Appendix G requires lead agencies to evaluate whether "the project [would] generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment."[76] This means that Kern County must not only analyze GHG emissions from the construction, operation, and maintenance of the injection wells, it also must analyze and mitigate emissions associated with transporting the carbon, and with any production of carbon and associated air emissions (along with any non-captured fuel that is generated and later combusted) that would not have otherwise occur in the absence of the project providing an incentive and location for sequestration—these emissions are reasonably foreseeable and significant consequences of the project.

Analysis of GHG impacts is particularly urgent given that immediate and aggressive GHG reductions are necessary to keep global warming below a 1.5°C rise above pre-industrial levels—the temperature increase beyond which the most catastrophic effects of climate change will occur.[77] Climate change is already wreaking havoc in California and across the globe, causing food and water insecurity, more frequent and intense heat waves, fires, and other extreme weather events, flooding of coastal regions from sea level rise, and accelerating species extinction.[78]

V. The EIR Must Utilize an Appropriate Baseline.

The Elk Hills NOP does not discuss the baseline that will be used to evaluate project impacts, but it does imply that the baseline may include historical emissions instead of the existing conditions at the time of analysis. This would be improper.

The baseline used in an EIR must generally reflect "physical environmental conditions as they exist at the time the notice of preparation is published."[79] Utilizing existing conditions for

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[73] Holtsmark, Bjart, The outcome is in the assumptions: Analyzing the effects on atmospheric CO 2 levels of increased use of bioenergy from forest biomass, 5 GCB Bioenergy 467 (2012); Schulze, E.D. et al., Large-scale bioenergy from additional harvest of forest biomass is neither sustainable nor greenhouse gas neutral, 4 Global Change Biology Bioenergy 611 (2012).
[74] Cal. Code Regs., tit. 14, § 15064(d).
[75] *See id.* § 15145.
[76] CEQA Guidelines, Appendix G.
[77] IPCC SR1.5.
[78] Intergovernmental Panel on Climate Change, Climate Change 2022, Impacts, Adaptation and Vulnerability (2022), https://www.ipcc.ch/report/ar6/wg2/.
[79] Cal Code Regs. tit. 14, § 15125(a).

the baseline is important to allow the public and decisionmakers to understand to what extent the proposed project would impact or worsen the environment. An agency can deviate from existing conditions under limited circumstances to "provide the most accurate picture practically possible of the project's impacts," such as historic conditions when conditions *change* or *fluctuate* over time.[80]

The NOP does not indicate what the baseline for the project will be, but it does suggest that the baseline may include historical emissions levels from operation where the carbon is sourced:

> the proposed project is expected to capture traditional sources of CO_2 emissions that have historically been emitted into the environment. As such, the provision of carbon capture and sequestration in perpetuity by the proposed project would reduce GHG emissions and is anticipated to offset GHGs that would otherwise be emitted by traditional sources.[81]

The EIR should not assume that CO_2 would have been generated and emitted from the proposed CO_2 source. For example, if the carbon comes from the restart of an idled biomass facility, the EIR may not consider those historical emissions. In that case, the historical emissions do not represent conditions that change or fluctuate over time. The EIR must include a description of the baseline of environmental conditions as they stand currently in 2022.

VI. The Environmental Impact Report Must Take California Resources Corporation's Precarious Financial Condition into Account When Evaluating Impacts and Mitigation.

In order to store carbon "in perpetuity,"[82] it is critical for CRC to have the resources to construct and complete a multi-year project, monitor to ensure carbon remains fully sequestered, and respond to any emergencies or project failures. This would be a tall order for any company, but it is an especially critical consideration here given that CRC recently emerged from bankruptcy and continues to owe billions of dollars in debt.

As the fossil fuel industry sinks further into decline, companies like CRC have weaponized bankruptcy proceedings and other maneuvers to evade their environmental clean-up and financial obligations to the public and its workers.[83] CRC, a company spun off from U.S. oil giant Occidental Petroleum in 2014, "was created specifically to offload Occidental's California cleanup liabilities."[84] Occidental spun off CRC to takeover roughly 15,300 poor-quality oil and gas wells and immediately burdened the new corporation with $4.95 billion of Occidental's

[80] *Id.* § 15125(a)(1); *Neighbors for Smart Rail v. Exposition Metro Line Constr. Auth.*, 57 Cal. 4th 439, 452 (2013) (noting an agency may omit existing conditions when an "analysis based on existing conditions would be uninformative or because it would be misleading to decision makers and the public.").
[81] Elk Hills NOP at 32
[82] *Id.* 4.
[83] Macey, Joshua, Bankruptcy as Bailout: Coal Company Insolvency and the Erosion of Federal Law, 71 Stanford Law Rev. 879 (2019), https://review.law.stanford.edu/wp-content/uploads/sites/3/2019/04/Macey-Salovaara-71-Stan.-L.-Rev.-879.pdf.
[84] Williams-Derry, Clark, *IEEFA report: California Schemin': What did Occidental Petroleum know about cleanup liabilities before the CRC spin-off?*, Inst. For Energy Econ. & Fin. Analysis (Feb. 6, 2020), https://ieefa.org/ieefa-report-california-schemin/.

debt.[85] By July 2020, when CRC filed for bankruptcy,[86] the company held 17,971 unplugged wells, including 11,806 idle wells,[87] and had an estimated outstanding debt of $6.3 billion.[88] Though CRC emerged from bankruptcy in October 2020 by restructuring $4.4 billion of its debt into equity interests for its creditors,[89] the company still owes over $2 billion and has little projected future revenue.

CRC's outstanding debts will likely grow. Only a third of CRC's wells are currently producing oil or gas and the company will soon incur substantial costs as it is required to plug and abandon idle wells. CRC projects that it will expend $517 million to plug its nearly 18,000 wells, discounted over the expected life of the wells.[90] However, a recent analysis by Sierra Club showed that CRC is dramatically undervaluing its future closure costs or underestimating how soon those costs will come due.[91] The average cost for CRC to plug and abandon its idle wells will likely exceed $50,000 per well, bringing its total projected well closure obligations to over $900 million unless CRC dramatically accelerates its well closure rate.[92] To match CRC's predicted discounted costs of $517 million, the analysis suggested that CRC will need to close more than 5,000 wells by 2025, and thereafter an average of over 620 wells per year until 2045.[93] In other words, CRC will need to expend roughly $250 million on well plugging by 2025 and thereafter over $31 million annually until 2045.

These looming costs are especially concerning because CRC's assets are not projected to be profitable. By 2020, only 4,274 of CRC's wells produced more than the equivalent of five barrels of oil per day.[94] Sierra Club concludes that CRC will likely default on its closure obligations by 2025 if the company cannot secure additional funding, at which point the company will attempt to dump the clean-up costs for its wells onto the state.[95] While Sierra Club's analysis predates the resolution of CRC's bankruptcy proceeding, which restructured $4.4 billion of CRC's loan obligations, CRC's active wells are still likely to be insufficient to fund its outstanding debts, pay nearly $1 billion in future well closure obligations, or meet its obligations to workers.[96]

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[85] Sierra Club, The Rise of Unplugged Wells for California's Taxpayers: California Resources Corporation – A Case Study [hereinafter *CRC Case Study*] at 3 (2020), https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/2335%20CRC-Wells_Report_02_high.pdf; Securities and Exchange Commission, Exhibit 2.1 Separation and Distribution Agreement by and between Occidental Petroleum Corporation and California Resources Corporation. (Nov. 25, 2014), https://www.sec.gov/Archives/edgar/data/1609253/000110465914084170/a14-25233_1ex2d1.htm.

[86] Notice of Chapter 11 Bankruptcy Case at 1, *In re* California Resources Corporation, 20-33568 (Bankr. T.S.D. 2020) (No. 689).

[87] CRC Case Study at 6-7. Idle wells are those that have not produced in two years.

[88] *Id.* at 3.

[89] Final Decree Closing Certain of the Chapter 11 Cases at 1, *In re* California Resources Corporation, 20-33568 (Bankr. T.S.D. 2020) (No. 689); Sullivan & Cromwell, LLP., California Resources Corporation Emerges from Chapter 11 Restructuring at 7 (Nov. 3, 2020), https://www.sullcrom.com/client-highlight-california-resources-corporation-emerges-from-chapter-11-restructuring.

[90] CRC Case Study at 6 (citing California Resources Corporation, Annual Report (Form 10-K) at 65 (2020).

[91] *Id.* at 1 (citing Boomhower, Judson et al., Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells, California Council on Science and Technology, at Table 8 (2020), https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf.

[92] *Id.*

[93] *Id.* at 7.

[94] *Id.*

[95] *Id.* at 8-10.

[96] *Id.* at 8.

Despite CRC's financial difficulties, its applications for the project have done little to allay concerns over its financial state and ability to pay for long term site care and emergency response. In its application to EPA for Class IV injection wells, the company stated "financial responsibility will be covered by" a letter of credit for "Injection Well Plugging and Post-Injection Site Care and Closure," and insurance for "Emergency and Remedial Response."[97] The insurance is described to "expire after injection cease[s]."[98] In other words, about 5 years in to a project that is supposed to sequester carbon forever. EPA has asked for third-party-generated financial responsibility cost estimates that cover post-injection site care, site closure, monitoring and emergency and remedial response; additional details about the proposed letter of credit; and information about "how the funds specified for Class VI financial responsibility . . . will be protected from other liabilities."[99]

Kern County should not rely on CRC to ensure carbon is stored "in perpetuity" without greater assurances. CRC's financial precarity is a particularly important consideration for evaluating potential mitigation for seismic risks, carbon leak risks, and other events that would require an emergency response.

VII. The EIR Should Consider Other Alternatives that Would Advance the State's Carbon Neutrality Goals While Protecting Communities and the Environment.

The EIR must identify and consider alternatives to the project that would avoid impacts to environmental justice communities near the project and protect the air, water, and species of Kern County. One of the primary purposes of the project appears to be "contribution to the goals of California for carbon neutrality by 2045."[100] The NOP describes the project location as suitable to help advance these goals due to its capacity to store carbon. A much better way to achieve these goals, however, is to phase out oil and gas extraction at Elk Hills. The County should analyze this as a project alternative.

Phasing out oil production in Elk Hills would be especially impactful because the field is one of the top ten producing oilfields in the state, producing 6% of California's oil.[101] Phasing out operations in the Elk Hills oil field, replacing oil production with renewable energy, and developing a just transition program for oil workers has significant potential to advance GHG reduction goals while creating jobs that are better shielded from the market contractions of a fading industry.[102]

VIII. The Planning Department Must Analyze the Potential Cumulative Impacts, Including from Other CCS Projects Proposed for the Area.

CEQA requires that EIRs analyze cumulative impacts, including impacts created or compounded as a result of the combination of the project evaluated in the EIR together with other closely related past, present, and reasonably foreseeable projects.[103] A project has

[97] Carbon TerraVault, Class VI Financial Responsibility Demonstration Cost Estimates Description 40 CFR 146.85, Elk Hills A1-A2 Storage Project (Aug. 2021).
[98] Carbon TerraVault, Class VI UIC Financial Responsibility Demonstration for Project ID R09-CA-0003 (Aug. 2021).
[99] U.S. EPA, CTV-Elk Hills Oil Field Class VI A1-A2 Project Review of Financial Responsibility Information (Dec. 15, 2021).
[100] Elk Hills NOP at 4.
[101] Fleming, John, Killer Crude: How California Produces Some of the Dirtiest, Most Dangerous Oil in the World, Center for Biological Diversity (2021) at 8.
[102] Pollin, Robert et al., A Program for Economic Recovery and Clean Energy Transition in California, Political Economy Research Institute (2021) at Chapter 7.
[103] Cal. Code Regs., tit. 14, § 15355.

"cumulatively considerable" impacts when its effects are "considerable when viewed in connection with the effects of" related projects.[104]

There are several closely related, foreseeable CCS projects proposed for Kern County and the surrounding areas. The Planning Department must take these projects (listed below) and any other related and foreseeable projects into account when evaluating the cumulative impacts of the Carbon TerraVault proposal. This evaluation must include considering the impacts to public safety from the dangers of compressed carbon pipelines, injection, and storage (including leaks).

Proposed CCS projects include:

1. Delano bioenergy with carbon capture and sequestration – a project to convert woody biomass into electricity or transportation fuel in Delano, CA (Kern County);[105]
2. Mendota bioenergy with carbon capture and sequestration — a project to convert biomass into transportation fuel and sequester the carbon in Class VI storage wells near Mendota, CA (Fresno County);[106] and
3. San Joaquin Renewables – a project to convert orchard biomass into natural gas for transportation fuel and sequester the carbon in Class VI storage wells near McFarland, CA (Kern County).[107]

And CRC has noted in investor presentations that it sees the Elk Hills project as just the first in a series of CCS projects to take advantage of the company's inventory of deep wells and depleted reservoirs, including in the Elk Hills oilfield.[108] This calls into question whether a larger project will be piecemealed over time.[109] Consideration of each CCS project in isolation is not permissible under CEQA.

The Planning Department must also consider the CCS project in light of Kern County's oil and gas ordinance, which, if upheld in court, would accelerate oil and gas development over the next two decades, allowing up to 43,000 new wells. CO_2 injection activities will add to the air quality, water quality, and public health risks from drilling and injecting for traditional production in communities that are already overburdened.

In conclusion, the draft EIR must take a hard look at the potential environmental impacts associated with the CCS project, and Kern County should ultimately deny CRC's application for a conditional use permit. The project is dangerous and subverts California's progress toward a carbon free future.

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[104] Cal. Pub. Res. Code § 21083(b); *see also* Cal. Code Regs § 15355(b)(2).
[105] *See* Cox, John, *Idle biomass plant near Delano would reopen under carbon burial proposal*, Bakersfield.com, Dec. 4, 2021, https://www.bakersfield.com/news/idle-biomass-plant-near-delano-would-reopen-under-carbon-burial-proposal/article_40b1cedc-54b1-11ec-bb81-9b8ecd1354ae.html.
[106] *See* Clean Energy Systems, *Mendota Bioenergy with Carbon Capture and Sequestration Project (BECCS)*, https://www.cleanenergysystems.com/MendotaBECCS (last visited Mar. 31, 2022).
[107] *See* San Joaquin Renewables, *About the Project*, https://sjrgas.com/the-project/ (last visited Mar. 31, 2022).
[108] California Resources Corporation, Carbon Storage Update (Oct. 6, 2021) at 9 (describing goals of first injection by 2025, 200 MMT permitted by 2025, 5 MMTPA injection by 2027), 13-15, 29.
[109] *See Las Virgenes Homeowners Federation, Inc. v. County of Los Angeles* (1986) 177 Cal.App.3d 300, 306; *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1218 (lead agency's failure to meaningfully address comments stating that two shopping centers with concurrently prepared EIRs will have cumulative adverse impacts resulted in an "underinclusive and misleading" environmental review process).

Thank you for your consideration of these important issues in determining the scope and content of the draft EIR. Please do not hesitate to contact us if you have any questions.

Respectfully submitted,

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April 4, 2022

To: Lorelei Oviatt, Director
Planning and Natural Resources Department

Cindi Hoover, Supervising Planner

From: Brian Blacklock, County Surveyor
By: Andres Arias, Engineering Tech III Phone: 28959

Subject: Draft Environmental Impact Report for the Carbon Terra Vault 1 by California Resources Corporation (PP22405)

I have reviewed the above noted project Notice of preparation of Environmental Impact Report and recommend the following conditions be placed on the Conditional Use Permits:

1. Prior to issuance of a building or grading permit: All survey monuments shall be tied out by a Licensed Land Surveyor. A corner record for each monument or record of survey shall be submitted to the County Surveyor for review and processing, per Section 8771 of the Professional Land Surveyor's (PLS) Act.

2. Prior to Final Inspection: All survey monuments that were destroyed during construction shall be re-set or have a suitable witness corner set. A post construction corner record for each monument re-set or a record of survey shall be submitted to the County Surveyor for processing, per Section 8771 of the Professional Land Surveyor's Act.

3. Upon completion of project: All survey monuments shall be accessible by a Licensed Land Surveyor or their representatives, with prior notice, per Section 8774 of the PLS Act and Civil Code 846.5 (a).

Thank you for the opportunity to review and comment on this project. Should you have any questions please contact me.

Office Memorandum - Kern County

TO: [Distribution List] **PLEASE SIGN AND DATE BELOW AS SOON AS RECEIVED AND RETURN TO PLANNING & NATURAL RESOURCES DEPARTMENT**

FROM: Cindi Hoover, Supervising Planner ((661) 862-8629) **DATE:** March 4, 2022
Planning & Natural Resources Department

SUBJECT: **NOTICE OF PREPARATION OF AN ENVIRONMENTAL IMPACT REPORT –** Carbon TerraVault 1 by California Resources Corporation (PP22405)

Enclosed is a document entitled Notice of Preparation of an Environmental Impact Report for the Carbon TerraVault 1 project. The Kern County Planning & Natural Resources Department as Lead Agency (per CEQA Guidelines Section 15050) solicits the views of your agency as to the scope and content of the environmental information, which is germane to your agency's statutory responsibilities in connection with the proposed project.

Any comments should be addressed to Cindi Hoover at the Planning and Natural Resources Department. The comment period ends ***April 4, 2022 at 5:00 pm.***

In order to verify that this document was received by your department, please date and sign this memo and return by office mail to the Planning and Natural Resources Department, Attn: Cindi Hoover.

Thank you in advance for your cooperation.

Distribution List (Kern County):

Administrative Office
Agriculture Department
PWD- Building & Development – Floodplain
PWD- Building & Development – Survey
Environmental Health Services
Fire Department – Aaron Duncan
Fire Department – Michael Nicholas
Library/Beale – Local History Room
Library Director- Andie Sullivan
Parks and Recreation
Sheriff
PWD- Building & Development- Development Review
PWD- Operations & Maintenance- Regulatory Monitoring & Reporting

RECEIVED: 3/4/22 **By:** Brian Blacklock **Dept.:** PW/County Surveyor

SIERRA CLUB

KERN-KAWEAH CHAPTER

P.O. Box 3357
Bakersfield, CA 93385
April 4, 2022

VIA ELECTRONIC MAIL

Kern County Planning Department
Attn: Cindi Hoover
2700 "M" Street, Suite 100
Bakersfield, CA 93301

Re: Notice of Preparation for Carbon TerraVault 1 (CTV 1) by California Resources Corporation (PP22405); PLN21-01378: ZCC No. 5, Map No. 118; ZCC No. 5, Map No. 119; ZCC No. 4, Map No. 120; CUP No. 13, Map No. 118; CUP No. 5, Map No. 119; CUP No. 3, Map No. 120

Dear Planners:

The proposed Carbon TerraVault 1 project is a 5,332.34-acre carbon capture and sequestration (CCS) field, associated Class VI geologic sequestration injection wells and related improvements for storage of Carbon Dioxide (CO_2). The proposed project is in unincorporated Kern County within the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield, approximately 8.5 miles from the City of Taft, and approximately 4 miles from the unincorporated community of Buttonwillow.

Considering the potential short term and long-term impacts of this development on the environmental health of Kern County and our planet, the EIR for this project should address numerous issues. We incorporate and attach an August 16, 2021, letter on the CCS issue from the Sierra Club to the California Air Resources Board (CARB) for reference and documentation.

We quote from the paper: Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf (ciel.org) "The world is confronting a climate emergency. Avoiding climate catastrophe requires immediate and dramatic reductions in greenhouse gas (GHG) emissions that are possible only with a significant investment of public resources in proven mitigation measures, beginning with eliminating fossil fuel use and halting deforestation. Carbon capture and storage (CCS) and carbon capture, utilization, and storage (CCUS) will not address these core drivers of the climate crisis or meaningfully reduce GHG emissions, and should not distract from real climate solutions. CCS and CCUS technologies are not only unnecessary for the rapid transformation required to keep warming under 1.5°C, they delay that transformation, providing the fossil fuel industry with a license to continue polluting.

This brief argues that carbon capture technologies:

• Do not remove carbon from the atmosphere, and in fact worsen the climate crisis when used to boost oil production.

• Have not been proven feasible or economic at scale and can only contain a fraction of source emissions.

• Prolong dependence on fossil fuels and delay their replacement with renewable alternatives.

• Create environmental, health, and safety risks for communities saddled with CCS infrastructure, such as pipelines and underground storage."

The EIR must address each of these bullet points. Specifically,

- The EIR must disclose whether the injected CO_2 will be used for enhanced oil recovery. If so, the lifecycle GHG emissions associated with the increased oil production must be accounted for in the EIR in computing the climate crisis consequences of the project.
- In analyzing the feasibility of this proposed project, the EIR must determine what other projects in the US have successfully captured and stored CO_2 at this scale? Have there been similar past projects that have failed?
- The EIR must disclose the specific "local industrial sources" of the to-be-sequestered CO_2.
- What technologies will be used to capture and store CO_2 at these sources?

- In order to capture CO_2, will these technologies burn fossil fuel or perhaps use electricity generated at fossil fuel power plants? If so, the EIR must account for these process fossil fuel combustion emissions in computing the climate crisis consequences of the project.
- What percentage of CO_2 produced at these "local industrial sources" will be captured by the technology?
- How much total CO_2 will be emitted into the atmosphere from these "local industrial sources" after the capture process? The EIR must account for these emissions in computing the climate crisis consequences of the project.
- Are the nearby Elk Hills and La Paloma power plants some of the "local industrial sources" of the CO_2 to be injected? If so, the EIR must consider and analyze replacing these power plants with renewable energy projects as an alternative to the proposed project.
- CO_2 will be transported by a combination of truck, pipeline and/or rail to the Class VI injection wells for the project. Pipelines can leak or rupture, and injection can contaminate water sources. These risks fall disproportionately on Black, Brown, Indigenous, and low-income communities, further entrenching a bleak history of environmental racism. The EIR must determine which communities will be affected by this transport process and must address the environmental, health, and safety risks for these communities.

The EIR must include specific measures to satisfy safety standards and EPA requirements. Class VI - Wells used for Geologic Sequestration of Carbon Dioxide | US EPA

EPA developed specific criteria for Class VI wells:

- Extensive site characterization requirements
- Injection well construction requirements for materials that are compatible with and can withstand contact with CO_2 over the life of a GS project
- Injection well operation requirements

- Comprehensive monitoring requirements that address all aspects of well integrity, CO_2 injection and storage, and ground water quality during the injection operation and the post-injection site care period
- Financial responsibility requirements assuring the availability of funds for the life of a GS project (including post-injection site care and emergency response)
- Reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm USDW protection

The worst accident on a CO_2 line occurred in 2020 near Satartia, Miss. A 24-inch pipeline owned by an oil and gas company ruptured, leading to the evacuation of more than 300 people. Forty-six were treated for injuries at local hospitals. The EIR must include measures to address the possibility of such accidents.

As noted in Sierra Club's August, 2021, letter to CARB, the 2018 IPCC report (Summary for Policymakers of IPCC Special Report on Global Warming of 1.5°C approved by governments — IPCC) cautioned against technologies such as CCUS given "concerns about storage safety and cost" and the "non-negligible risk of carbon dioxide leakage from geological storage and the carbon dioxide transport infrastructure." The EIR must include measures to address the possibility of **CO_2 leakage** from the transport process and from the injection field.

The EIR must consider **alternatives** to the proposed project. We note that "[a] potential alternative should not be excluded from consideration merely because it 'would impede to some degree the attainment of the project objectives, or would be more costly" even when that alternative includes Project development on an alternative site. *Save Round Valley Alliance v. County of Inyo*, 157 Cal. App. 4th 1437, 1456-57 (2007).

- The EIR should consider a **Renewable Energy Alternative** focused on developing the 5332-acre area into a large-scale solar photovoltaic project. This alternative on a large scale would be used to generate clean energy with negligible GHG emissions and, if used to replace fossil-fuel power plants such as the nearby Elk Hills and La Paloma plants, would negate the

need to sequester the CO_2 associated with these outdated facilities. As noted in Sierra Club's August, 2021, letter to CARB, studies (The health and climate impacts of carbon capture and direct air capture (stanford.edu)) have shown that replacing fossil fuels with clean energy resources such as wind or solar will not only result in more CO_2 emission reductions than relying on CCUS equipment, but it will also result in reductions in air pollution emissions and doesn't have the added costs and risks associated with CCUS.

- The EIR should consider a **Leave-it-in-the-Ground Alternative**, in which the oil wells on this 5332-acre area would be properly shut down. This alternative would be a much simpler and more elegant solution to the Net Zero Emission and carbon neutrality goals and objectives of the project. Instead of capturing carbon to pump it back underground, we should keep fossil fuels in the ground in the first place.
- The EIR should consider a **combination** of the two alternatives suggested above, solar PV as well as shutting in the oil wells. As noted in Sierra Club's August, 2021, letter to CARB, "Clean energy resources have additional benefits that these technologies do not have such as reducing non-CO_2 air pollutants caused by fossil combustion as well as eliminating the risks of oil spills, oil fires, gas leaks or gas explosions."
- The EIR should consider a **Nature-based Carbon Sequestration Alternative**, sequestering carbon in soils and vegetation, tree planting and urban forestry projects. Tree planting plays an essential role in achieving the goal of reaching net zero emissions. One recent study found that California's working and urban lands have the potential to absorb up to 103 MMT CO2e additional per year by 2030. Sequestration policies must be designed to address the needs of vulnerable populations, especially farmworkers, frontline, and urban communities.

Each of the above alternative suggestions effectively satisfies all the project objectives except the underground CO_2 storage objective, which, of course, could never be satisfied by an alternative to underground CO_2 storage and which should not lead to exclusion from consideration.

Sierra Club's August, 2021, letter to CARB states, "CARB's own presentation showed how expensive these technologies will be ($190/200 per ton) as

compared to natural and working land strategies ($11 per ton)." The EIR should compare the **economic feasibility** of each alternative to that of the proposed project.

In the bipartisan infrastructure bill that the Senate passed on August 10, 2021, there was a record $9 billion plus of funding targeted for carbon capture. The EIR must disclose whether the developer, California Resources Corporation, is receiving federal taxpayer funding for this project.

Instead of bankrolling CCS, public funds could be boosting sustainable, job-creating solutions to the climate crisis, for fossil-dependent workers and communities; phasing out oil and gas; investing in energy efficiency and non-combustible renewable energy sources; and protecting forests and other ecosystems that naturally capture and store carbon. The EIR should take all these considerations into account in determining the **environmentally superior alternative** and in evaluating the comparative merits of the alternatives and the project.

The southern San Joaquin Valley fights it out every year with Los Angeles for having the worst air pollution in the nation. See the American Lung Association report at http://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/states/california/. Since our extreme air pollution affects the health of many residents, the EIR must thoroughly address the issue.

According to CalEnviroScreen 4.0 | OEHHA, the tract containing this project is in the 96th percentile for pollution burden, and the adjoining tract is in the 94th percentile for PM 2.5 exposure and is 64% Hispanic. As noted in Sierra Club's August, 2021, letter to CARB, "CCUS technologies will not reduce air pollutants aside from CO_2 and will not address the harms of fossil fuel pollution that are felt by environmental justice communities. In fact, research (The health and climate impacts of carbon capture and direct air capture (stanford.edu)) has shown that these technologies can increase co-pollutants at the source. " The EIR must quantify and address criteria pollutant **air pollution** during construction and operation and at every stage of the lifecycle of the CCS project including capture, transport, and injection.

Special-status species such as San Joaquin kit fox, blunt-nosed leopard lizard, grasshopper sparrow, golden eagle, Tulare grasshopper mouse, burrowing owl, and loggerhead shrike may occur in the proposed project areas. Given the special status of these and other species, the EIR should require pre-construction surveys to observe CDFW protocols and to be extended to a buffer area surrounding the sites.

Loss of habitat is a major reason for species decline. While many of these species may have been driven out of the project site by oilfield operations, the EIR should consider reintroducing some of the native plant species by replanting them in project open space areas.

According to the publication *Conservation Strategies for San Joaquin Kit Foxes in Urban Environments* by Brian Cypher, Christine Van Horn Job, and Scott Phillips at http://esrp.csustan.edu/publications/pdf/cypher_etal_2012_urban_kitfox_conservation_esrp.pdf, "To the extent practical and possible, urban planners could design new developments in a manner that facilitates use by kit foxes." This project should be designed with kit fox conservation measures in mind, perhaps including artificial kit fox dens and movement corridors as suggested in the above document.

It is possible that kit fox dens are located on the site. If a den cannot be avoided, will it be excavated and the kit foxes relocated? The publication *Feasibility and Strategies for Translocating San Joaquin Kit Foxes to Vacant or Restored Habitats* by Samantha Bremner-Harrison and Brian Cypher at http://esrp.csustan.edu/publications/pdf/esrp_2007_kitfoxreloction_w.pdf gives evidence that kit fox relocation is complex and will likely not be successful. The EIR should address this evidence.

The EIR must include a comprehensive traffic study that analyzes CO_2 transport impacts via truck and rail between CO_2 sources and the injection sites as well as construction and other operational impacts.

The EIR must address the potential for groundwater contamination and depletion by this project.

Please place the Sierra Club on the distribution list for the Carbon TerraVault 1 project to receive any noticing of meetings, hearings, availability of documents, and to receive the environmental documents. We prefer email communications and electronic formatting of documents. Thank you for your consideration and for the opportunity to comment.

Sincerely,



Gordon L. Nipp, Ph.D.
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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

April 4, 2022

Cindi Hoover
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Bakersfield, CA, 93301

Project: Notice of Preparation-Draft Environmental Impact Report (DEIR) for the Carbon Terravault 1 (CTV 1) Carbon Capture and Sequestration Project by California Resources Corporation (CRC)

District CEQA Reference No: 20220282

Dear Ms. Hoover:

The San Joaquin Valley Unified Air Pollution Control District (District) has reviewed the project referenced above from the County of Kern (County) consisting of a 5,332.34 acre carbon capture and sequestration field (Project). The Project is located at west side of Elk Hills Road and north of Skyline Road, within the Elk Hills Oil Field in Kern County, CA.

Project Scope

The Project consists of a 5,745.44 ace carbon capture and sequestration field. The proposed project would take local industrial sources of carbon dioxide that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells. The carbon dioxide would then be injected into identified geographically confined reservoirs for storage in perpetuity. The site would include four to six injection wells and associated infrastructure, capable of storing approximately 48 million metric tons of Carbon Dioxide within identified geographically confined reservoirs.

The District’s initial review of the Project concludes that emissions resulting from construction and/or operation of the Project may exceed the following thresholds of significance: 100 tons per year of carbon monoxide (CO), 10 tons per year of oxides of nitrogen (NOx), 10 tons per year of reactive organic gases (ROG), 27 tons per year of oxides of sulfur (SOx), 15 tons per year of particulate matter of 10 microns or less in size (PM10), or 15 tons per year of particulate matter of 2.5 microns or less in size (PM2.5).

Samir Sheikh
Executive Director/Air Pollution Control Officer

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The District recommends that a more detailed preliminary review of the Project be conducted for the Project's construction and operational emissions.

Other potential significant air quality impacts related to Toxic Air Contaminants (see information below under Health Risk Assessment), Ambient Air Quality Standards, Hazards and Odors, may require assessments and mitigation. More information can be found in the District's Guidance for Assessing and Mitigating Air Quality Impacts at: https://www.valleyair.org/transportation/GAMAQI.pdf

The District offers the following comments:

1) Project Related Criteria Pollutant Emissions

At the federal level under the National Ambient Air Quality Standards (NAAQS), the District is designated as extreme nonattainment for the 8-hour ozone standards and serious nonattainment for the particulate matter less than 2.5 microns in size (PM2.5) standards. At the state level under California Ambient Air Quality Standards (CAAQS), the District is designated as nonattainment for the 8-hour ozone, PM10, and PM2.5 standards.

The District recommends that a more detailed preliminary review of the Project be conducted for the Project's construction and operational emissions. The additional environmental review of the Project's potential impact on air quality should consider the following items:

1a) Project Related Construction Emissions

Project construction air emissions are short-term emissions generated from construction activities and may exceed the District's significance thresholds. Therefore, the District recommends, to lessen air quality impacts from construction-related diesel exhaust emissions, the County consider incorporating the below measure into the Project.

Recommended Measure: To reduce impacts from construction-related diesel exhaust emissions, the Project should utilize clean off-road construction equipment, including the latest tier equipment as feasible.

1b) Project Related Operational Emissions

Emissions from stationary sources and mobile sources should be analyzed separately. For reference, the District's annual criteria thresholds of significance for operational emissions are listed above.

1c) Recommended Model

Project related criteria pollutant emissions from construction and operational sources should be identified and quantified. Emissions analysis should be performed using CalEEMod (**Cal**ifornia **E**mission **E**stimator **Mod**el), which uses the most recent approved version of relevant Air Resources Board (ARB) emissions models and emission factors. CalEEMod is available to the public and can be downloaded from the CalEEMod website at: www.caleemod.com.

1d) Project Related Operational Emissions– Truck Routing

Truck routing involves the path/roads heavy-duty trucks take to and from their destination. The air emissions from heavy-duty trucks can impact residential communities and sensitive receptors.

The District recommends the County consider evaluating heavy-duty truck routing patterns to help limit emission exposure to residential communities and sensitive receptors. More specifically, this measure would assess current truck routes, in consideration of the number and type of each vehicle, destination/origin of each vehicular trip, time of day/week analysis, vehicle miles traveled and emissions. The truck routing evaluation would also identify alternative truck routes and their impacts on VMT, and air quality.

1e) Project Related Operational Emissions– Cleanest Available Truck

The San Joaquin Valley will not be able to attain stringent health-based federal air quality standards without significant reductions in emissions from heavy-heavy duty (HHD) Trucks, the single largest source of NOx emissions in the San Joaquin Valley. The District recently adopted the 2018 PM2.5 Plan, which includes significant new reductions from HHD Trucks, including emissions reductions by 2023 through the implementation of the California Air Resources Board (CARB) Statewide Truck and Bus Regulation, which requires truck fleets operating in California to meet the 2010 0.2 g/bhp-hr NOx standard by 2023. Additionally, to meet the federal air quality standards by the 2020 to 2024 attainment deadlines, the District's Plan relies on a significant and immediate transition of heavy duty truck fleets to zero or near-zero emissions technologies, including the near-zero truck standard of 0.02 g/bhp-hr NOx established by the California Air Resources Board.

For carbon capture and sequestration projects which can generate a high volume of heavy duty truck traffic the District recommends that the following mitigation

measures be considered by the County for inclusion in the DEIR for project related operational emissions since the project may exceed the District significance threfsholds

- Advise fleets associated with Project operational activities to utilize the cleanest available HHD truck technologies, including zero and near-zero (0.02 g/bhp-hr NOx) technologies as feasible.

- Advise all on-site service equipment (cargo handling, yard hostlers, forklifts, pallet jacks, etc.) to utilize zero-emissions technologies as feasible.

In addition, the District recommends that the County include mitigation measures to reduce project related operational impacts through incorporation of design elements, for example, increased energy efficiency, reducing vehicle miles traveled, etc. More information on mitigation measures can be found on the District's website at: http://www.valleyair.org/transportation/ceqa_idx.htm.

1f) Project Related Operational Emissions– Reduce Idling of Heavy Duty Trucks

The goal of this strategy is to limit the potential for localized PM2.5 and toxic air quality impacts associated with failure to comply with the state's Heavy Duty anti-idling regulation (e.g limiting vehicle idling to specific time limits). The diesel exhaust from excessive idling has the potential to impose significant adverse health and environmental impacts. Therefore, efforts to ensure compliance of the anti-idling regulation, especially near sensitive receptors, is important to limit the amount of idling within the community, which will result in community air quality benefits.

1g) Project Related Operational Emissions– Electric On-Site Off-Road and On-Road Equipment

Since the Project consists of a carbon capture and sequestration facility, it may have the potential to result in increased use of off-road equipment (i.e. forklifts) and/or on-road equipment (i.e. mobile yard trucks with the ability to move materials). The District recommends the County advise the project proponent to utilize electric or zero emission off-road and on-road equipment used on-site for this Project.

2) Voluntary Emission Reduction Agreement

If the Project is expected to have a significant impact, the District recommends the EIR also include a discussion on the feasibility of implementing a Voluntary Emission Reduction Agreement (VERA) for this Project.

A VERA is a mitigation measure by which the project proponent provides pound-for-pound mitigation of emissions increases through a process that develops, funds, and implements emission reduction projects, with the District serving a role of administrator of the emissions reduction projects and verifier of the successful mitigation effort. To implement a VERA, the project proponent and the District enter into a contractual agreement in which the project proponent agrees to mitigate Project specific emissions by providing funds for the District's incentives programs. The funds are disbursed by the District in the form of grants for projects that achieve emission reductions. Thus, project-related impacts on air quality can be mitigated. Types of emission reduction projects that have been funded in the past include electrification of stationary internal combustion engines (such as agricultural irrigation pumps), replacing old heavy-duty trucks with new, cleaner, more efficient heavy-duty trucks, and replacement of old farm tractors.

In implementing a VERA, the District verifies the actual emission reductions that have been achieved as a result of completed grant contracts, monitors the emission reduction projects, and ensures the enforceability of achieved reductions. After the project is mitigated, the District certifies to the Lead Agency that the mitigation is completed, providing the Lead Agency with an enforceable mitigation measure demonstrating that project-specific regional emissions have been mitigated to less than significant. To assist the Lead Agency and project proponent in ensuring that the environmental document is compliant with CEQA, the District recommends the Draft EIR includes an assessment of the feasibility of implementing a VERA.

3) Health Risk Screening/Assessment

A Health Risk Screening/Assessment identifies potential Toxic Air Contaminants (TACs) impact on surrounding sensitive receptors such as hospitals, daycare centers, schools, work-sites, and residences. TACs are air pollutants identified by the Office of Environmental Health Hazard Assessment/California Air Resources Board (OEHHA/CARB) that pose a present or potential hazard to human health. A common source of TACs can be attributed to diesel exhaust emitted from both mobile and stationary sources. List of TACs identified by OEHHA/CARB can be found at: https://ww2.arb.ca.gov/resources/documents/carb-identified-toxic-air-contaminants

The District recommends the development project(s) be evaluated for potential health impacts to surrounding receptors (on-site and off-site) resulting from operational and multi-year construction TAC emissions.

i) The District recommends conducting a screening analysis that includes all sources of emissions. A screening analysis is used to identify projects which may have a significant health impact. A prioritization, using CAPCOA's updated methodology, is the recommended screening method. A prioritization score of 10 or greater is considered to be significant and a refined Health Risk Assessment (HRA) should be performed.

   For your convenience, the District's prioritization calculator can be found at: http:www.valleyair.org/busind/pto/emission_factors/Criteria/Toxics/Utilities/PRIORITIZATION%20RMR%202016.XLS.

ii) The District recommends a refined HRA for development projects that result in a prioritization score of 10 or greater. Prior to performing an HRA, it is recommended that development project applicants contact the District to review the proposed modeling protocol. A development project would be considered to have a significant health risk if the HRA demonstrates that the project related health impacts would exceed the Districts significance threshold of 20 in a million for carcinogenic risk and 1.0 for the Acute and Chronic Hazard Indices, and would trigger all feasible mitigation measures. The District recommends that development projects which result in a significant health risk not be approved.

   For HRA submittals, please provide the following information electronically to the District for review:

   - HRA AERMOD model files
   - HARP2 files
   - Summary of emissions source locations, emissions rates, and emission factor calculations and methodology.

   More information on toxic emission factors, prioritizations and HRAs can be obtained by:

   - E-Mailing inquiries to: hramodeler@valleyair.org

   The District can be contacted at (559) 230-6000 for assistance.

4) Ambient Air Quality Analysis

An Ambient Air Quality Analysis (AAQA) uses air dispersion modeling to determine if emissions increases from a project will cause or contribute to a violation of State or National Ambient Air Quality Standards. The District recommends an AAQA be performed for the Project if emissions exceed 100 pounds per day of any pollutant.

An acceptable analysis would include emissions from both project-specific permitted and non-permitted equipment and activities. The District recommends consultation with District staff to determine the appropriate model and input data to use in the analysis.

Specific information for assessing significance, including screening tools and modeling guidance, is available online at the District's website: www.valleyair.org/ceqa.

5) Cumulative Air Impacts

In addition to the discussions on the topics identified above, the District recommends the EIR also include a discussion of whether the Project would result in a cumulatively considerable net increase of any criteria pollutant or precursor for which the San Joaquin Valley Air Basin is in non-attainment. More information on the District's attainment status can be found online by visiting the District's website at: http://valleyair.org/aqinfo/attainment.htm.

6) District Rules and Regulations

The District issues permits for many types of air pollution sources and regulates some activities not requiring permits. A project subject to District rules and regulation would reduce its impacts on air quality through compliance with regulatory requirements. In general, a regulation is a collection of rules, each of which deals with a specific topic. Here are a couple of example, Regulation II (Permits) deals with permitting emission sources and includes rules such as District permit requirements (Rule 2010), and New and Modified Stationary Source Review (Rule 2201).

The list of rules below is neither exhaustive nor exclusive. Current District rules can be found online at: www.valleyair.org/rules/1ruleslist.htm. To identify other District rules or regulations that apply to this Project or to obtain information about District permit requirements, the applicant is strongly encouraged to contact the District's Small Business Assistance (SBA) Office at (661) 392-5665.

6a) District Rules 2010 and 2201 - Air Quality Permitting for Stationary Sources

Stationary Source emissions include any building, structure, facility, or installation which emits or may emit any affected pollutant directly or as a fugitive emission. District Rule 2010 requires operators of emission sources to obtain an Authority to Construct (ATC) and Permit to Operate (PTO) from the District. District Rule 2201 requires that new and modified stationary sources of emissions mitigate their emissions using best available control technology (BACT).

This Project may be subject to District Rule 2010 (Permits Required) and Rule 2201 (New and Modified Stationary Source Review) and may require District permits. Prior to construction, the Project proponent should submit to the District an application for an Authority to Construct (ATC). For further information or assistance, the project proponent may contact the District's Small Business Assistance (SBA) Office at (661) 392-5665.

6b) District Rule 9510 (Indirect Source Review)

Per District Rule 9510 (Indirect Source Review) section 4.4.3, a development project on a facility whose primary functions are subject to District Rule 2201 or District Rule 2010 are exempt from the requirements of the rule. The District has reviewed the information provided and has determined that the primary functions of this Project are subject to District Rule 2201 (New and Modified Stationary Source Review Rule) or District Rule 2010 (Permits Required). As a result, District Rule 9510 requirements and related fees do not apply to the Project referenced above.

6c) Other District Rules and Regulations

The Project may also be subject to the following District rules: Regulation VIII, (Fugitive PM10 Prohibitions), Rule 4102 (Nuisance), Rule 4601 (Architectural Coatings), and Rule 4641 (Cutback, Slow Cure, and Emulsified Asphalt, Paving and Maintenance Operations). In the event an existing building will be renovated, partially demolished or removed, the project may be subject to District Rule 4002 (National Emission Standards for Hazardous Air Pollutants).

7) District Comment Letter

The District recommends that a copy of the District's comments be provided to the Project proponent.

If you have any questions or require further information, please contact Matt Crow by e-mail at Matt.Crow@valleyair.org or by phone at (559) 230-5931.

Sincerely,

Brian Clements
Director of Permit Services



For Mark Montelongo
Program Manager

Cindi Hoover

From: Lau, Scott@DOT <Scott.Lau@dot.ca.gov>
Sent: Thursday, April 7, 2022 8:24 AM
To: Cindi Hoover
Cc: Mendibles, Lorena@DOT
Subject: Caltrans response to the Carbon TerraVault DEIR

CAUTION: This email originated from outside of the organization. Do not click links, open attachments, or provide information unless you recognize the sender and know the content is safe.

Good morning Cindi,

I have reviewed the DEIR for the Carbon TerraVault and have no comments.

Respectfully,



Scott Lau
Associate Transportation Planner
California Department of Transportation
1352 West Olive Avenue
Fresno, CA 93778
Cell: (559) 981-7341

From:	Whitmore, Stephanie A.
To:	Lee, Annie
Cc:	Smith, Michael
Subject:	FW: Carbon TerraVault 1 by California Resources Corporation Project, SCH No. 2022030180.pdf
Date:	Thursday, April 7, 2022 9:09:28 AM
Attachments:	Carbon TerraVault 1 by California Resources Corporation Project, SCH No. 2022030180.pdf image001.png

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From: Cindi Hoover <hooverc@kerncounty.com>
Sent: Wednesday, April 6, 2022 12:02 PM
To: Whitmore, Stephanie A. <Stephanie.Whitmore@wsp.com>
Cc: Smith, Michael <Michael.D.Smith@wsp.com>; Lorelei Oviatt <Loreleio@kerncounty.com>
Subject: FW: Carbon TerraVault 1 by California Resources Corporation Project, SCH No. 2022030180.pdf

Stephanie,

We received an additional comment from CDFW today. This comment makes 13 total. Please include this comment in the record.

Regards,
Cindi Hoover,
Division Chief
Plan Development and Special Projects Division
Kern County Planning & Natural Resources

From: Wildlife R4 CEQA Program <R4CEQA@wildlife.ca.gov>
Sent: Wednesday, April 6, 2022 11:31 AM
To: Cindi Hoover <hooverc@kerncounty.com>
Cc: OPR State Clearinghouse <State.Clearinghouse@opr.ca.gov>; Marquez, Jaime@Wildlife

<Jaime.Marquez@Wildlife.ca.gov>
Subject: Carbon TerraVault 1 by California Resources Corporation Project, SCH No. 2022030180.pdf

CAUTION: This email originated from outside of the organization. Do not click links, open attachments, or provide information unless you recognize the sender and know the content is safe.

Ms. Hoover,

Please see the attached letter.

If you have any questions, please contact Jaime Marquez, Environmental Scientist at Jaime.Marquez@wildlife.ca.gov or by telephone at (559)580-3200.

Thank you,

CDFW R4 CEQA Support Staff

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State of California – Natural Resources Agency
DEPARTMENT OF FISH AND WILDLIFE
Central Region
1234 East Shaw Avenue
Fresno, California 93710
(559) 243-4005
www.wildlife.ca.gov

GAVIN NEWSOM, Governor
CHARLTON H. BONHAM, Director

April 6, 2022

Cindi Hoover
Kern County Planning and Natural Resources Department
2700 "M" Street, Suite 100
Bakersfield, California 93301

Subject: Carbon TerraVault 1 by California Resources Corporation (Project)
Notice of Preparation (NOP)
State Clearinghouse No. 2022030180

Dear Ms. Hoover:

The California Department of Fish and Wildlife (CDFW) received a NOP for an Environmental Impact Report (EIR) from Kern County, as Lead Agency, for the Project pursuant the California Environmental Quality Act (CEQA) and CEQA Guidelines.[1]

Thank you for the opportunity to provide comments and recommendations regarding those activities involved in the Project that may affect California fish and wildlife. Likewise, CDFW appreciates the opportunity to provide comments regarding those aspects of the Project that CDFW, by law, may be required to carry out or approve through the exercise of its own regulatory authority under the Fish and Game Code. While the comment period may have ended, CDFW would appreciate if you will still consider our comments.

CDFW ROLE

CDFW is California's **Trustee Agency** for fish and wildlife resources and holds those resources in trust by statute for all the people of the State (Fish & G. Code, §§ 711.7, subd. (a) & 1802; Pub. Resources Code, § 21070; CEQA Guidelines § 15386, subd. (a)). CDFW, in its trustee capacity, has jurisdiction over the conservation, protection, and management of fish, wildlife, native plants, and habitat necessary for biologically sustainable populations of those species (*Id.*, § 1802). Similarly, for purposes of CEQA, CDFW is charged by law to provide, as available, biological expertise during public agency environmental review efforts, focusing specifically on

[1] CEQA is codified in the California Public Resources Code in section 21000 et seq. The "CEQA Guidelines" are found in Title 14 of the California Code of Regulations, commencing with section 15000.

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projects and related activities that have the potential to adversely affect fish and wildlife resources.

CDFW is also submitting comments as a **Responsible Agency** under CEQA (Pub. Resources Code, § 21069; CEQA Guidelines, § 15381). CDFW expects that it may need to exercise regulatory authority as provided by the Fish and Game Code. As proposed, for example, the Project may be subject to CDFW's lake and streambed alteration regulatory authority (Fish & G. Code, § 1600 et seq.). Likewise, to the extent implementation of the Project as proposed may result in "take" as defined by State law of any species protected under the California Endangered Species Act (CESA) (Fish & G. Code, § 2050 et seq.), related authorization as provided by the Fish and Game Code will be required.

As a responsible agency, CDFW is responsible for providing, as available, biological expertise during public agency environmental review efforts (e.g., CEQA), focusing specifically on project activities that have the potential to adversely affect fish and wildlife resources. CDFW provides recommendations to identify potential impacts and possible measures to avoid or reduce those impacts.

CDFW has jurisdiction over fully protected species of birds, mammals, amphibians and reptiles, and fish, pursuant to Fish and Game Code sections 3511, 4700, 5050, and 5515. Take of any fully protected species is prohibited and CDFW cannot authorize their incidental take.

Other Rare Species: Species of plants and animals need not be officially listed as Endangered, Rare or Threatened (E, R, or T) on any State or federal list pursuant to CESA and/or the federal Endangered Species Act (ESA) to be considered E, R, or T under CEQA. If a species can be shown to meet the criteria for a listing as E, R, or T under CESA and/or ESA as specified in the CEQA Guidelines (Cal. Code Regs. tit. 14, Chapter 3, § 15380), it should be fully considered in the environmental analysis for the Project.

Nesting Birds: CDFW has jurisdiction over actions with potential to result in the disturbance or destruction of active nest sites or the unauthorized take of birds. Fish and Game Code sections that protect birds, their eggs and nests include, §§ 3503 (regarding unlawful take, possession or needless destruction of the nest or eggs of any bird), 3503.5 (regarding the take, possession or destruction of any birds-of-prey or their nests or eggs), and 3513 (regarding unlawful take of any migratory nongame bird).

PROJECT DESCRIPTION SUMMARY

Proponent: California Resources Corporation

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Objective: The Carbon TerraVault 1 Project, as proposed by California Resources Corporation would develop an approximate 5,745 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells, and related improvements for storage of Carbon Dioxide (CO2). The proposed project would take local industrial sources of CO2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project. Potential sources and locations of sources will be specifically identified and analyzed to the extent legally required by CEQA in the Draft EIR. The CO2 would then be injected into identified geographically confined reservoirs for storage in perpetuity.

Location: Central Valley portion of unincorporated Kern County, west side of Elk Hills Road and north side of Skyline Road, within the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield, approximately 8.5 miles from the City of Taft, and approximately 4 miles from the unincorporated community of Buttonwillow, also being located within sections 7, 8, 9, 10, 13, 15, 16, 17, 18, and 26 of Township 30 South, Range 23 East, Mount Diablo Base and Meridian (MDBM), County of Kern, State of California.

Timeframe: Unspecified

COMMENTS AND RECOMMENDATIONS

CDFW offers the comments and recommendations below to assist the County in adequately identifying and/or mitigating the Project's significant, or potentially significant, direct and indirect impacts on fish and wildlife (biological) resources. Editorial comments or other suggestions may also be included to improve the CEQA document.

The Project area is known to support high densities of several special-status animal species including the State and federally endangered and State fully protected blunt-nosed leopard lizard (*Gambelia sila*); the State and federally endangered giant kangaroo rat (*Dipodomys ingens*); the State threatened and federally endangered San Joaquin kit fox (*Vulpes macrotis mutica*); the State threatened Swainson's hawk (*Buteo swainsoni*) and San Joaquin (also known as Nelson's) antelope squirrel (*Ammospermophilus nelsoni*); the State species of special concern American badger (*Taxidea taxus*), short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*), burrowing owl (*Athene cunicularia*), and California glossy snake (*Arizona elegans occidentalis*). The Project area is also in the range of several special-status plant species including but not limited to the State and federally endangered and California rare plant rank (CRPR) 1B.1 California jewelflower (*Caulanthus californicus*)

There is an abundance of information about the extensive rare biological resources present throughout the Elk Hills Oil Field (EHOF), due to its history as the Naval

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Petroleum Reserve 1 (NPR1). NPR1 was sold to Occidental Petroleum as part of the 1996 National Defense Act that directed the Department of Energy to sell the oilfield; Occidental Petroleum (OXY) completed the purchase in 1998. In addition to the extensive biological information collected by DOE, a joint PEIR/SEIS was prepared by DOE/Kern County in 1997 to support the transfer. CDFW issued a 1997 CESA MOU and subsequent amendments, which was then superseded by a 2014 Incidental Take Permit (ITP), supported by the Kern County Oil and Gas EIR. CDFW's 2014 ITP permitting effort was supported by extensive biological survey information and related modeling provided by OXY. CDFW requests that the EIR fully identify potential impacts to biological resources, including the above-mentioned species by evaluating the extensive existing biological information. CDFW can provide some of this information if needed, as we relied heavily upon it for our more recent permitting efforts. . CDFW recommends that the following be incorporated into the EIR.

I. Environmental Setting and Related Impact

Would the Project have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations, or by CDFW or the United States Fish and Wildlife Service (USFWS)?

COMMENT 1: Blunt-nosed Leopard Lizard (*Gambelia sila*; BNLL)

Issue: Comprehensive BNLL population monitoring has been conducted across the EHOF for over the last 45 years. As a result, areas of BNLL occurrences within the EHOF are well known and documented by repeated survey efforts. At the EHOF, BNLL seem to prefer the flat, open, gently sloping terrain of perimeter areas of the EHOF and sandy bottomed flat washes that occur in the flat, gently sloping terrain of perimeter areas. The distribution of blunt-nosed leopard lizards on the EHOF is primarily restricted to the northeast and southwest flatter portions of the EHOF, with some sightings in the northwest corner. The majority of sightings are in the Buena Vista Valley. An extensive habitat use study of blunt-nosed leopard lizard microhabitat and home range characteristics was conducted on the EHOF and published in 1998 (Warrick et al. 1998). Based on the studies conducted, it was determined that optimal habitat for the blunt-nosed leopard lizard at the EHOF would be characterized by flat terrain, numerous small mammal burrows, sufficient vegetation to support an abundant and diverse prey base and interconnected patches of bare ground or sparse vegetation distributed throughout the landscape. A majority of the best habitat with suitable features for sensitive species such as the BNLL, and others, has been placed into conserved status in the Elk Hills Conservation Area along the north and south flanks of the EHOF. This area provides 7,878 acres of undisturbed habitat that is preserved in perpetuity and wherein future development is strictly limited to no more than 10% on a quarter section basis.

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Specific impact: It appears based on the Project Description in the NOP that the project is proposed in at least a portion of what is known as the highest quality BNLL habitat within the EHOF. Potentially significant impacts associated with ground-disturbing activities include habitat loss, burrow collapse, reduced reproductive success, reduced health and vigor of eggs and/or young, and direct mortality. Given the Fully Protected status of BNLL, it is unclear that the Project could be implemented and avoid a violation of Fish and Game Code Section 5050.

Evidence impact is potentially significant: Habitat loss resulting from agricultural, urban, and industrial development is the primary threat to BNLL (ESRP 2020a). Little suitable habitat for BNLL remains in central Kern County (USFWS 1998). The Project and surrounding area contain some of the highest quality remaining habitat for BNLL; therefore, subsequent ground disturbing activities and conversion of suitable habitat associated with the Project may have the potential to significantly impact local BNLL populations. Due to the significant loss of habitat for the species from land conversion and incompatible land use, CDFW advises that a robust cumulative impact analysis is warranted and addressed in the CEQA document prepared for the Project.

Recommended Mitigation Measure 1: BNLL Surveys

CDFW recommends conducting surveys in the proposed Project Area in accordance with the "Approved Survey Methodology for the Blunt-nosed Leopard Lizard" (CDFW 2019). This survey protocol, designed to optimize BNLL detectability, reasonably assures CDFW that BNLL would be detected if present.

CDFW advises that BNLL surveys be completed by a qualified wildlife biologist as described in the survey protocol above across the entire Project site prior to CEQA analysis. These surveys must be also be conducted no more than one year prior to initiation of ground and/or vegetation disturbance. Protocol-level surveys for BNLL are not synonymous with 30-day "preconstruction surveys" often recommended for other wildlife species. In addition, the BNLL protocol specifies different survey effort requirements based on whether the disturbance results from maintenance activities or if the disturbance results in habitat removal (CDFW 2019).

Recommended Mitigation Measure 2: BNLL Take Avoidance

BNLL detection during protocol-level surveys warrants consultation with CDFW to discuss how to implement ground-disturbing activities and avoid take. Because BNLL is a State Fully Protected species, no take incidental or otherwise, can be authorized by CDFW.

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CDFW's recommendation for avoiding take, providing for individual and population persistence, and conforming to the applicable recovery goals is to design the project to avoid all occupied BNLL habitat, and base that avoidance on known spatial ecology of BNLL. The design should reflect known home range estimates and movement distances, with the intent to avoid fragmenting occupied habitat and habitat necessary to support and recover the species. CDFW recommends using maximum observed home range areas and movement distances instead of average home range areas, which underestimate the area that many BNLL individuals are known to use. This is particularly significant in areas that may be subject to high ecological or climatological variability, such as the Project site.

To determine a buffer that has a reasonable chance of preventing take, CDFW reviewed the best available scientific information on the area which individual BNLL use (home range) and the distances that individuals are known to move between points. Below is a summary of relevant findings from the available published literature and unpublished data on BNLL spatial ecology.

Tollestrup (1983): Seventeen BNLL were marked, recaptured, and observed visually (no telemetry). Home ranges were derived from a one-month study period and considered to be underestimated. Seasonal shifts in activity areas were detected, specifically between the breeding and non-breeding season. One individual moved 1,509 feet between successive capture points.

Warrick et al (1998): Five females and eleven males were tracked with radio telemetry for 17-71 days. One lizard's home range steadily increased even after 40 days. The authors conclude that ten of the lizards' home ranges, which were based on less than 30 locations, should be considered minimum values. One lizard exhibited a dramatic home range shift which was not included in its home range estimate. Female home range estimates (convex polygon) were 1.2 to 11.0 acres. Male home range estimates were 3.9 to 21.7 acres. Where upland habitat had relatively dense vegetation, washes were used significantly more than the upland areas. Where vegetation was sparse in grasslands, grassland habitat was used more than other habitats, including washes.

Unpublished Data: Dr. David Germano of California State University Bakersfield provided some summary statistics of unpublished telemetry data from 2002-2004. Thirty-three males and 24 females were tracked in three different years. It is unknown as of yet how many individuals were tracked in multiple years and how many were tracked for single years. Female home range estimates (95% minimum convex polygon) were 1.1 to 16.5 acres. Male home range estimates were 1.8 to 52.4 acres. These estimates excluded three females which used home ranges greater than 98.8 acres (unknown how much greater).

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Table 1 summarizes the maximum home range and movement distances detected.

Table 1. Maximum Known Home Range Estimates and Movement Distances

Source	Maximum Movement Distance Detected (ft)	Maximum Home Range Estimate (acres)
Tollestrup (1983)	1509	4.4
Warrick et al. (1998)	NA	21.7
Germano 2002-2004 data (unpublished)	NA	98.8

Several factors make predicting the locations of BNLL when construction commences highly uncertain. These uncertainties make the proposal unlikely to avoid direct mortality of individual BNLL during Project construction. For example, the lizards would be detected when on the surface; between the detection date and the start of construction, they will move and occupy unknown locations underground, possibly long distances from the point of detection. The lizard's location underground when construction commences is not predictable and unlikely to be encompassed by a five-acre buffer of any shape. Also, when a lizard is detected, it is unlikely to be at the center of its home range. It may be on the margin or elsewhere within an irregularly-shaped home range area. Predicting the size and shape of the home range is not feasible unless there are completely unsuitable habitat types which would limit spatial use. The entire Project site consists of potential habitat for BNLL. They may be in any burrow during the inactive season, including undetectable burrows that lizards construct themselves and small mammal burrows that are backfilled.

Predicting home range locations based on habitat type is also highly uncertain. One of the two study sites in Warrick et al (1998) was 80% grassland, and lizards used that area in proportion to its availability, even with open wash habitats available.

If the maximum known distance moved (1509 feet) were used as a radius for prescribing buffer areas, the buffer area would need to be 164 acres. This approach would be based on only one study (Tollestrup 1983) and is probably an underestimation of spatial use. The two studies which used more reliable, radio telemetry methods did not present any movement distances.

The maximum home range estimate of 98.8 acres was observed with three female lizards. Females typically exhibit smaller home ranges than males. Of the BNLL studied in the two available telemetry studies, approximately one in 25 had home ranges that exceeded 98.8 acres (Warrick et al. 1998, Dr. David Germano, California State University Bakersfield, unpublished data). That rate would increase to one in 20 lizards if considering only the study where those observations were made.

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If one in 20-25 lizards has a home range greater than 98.8 acres, then CDFW expects some lizards on the Project site to use areas of similar size. CDFW recommends using 98.8 acres as a minimum starting point for BNLL take avoidance buffers. Prescribing a 98.8-acre buffer around a detected lizard may encompass a wide range of expected home ranges. However, placing an avoidance buffer around the lizard observation assumes that we know where the lizard's home range is relative to the location of the observation. Since we have no way of predicting the size or shape of the home range based on a single observation of a lizard, a reasonable plan for avoidance is to assume that the lizard might utilize up to 98.8 acres in any direction from where it was observed. A circular home range could be assumed due to the uncertainty of home range shape. The diameter of a 98.8-acre circle is 2340.8 feet. Using that distance as a buffer from the point where the lizard is detected yields an approximately 395-acre circle which could be prescribed as a buffer area.

COMMENT 2: San Joaquin Kit Fox (SJKF)

Issue: SJKF is known to occur in high densities throughout Project site (CDFW 2022). Aerial imagery shows that the project area consists of oil wells, agricultural field, non-native annual grassland habitat, and patches of ruderal habitat, habitat types, some of which, are suitable to support SJKF. In addition to grasslands, SJKF den in a variety of areas such as rights-of-way, vacant lots, agricultural and fallow or ruderal habitat, dry stream channels, and canal levees, and populations can fluctuate over time. SJKF are also capable of occupying urban environments (Cypher and Frost 1999). SJKF may be attracted to the Project area due to the type and level of ground-disturbing activities and the loose, friable soils resulting from intensive ground disturbance. As a result, there is potential for SJKF to occupy the Project site and surrounding area.

Specific impact: Without appropriate avoidance and minimization measures for SJKF, potential significant impacts associated with Project related activities include, den collapse, inadvertent entrapment, reduced reproductive success, reduction in health and vigor of young, and direct mortality of individuals.

Evidence impact is potentially significant: Habitat loss resulting from land conversion to agricultural, urban, and industrial development is the primary threat to SJKF (Cypher et al. 2013). Western Kern County supports relatively large areas of high suitability habitat and one of the largest remaining populations of SJKF (Cypher et al. 2013). The Project and surrounding area contain undeveloped land; therefore, subsequent ground disturbing activities and conversion of suitable habitat associated with the Project may have the potential to significantly impact local SJKF populations.

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Recommended Mitigation Measure 3: SJKF Surveys

CDFW recommends assuming presence of SJKF in the Project Area based on extensive biological information collected previously within the Project Area. Conducting den surveys by conducting surveys following the USFWS' "Standardized recommendations for protection of the San Joaquin kit fox prior to or during ground disturbance" (2011) may provide some index of the potential Project related impacts to SJKF.

Recommended Mitigation Measure 4: SJKF Avoidance

Avoidance of Project Related Impacts to SJKF is likely infeasible. To minimize direct impacts to dens, CDFW recommends implementing no-disturbance buffers, as described in the USFWS "Standardized recommendations for protection of the San Joaquin kit fox prior to or during ground disturbance" (2011) around den sites.

Recommended Mitigation Measure 5: SJKF Take Authorization

This Project warrants consultation with CDFW and acquisition of an an Incidental Take Permit (ITP) prior to ground-disturbing activities, pursuant to Fish and Game Code section 2081 subdivision (b). The existing ITP issued to OXY/CRC does not include the proposed Project as a Covered Activity.

Recommended Mitigation Measure 6: Perimeter Fences

CDFW recommends all perimeter fencing be raised five to seven inches above ground level and knuckled under to allow SJKF movement through the Project site and to minimize impacts to SJKF habitat connectivity.

COMMENT 3: Giant Kangaroo Rat (GKR) Tipton Kangaroo Rat (TKR) and Short-Nosed Kangaroo Rat (SNKR)

Issue: GKR, TKR, and SNKR have been documented to occur near the Project site (CDFW 2022), and the Project Area supports some of the best GKR habitat present on the EHOF. These species inhabit sandy-loam soils located in grassland habitat with scattered shrubs. Suitable habitat includes areas of grassland, upland scrub, and alkali sink habitats that contain requisite habitat elements, such as small mammal burrows. The land use described in the NOP indicates that suitable habitat is present on the Project site therefore, there is potential for these species to occupy or colonize the Project.

Specific impact: Without appropriate avoidance and minimization measures for GKR, TKR, and SNKR, potential significant impacts from Project activities include

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loss of habitat, burrow collapse, inadvertent entrapment of individuals, reduced reproductive success such as reduced health or vigor of young, and direct mortality of individuals.

Evidence impact is potentially significant: Habitat loss resulting from agricultural, urban, and industrial development is the primary threat to GKR, TKR, and SNKR. Further, habitat fragmentation may accelerate the decline of these species. The Project and surrounding area contain undeveloped land; therefore, if the Project area is occupied by GKR, TKR, and/or SNKR subsequent ground disturbing activities and conversion of suitable habitat associated with the Project may have the potential to significantly impact local populations of these species.

Recommended Mitigation Measure 7: GKR, TKR, and SNKR Trapping Surveys

CDFW recommends that a trapping plan for determining presence of GKR, TKR, and SNKR be submitted to and approved by CDFW prior to subsequent trapping efforts. CDFW recommends these surveys be conducted by a qualified biologist who holds a CDFW Memorandum of Understanding for GKR, TKR, and SNKR, and any appropriate USFWS permit(s). CDFW further recommends that these surveys be conducted between April 1 and October 31, when kangaroo rats are most active and well in advance of ground- and/or vegetation-disturbing activities in order to determine if impacts to GKR, TKR, and/or SNKR could occur. Once completed, all survey results should be sent to CDFW.

Recommended Mitigation Measure 8: GKR, TKR, and SNKR Avoidance

If potential habitat is present and trapping is not feasible, CDFW advises maintenance of a 50-foot minimum no-disturbance buffer around all small mammal burrow entrances. In addition, CDFW advises that Fish and Game Code Section 86 defines take as hunt, pursue, catch, capture, or kill, or attempt to hunt, pursue, catch, capture, or kill. Although these recommended buffer distances may be sufficient to avoid direct mortality or burrow destruction, encircling a burrow with development activities may inhibit the ability of GKR, TKR, and SNKR to freely disperse to and from burrows and has the potential to be considered “capture” and/or ultimately result in take in the form of mortality. Therefore, CDFW recommends that in addition to the buffer distances, that no burrow is surrounded more than 180 degrees by development activities.

Recommended Mitigation Measure 9: GKR and TKR Take Authorization

If GKR or TKR are found within the Project area during trapping as described above, preconstruction surveys, or construction activities, consultation with CDFW is advised immediately to discuss how to implement the Project. Given the known high

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densities of GKR on the Project Site, CDFW recommends acquisition of an ITP pursuant to Fish and Game Code Section 2081(b) with GKR as a covered Species prior to any ground-disturbing activities. The existing ITP issued to OXY/CRC does not include the proposed Project as a Covered Activity.

COMMENT 4: San Joaquin (also known as Nelson's) Antelope Squirrel (SJAS)

Issue: SJAS are known to occur throughout the EHOF, even within the High Production Area. SJAS inhabit sandy-loam soils in areas of grassland, upland scrub, and alkali sink habitats that contain requisite habitat elements, such as small mammal burrows.

Specific impact: Without appropriate avoidance and minimization measures for SJAS, potential significant impacts include loss of habitat, burrow collapse, inadvertent entrapment of individuals, reduced reproductive success such as reduced health or vigor of young, and direct mortality of individuals.

Evidence impact is potentially significant: Habitat loss resulting from agricultural, urban, and industrial development is the primary threat to SJAS. Further, habitat fragmentation may accelerate the decline of the species. Very little suitable habitat for this species remains outside of the western Kern County and eastern San Luis Obispo County area (ESRP 2020e, USFWS 1998). The Project Area is known to support SJAS; therefore, subsequent ground disturbing activities and habitat conversion associated with the Project may have the potential to significantly impact local SJAS populations.

Recommended Mitigation Measure 10: SJAS Surveys

Prior to initiating ground- and/or vegetation- disturbing activities, CDFW recommends that a qualified biologist conduct focused daytime visual surveys for SJAS using line transects with 10- to 30-meter spacing. CDFW further advises that these surveys be conducted between April 1 and September 20, during daytime temperatures between 68° and 86° F, to maximize detectability (CDFG 1990). All survey results should be sent to CDFW after completion.

Recommended Mitigation Measure 11: SJAS Avoidance

CDFW recommends maintenance of a 50-foot minimum no-disturbance buffer around all small mammal burrow entrances until the completion of Project activities. As recommended for GKR and SNKR, CDFW recommends that in addition to the buffer distances, that no burrow is surrounded more than 180 degrees by development activities.

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Recommended Mitigation Measure 12: SJAS Take Authorization

CDFW recommends acquisition of a take authorization through the acquisition of an Incidental Take Permit (ITP), pursuant to Fish and Game Code section 2081(b) with SJAS as a covered species to comply with CESA. The existing ITP issued to OXY/CRC does not include the proposed Project as a Covered Activity.

COMMENT 5: Swainson's Hawk (SWHA)

Issue: SWHA have been documented to occur in the areas bordering Elk Hills (CDFW 2022). Therefore, SWHA have the potential to nest near the Project site, and forage within the Project site. The habitat types present at the Project site all provide suitable foraging habitat for SWHA, increasing the likelihood of SWHA occurrence within the vicinity. In addition, any trees in the Project vicinity have the potential to provide suitable nesting habitat.

Specific impact: Without appropriate avoidance and minimization measures for SWHA, potential significant impacts that may result from Project activities include nest abandonment, loss of nest trees, loss of foraging habitat that would reduce nesting success (loss or reduced health or vigor of eggs or young), and direct mortality. All trees, including non-native or ornamental varieties, near the Project site may provide potential nesting sites.

Evidence impact would be significant: SWHA exhibit high nest-site fidelity year after year and lack of suitable nesting habitat limits their local distribution and abundance (CDFW 2016). If potential nest sites occur in the Project vicinity, approval of the Project may lead to subsequent ground-disturbing activities that involve noise, groundwork, construction of structures, and movement of workers that could affect nests and has the potential to result in nest abandonment and/or loss of foraging habitat, significantly impacting local nesting SWHA. In addition, conversion of undeveloped land can directly influence distribution and abundance of SWHA, due to the reduction in foraging habitat.

Recommended Mitigation Measure 13: Focused SWHA Surveys

To evaluate potential Project-related impacts, CDFW recommends that a qualified wildlife biologist conduct surveys for nesting SWHA following the entire survey methodology developed by the SWHA Technical Advisory Committee (SWHA TAC 2000) prior to Project implementation (during CEQA analysis). SWHA detection during protocol-level surveys warrants consultation with CDFW to discuss how to implement Project activities and avoid take.

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Recommended Mitigation Measure 14: SWHA Avoidance

CDFW recommends that if Project-specific activities will take place during the SWHA nesting season (i.e., March 1 through September 15), and active SWHA nests are present, a minimum ½-mile no-disturbance buffer be delineated and maintained around each nest, regardless of when it was detected by surveys or incidentally, until the breeding season has ended or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or parental care for survival, to prevent nest abandonment and other take of SWHA as a result of Project activities.

Recommended Mitigation Measure 15: SWHA Take Authorization

CDFW recommends that in the event an active SWHA nest is detected, and a ½-mile no-disturbance buffer is not feasible, consultation with CDFW is warranted to discuss how to implement the project and avoid take. If take cannot be avoided, take authorization through the acquisition of an Incidental Take Permit (ITP), pursuant to Fish and Game Code section 2081(b) is necessary to comply with CESA.

Recommended Mitigation Measure 16: Loss of SWHA Foraging Habitat

CDFW recommends compensation for the loss of SWHA foraging habitat as described in CDFW's "Staff Report Regarding Mitigation for Impacts to Swainson's Hawks" (CDFG 1994) to reduce impacts to foraging habitat to less than significant. The Staff Report recommends that mitigation for habitat loss occur within a minimum distance of 10 miles from known nest sites. CDFW has the following recommendations based on the Staff Report:

- For projects within 1 mile of an active nest tree, a minimum of 1 acre of habitat management (HM) land for each acre of development is advised.

- For projects within 5 miles of an active nest but greater than 1 mile, a minimum of ¾ acre of HM land for each acre of development is advised.

- For projects within 10 miles of an active nest tree but greater than 5 miles from an active nest tree, a minimum of ½ acre of HM land for each acre of development is advised.

Recommended Mitigation Measure 17: SWHA Tree Removal

CDFW recommends that the removal of known SWHA nest trees, even outside of the nesting season, be replaced with an appropriate native tree species planting at a ratio of 3:1 at or near the Project area or in another area that will be protected in

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perpetuity. This mitigation would offset the local and temporal impacts of nesting habitat loss.

COMMENT 6: Special-status Plants

Issue: Several special-status plant species meeting the definition of rare or endangered under CEQA section 15380 have been documented to occur near the Project area, including but not limited to, the State and federally endangered and CRPR 1B.1 California jewelflower (CDFW 2022).

Specific impact: Without appropriate avoidance and minimization measures for special-status plants, potential significant impacts associated with subsequent construction include loss of habitat, loss or reduction of productivity, and direct mortality.

Evidence impact would be significant: The California jewelflower and many other special-status plant species are threatened by grazing and agricultural, urban, and energy development. Many historical occurrences of these species are presumed extirpated (CNPS 2020). Though new populations have recently been discovered, impacts to existing populations have the potential to significantly impact populations of plant species.

Recommended Mitigation Measure 18: Special-Status Plant Surveys

CDFW recommends that individual Project sites be surveyed for special-status plants by a qualified botanist following the “Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities” (CDFG 2018). This protocol, which is intended to maximize detectability, includes the identification of reference populations to facilitate the likelihood of field investigations occurring during the appropriate floristic period.

Recommendation Mitigation Measure 19: Sensitive Natural Communities

In addition to surveying for special-status plants as stated above, CDFW recommends the Project area is also surveyed for the presence of sensitive natural communities, which is also part of CDFW’s botanical survey protocol (CDFW 2018). If sensitive natural communities are found, CDFW recommend impacts to them are fully evaluated in the CEQA document.

Recommended Mitigation Measure 20: Special-Status Plant Avoidance

CDFW recommends that special-status plant species be avoided whenever possible by delineating and observing a no-disturbance buffer of at least 50 feet from the

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outer edge of the plant population(s) or specific habitat type(s) required by special-status plant species. If buffers cannot be maintained, then consultation with CDFW may be warranted to determine appropriate minimization and mitigation measures for impacts to special-status plant species.

Recommended Mitigation Measure 21: Listed Plant Species Take Authorization

If a State-listed plant species is identified during botanical surveys, consultation with CDFW is warranted to determine if the Project can avoid take. If take cannot be avoided, take authorization is warranted. Take authorization would occur through acquisition of an ITP, pursuant to Fish and Game Code section 2081(b).

COMMENT 7: Burrowing Owl (BUOW)

Issue: BUOW have been documented in the Project vicinity (CDFW 2022). BUOW inhabit open grassland and similar habitat types containing small mammal burrows, a requisite habitat feature used by BUOW for nesting and cover. The NOP reports that these habitat features are present on the Project site, therefore, there is potential for BUOW to occupy or colonize the Project.

Specific impact: Potentially significant direct impacts associated with subsequent activities and land conversion include habitat loss, burrow collapse, inadvertent entrapment, nest abandonment, reduced reproductive success, reduction in health and vigor of eggs and/or young, and direct mortality of individuals.

Evidence impact is potentially significant: BUOW rely on burrow habitat year-round for their survival and reproduction. Habitat loss and degradation are considered the greatest threats to BUOW in California's Central Valley (Gervais et al. 2008). The Project and surrounding area contain undeveloped land; therefore, subsequent ground-disturbing activities associated with the Project have the potential to significantly impact local BUOW populations. In addition, and as described in CDFW's "Staff Report on Burrowing Owl Mitigation" (CDFG 2012), excluding and/or evicting BUOW from their burrows is considered a potentially significant impact under CEQA.

Recommended Mitigation Measure 22: BUOW Surveys

CDFW recommends assessing presence or absence of BUOW by having a qualified biologist conduct surveys following the California Burrowing Owl Consortium's "Burrowing Owl Survey Protocol and Mitigation Guidelines" (CBOC 1993) and the "Staff Report on Burrowing Owl Mitigation" (CDFG 2012), which suggest three or more surveillance surveys conducted during daylight with each visit occurring at

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least three weeks apart during the peak breeding season (i.e., April 15 to July 15), when BUOW are most detectable. In addition, CDFW advises that surveys include a minimum 500-foot buffer area around the Project area.

Recommended Mitigation Measure 23: BUOW Avoidance

Should a BUOW be detected, CDFW recommends that no-disturbance buffers, as outlined in the "Staff Report on Burrowing Owl Mitigation" (CDFG 2012), be implemented prior to and during any ground-disturbing activities. Specifically, CDFW's Staff Report recommends that impacts to occupied burrows be avoided in accordance with the following table unless a qualified biologist approved by CDFW verifies through non-invasive methods that either: 1) the birds have not begun egg laying and incubation; or 2) that juveniles from the occupied burrows are foraging independently and are capable of independent survival.

Location	Time of Year	Level of Disturbance		
		Low	Med	High
Nesting sites	April 1-Aug 15	200 m*	500 m	500 m
Nesting sites	Aug 16-Oct 15	200 m	200 m	500 m
Nesting sites	Oct 16-Mar 31	50 m	100 m	500 m

* meters (m)

Recommended Mitigation Measure 24: BUOW Passive Relocation and Mitigation

If BUOW are found within these recommended buffers and avoidance is not possible, it is important to note that according to the Staff Report (CDFG 2012), excluding birds from burrows is not a take avoidance, minimization, or mitigation method and is instead considered a potentially significant impact under CEQA. However, if it is necessary for Project implementation, CDFW recommends that burrow exclusion be conducted by qualified biologists and only during the non-breeding season, before breeding behavior is exhibited and after the burrow is confirmed empty through non-invasive methods, such as surveillance. CDFW recommends replacement of occupied burrows with artificial burrows at a ratio of one (1) burrow collapsed to one (1) artificial burrow constructed (1:1) to mitigate for evicting BUOW and the loss of burrows. BUOW may attempt to colonize or re-colonize an area that will be impacted; thus, CDFW recommends ongoing surveillance at a rate that is sufficient to detect BUOW if they return.

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COMMENT 8: Other State Species of Special Concern

Issue: San Joaquin pocket mouse, California glossy snake, and American badger have the potential to occur in the Project area. These species have been documented to occur in the vicinity of the Project site, which supports requisite habitat elements (CDFW 2022).

Specific impact: Without appropriate avoidance and minimization measures for these species, potentially significant impacts associated with ground disturbance include habitat loss and nest/den/burrow abandonment, which may result in reduced health or vigor of eggs and/or young, and direct mortality.

Evidence impact is potentially significant: Habitat loss threatens all of the species mentioned above (Gittleman et al. 2001, Shuford and Gardali 2008, Thomson et al. 2016). The Project and surrounding area contain undeveloped land; therefore, subsequent ground disturbing activities and habitat conversion associated with the Project may have the potential to significantly impact local the populations of these species.

Recommended Mitigation Measure 25: Habitat Assessment

CDFW recommends that a qualified biologist conduct a habitat assessment in advance of project implementation, to determine if project areas or their immediate vicinity contain potential habitat for the species mentioned above.

Recommended Mitigation Measure 26: Surveys

If potential habitat is present, CDFW recommends that a qualified biologist conduct focused surveys for applicable species and their requisite habitat features to evaluate potential impacts resulting from ground and vegetation disturbance.

Recommended Mitigation Measure 27: Avoidance

Avoidance whenever possible is encouraged via delineation and observance a 50-foot no-disturbance buffer around dens of mammals like the American badger as well as the entrances of burrows that can provide refuge for special-status small mammals and California glossy snake.

Editorial Comments and/or Suggestions

Federally Listed Species: CDFW recommends consulting with USFWS regarding potential impacts to federally listed species including but not limited to the blunt-nosed leopard lizard, giant kangaroo rat, and San Joaquin kit fox. Take under the Federal

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Endangered Species Act (FESA) is more broadly defined than CESA; take under FESA also includes significant habitat modification or degradation that could result in death or injury to a listed species by interfering with essential behavioral patterns such as breeding, foraging, or nesting. Consultation with the USFWS in order to comply with FESA is advised well in advance of any Project activities.

Lake and Streambed Alteration: If streams, swales, or drainages occur on the Project site, Project activities may be subject to CDFW's regulatory authority pursuant Fish and Game Code section 1600 et seq. Fish and Game Code section 1602 requires an entity to notify CDFW prior to commencing any activity that may (a) substantially divert or obstruct the natural flow of any river, stream, or lake; (b) substantially change or use any material from the bed, bank, or channel of any river, stream, or lake (including the removal of riparian vegetation): (c) deposit debris, waste or other materials that could pass into any river, stream, or lake. "Any river, stream, or lake" includes those that are ephemeral or intermittent as well as those that are perennial.

CDFW is required to comply with CEQA in the issuance of a Lake or Streambed Alteration Agreement (LSAA); therefore, if the CEQA document approved for the Project does not adequately describe the Project and its impacts to lakes or streams, a subsequent CEQA analysis may be necessary for LSAA issuance. For information on notification requirements, please refer to CDFW's website (https://wildlife.ca.gov/Conservation/LSA) or contact CDFW staff in the Central Region Lake and Streambed Alteration Program at (559) 243-4593.

Nesting Birds: CDFW has jurisdiction over actions with potential to result in the disturbance or destruction of active nest sites or the unauthorized take of birds. Fish and Game Code sections that protect birds, their eggs and nests include sections 3503 (regarding unlawful take, possession or needless destruction of the nest or eggs of any bird), 3503.5 (regarding the take, possession or destruction of any birds-of-prey or their nests or eggs), and 3513 (regarding unlawful take of any migratory nongame bird).

CDFW encourages Project implementation to occur during the bird non-nesting season; however, if Project activities must occur during the nesting season (i.e., February through mid-September), the Project applicant is responsible for ensuring that implementation of the Project does not result in violation of the Migratory Bird Treaty Act or relevant Fish and Game Codes as referenced above.

To evaluate Project-related impacts on nesting birds, CDFW recommends that a qualified wildlife biologist conduct pre-activity surveys for active nests no more than 10 days prior to the start of ground disturbance to maximize the probability that nests that could potentially be impacted by the Project are detected. CDFW also recommends that surveys cover a sufficient area around the work site to identify nests and determine their status. A sufficient area means any area potentially affected by a project. In

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addition to direct impacts (i.e., nest destruction), noise, vibration, and movement of workers or equipment could also affect nests. Prior to initiation of construction activities, CDFW recommends that a qualified biologist conduct a survey to establish a behavioral baseline of all identified nests. Once construction begins, CDFW recommends that a qualified biologist continuously monitor nests to detect behavioral changes resulting from the project. If behavioral changes occur, CDFW recommends that the work causing that change cease and CDFW be consulted for additional avoidance and minimization measures.

If continuous monitoring of identified nests by a qualified wildlife biologist is not feasible, CDFW recommends a minimum no-disturbance buffer of 250 feet around active nests of non-listed bird species and a 500-foot no-disturbance buffer around active nests of non-listed raptors. These buffers are advised to remain in place until the breeding season has ended or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or parental care for survival. Variance from these no-disturbance buffers is possible when there is compelling biological or ecological reason to do so, such as when the construction area would be concealed from a nest site by topography. CDFW recommends that a qualified wildlife biologist advise and support any variance from these buffers and notify CDFW in advance of implementing a variance.

Impacts to Conserved Lands
As a condition of previous CDFW and USFWS permits, OXY placed 7,878 acres of high quality habitat within the EHOF into permanently conserved status via recordation of a Conservation Easement in favor of CDFW. The so called Elk Hills Conservation Area is present along the north and South flanks of the EHOF, which appears to be within or adjacent to the Proposed Project. The EIR prepared for this project should analyze any potential direct or indirect impacts to this conserved habitat and the associated special status species.

ENVIRONMENTAL DATA

CEQA requires that information developed in environmental impact reports and negative declarations be incorporated into a database, which may be used to make subsequent or supplemental environmental determinations (Pub. Resources Code, § 21003, subd. (e)). Accordingly, please report any special-status species and natural communities detected during Project surveys to the CNDDB. The CNDDB field survey form can be found at the following link: https://www.wildlife.ca.gov/Data/CNDDB/Submitting-Data. The completed form can be mailed electronically to CNDDB at the following email address: CNDDB@wildlife.ca.gov. The types of information reported to CNDDB can be found at the following link: https://www.wildlife.ca.gov/Data/CNDDB/Plants-and-Animals.

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FILING FEES

The Project, as proposed, would have an impact on fish and/or wildlife, and assessment of filing fees is necessary. Fees are payable upon filing of the Notice of Determination by the Lead Agency and serve to help defray the cost of environmental review by CDFW. Payment of the fee is required in order for the underlying project approval to be operative, vested, and final (Cal. Code Regs, tit. 14, § 753.5; Fish & G. Code, § 711.4; Pub. Resources Code, § 21089).

CONCLUSION

CDFW appreciates the opportunity to comment on the NOP to assist Kern County in identifying and mitigating Project impacts on biological resources.

If you have any questions, please contact Jaime Marquez, Environmental Scientist, at the address provided on this letterhead, by telephone at (559) 580-3200, or by electronic mail at Jaime.Marquez@wildlife.ca.gov.

Sincerely,

DocuSigned by:
Bob Stafford
5343A684FF02469...

Bob Stafford for Julie A. Vance
Regional Manager

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Attachment 1

MITIGATION MONITORING AND REPORTING PROGRAM (MMRP) FOR CALIFORNIA DEPARTMENT OF FISH AND WILDLIFE RECOMMENDED MITIGATION MEASURES

PROJECT: Carbon TerraVault 1
SCH No.: 2022030180

RECOMMENDED MITIGATION MEASURE	STATUS/DATE/INITIALS
Before Disturbing Soil or Vegetation	
Mitigation Measure 1: BNLL Surveys	
Mitigation Measure 3: SJKF Surveys	
Mitigation Measure 5: SJKF Take Authorization	
Mitigation Measure 7: GKR, TKR, and SNKR Trapping Surveys	
Mitigation Measure 9: GKR, TKR, and SNKR Take Authorization	
Mitigation Measure 10: SJAS Surveys	
Mitigation Measure 12: SJAS Take Authorization	
Mitigation Measure 13: Focused SWHA Surveys	
Mitigation Measure 15: SWHA Take Authorization	
Mitigation Measure 16: Loss of SWHA Foraging Habitat	
Mitigation Measure 17: SWHA Tree Removal	
Mitigation Measure 18: Special-Status Plant Surveys	
Mitigation Measure 19: Sensitive natural Communities	
Mitigation Measure 21: Listed Plant Species Take Authorization	
Mitigation Measure 22: BUOW Surveys	
Mitigation Measure 24: BUOW Passive Relocation and Mitigation	
Mitigation Measure 25: Habitat Assessment	
Mitigation Measure 26: Surveys	
During Construction	
Mitigation Measure 2: BNLL Take Avoidance	
Mitigation Measure 4: SJKF Avoidance	
Mitigation Measure 6: Perimeter Fencing	
Mitigation Measure 8: GKR, TKR, and SNKR Avoidance	
Mitigation Measure 11: SJAS Avoidance	
Mitigation Measure 14: SWHA Avoidance	
Mitigation Measure 20: Special-Status Plant Avoidance	
Mitigation Measure 23: BUOW Avoidance	

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Mitigation Measure 27: Avoidance	

A.3 Scoping Meeting Agenda

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AGENDA

KERN COUNTY PLANNING & NATURAL RESOURCES DEPARTMENT

Scoping Meeting

Kern County Planning and Natural Resources Department
Public Services Building
2700 "M" Street, Public Meeting Room 1-A
Bakersfield, California 93301

March 18, 2022 – 1:30 p.m.

Pursuant to revised Section 21083.9 of the Public Resources Code, California Environmental Quality Act, effective January 1, 2002, this scoping meeting is being held to receive comments from agencies and public on the preparation of Environmental Impact Reports (EIR) for certain projects. The process of determining the scope, focus, and content of the EIR is known as "scoping." Scoping helps to identify the range of actions, alternatives, environmental effects, methods of assessment, and mitigation measures to be analyzed in depth, and eliminate from detailed study those issues that are not important to the decision at hand. This is not a public hearing, however the public may be present and offer comments. If you attend as a member of the public to address an item on the agenda, please let the chairperson know when discussion begins on that item. Each project will be presented by staff followed by an opportunity for comments for the record.

A. INTRODUCTION: Staff

B. NEW CASES:

EIR – Notice of Preparation:
Carbon TerraVault 1 Project
by California Resources Corporation (PP22405)

Zone Classification Change 5, Map 118; Zone Classification Change 5, Map 119; Zone Classification Change 4, Map 120; Conditional Use Permit 13, Map 118; Conditional Use Permit 5, Map 119; Conditional Use Permit 3, Map 120

AMERICANS WITH DISABILITIES ACT
(Government Code Section 54953.2)

Disabled individuals who need special assistance to attend or participate in the scoping meeting may request assistance at the Kern County Planning Department or by calling Adrenne Lane-Price at (661) 862-8615. Every effort will be made to reasonably accommodate individuals with disabilities by making meeting materials available in alternative formats. Requests for assistance should be made five (5) working days in advance whenever possible.

Posted: March 14, 2022
CLH

SUBMIT WRITTEN COMMENTS ON THE NOP BY APRIL 4, 2022 AT 5:00 PM

Mail to:
Kern County Planning and Natural Resources Department
Attn: Cindi Hoover
2700 'M' Street, Suite 100
Bakersfield, CA 93301
Phone: (661) 862-8629, **Email:** hooverc@kerncounty.com

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A.4 Summary of Proceedings

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SUMMARY OF PROCEEDINGS

KERN COUNTY AGENCY SCOPING MEETING

Kern County Planning Department
2700 M Street, Suite 100
Bakersfield, California

Conference Room

Date March 18, 2022

STAFF ATTENDANCE: Cindi Hoover, Division Chief
Katrina Slayton, Division Chief
Brigiett Guzman, Planner 1

The meeting convened at 1:30 p.m. with Ms. Hoover introducing Staff in attendance and outlining the purpose of the scoping meeting. Items were then discussed in order as identified on the agenda.

NOTICE OF PREPARATION PROJECT:

Environmental Impact Report – Notice of Preparation:
Carbon TerraVault 1 by California Resources Corporation (PP22405)

Ms. Hoover introduced and described the proposed project, provided a brief history of the project and asked if there were any comments.

No public comments were presented.

Public testimony closed at approximately 1:38 p.m.

Notes prepared by
Cindi Hoover, Division Chief

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Appendix B

Air Quality and Greenhouse Gas Emissions Technical Documentation

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B.1 Air Quality Impacts Analysis

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AIR QUALITY IMPACT ANALYSIS

Carbon Terravault 1
Carbon Capture and Sequestration Project
California Resources Corporation

Kern County, CA

Prepared For:

QK, Inc.
5080 California Avenue, Suite 220
Bakersfield, CA 93309

Prepared By:

TRINITY CONSULTANTS
4900 California Avenue, Suite 420A
Bakersfield, CA 93309
661-282-2200

May 2023
(Revised November 2023)

Project 220505.0184

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1. EXECUTIVE SUMMARY

Trinity Consultants has completed an Air Quality Impact Analysis (AQIA) for the proposed Carbon TerraVault 1 (CTV 1) Carbon Capture And Sequestration Project (Project) by California Resources Corporation (CRC). The Project would be located within the Elk Hills Oilfield in an unincorporated portion of western Kern County, California. The Project will involve a 5,332-acre carbon capture and sequestration field, associated sequestration injection wells and related improvements for storage of Carbon Dioxide (CO_2).

The proposed Project's construction would include the following criteria pollutant emissions: reactive organic gases (ROG), carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and suspended particulate matter (PM_{10} and $PM_{2.5}$). Project operations would generate air pollutant emissions from mobile sources (vehicle activity from employees, and deliveries), energy sources, and area sources (incidental activities related to architectural coating, consumer products, and landscape maintenance). Project construction and operational activities would also generate greenhouse gas (GHG) emissions. Criteria and GHG emissions were estimated using the California Emissions Estimator Model (CalEEMod) Version 2022.1.1.13 (California Air Pollution Control Officers Association (CAPCOA) 2022), which is the most current version of the model approved for use by the San Joaquin Valley Air Pollution Control District (SJVAPCD).

Table 4-7**7 through 4-12** present the Project's construction emissions, baseline operational mobile source emissions, operational mobile source emissions increase, baseline operational stationary source emissions, operational stationary source emission increase and total emissions from oil and gas operations from wells on a per well basis. As discussed in Section 4.11, the Project will reduce the overall GHG emissions impact to air quality.

SJVAPCD uses a single threshold for determination of significance for both project specific and cumulative impacts. Section 5 discusses both a qualitative and quantitative evaluation of the cumulative projects that the Project's contribution would pose.

2. INTRODUCTION

2.1 Purpose

This AQIA was prepared pursuant to the SJVAPCD Guidance for Assessing and Mitigating Air Quality Impacts (GAMAQI) (SJVAPCD 2015), the Kern County Planning and Community Development Department's (KCPD) Air Quality Preparation Guidelines (KCPD 2006), and the California Environmental Quality Act (CEQA) Statute and Guidelines (CEQA 2023).

2.2 General Project Description

The Carbon TerraVault 1 Carbon Capture and Sequestration Project is consideration of the approval of multiple Conditional Use Permits (CUP) (CUP No. 13, Map no. 118, CUP No. 5, Map 119, CUP No. 3, Map 120) and related changes in zoning designations (ZCC No.5, Map No.118, ZCC No. 5, Map 119, ZCC No. 4, Map 120 for the construction and operation of a 7,385.67 acre carbon capture and storage (CCS) facility, with associated Class VI Underground Injection Control (UIC) wells, 13 miles of facility pipeline for capture from the pre-combustion gas and related infrastructure improvements for the capture, transfer, and storage of CO2.

The first source of CO2 for injection would capture carbon dioxide (CO2) from natural gas streams within the Elk Hills oilfield operations at the existing cryogenic and fractionation natural gas plant (CGP-1) facility. This natural gas provides the fuel for the 550 MW Elk Hills Power plant that provides electricity for both oilfield operations and the California wide power system. The site of the injection and each individual capture location are each limited to less than 1 acre each (facilities) with the remaining over 5000 acres included in the Conditional Use Boundary comprising the pore space underground for mineralization of the CO2 through natural effects into the empty spaces in the rock and long-term storage (Approved Storage Area) with the land on the surface over the pore space (CCS Surface Land Area). The Conditional Use Permit boundaries corresponds to the US Environmental Protection Agency (EPA) Pacific Southwest (Region 9) Class VI UIC Permit in process (Carbon TerraVault 1 26 -R and Carbon TerraVault 1 A-1 and A-2). No additional sources of CO2 or new development are proposed for the CCS Surface Land Area outside the defined facilities for the first source of CO2 capture.

The project would develop in 2 phases for capture site infrastructure for five natural gas streams; up to 6 Class VI UIC injection wells (Phase 1 wells – 3 new, 1 modified existing Phase 2 wells - 2 modified Class II wells used for enhanced oil recovery), 10 existing wells converted to monitoring wells and 2 new monitoring wells. The project requires approval of a Zone Change Case (ZCC No. 5, Map No. 118; ZCC No. 5, Map No. 119; ZCC No. 4, Map No. 120) from A-1 (Limited Agriculture) to A (Exclusive Agriculture) on approximately 3,208 acres.

The proposed project site is located within the Elk Hills Oilfield, which comprises an approximately 75-square mile (47,800-acre) complex in the San Joaquin Valley of unincorporated Kern County. The site, which contains privately owned by CRC parcels, is located on the west side of Elk Hills Road and to the north side of Skyline Road, within the administrative boundary of the Elk Hills Oil Field. The boundaries of the CCS Surface Land Area and Underground Approved Storage Area (Pore space) for the project area is approximately 26 miles from the City of Bakersfield and approximately 8.5 miles from the City of Taft. The surrounding area is composed of agricultural fields, both active and fallow, and other existing oilfields. They include the Midway/Sunset Oil Field, McKittrick Oilfield, and Cymric Oil Field. The site is accessed over private oilfield

roads with the primary gated with security entrance to the Elk Hills located at the western intersection of Skyline Drive and Elk Hills Road.

The proposed project at full operation is designed to inject 1.5 million metric tons (typ) per year of concentrated CO2 with a total capacity of 48 million metric tons of CO2 within the confined reservoirs. The first source for capture of CO2 will be utilizing the existing operations of the natural gas extraction processes for CRC. Currently, natural gas is extracted, along with crude oil and reservoir formation water (processed water) from various production wells throughout the 110-year-old Elk Hills field prior to processing in the existing CGP-1. These products are transported by field gathering lines to an expansive network of separation facilities within the oilfield and are divided into three concentrated streams or flows of raw material: natural gas, crude oil, and produced water. The proposed project would capture CO2 from the existing produced natural gas streams that occur from existing oilfield operations.

- The produced water would be redirected back into the originating reservoirs through Class II water injection wells.
- Crude oil would be routed to larger gathering systems and ultimately sent to sales facilities.
- Natural gas would be primarily sent to the existing CGP-1 for further processing and component separation. It is also used for pressure management; whereby natural gas is reinjected into the oil-bearing formation to maintain pressure in oil wells and improve Elk Hills oil production.

A portion of that natural gas is used as fuel source for the 550MW Elk Hills Power Plant located in the Elk Hills oilfield. The Elk Hills Power Plant provides about one third of its power to the oilfield for operations and the remainder is distributed to the California power grid via the Pacific Gas and Electric (PG&E) substation in Buttonwillow. The plant was certified through the California Energy Commission process on December 6, 2000, and began commercial operation on July 24, 2003. The CO2 would then be transported by facility pipeline to the dedicated Class VI UIC wells for the project, all of which would be located within the existing CUP boundary. The CO2 would be injected into identified geographically confined reservoirs for storage in perpetuity.

Figure 2-1. Regional Location

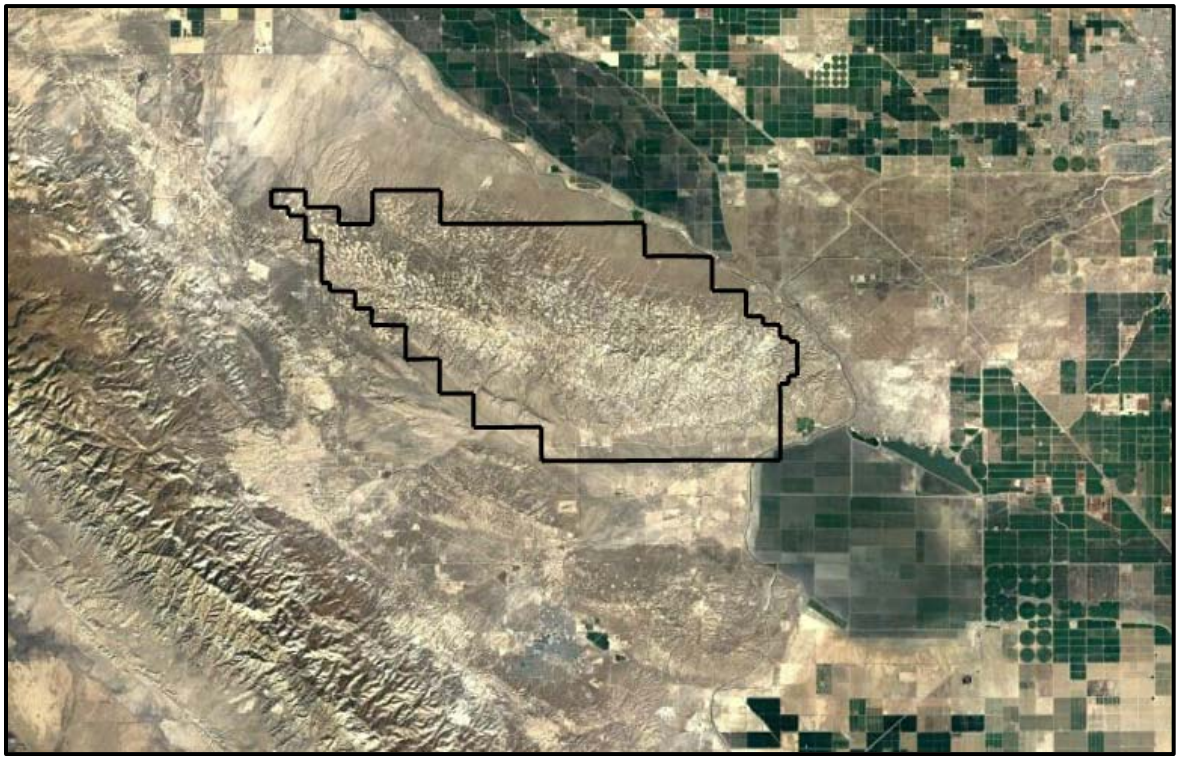


Figure 2-2. Project Location

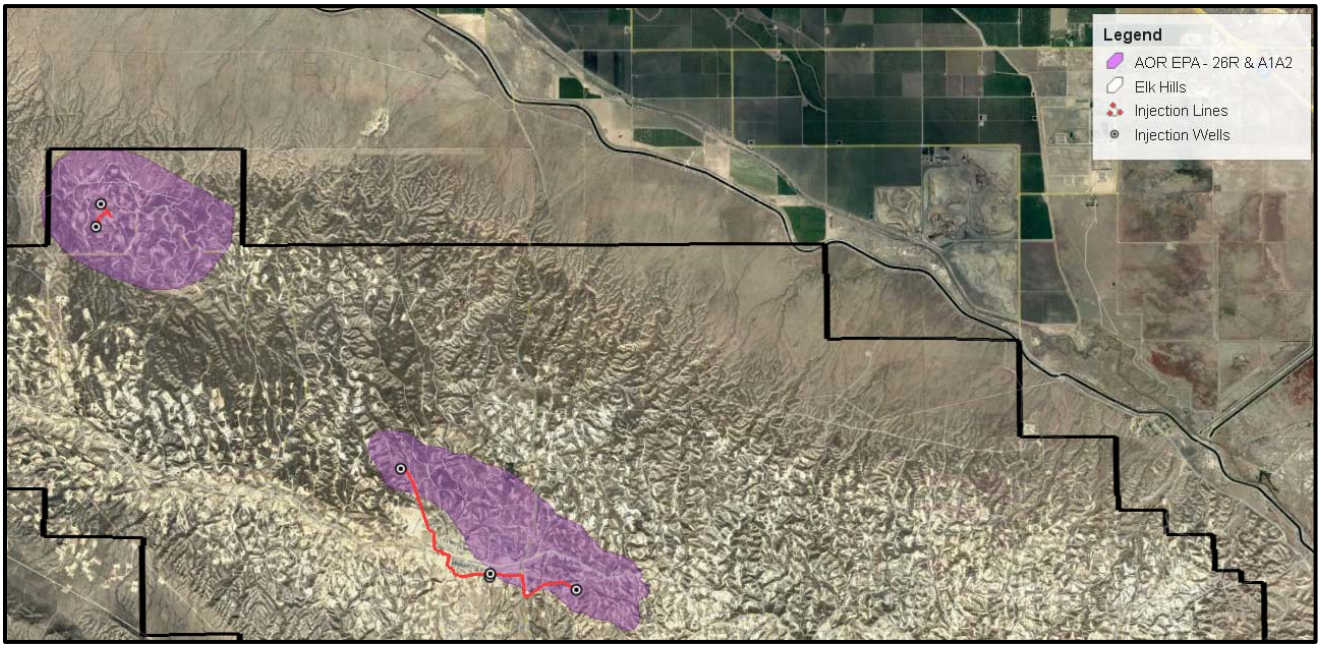
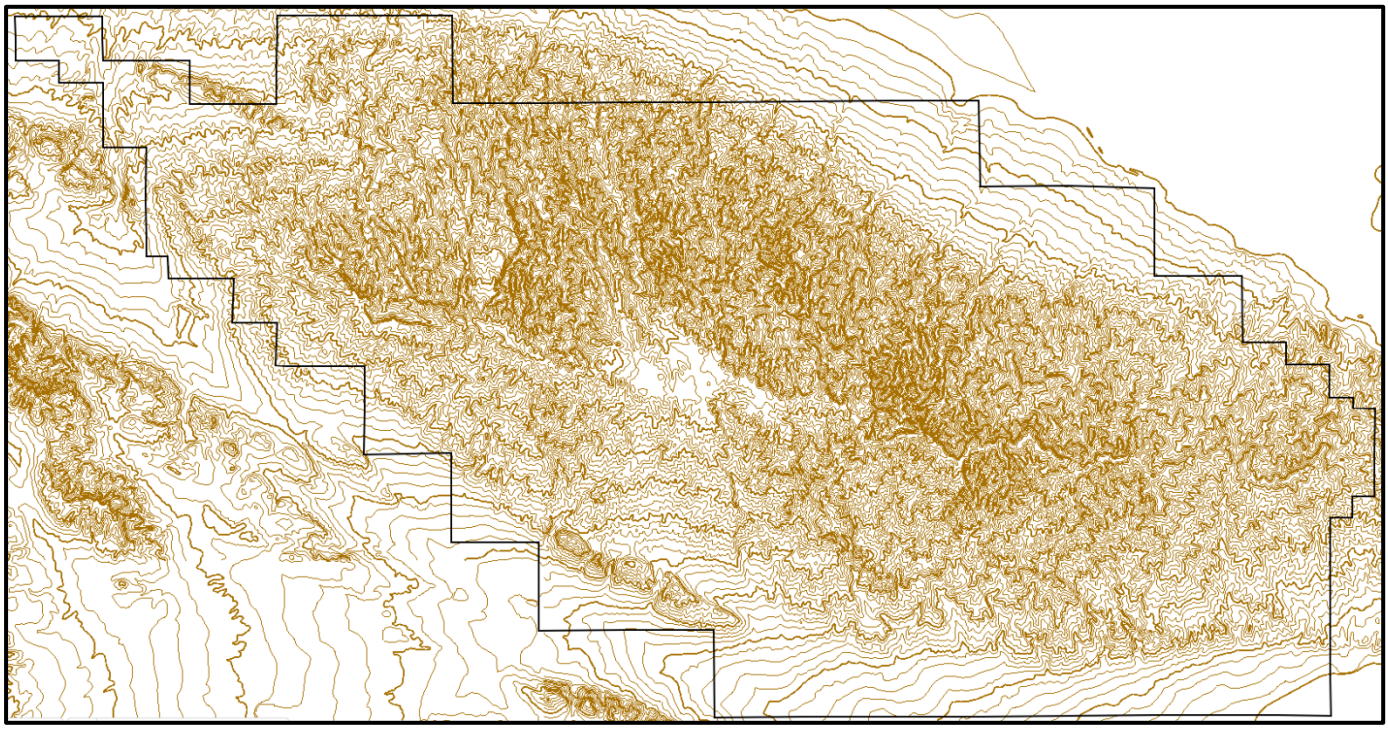


Figure 2-3 depicts the Project site's topography based on Kern County's Interactive County Map (Kern 2023). The Project site's elevation varies with an approximate peak elevation of 1,551 feet above mean sea level.

Figure 2-3. Project Site Topography



3. SETTING

Protection of the public health is maintained through the attainment and maintenance of ambient air quality standards for various atmospheric compounds and the enforcement of emissions limits for individual stationary sources. The Federal Clean Air Act requires that the U.S. Environmental Protection Agency (EPA) establish National Ambient Air Quality Standards (NAAQS) to protect the health, safety, and welfare of the public. NAAQS have been established for ozone (O_3), CO, NO_2, SO_2, PM_{10} and $PM_{2.5}$, and lead (Pb). California has also adopted ambient air quality standards (CAAQS) for these "criteria" air pollutants. CAAQS are more stringent than the corresponding NAAQS and include standards for hydrogen sulfide (H_2S), vinyl chloride (chloroethene), and visibility reducing particles. The U.S. Clean Air Act Amendments of 1977 required each state to identify areas that were in non-attainment of the NAAQS and to develop State Implementation Plans (SIP's) containing strategies to bring these non-attainment areas into compliance. NAAQS and CAAQS designation/classification for Kern County are presented in **Section 3.1** below.

Responsibility for regulation of air quality in California lies with the California Air Resources Board (CARB) and the 35 local air districts with oversight responsibility held by the EPA. CARB is responsible for regulating mobile source emissions, establishing CAAQS, conducting research, managing regulation development, and providing oversight and coordination of the activities of the 35 air districts. The air districts are primarily responsible for regulating stationary source emissions and monitoring ambient pollutant concentrations. CARB also determines whether air basins, or portions thereof, are "unclassified," in "attainment" or in "non-attainment" for the NAAQS and CAAQS relying on statewide air quality monitoring data.

3.1 Air Quality Standards

The Project area is located within Kern County's portion of the San Joaquin Valley Air Basin (SJVAB or Basin). Kern County is included among the eight counties that comprise the SJVAPCD. The SJVAPCD acts as the regulatory agency for air pollution control in the Basin and is the local agency empowered to regulate air pollutant emissions for the Project area. **Table 3-1** provides the NAAQS and CAAQS.

Table 3-1. Federal & California Air Quality Standards

Pollutant	Averaging Time	NAAQS	CAAQS
		Concentration	
O_3	8-hour	0.070 ppm (137 µg/m^3)[a]	0.070 ppm (137 µg/m^3)
	1-hour		0.09 ppm (180 µg/m^3)
CO	8-hour	9 ppm (10 µg/m^3)	9 ppm (10 µg/m^3)
	1-hour	35 ppm (40 µg/m^3)	20 ppm (23 µg/m^3)
NO_2	Annual Average	53 ppb (100 µg/m^3)	0.030 ppm (57 µg/m^3)
	1-Hour	100 ppb (188.68 µg/m^3)	0.18 ppm (339 µg/m^3)
SO_2	3-Hour	0.5 ppm (1,300 µg/m^3)	
	24 Hour	0.14 ppm (365 µg/m^3)	0.04 ppm (105 µg/m^3)
	1-Hour	75 ppb (196 µg/m^3)	0.25 ppm (655 µg/m^3)
Particulate Matter (PM_{10})	Annual Arithmetic Mean		20 µg/m^3
	24-Hour	150 µg/m^3	50 µg/m^3
Fine Particulate Matter ($PM_{2.5}$)	Annual Arithmetic Mean	12 µg/m^3	12 µg/m^3
	24-Hour	35 µg/m^3	
Sulfates	24-Hour		25 µg/m^3
Pb[d]	Rolling Three-Month Average	0.15 µg/m^3	
	30 Day Average		1.5 µg/m^3
H_2S	1-Hour		0.03 ppm (42 µg/m^3)
Vinyl Chloride (chloroethene)	24-Hour		0.010 ppm (26 µg/m^3)
Visibility Reducing particles	8 Hour (1000 to 1800 PST)		[b]

ppm = parts per million
ppb = parts per billion
mg/m^3 = milligrams per cubic meter
µg/m^3 = micrograms per cubic meter

Source: CARB 2016

a. On October 1, 2015, the national 8-hour ozone primary and secondary standards were lowered from 0.075 to 0.070 ppm

b. In 1989, CARB converted both the general statewide 10-mile visibility standards and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are "extinction of 0.23 per kilometer" and "extinction of 0.07 per kilometer" for the statewide and Lake Tahoe Air Basin standards, respectively.

Under the provisions of the U.S. Clean Air Act, the Kern County portion of the SJVAB has been classified as nonattainment/extreme, nonattainment/severe, nonattainment, attainment/unclassified, attainment, or unclassified under the established NAAQS and CAAQS for various criteria pollutants. **Table 3-2** provides the SJVAB's designation and classification based on the various criteria pollutants under both NAAQS and CAAQS.

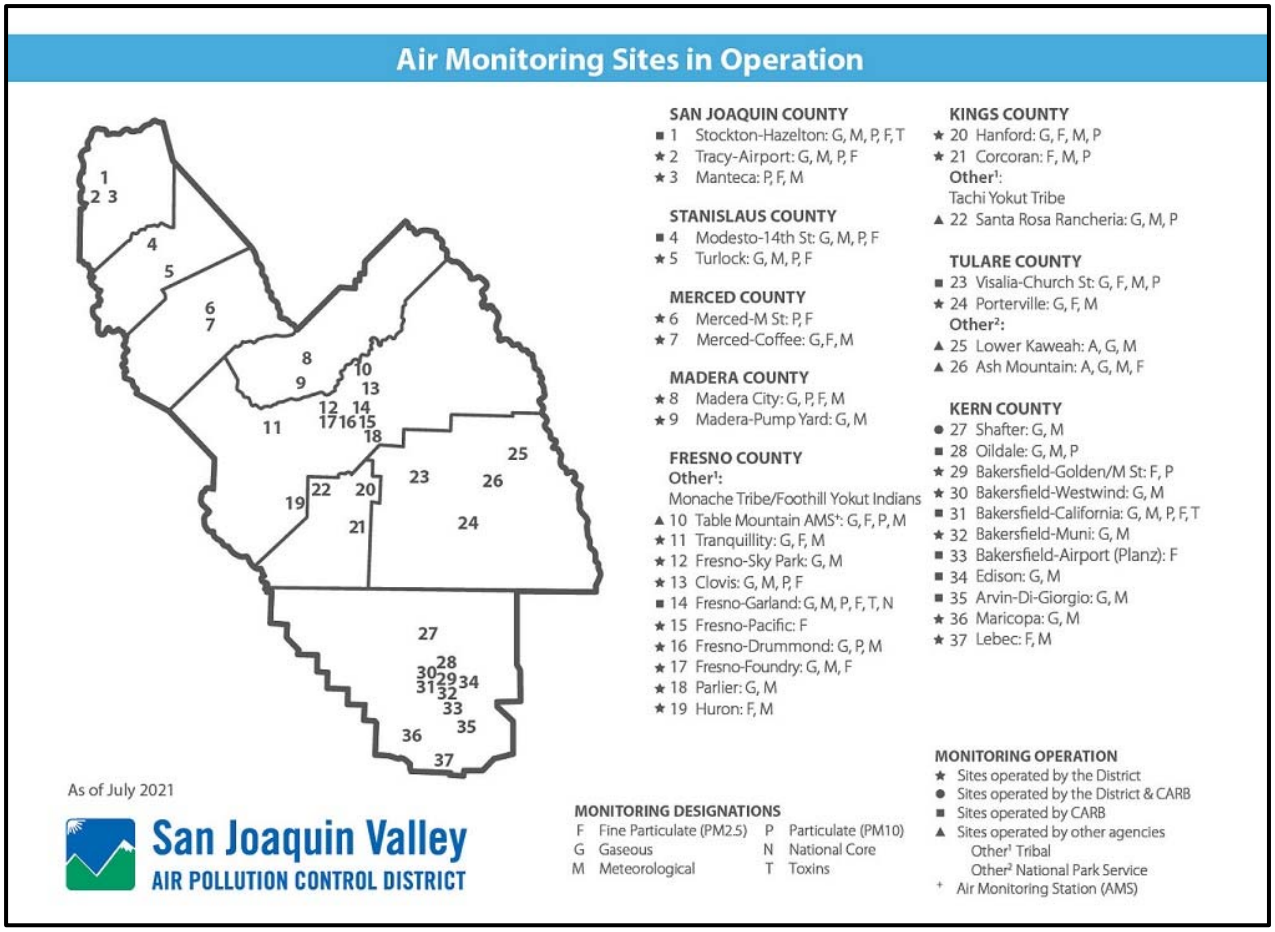
Table 3-2. SJVAB Attainment Status

Pollutant	NAAQS[a]	CAAQS[b]
O_3, 1-hour	No Federal Standard[f]	Nonattainment/Severe
O_3, 8-hour	Nonattainment/Extreme[e]	Nonattainment
PM_{10}	Attainment[c]	Nonattainment
$PM_{2.5}$	Nonattainment[d]	Nonattainment
CO	Attainment/Unclassified	Attainment/Unclassified
NO_2	Attainment/Unclassified	Attainment
SO_2	Attainment/Unclassified	Attainment
Pb (Particulate)	No Designation/Classification	Attainment
H_2S	No Federal Standard	Unclassified
Sulfates	No Federal Standard	Attainment
Visibility Reducing Particulates	No Federal Standard	Unclassified
Vinyl Chloride	No Federal Standard	Attainment

Source: SJVAPCD 2022a
Note:
a. See 40 CFR Part 81
b. See CCR Title 17 Sections 60200-60210
c. On September 25, 2008, EPA redesignated the San Joaquin Valley to attainment for the PM_{10} National Ambient Air Quality Standard (NAAQS) and approved the PM_{10} Maintenance Plan.
d. The Valley is designated nonattainment for the 1997 $PM_{2.5}$ NAAQS. EPA designated the Valley as nonattainment for the 2006 $PM_{2.5}$ NAAQS on November 13, 2009 (effective December 14, 2009).
e. Though the Valley was initially classified as serious nonattainment for the 1997 8-hour O_3 standard, EPA approved Valley reclassification to extreme nonattainment in the Federal Register on May 5, 2010 (effective June 4, 2010).
f. Effective June 15, 2005, the EPA revoked the federal 1-hour O_3 standard, including associated designations and classifications. EPA had previously classified the SJVAB as extreme nonattainment for this standard. EPA approved the 2004 Extreme Ozone Attainment Demonstration Plan on March 8, 2010 (effective April 7, 2010). Many applicable requirements for extreme 1-hour O3 nonattainment areas continue to apply to the SJVAB.

The SJVAPCD, along with CARB, operates an air quality monitoring network that provides information on average concentrations of those pollutants for which Federal or State agencies have established NAAQS and CAAQS, respectively. The monitoring stations in the San Joaquin Valley are depicted in **Figure 3-1**.

Figure 3-1. SJVAPCD Monitoring Network



Source: SJVAPCD 2022b

3.2 Existing Air Quality

For the purposes of background data and this air quality analysis, this analysis relied on data collected in the last three years for the CARB monitoring stations that are located in the closest proximity to the project site. **Table 3-3** provides the background concentrations for O_3, particulate matter of 10 microns (PM_{10}), particulate matter of less than 2.5 microns ($PM_{2.5}$), CO, NO_2, SO_2, and Pb. Information is provided for the Bakersfield – 5558 California Avenue, Bakersfield – 410 E. Planz Road, Bakersfield – Golden State Highway Oildale – 3311 Manor Street, Maricopa – Stanislaus Street, and Shafter – Walker Street monitoring stations for 2019 through 2021. No data is available for H_2S, Vinyl Chloride or other toxic air contaminants in Kern County.

Table 3-3. Existing Air Quality Monitoring Data in Project Area

Pollutant and Monitoring Station Location	Maximum Concentration			Days Exceeding Standard		
	2019	2020	2021	2019	2020	2021
O_3 – 1-hour CAAQS (0.09 ppm)						
Bakersfield - 5558 California Ave	0.097	0.110	0.090	2	3	0
Oildale - 3311 Manor Street	0.099	0.109	0.107	1	3	6
Maricopa – Stanislaus Street	0.086	0.122	0.083	0	7	0
O_3 – 8-hour CAAQS (0.070 ppm)						
Bakersfield - 5558 California Ave	0.088	0.098	0.081	28	25	11
Oildale - 3311 Manor Street	0.087	0.096	0.095	20	24	46
Maricopa – Stanislaus Street	0.080	0.096	0.077	45	40	11
O_3 – 8-hour NAAQS (0.070 ppm)						
Bakersfield - 5558 California Ave	0.088	0.098	0.080	24	25	11
Oildale - 3311 Manor Street	0.086	0.096	0.095	16	23	43
Maricopa – Stanislaus Street	0.080	0.095	0.077	41	38	10
PM_{10} – 24-hour CAAQS (50 µg/m^3)						
Bakersfield - 5558 California Ave	125.9	196.8	439.3	17	18	124
Oildale - 3311 Manor Street	392.1	277.3	423.0	118	123	129
PM_{10} – 24-hour NAAQS (150 µg/m^3)						
Bakersfield - 5558 California Ave	116.3	193.8	437.5	0	1	3
Oildale - 3311 Manor Street	389.3	517.2	421.4	8	15	2
$PM_{2.5}$ - 24-hour NAAQS (35 µg/m^3)						
Bakersfield - 5558 California Ave	59.1	150.7	72.3	12	44	40
Bakersfield – Golden State Highway	66.1	150.2	78.5	4	10	43
Bakersfield – 410 E Planz Road	83.7	158.6	70.5	3	17	17
CO - 8-Hour CAAQS & NAAQS (9.0 ppm)						
No data collected	*	*	*	*	*	*
NO_2 - 1-Hour CAAQS (0.18 ppm)						
Bakersfield - 5558 California Ave	0.067	0.050	0.057	0	0	0
Shafter - Walker Street	0.049	0.040	0.047	0	0	0
NO_2 - 1-Hour NAAQS (0.10 ppm)						
Bakersfield - 5558 California Ave	0.0671	0.0504	0.0572	0	0	0
Shafter - Walker Street	0.0493	0.0409	0.0478	0	0	0
SO_2 – 24-hour Concentration - CAAQS (0.04 ppm) & NAAQS (0.14 ppm)						
No data collected	*	*	*	*	*	*
Pb - Maximum 30-Day Concentration CAAQS (1500 ng/m^3)						
Bakersfield - 5558 California Ave	8.5	5.7	9.9	*	*	*

Source: CARB 2022a
Notes: ppm= parts per million
* There was insufficient (or no) data available to determine the value.

The following is a description of criteria air pollutants, typical sources and health effects and the recently documented pollutant levels in the project vicinity.

3.2.1 Ozone (O_3)

The most severe air quality problem in the San Joaquin Valley is high concentrations of O_3. High levels of O_3 cause eye irritation and can impair respiratory functions. High levels of O_3 can also affect plants and materials. Grapes, lettuce, spinach and many types of garden flowers and shrubs are particularly vulnerable to O_3 damage. O_3 is not emitted directly into the atmosphere but is a secondary pollutant produced through photochemical reactions involving hydrocarbons and nitrogen oxides (NOx). Significant O_3 generation requires about one to three hours in a stable atmosphere with strong sunlight. For this reason, the months of April through October comprise the "ozone season." O_3 is a regional pollutant because O_3 precursors are transported and diffused by wind concurrently with the reaction process. The data contained in **Table 3-3** shows that the Bakersfield, Oildale and Maricopa areas exceeded the 1-hour average ambient O_3 CAAQS and the 8-hour average ambient O_3 NAAQS and CAAQS during the 2019 through 2021 period.

3.2.2 Suspended Particulate Matter (PM_{10} and $PM_{2.5}$)

Both State and Federal particulate standards now apply to particulates under 10 microns (PM_{10}) rather than to total suspended particulate (TSP), which includes particulates up to 30 microns in diameter. Continuing studies have shown that the smaller-diameter fraction of TSP represents the greatest health hazard posed by the pollutant; therefore, EPA has recently established NAAQS for $PM_{2.5}$. The project area is classified as attainment for PM_{10} and non-attainment for particulates under 2.5 microns ($PM_{2.5}$) for NAAQS.

Particulate matter consists of particles in the atmosphere resulting from many kinds of dust and fume-producing industrial and agricultural operations, from combustion, and from atmospheric photochemical reactions. Natural activities also increase the level of particulates in the atmosphere; wind-raised dust and ocean spray are two sources of naturally occurring particulates. The largest sources of PM_{10} and $PM_{2.5}$ in Kern County are vehicle movement over paved and unpaved roads, demolition and construction activities, farming operations, and unplanned fires. PM_{10} and $PM_{2.5}$ are considered regional pollutants with elevated levels typically occurring over a wide geographic area. Concentrations tend to be highest in the winter, during periods of high atmospheric stability and low wind speed. In the respiratory tract, very small particles of certain substances may produce injury by themselves or may contain absorbed gases that are injurious. Particulates of aerosol size suspended in the air can both scatter and absorb sunlight, producing haze and reducing visibility. They can also cause a wide range of damage to materials.

Table 3-3 shows that PM_{10} levels regularly exceeded the CAAQS but not the NAAQS at two monitoring stations over the three-year period of 2019 through 2021. **Table 3-3** shows that $PM_{2.5}$ NAAQS were exceeded from 2019 through 2021. Similar levels can be expected to occur in the vicinity of the Project site.

3.2.3 Carbon Monoxide (CO)

Ambient CO concentrations normally correspond closely to the spatial and temporal distributions of vehicular traffic. Relatively high concentrations of CO would be expected along heavily traveled roads and near busy intersections. Wind speed and atmospheric mixing also influence CO concentrations; however, under inversion conditions prevalent in the San Joaquin Valley, CO concentrations may be more uniformly distributed over a broad area.

Internal combustion engines, principally in vehicles, produce CO due to incomplete fuel combustion. Various industrial processes also produce CO emissions through incomplete combustion. Gasoline-powered motor vehicles are typically the major source of this contaminant. CO does not irritate the respiratory tract but passes

through the lungs directly into the blood stream, and by interfering with the transfer of fresh oxygen to the blood, deprives sensitive tissues of oxygen, thereby aggravating cardiovascular disease, causing fatigue, headaches, and dizziness. CO is not known to have adverse effects on vegetation, visibility, or materials.

Table 3-3 reports no CO data is available for the three-year period from 2019 through 2021; historically Bakersfield area data for CO has been below the CAAQS and NAAQS.

3.2.4 Nitrogen Dioxide (NO_2) and Hydrocarbons

Kern County has been designated as an attainment area for the NAAQS for NO_2. NO_2 is the "whiskey brown" colored gas readily visible during periods of heavy air pollution. Mobile sources and oil and gas production account for nearly all of the County's NOx emissions, most of which is emitted as NO_2. Combustion in motor vehicle engines, power plants, refineries and other industrial operations are the primary sources in the region. Railroads and aircraft are other potentially significant sources of combustion air contaminants. Oxides of nitrogen are direct participants in photochemical smog reactions. The emitted compound, nitric oxide, combines with oxygen in the atmosphere in the presence of hydrocarbons and sunlight to form NO_2 and O_3. NO_2, the most significant of these pollutants, can color the atmosphere at concentrations as low as 0.5 ppm on days of 10-mile visibility. NOx is an important air pollutant in the region because it is a primary receptor of ultraviolet light, which initiates the reactions producing photochemical smog. It also reacts in the air to form nitrate particulates.

Motor vehicles are the major source of reactive hydrocarbons in the basin. Other sources include evaporation of organic solvents and petroleum production and refining operations. Certain hydrocarbons can damage plants by inhibiting growth and by causing flowers and leaves to fall. Levels of hydrocarbons currently measured in urban areas are not known to cause adverse effects in humans. However, certain members of this contaminant group are important components in the reactions, which produce photochemical oxidants.

Table 3-3 shows that the Shafter area exceeded the 1-hour average ambient NO_2 NAAQS and CAAQS for the 2019 through 2021 period. Hydrocarbons are not currently monitored.

3.2.5 Sulfur Dioxide (SO_2)

Kern County has been designated as an attainment area for the NAAQS for SO_2. SO_2 is the primary combustion product of sulfur, or sulfur containing fuels. Fuel combustion is the major source of this pollutant, while chemical plants, sulfur recovery plants, and metal processing facilities are minor contributors. Gaseous fuels (natural gas, propane, etc.) typically have lower percentages of sulfur containing compounds than liquid fuels such as diesel or crude oil. SO_2 levels are generally higher in the winter months. Decreasing levels of SO_2 in the atmosphere reflect the use of natural gas in power plants and boilers.

At high concentrations, SO_2 irritates the upper respiratory tract. At lower concentrations, when respirated in combination with particulates, SO_2 can result in greater harm by injuring lung tissues. Sulfur oxides (SOx), in combination with moisture and oxygen, results in the formation of sulfuric acid, which can yellow the leaves of plants, dissolve marble, and oxidize iron and steel. SOx can also react to produce sulfates that reduce visibility and sunlight.

Table 3-3 shows no data has been reported over the three-year period in Kern County.

3.2.6 Lead (Pb) and Suspended Sulfate

Ambient Pb levels have dropped dramatically due to the increase in the percentage of motor vehicles that run exclusively on unleaded fuel. Ambient Pb levels in Elk Hills are well below the ambient standard and are

expected to continue to decline; the data reported in **Table 3-3** only shows the highest concentration as the number of days exceeding standards are not reported. Suspended sulfate levels have stabilized to the point where no excesses of the State standard are expected in any given year.

3.3 Climate

The most significant single control on the weather pattern of the San Joaquin Valley is the semi-permanent subtropical high-pressure cell, referred to as the "Pacific High." During the summer, the Pacific High is positioned off the coast of northern California, diverting ocean-derived storms to the north. Hence, the summer months are virtually rainless. During the winter, the Pacific High moves southward allowing storms to pass through the San Joaquin Valley. Almost all of the precipitation expected during a given year occurs from December through April. During the summer, the predominant surface winds are out of the northwest. Air enters the Valley through the Carquinez strait and flows toward the Tehachapi Mountains. This up-valley (northwesterly) wind flow is interrupted in early fall by the emergence of nocturnal, down-valley (southeasterly) winds which become progressively more predominant as winter approaches. Wind speeds are generally highest during the spring and lightest in fall and winter. The relatively cool air flowing through the Carquinez strait is warmed on its journey south through the Valley. On reaching the southern end of the Valley, the average high temperature during the summer is nearly 100 degrees Fahrenheit (°F). Relative humidity during the summer is quite low, causing large diurnal temperature variations. Temperatures during the summer often drop into the upper 60s. In winter, the average high temperatures reach the mid-50s and the average low drops to the mid-30s. In addition, another high-pressure cell, known as the "Great Basin High," develops east of the Sierra Nevada Mountain Range during winter. When this cell is weak, a layer of cool, damp air becomes trapped in the basin and extensive fog results. During inversions, vertical dispersion is restricted, and pollutant emissions are trapped beneath the inversion and pushed against the mountains, adversely affecting regional air quality. Surface-based inversions, while shallow and typically short-lived, are present most mornings. Elevated inversions, while less frequent than ground-based inversions, are typically longer lasting and create more severe air stagnation problems. The winter season characteristically has the poorest conditions for vertical mixing of the entire year.

Meteorological data for various monitoring stations is maintained by the Western Regional Climate Center. Meteorological data for the Project site is expected to be similar to the data recorded at the Buttonwillow monitoring station. This data is provided in **Table 3-4**, which contains average precipitation data recorded at the Buttonwillow monitoring station. Over the 115-year period from January of 1901 through June of 2016 (the most recent data available), the average annual precipitation was 5.64 inches.

Table 3-4. Buttonwillow Weather Data

Period of Record Monthly Climate Summary for the Period 01/05/1901 to 6/10/2016													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Avg. Maximum Temp (F)	56.4	63.2	69.1	76.0	84.7	92.4	98.4	96.7	91.7	81.4	67.4	57.2	77.9
Avg. Minimum Temp (F)	35.2	39.0	43.0	47.2	54.1	60.1	65.3	63.3	57.9	48.8	39.2	34.5	49.0
Average Total Precipitation (in.)	1.06	1.07	0.97	0.55	0.21	0.05	0.02	0.02	0.12	0.27	0.55	0.75	5.64
Average Snowfall (in.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Average Snow Depth (in.)	0	0	0	0	0	0	0	0	0	0	0	0	0
Percent of possible observations for period of record: Max. Temp.: 99.1% Min. Temp.: 99.1% Precipitation: 98.8% Snowfall: 99.2% Snow Depth: 99.2%													
Source: Western Regional Climate Center, 2023.													

3.4 Climate Change and Greenhouse Gases

3.4.1 Global Climate Change

"Global climate change" refers to change in average meteorological conditions on the earth with respect to temperature, precipitation, and storms, lasting for decades or longer. The term "global climate change" is often used interchangeably with the term "global warming," but "global climate change" is preferred by some scientists and policy makers to "global warming" because it helps convey the notion that in addition to rising temperatures, other changes in global climate may occur. Climate change may result from the following influences:

- Natural factors, such as changes in the sun's intensity or slow changes in the Earth's orbit around the sun;
- Natural processes within the climate system (e.g., changes in ocean circulation); and/or
- Human activities that change the atmosphere's composition (e.g., through burning fossil fuels) and the land surface (e.g., deforestation, reforestation, urbanization, and desertification).

As determined from worldwide meteorological measurements between 1990 and 2005, the primary observed effect of global climate change has been a rise in the average global tropospheric temperature of 0.36 degree Fahrenheit (°F) per decade. Climate change modeling shows that further warming could occur, which could induce additional changes in the global climate system during the current century. Changes to the global climate system, ecosystems, and the environment of California could include higher sea levels, drier or wetter weather, changes in ocean salinity, changes in wind patterns or more energetic aspects of extreme weather (e.g., droughts, heavy precipitation, heat waves, extreme cold, and increased intensity of tropical cyclones). Specific effects from climate change in California may include a decline in the Sierra Nevada snowpack, erosion of California's coastline, and seawater intrusion in the Sacramento-San Joaquin River Delta.

Human activities, including fossil fuel combustion and land use changes, release carbon dioxide (CO_2) and other compounds cumulatively termed greenhouse gases (GHGs). GHGs are effective at trapping radiation that would otherwise escape the atmosphere. This trapped radiation warms the atmosphere, the oceans, and the earth's surface (USGCRP, 2014). Many scientists believe "most of the warming observed over the last 50 years is attributable to human activities" (IPCC, 2017). The increased amount of CO_2 and other GHGs in the atmosphere is the alleged primary result of human-induced warming.

GHGs are present in the atmosphere naturally, released by natural sources, or formed from secondary reactions taking place in the atmosphere. They include CO_2, methane (CH_4), nitrous oxide (N_2O), and O_3. In the last 200 years, substantial quantities of GHGs have been released into the atmosphere, primarily from fossil fuel combustion. These human-induced emissions are increasing GHG concentrations in the atmosphere, therefore enhancing the natural greenhouse effect. The GHGs resulting from human activity are believed to be causing global climate change. While human-made GHGs include CO_2, CH_4, and N_2O, some (like chlorofluorocarbons [CFCs]) are completely new to the atmosphere. GHGs vary considerably in terms of Global Warming Potential (GWP), the comparative ability of each GHG to trap heat in the atmosphere. The GWP is based on several factors, including the relative effectiveness of a gas to absorb infrared radiation and the length of time that the gas remains in the atmosphere ("atmospheric lifetime"). The GWP of each gas is measured relative to CO_2, the most abundant GHG. The definition of GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to the ratio of heat trapped by one unit mass of CO_2 over a specified time period. GHG emissions are typically measured in terms of pounds or tons of "CO_2 equivalents" (CO_2e).

Methane is produced when organic matter decomposes in environments lacking sufficient oxygen. Natural sources of CH_4 production include wetlands, termites, and oceans. Human activity accounts for the majority of the approximately 500 million metric tons of CH_4 emitted annually. These anthropogenic sources include the mining and burning of fossil fuels; digestive processes in ruminant livestock such as cattle; rice cultivation; and the decomposition of waste in landfills. The major removal process for atmospheric CH_4, the chemical breakdown in the atmosphere, cannot keep pace with source emissions; therefore, CH_4 concentrations in the atmosphere are rising.

Worldwide emissions of GHGs in 2008 were 30.1 billion metric tons of CO_2e and have increased considerably since that time (United Nations, 2011). It is important to note that the global emissions inventory data are not all from the same year and may vary depending on the source of the data (U.S. EPA, 2019). Emissions from the top five emitting countries and the European Union accounted for approximately 70% of total global GHG emissions in 2014. The United States was the number two producer of GHG emissions behind China. The primary GHG emitted by human activities was CO_2, representing approximately 76% of total global GHG emissions (U.S. EPA, 2019).

In 2017, the United States emitted approximately 6.5 million metric tons of CO_2e. Of the six major sectors nationwide (electric power industry, transportation, industry, agriculture, commercial, and residential), the electric power industry and transportation sectors combined account for approximately 57% of the GHG emissions; the majority of the electrical power industry and all of the transportation emissions are generated from direct fossil fuel combustion. Between 1990 and 2017, total United States GHG emissions rose approximately 1.3% (U.S. EPA, 2019).

Worldwide, energy-related CO_2 emissions are expected to increase at an average rate of 0.6% annually between 2018 and 2050, compared with the average growth rate of 1.8% per year from 1990 to 2018. Much of the increase in these emissions is expected to occur in the developing world where emerging economies, such as China and India, fuel economic development with fossil fuel energy. Developing countries' emissions are expected to grow above the world average at a rate of approximately 1% annually between 2018 and 2050 and surpass emissions of industrialized countries by 2025 (U.S. EIA, 2019).

CARB is responsible for developing and maintaining the California GHG emissions inventory. This inventory estimates the amount of GHGs emitted into and removed from the atmosphere by human activities within the state of California and supports the Assembly Bill (AB) 32 Climate Change Program. CARB's current GHG emission inventory covers the years 2000 through 2017 and is based on fuel use, equipment activity, industrial processes, and other relevant data (e.g., housing, landfill activity, and agricultural lands).

In 2017, emissions from statewide emitting activities were 424 million metric tons of CO_2 equivalent (MMT CO_2e), which is 5 MMT CO_2e lower than 2016 levels. 2017 emissions have decreased by 14% since peak levels in 2004 and are 7 MMT CO_2e below the 1990 emissions level and the State's 2020 GHG limit. Per capita GHG emissions in California have dropped from a 2001 peak of 14.1 tonnes per person to 10.7 tonnes per person in 2017, a 24% decrease (CARB 2019).

CARB estimates that transportation was the source of approximately 40% of California's GHG emissions in 2017, followed by electricity generation at 15%. Other sources of GHG emissions were industrial sources at 21%, residential plus commercial activities at 10%, and agriculture at 8% (CARB 2019).

CARB has projected the estimated statewide GHG emissions for the year 2020, which represent the emissions that would be expected to occur with reductions anticipated from Pavley I and the Renewables Electricity Standard (30 MMT CO_2e total), will be 509 MMT of CO_2e (CARB, 2014). GHG emissions from the transportation and electricity sectors as a whole are expected to increase at approximately 36% and 20% of total CO_2e emissions, respectively, as compared to 2009. The industrial sector consists of large stationary sources of GHG emissions and the percentage of the total 2020 emissions is projected to be 18% of total CO_2e emissions. The remaining sources of GHG emissions in 2020 are high global warming potential gases at 6%, residential and commercial activities at 10%, agriculture at 7%, and recycling and waste at 2%.

3.4.2 Effects of Global Climate Change

Changes in the global climate are assessed using historical records of temperature changes that have occurred in the past. Climate change scientists use this temperature data to extrapolate a level of statistical significance specifically focusing on temperature records from the last 150 years (the Industrial Age) that differ from past climate changes in rate and magnitude.

The Intergovernmental Panel on Climate Change (IPCC) constructed several emission trajectories of GHGs needed to stabilize global temperatures and climate change impacts. In its Fifth Assessment Report, the IPCC predicted that the global mean temperature change from 1990 to 2100 could range from 1.1 degree Celsius (°C) to 6.4 °C (8 to 10.4 °Fahrenheit) (IPCC, 2013). Global average temperatures and sea levels are expected to rise under all scenarios (IPCC, 2014). The IPCC concluded that global climate change was largely the result of human activity, mainly the burning of fossil fuels. However, scientific literature is not consistent regarding many of the aspects of climate change, the actual temperature changes during the 20th century, and contributions from human versus non-human activities.

Effects from global climate change may arise from temperature increases, climate sensitive diseases, extreme weather events, and degradation of air quality. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems. Heat-related problems include heat rash and heat stroke, drought, etc. In addition, climate-sensitive diseases may increase, such as those spread by mosquitoes and other disease-carrying insects. Such diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding and hurricanes can displace people and agriculture. Global warming may also contribute to air quality problems from increased frequency of smog and particulate air pollution.

According to the 2006 California Climate Action Team (CAT) Report, several climate change effects can be expected in California over the course of the next century (CalEPA, 2006). These are based on trends established by the IPCC and are summarized below.

- A diminishing Sierra snowpack declining by 70% to 90%, threatening the state's water supply.

- A rise in sea levels, resulting in the displacement of coastal businesses and residences. During the past century, sea levels along California's coast have risen about seven inches. If emissions continue unabated and temperatures rise into the higher anticipated warming range, sea level is expected to rise an additional 22 to 35 inches by the end of the century. Sea level rises of this magnitude would inundate coastal areas with salt water, accelerate coastal erosion, threaten vital levees and inland water systems, and disrupt wetlands and natural habitats. (Note: This condition would not affect the proposed Project area, as it is a significant distance away from coastal areas.)
- An increase in temperature and extreme weather events. Climate change is expected to lead to increases in the frequency, intensity, and duration of extreme heat events and heat waves in California. More heat waves can exacerbate chronic disease or heat-related illness.
- Increased risk of large wildfires if rain increases as temperatures rise. Wildfires in the grasslands and chaparral ecosystems of southern California are estimated to increase by approximately 30% toward the end of the 21st century because more winter rain will stimulate the growth of more plant fuel available to burn in the fall. In contrast, a hotter, drier climate could promote up to 90% more northern California fires by the end of the century by drying out and increasing the flammability of forest vegetation.
- Increasing temperatures from 8 to 10.4 °F under the higher emission scenarios, leading to a 25% to 35% increase in the number of days that ozone pollution levels are exceeded in most urban areas (see below).
- Increased vulnerability of forests due to forest fires, pest infestation, and increased temperatures.
- Reductions in the quality and quantity of certain agricultural products. The crops and products likely to be adversely affected include wine grapes, fruit, nuts, and milk.
- Exacerbation of air quality problems. If temperatures rise to the medium warming range, there could be 75 to 85% more days with weather conducive to ozone formation in Los Angeles and the San Joaquin Valley, relative to today's conditions. This is more than twice the increase expected if rising temperatures remain in the lower warming range. This increase in air quality problems could result in an increase in asthma and other health-related problems.
- A decrease in the health and productivity of California's forests. Climate change can cause an increase in wildfires, an enhanced insect population, and establishment of non-native species.
- Increased electricity demand, particularly in the hot summer months.
- Increased ground-level ozone formation due to higher reaction rates of ozone precursors.

3.4.3 Global Climate Change Regulatory Issues

In 1988, the United Nations established the Intergovernmental Panel on Climate Change to evaluate the impacts of global warming and to develop strategies that nations could implement to curtail global climate change. In 1992, the United Nations Framework Convention on Climate Change established an agreement with the goal of controlling GHG emissions, including methane. As a result, the Climate Change Action Plan was developed to address the reduction of GHGs in the United States. The plan consists of more than 50 voluntary programs. Additionally, the Montreal Protocol was originally signed in 1987 and substantially amended in 1990 and 1992. The Montreal Protocol stipulates that the production and consumption of compounds that deplete O_3 in the stratosphere (chlorofluorocarbons [CFCs], halons, carbon tetrachloride, and methyl chloroform) were phased out by 2000 (methyl chloroform was phased out by 2005).

On September 27, 2006, Assembly Bill 32 (AB32), the California Global Warming Solutions Act of 2006 (the Act) was enacted by the State of California. The legislature stated, "Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." The Act caps California's GHG emissions at 1990 levels by 2020. The Act defines GHG emissions as all of the following gases: carbon dioxide (CO_2), methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. This agreement represents the first enforceable statewide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national

and international actions will be necessary to fully address the issue of global warming, AB32 lays out a program to inventory and reduce GHG emissions in California and from power generation facilities located outside the state that serve California residents and businesses.

AB32 charges CARB with responsibility to monitor and regulate sources of GHG emissions in order to reduce those emissions. CARB has adopted a list of discrete early action measures that can be implemented to reduce GHG emissions. CARB has defined the 1990 baseline emissions for California and has adopted that baseline as the 2020 statewide emissions cap. CARB is conducting rulemaking for reducing GHG emissions to achieve the emissions cap by 2020. In designing emission reduction measures, CARB must aim to minimize costs, maximize benefits, improve, and modernize California's energy infrastructure, maintain electric system reliability, maximize additional environmental and economic co-benefits for California, and complement the state's efforts to improve air quality.

Subsequent legislation by the California legislature has included Senate Bill (SB) 32, which expanded upon AB32 to reduce GHG emissions to 40% below the 1990 levels by 2030; AB197 which increased the legislative oversight of the CARB by adding two legislatively appointed non-voting members to the CARB Board and provided additional protection to disadvantaged communities; SB350, which increased California's renewable energy electricity procurement goal and SB100, which established a landmark policy requiring renewable energy and zero-carbon resources to supply 100 percent of electrical retail sales to end use customers and 100 percent of electricity procured to serve state agencies by 2045.

Global warming and climate change have received substantial public attention for more than 20 years. For example, the United States Global Change Research Program was established by the Global Change Research Act of 1990 to enhance the understanding of natural and human-induced changes in the Earth's global environmental system, to monitor, understand, and predict global change, and to provide a sound scientific basis for national and international decision-making. Even so, the analytical tools have not been developed to determine the effect on worldwide global warming from a particular increase in GHG emissions, or the resulting effects on climate change in a particular locale. The scientific tools needed to evaluate the impacts that a specific project may have on the environment are even farther in the future.

The California Supreme Court's CEQA decision on the Newhall Ranch development case, Center for Biological v. California Department of Fish and Wildlife (November 30, 2015, Case No. 217763), determined that the project's Environmental Impact Report (EIR) did not substantiate the conclusion that the GHG cumulative impacts would be less than significant. The EIR determined that the Newhall Ranch development project would reduce GHG emissions by 31 percent from business as usual (BAU). This reduction was compared to California's target of reducing GHG emissions statewide by 29 percent from business as usual. The Court determined that "the EIR's deficiency stems from taking a quantitative comparison method developed by the Scoping Plan as a measure of the greenhouse gas reduction effort required by the state as a whole, and attempting to use that method, without adjustments, for a purpose very different from its original design." In the Court's final ruling it offered suggestions that were deemed appropriate use of the BAU methodology:

1. Lead agencies can use the comparison to BAU methodology if they determine what reduction a particular project must achieve in order to comply with statewide goals,
2. Project design features that comply with regulations to reduce emissions may demonstrate that those components of emissions are less that significant, and
3. Lead agencies could also demonstrate compliance with locally adopted climate plans or could apply specific numerical thresholds developed by some local agencies.

Kern County, the Lead CEQA agency for this Project, has not developed specific thresholds for GHGs. As discussed in **Section 4.1**, the SJVAPCD, a CEQA Trustee Agency for this Project, has developed thresholds

to determine significance of a proposed project – either implement Best Performance Standards or achieve a 29% reduction from BAU (a specific numerical threshold). However, the SJVAPCD has established their BAU and baseline emissions based on the years 2002-2004 and 2020, respectively. The 2020 projected baseline has passed, and at this time, no new guidance has been approved for determining BAU and projected baseline for the next target year. Therefore, the 29% reduction from BAU cannot be applied to the subject Project in order to determine significance. Additionally, a Best Performance Standards threshold has not been established. However, for this Project the GHG impact will be a net benefit impact resulting in reduced GHG emissions.

4. IMPACT ASSESSMENT

4.1 Significance Criteria

To determine whether a proposed Project could create a potential CEQA impact, local, State, and Federal agencies have developed various means by which a project's impacts may be measured and evaluated. Such means can generally be categorized as follows:

- Thresholds of significance adopted by air quality agencies to guide lead agencies in their evaluation of air quality impacts under the CEQA.
- Regulations established by air districts, CARB and EPA for the evaluation of stationary sources when applying for Authorities to Construct, Permits to Operate and other permit program requirements (e.g., New Source Review).
- Thresholds utilized to determine if a project would cause or contribute significantly to violations of the ambient air quality standards or other concentration-based limits.
- Regulations applied in areas where severe air quality problems exist.

Summary tables of these emission-based and concentration-based thresholds of significance for each pollutant are provided below along with a discussion of their applicability.

4.1.1 Thresholds Adopted for the Evaluation of Air Quality Impacts under CEQA

In order to maintain consistency with CEQA, the SJVAPCD (2015) adopted guidelines to assist applicants in complying with the various requirements. According to the SJVAPCD's GAMAQI, a project would have potentially significant air quality impacts when the project:

- Creates a conflict with or obstructs implementation of the applicable air quality plan;
- Causes a violation of any air quality standard or generates substantial contribution towards exceeding an existing or projected air quality standard;
- Results in a cumulatively considerable net increase of any criteria pollutant for which the project region is designated non-attainment under a NAAQS and CAAQS (including emissions which exceed quantitative thresholds for O_3 precursors);
- Exposes sensitive receptors to substantial pollutant concentrations; or
- Creates objectionable odors that affect a substantial number of people.

The SJVAPCD GAMAQI thresholds are designed to implement the general criteria for air quality emissions as required in the CEQA Guidelines, Appendix G, Paragraph III (Title 14 of the California Code of Regulations §15064.7) and CEQA (California Public Resources Code Sections 21000 et. al). SJVAPCD's specific CEQA air quality thresholds are presented in **Table 4-1**.

Table 4-1. SJVAPCD CEQA Thresholds of Significance

Criteria Pollutant	Significance Level	
	Construction	Operational
CO	100 tons/yr	100 tons/yr
NOx	10 tons/yr	10 tons/yr
ROG	10 tons/yr	10 tons/yr
SOx	27 tons/yr	27 tons/yr
PM_{10}	15 tons/yr	15 tons/yr
$PM_{2.5}$	15 tons/yr	15 tons/yr
Source: SJVAPCD 2015		

4.1.2 Thresholds for Ambient Air Quality Impacts

CEQA Guidelines – Appendix G (Environmental Checklist) states that a project that would "violate any air quality standard or contribute substantially to an existing or projected air quality violation" would be considered to create significant impacts on air quality. Therefore, an AQIA should determine whether the emissions from a project would cause or contribute significantly to violations of the NAAQS or CAAQS (presented above in **Table 3-1**) when added to existing ambient concentrations.

The EPA has established the Federal Prevention of Significant Deterioration (PSD) program to determine what comprises "significant impact levels" (SIL) to NAAQS attainment areas. A project's impacts are considered less than significant if emissions are below PSD SIL for a particular pollutant. When a SIL is exceeded, an additional "increment analysis" is required. As the Project would not include modification to the stationary source under NSR, it would not be subject to either PSD or NSR review. The PSD SIL thresholds are used with ambient air quality modeling for a CEQA project to address whether the Project would "violate any air quality standard or contribute substantially to an existing or projected air quality violation." Ambient air quality emissions estimates below the PSD SIL thresholds would result in less than significant ambient air quality impacts for both a project and cumulative CEQA impact analysis. The SJVAB is classified as non-attainment for the O_3 NAAQS and, as such, is subject to "non-attainment new source review" (NSR). PSD SILs and increments are more stringent than the CAAQS or NAAQS and represent the most stringent thresholds of significance.

4.1.3 Thresholds for Hazardous Air Pollutants

The SJVAPCD's GAMAQI states, "From a health risk perspective there are basically two types of land use projects that have the potential to cause long-term public health risk impacts:

- Type A Projects: Land use projects that will place new toxic sources in the vicinity of existing receptors, and
- Type B Projects: Land use projects that will place new receptors in the vicinity of existing toxics sources" (SJVAPCD 2015).

The Project is a Type A Project and will therefore be evaluated for health risk. **Table 4-2**Table 4-2 presents the thresholds of significance used with toxic air contaminants when evaluating hazardous air pollutants (HAPs).

Table 4-2. Measures of Significance - Toxic Air Contaminants

Agency	Level	Description
Significance Thresholds Adopted for the Evaluation of Impacts Under CEQA		
SJVAPCD	Carcinogens	Maximally Exposed Individual risk **equals or exceeds** 20 in one million.
	Non-Carcinogens	**Acute**: Hazard Index **equals or exceeds** 1 for the Maximally Exposed Individual.
		Chronic: Hazard Index **equals or exceeds** 1 for the Maximally Exposed Individual.
Source: SJVAPCD 2015		

4.1.4 Cumulative Impacts Threshold of Significance

Attachment A of Kern County's Guidelines for Preparing an Air Quality Assessment for Use in Environmental Impact Reports states "the following threshold are defined for purposes of determining cumulative effects as the baseline for "considerable". "Projects in the San Joaquin Valley Air Pollution Control District…will be subject

to the following significance thresholds". The thresholds outlined in the guidelines mirror the individual project significance thresholds of 15 tons per year for PM_{10} and 10 tons per year for NO_X and ROG. Therefore, owing to the inherently cumulative nature of air quality impacts, the threshold for whether a project would make a cumulatively considerable contribution to a significant cumulative impact is simply whether the project would exceed project-level thresholds.

4.1.5 Global Climate Change Thresholds of Significance

On December 17, 2009, SJVAPCD adopted Guidance for Valley Land-use Agencies in Addressing GHG Emission Impacts for New Projects under CEQA (SJVAPCD 2009); which outlined the SJVAPCD's methodology for assessing a project's significance for GHGs under CEQA. The following criteria was outlined in the document to determine whether a project could have a significant impact:

- Projects determined to be exempt from the requirements of CEQA would be determined to have a less than significant individual and cumulative impact for GHG emissions and would not require further environmental review, including analysis of project specific GHG emissions. Projects exempt under CEQA would be evaluated consistent with established rules and regulations governing project approval and would not be required to implement BPS.
- Projects complying with an approved GHG emission reduction plan or GHG mitigation program which avoids or substantially reduces GHG emissions within the geographic area in which the project is located would be determined to have a less than significant individual and cumulative impact for GHG emissions. Such plans or programs must be specified in law or approved by the lead agency with jurisdiction over the affected resource and supported by a CEQA compliant environmental review document adopted by the lead agency. Projects complying with an approved GHG emission reduction plan or GHG mitigation program would not be required to implement best performance standards.
- Projects implementing Best Performance Standards would not require quantification of project specific GHG emissions. Consistent with CEQA Guidelines, such projects would be determined to have a less than significant individual and cumulative impact for GHG emissions.
- Projects not implementing Best Performance Standards would require quantification of project specific GHG emissions and demonstration that project specific GHG emissions would be reduced or mitigated by at least 29%, compared to Business-as-Usual (BAU), including GHG emission reductions achieved since the 2002-2004 baseline period. Projects achieving at least a 29% GHG emission reduction compared to BAU would be determined to have a less than significant individual and cumulative impact for GHG.
- Notwithstanding any of the above provisions, projects requiring preparation of an Environmental Impact Report for any other reason would require quantification of project specific GHG emissions. Projects implementing BPS or achieving at least a 29% GHG emission reduction compared to BAU would be determined to have a less than significant individual and cumulative impact for GHG.

4.2 Project Related Emissions

This document was prepared pursuant to the SJVAPCD's GAMAQI. The GAMAQI identifies separate thresholds for a project's short-term (construction) and long-term (operational) emissions.

Project emissions were estimated for the following project development stages:

- Short-term (Construction) – Construction emissions of the proposed Project were estimated in CalEEMod based on construction schedules of 18 days per well, 2 years for the capture facilities and 1 year for the pipelines.
- Long-term (Operations) – Long term mobile emissions were also estimated using EMFAC2021 and stationary source emissions were estimated using annual emission inventory reports and permit to

operate emission limits. Additionally, the new amine unit valve fugitive emissions have been quantified using the California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities.

4.2.1 Short-Term Emissions

The CalEEMod equipment list was updated to reflect the list of proposed construction equipment and schedule that was provided by the CRC and is included in **Appendix B**. Construction traffic volumes entered into CalEEMod matched the traffic report (Ruettgers & Schuler 2023) prepared for the Project. Applying model defaults as well as a conservative analysis approach, construction emissions were estimated as if construction started in January of 2024. The dates entered into the CalEEMod program may not represent the actual dates the equipment will operate; however, the total construction time is accurate, and therefore, all estimated emission totals are conservative and reflect a reasonable and legally sufficient estimate of potential impacts. All construction equipment activity assumption levels were based on the specified CalEEMod default values for type and number of equipment and horsepower, hours per day and days per week. CalEEMod inputs and resulting outputs can be found in **Appendix B**.

SJVAPCD's required construction site measures for all projects were also applied:

- Water exposed areas 3 times per day; and
- Reduce vehicle speed to less than 15 miles per hour.

Construction Mobile Source Assumptions:

- 40-mile trip distance.
- 160 average daily trips (ADTs) from workers during facilities construction.
- 32 ADTs (1-Ton work truck) from workers and 20 ADTs (12 from 5-ton utility flatbed truck and 8 from water truck) from hauling during pipeline construction.
- 16 ADTs from workers and 2 ADTs from vendor trips during well pad construction.
- 12 ADTs from workers and 10 ADTs from vendor trips during well construction.

Construction Equipment Source Assumptions:

- 2-year construction schedule for facilities construction (523 days total).

Table 4-3. Facilities Construction Equipment

Equipment	CalEEMod Equipment Designation	Quantity	Total Operating Hours per	Average Daily Operating Hours
Hydro Crane	Cranes	5	1968.75	3.8
ForkLift	Forklifts	7	1968.75	3.8
Excavator	Excavators	1	1968.75	3.8
Backhoe	Tractors/Loaders/Backhoes	4	1968.75	3.8
Air Compressor	Air Compressors	20	246.09	0.5
Crane	Cranes	3	246.09	0.5
Loader	Rubber Tired Loader	3	246.09	0.5
Dozer	Rubber Tired Dozers	1	1968.75	3.8
Dump Truck	Off-Highway Trucks	2	1968.75	3.8
Welding Truck	Welders	8	1968.75	3.8

- 1-year construction schedule for pipeline construction (220 days total).

Table 4-4. Pipeline Construction Equipment

Equipment	CalEEMod Equipment Designation	Quantity	Average Daily Operating Hours
Crane	Cranes	3	5.0
Boom Truck	Other Construction Equipment	3	5.0
Crane	Cranes	3	2.5
Side Boom	Other Construction Equipment	6	5.0
Bending Machine	Other Material Handling Equipment	1	2.5
Air Compressor	Air Compressors	4	5.0
Air Compressor	Air Compressors	1	2.5
Welding Machines	Welders	8	5.0
DitchWitch	Off-Highway Trucks	1	2.5
Vacuum Truck	Other Construction Equipment	2	2.5

- 11-day construction schedule for well pad construction per well (18 wells = 198 days total)

Table 4-5. Well Pad Construction Equipment (Per Well)

Equipment	CalEEMod Equipment Designation	Quantity	Total Operating Hours per	Average Daily Operating Hours
Grader	Graders	1	16	1.5
Front Loader	Tractors/Loaders/Backhoes	1	40	3.6
Excavator	Excavators	1	32	2.9
Water Truck	Other Construction Equipment	1	40	3.6

- 18-day construction schedule for well drilling construction per well (18 wells = 324 days total)

Table 4-6. Well Drilling Construction Equipment (Per Well)

Equipment	CalEEMod Equipment Designation	Quantity	Total Operating Hours per	Average Daily Operating Hours
Forklift	Forklifts	1	72.0	4.0
Drilling Rig Motor	Bore/Drill Rigs	1	275.4	15.3
Drilling Rig Motor	Bore/Drill Rigs	1	322.2	17.9
Drilling Rig Motor	Bore/Drill Rigs	1	216.0	12.0
Small Generator	Generator Sets	1	8.0	0.4
Light Tower	Generator Sets	2	216.0	12.0
Water Truck	Other Construction Equipment	1	144.0	8.0
Vacuum Truck	Other Construction Equipment	1	432.0	24.0

Table 4-7 presents the Project's short-term emissions based on the anticipated construction period. Emissions are laid out in a worst-case scenario with a full year of pipeline construction overlapping a full year of facilities construction activities.

Table 4-7. Short-Term Project Emissions

Emissions Source	Pollutant (tons/year)					
	ROG	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$
Facilities Construction Year 1	0.61	3.99	5.14	0.01	0.79	0.32
Pipelines Construction	0.74	6.07	7.06	0.01	0.42	0.3
Year 1 Construction Total	**1.35**	**10.06**	**12.2**	**0.02**	**1.21**	**0.62**
Facilities Construction Year 2	0.57	3.65	4.97	0.01	0.77	0.3
Year 2 Construction Total	**0.57**	**3.65**	**4.97**	**0.01**	**0.77**	**0.3**
Source: Trinity Consultants 2023						

4.2.2 Long-Term Operations Emissions

Long-term emissions are caused by operational stationary and mobile sources. Long-term emissions would consist of the following components:

4.2.2.1 Fugitive Dust Emissions

Operation of the Project site at full build-out is not expected to present a substantial source of fugitive dust (PM_{10}) emissions. The main source of PM_{10} emissions would be from vehicular traffic associated with the Project site.

PM_{10}, on its own as well as in combination with other pollutants, creates a health hazard. The SJVAPCD's Regulation VIII establishes required controls to reduce and minimizing fugitive dust emissions. The following SJVAPCD Rules and Regulations apply to the proposed Project (and all projects):

- Rule 4102 - Nuisance
- Regulation VIII – Fugitive PM10 Prohibitions
  - Rule 8011 - General Requirements
  - Rule 8021 - Construction, Demolition, Excavation, Extraction, and Other Earthmoving Activities
  - Rule 8041 - Carryout and Trackout
  - Rule 8051 - Open Areas

The Project would comply with applicable SJVAPCD Rules and Regulations, the local zoning codes, and additional emissions reduction measures recommended later in this analysis, in Section 7, Mitigation and Other Recommended Measures.

4.2.2.2 Mobile Source Exhaust Emissions

Project-related transportation activities from employees and various other oil and gas operations would generate mobile source ROG, NOx, SOx, CO, PM_{10}, and $PM_{2.5}$ exhaust emissions. Exhaust emissions would vary substantially from day to day but would average out over the course of an operational year. The Traffic Study (Ruettgers & Schuler 2023) analyzed the potential for operational vehicular traffic from the operations and maintenance of the compression and pumping facility. The traffic study estimated 20 average daily trips from worker vehicles.

Operational Mobile Source Assumptions:

- Baseline has 13 dedicated workers making 26 ADTs per day.
- Project includes an additional 10 workers making 20 ADTs (per traffic study).
- 40-mile trip distance.

- EMFAC2021 v1.0.2 was used to estimate mobile source emission.
    - County: Kern
    - Calendar Year: Baseline 2022, Post-Project 2025
    - Season: Annual
    - Vehicle Category: EMFAC202x (LDA, LDT1 and LDT2)
    - Model Year: Aggregate
    - Speed: Aggregate
    - Fuel: Gasoline

Table 4-8. Baseline Mobile Source (Operational) Exhaust Emissions

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
Baseline Mobile Emissions	0.010	0.053	0.597	0.001	0.007	0.002
Source: Trinity Consultants 2023						

Table 4-9. Mobile Source (Operational) Exhaust Emissions Increase

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
Project Mobile Emissions Increase	0.002	0.012	0.222	0.001	0.005	0.002
Source: Trinity Consultants 2023						

4.2.2.3 Stationary Source Emissions

The CCS Facility will be located at the existing stationary source CGP-1 Facility (S-9168) and capture CO2 from natural gas streams which provides fuel for the 550 Mw Elk Hill Power Plant (S-3523). In order to give a clear picture of what the Project site will look like before and after the Project the baseline emissions from S-9168 and S-3523 facilities were calculated. Baseline emissions for S-9168 and S-3523 were taken from the facilities 2022 annual emissions inventory and are based on actual historical data and can be found in **Appendix B**. The Project is not requesting any increase to any existing permitted stationary sources. In addition to the existing permitted sources, two new amine units will be installed (one in each phase) at the Project site. These amine units will have criteria emissions from fugitive component leaks and have been calculated according to the California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities which can be found in **Appendix B**.

Stationary Source Emissions Assumptions:

- Baseline Emissions used 2022 Annual Emissions Inventory for S-9168 and S-3523.
- No increase in currently permitted units requested.
- Two additional Amine units will be installed (one in each Phase of the Project). Fugitive emissions from these units were calculated using the California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities based on the component counts of all valves, pump seals, others, connectors, and flanges associated with the amine units.

Table 4-10. Baseline Stationary Source (Operational) Emissions

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
S-9168 Baseline Emissions	4.07	1.91	5.05	0.07	4.35	4.35
S-3523 Baseline Emissions	0.01	74.16	2.24	8.08	42.85	42.85
Total Baseline Emissions	**4.08**	**76.07**	**7.29**	**8.15**	**47.2**	**47.2**
Source: Trinity Consultants 2023						

Table 4-11. Stationary Source (Operational) Emissions Increase

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
Phase 1 New Amine Unit	0.53	0.00	0.00	0.00	0.00	0.00
Phase 2 New Amine Unit	0.53	0.00	0.00	0.00	0.00	0.00
Total Post-Project Emissions Increase	**1.06**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Source: Trinity Consultants 2023						

4.2.3 Total Emissions of All Oil and Gas Activities on a Per Well Basis

A suggested mitigation of the Project is to enter into a Voluntary Emission Reduction Agreement (VERA) to reduce the Project's impacts from NO_X, ROG, and PM_{10} net incremental emissions that are not addressed as conditions of SJVAPCD permitting to a no net increase over criteria pollutants that would otherwise exist without development of the Project. The Oil and Gas Emission Reduction Agreement (OG-ERA) is a required mitigation for new well permits under the Oil and Gas Conformity Review and Minor Activities Permit. One of the menu options to achieve the mandated emission reductions is to pay a calculated mitigation fee. The Kern County Planning Department has calculated total emissions of all oil and gas activities on a per well basis and is segmented into 1000 foot well depth increments. The VERA fee would be calculated based on the calculated emission tonnage for the total wells of the Project. **Table 4-12** list the Project's wells, well depths and associated total emissions (NO_X, ROG, and PM_{10}).

Table 4-12. Total Emissions on a Per Well Basis

Well Name	Description	Depth (ft)	Emissions (Tons)
26R Reservoir			
363C-27R	Injector	6290	4.55
353XC-35R (new)	Injector	6390	4.55
373-35R (new)	Injector	7010	5.36
345C-35R (new)	Injector	5690	3.98
341-27R	Plume monitoring	6981	4.55
328-25R	Plume monitoring	5268	3.98
376-36R	Plume monitoring	5832	3.98
355X-26R	Above-zone monitoring	4063	2.35
USDW Monitoring (new)	USDW monitoring	400	1.28
A1/A2 Reservoir			
355-7R	Injector	8387	6.17
357-7R	Injector	8420	6.17
353A-7R	Plume monitoring	8773	6.17
335X-7R	Plume monitoring	8737	6.17
327-7R-RD1	Above-Zone monitoring	3782	2.03
345-7R	A3+ Monitoring	8904	6.17
388X-7R	A3+ Monitoring	8800	6.17
342-17R	A3+ Monitoring	8844	6.17
USDW Monitoring (new)	USDW monitoring	740	1.28
Total			**81.08**

4.3 Potential Impact on Sensitive Receptors

Sensitive receptors are defined as locations where young children, chronically ill individuals, the elderly or people who are more sensitive than the general population reside, such as schools, hospitals, nursing homes, and daycare centers. There are no known sensitive receptors within 2 miles of the Project site.

4.4 Potential Impacts to Visibility to Nearby Areas

Visibility impact analyses are intended for stationary sources of emissions which are subject to the Prevention of Significant Deterioration (PSD) requirements in 40 CFR Part 60; they are not usually conducted for area sources. Because the Project's PM_{10} emissions increase is predicted to be less than the PSD threshold levels, an impact at any Class 1 area or military/airspace operation within 100 kilometers of the Project (including San Rafael Wilderness, Domeland Wilderness, Edwards Air Force Base, China Lake Naval Weapons Station, and the entire R-2508 Airspace Complex) is extremely unlikely. Therefore, based on the Project's predicted less-than significant PM_{10} emissions, the Project would be expected to have a less than significant impact to visibility at any Class 1 area or military/airspace operation.

4.5 Potential Impacts from Carbon Monoxide

Ambient CO concentrations normally correspond closely to the spatial and temporal distributions of vehicular traffic. Relatively high concentrations of CO would be expected along heavily traveled roads and near busy intersections. CO concentrations are also influenced by wind speed and atmospheric mixing. CO concentrations may be more uniformly distributed when inversion conditions are prevalent in the valley. Under certain meteorological conditions, CO concentrations along a congested roadway or intersection may reach unhealthful levels for sensitive receptors, e.g. children, the elderly, hospital patients, etc. This localized impact

can result in elevated levels of CO, or "hotspots" even though concentrations at the closest air quality monitoring station may be below NAAQS and CAAQS.

The localized Project impacts depend on whether ambient CO levels in the Project vicinity would be above or below NAAQS. If ambient levels are below the standards, a project is considered to have significant impacts if a project's emissions exceed of one or more of these standards. If ambient levels already exceed a state standard, a project's emissions are considered significant if they would increase one-hour CO concentrations by 10 ppm or more or eight-hour CO concentrations by 0.45 ppm or more. There are two criteria established by the SJVAPCD's GAMAQI by which CO "Hot Spot" modeling is required:

1. A traffic study for the project indicates that the Level of Service (LOS) on one or more streets or at one or more intersections in the project vicinity would be reduced to LOS E or F; or
2. A traffic study indicates that the project would substantially worsen an already existing LOS F on one or more streets or at one or more intersections in the project vicinity.

According to the traffic study (Ruettgers & Schuler 2023) that was prepared for this Project, due to the amount of peak hour trips being generally less than 50 trips in the peak hour a LOS analysis is not warranted. Therefore, due to the location and traffic increase anticipated from this Project, impacted intersections and roadway segments are anticipated to operate at a LOS of C or better. Therefore, CO "Hotspot" Modeling was not conducted for this Project and no concentrated excessive CO emissions are expected to be caused once the proposed Project is completed.

4.6 Predicted Health Risk Impacts

GAMAQI recommends that Lead Agencies consider situations wherein a new or modified source of HAPs is proposed for a location near an existing residential area or other sensitive receptor when evaluating potential impacts related to HAPs.

The proposed Project would result in new emissions of Hazardous Air Pollutants (HAPs) of diesel particulate matter (DPM) from construction equipment exhaust and operational fugitive VOC emissions from the new amine units and would be located near existing residents and workers; therefore, an assessment of the potential risk to the population attributable to emissions of hazardous air pollutants from the proposed Project is required.

To predict the potential health risk to the population attributable to emissions of HAPs from the proposed Project, ambient air concentrations were predicted with dispersion modeling to arrive at a conservative estimate of increased individual carcinogenic risk that might occur as a result of continuous exposure over a 2-year construction timeline and a 68-year lifetime for operational exposure. Similarly, predicted concentrations were used to calculate non-cancer chronic and acute hazard indices (HIs), which are the ratio of expected exposure to acceptable exposure. The basis for evaluating potential health risk is the identification of sources with increased HAPs.

Health risk is determined using the Hotspots Analysis and Reporting Program (HARP2) software distributed by the CARB; HARP2 requires peak 1-hour emission rates and annual-averaged emission rates for all pollutants for each modeling source (CARB 2015). Assumptions used to calculate the emission rates for the proposed Project are outlined below.

The most recent version of EPA's AMS/EPA Regulatory Model - AERMOD was used to predict the dispersion of emissions from the proposed Project. The analysis employed all of the regulatory default AERMOD model keyword parameters, including elevated terrain options.

For construction health impacts, diesel combustion emissions from diesel on-site construction equipment and HHD trucks from hauling and vendor trips were modeled as an area source for on-site construction activity on the property. DPM was calculated using CalEEMod for on-site construction equipment. A unit emission rate of 1 grams/second (g/sec) was input to AERMOD for the area source.

For operational health impacts, Fugitive leaks were modeled as volume sources. A unit emission rate of 1 grams/second (g/sec) was input to AERMOD for the volume sources.

Discrete receptors were placed on houses and businesses within close proximity of the Project site. A total of 177 discrete off-site receptors analyzed. Elevated terrain options were employed even though there is not complex terrain in the Project area.

SJVAPCD-provided, AERMET UStar processed meteorological datasets for the Missouri Triangle monitoring station, calendar years 2004 through 2018 was input to AERMOD (SJVAPCD 2018). This was the most recent available dataset available at the time the modeling was conducted. Rural dispersion parameters were used because the operation and the majority of the land surrounding the facility is considered "rural" under the Auer land use classification method (Auer 1978).

Plot files generated by AERMOD were uploaded to the Air Dispersion Modeling and Risk Assessment Tool (ADMRT) program in the Hotspots Analysis and Reporting Program Version 2 (HARP 2) (CARB 2015). ADMRT post-processing was used to assess the potential for excess cancer risk and chronic and acute non-cancer effects using the most recent health effects data from the California EPA Office of Environmental Health Hazard Assessment (OEHHA). HARP2 site parameters were set for the mandatory minimum pathways of inhalation, soil ingestion, dermal, and mother's milk. In addition to the aforementioned pathways, the home-grown garden pathway was included as well. Risk reports were generated using the derived OEHHA analysis method for carcinogenic risk and non-carcinogenic chronic and acute risk. Site parameters are included in the HARP2 output files. Total cancer risk was predicted for each receptor. A hazard index was computed for chronic non-cancer health effects for each applicable endpoint and each receptor. A hazard index for acute non-cancer health effects was computed for each applicable endpoint and each receptor.

SJVAPCD has set the level of significance for carcinogenic risk at twenty in one million, which is understood as the possibility of causing twenty additional cancer cases in a population of one million people. The level of significance for chronic and acute non-cancer risk is a hazard index of 1.0. All receptors were modeled as residential receptors with a 70-year exposure. This is conservative since all on-site receptors and business receptors would be exposed less than 70 years.

The carcinogenic risk and the health hazard index (HI) for chronic non-cancer risk at the point of maximum impact (PMI) do not exceed the significance levels of twenty in one million (20×10^{-6}) and 1.0, respectively for the proposed Project. The PMIs, are identified by receptor location and risk, and are provided in **Table 4-11**. The electronic AERMOD and HARP2 output files are provided in **Attachment E**.

Table 4-13. Potential Maximum Impacts Predicted by HARP

	Value	UTM East	UTM North
Excess Cancer Risk	2.62E-07	265161.68	3909171.5
Chronic Hazard Index	1.72E-04	265161.68	3909171.5
Acute Hazard Index	6.46E-04	265161.7	3909171.5

As shown above in **Table 4-11**, the maximum predicted cancer risk for the proposed Project is 2.62E-07. The maximum chronic non-cancer hazard index for the proposed Project is 1.72E-04. The maximum acute non-

cancer hazard index for the proposed Project is 6.46E-04. Since the PMI remained below the significance threshold for cancer, chronic, and acute risk, this Project would not have an adverse effect to any of the surrounding communities.

The potential health risk attributable to the proposed Project is determined to be *less than significant* based on the following conclusions:

1. Potential carcinogenic risk from the proposed Project is below the significance level of twenty in a million at each of the modeled receptors; and
2. The hazard index for the potential chronic non-cancer risk from the proposed Project is below the significance level of 1.0 at each of the modeled receptors.
3. The hazard index for the potential acute non-cancer risk from the proposed Project is below the significance level of 1.0 at each of the modeled receptors.

Therefore, the potential risk to the population attributable to emissions of HAPs from the proposed Project would be less than significant.

4.7 Potential Impacts from Valley Fever

The proposed project has the potential to generate fugitive dust and suspend Valley Fever spores with the dust that could then reach nearby sensitive receptors. It is possible that onsite workers could be exposed to Valley Fever spores as fugitive dust is generated during construction. In order to mitigate potential risk, the proposed Project would provide training and personal protective respiratory equipment to construction workers and provide information to all construction personnel and visitors about Valley Fever. Therefore, the exposure to Valley Fever would be minimized. With the implementation of the mitigation measures, dust from the construction of the proposed project would not add significantly to the existing exposure level of people to this fungus, including construction workers, and impacts would be reduced to less-than-significant levels.

4.8 Potential Impacts from Asbestos

Naturally occurring asbestos can be released from serpentinite and ultramafic rocks when the rock is broken or crushed. At the point of release, the asbestos fibers may become airborne, causing air quality and human health hazards. These rocks have been commonly used for unpaved gravel roads, landscaping, fill projects, and other improvement projects in some localities. Asbestos may be released to the atmosphere due to vehicular traffic on unpaved roads, during grading of development projects, and at mining operations.

Serpentinite and/or ultramafic rock are known to be present in 44 of California's 58 counties. These rocks are particularly abundant in the counties associated with the Sierra Nevada foothills, the Klamath Mountains, and Coast Ranges. However, according to information provided by the Department of Conservation Division of Mines and Geology, the project site is not located in an area where naturally occurring asbestos is likely to be present (CDCDMG, 2000). Therefore, impacts associated with exposure of construction workers and nearby sensitive receptors to asbestos would be less than significant.

4.9 Odor Impacts and Mitigation

The SJVAPCD's GAMAQI states "An analysis of potential odor impacts should be conducted for both of the following two situations:

1. Generators – projects that would potentially generate odorous emissions proposed to locate near existing sensitive receptors or other land uses where people may congregate, and

2. Receivers – residential or other sensitive receptor projects or other projects built for the intent of attracting people locating near existing odor sources." (SJVAPCD 2015).

The GAMAQI also states, "The District has identified some common types of facilities that have been known to produce odors in the San Joaquin Valley Air Basin. These are presented in Table 6 (Screening Levels for Potential Odor Sources), along with a reasonable distance from the source within which, the degree of odors could possibly be significant. [Table 6] can be used as a screening tool to qualitatively assess a project's potential to adversely affect area receptors." (SJVAPCD, 2015). Because the Project is a Sanitary Landfill and there are no receptors located within a 1-mile radius of the Project, the Project is not expected to be a source of objectionable odors.

Based on the provisions of the SJVAPCD's GAMAQI, the proposed Project would not exceed any screening trigger levels to be considered a source of objectionable odors or odorous compounds (SJVAPCD, 2015). Furthermore, there does not appear to be any significant source of objectionable odors in close proximity that may adversely impact the Project site when it is in operation. Additionally, the Project emissions estimates indicate that it would not be expected to adversely impact surrounding receptors. As such, the proposed Project would not be a source of any odorous compounds nor would it likely be impacted by any odorous source.

4.10 Impacts to Ambient Air Quality

As stated in the GAMAQI (2015, p 96-97), SJVAPCD has developed screening levels for requiring an Ambient Air Quality Analysis (AAQA). The SJVAPCD recommends that an AAQA be performed for all criteria pollutants when emissions of any criteria pollutant resulting from project construction or operational activities exceed the 100 pounds per day screening level, after compliance with Rule 9510 requirements and implementation of all enforceable mitigation measures.

The Project will be entering into a VERA which will reduce average daily emissions for construction and operational activities associated with this Project to a no net increase level. Therefore, an AAQA is not required for this Project.

4.11 Impacts to Greenhouse Gases and Climate Change

The proposed Project will have GHG emissions from construction and operation. These GHG emissions include emissions from mobile and stationary source. New regulations and new technologies in the future, and phase out of old equipment over time, will lead to a reduction of GHG emissions, but the reduction is not currently quantifiable. Additionally, the project, as proposed, has the capacity for up to 48 million metric tons of estimated storage and capable of sequestrating in excess of 1.5 million metric tons of CO_2 per year. The installed Amine equipment will have a capture nameplate efficiency of 95%. The Project will achieve net negative GHG emissions impact.

The proposed Project's construction and operational GHG emissions were estimated using the CalEEMod program and EMFAC2021, stationary source emissions we take from annual emissions inventory and calculated based on design capacity. **Table 4-14** summarizes the estimated GHG emissions for the for the first source at the Project site and the reductions from the implementation of the Project. GHG emission calculations can be found in **Appendix B**.

Table 4-14. Estimated GHG Emissions for First Source – Collection Elk Hills Field Gas (MT/Year)

Year	Gas Plant Emissions	Power Plant Emissions	Total Plants Emissions	Capture Facility Mobile Emissions	Captured and Injected Emissions
Baseline	2,770,146	3,706,794	6,476,940	-	-
Capture Year 1 (2026)	2,770,146	3,706,794	6,476,940	85.0	101,743
Capture Years 2-20 (2027-2045) per year	2,770,146	3,706,794	6,476,940	85.0	203,486
Total Years 1-20 (2026-2045)	**55,402,920**	**74,135,880**	**129,538,800**	**1,700**	**3,967,977**

The Project will not result in the emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), or sulfur hexafluoride (SF_6), the other gases identified as GHG in AB32. The proposed Project may be subject to future regulations developed by CARB to address GHG emissions.

4.11.1 Feasible and Reasonable Mitigation Relative to Global Warming

CEQA requires that all feasible and reasonable mitigation be applied to the project to reduce the impacts from construction and operations on air quality. The SJVAPCD's "Non-Residential On-Site Mitigation Checklist" was utilized in preparing the mitigation measures and evaluating the projects features. These measures include using controls that limit the exhaust from construction equipment and using alternatives to diesel when possible. Additional reductions would be achieved through the regulatory process of the air district and CARB as required changes to diesel engines are implemented which would affect the product delivery trucks and limits on idling.

Since the Project reduces GHG emissions it is possible to determine whether the Project individually would have a significant impact on global warming or climate change, the Project would contribute to reductions in cumulative GHG emissions in California as well as related health effects. Therefore, it is possible to assess, with certainty, whether the Project's contribution would be cumulatively considerable, within the meaning of CEQA Guidelines Sections 15065(a)(3) and 15130.

The strategies currently being implemented by CARB may help in reducing the Project's GHG emissions and are summarized in the table below.

Table 4-15. Select CARB GHG Emission Reduction Strategies

Strategy	Description of Strategy
Vehicle Climate Change Standards	AB 1493 (Pavley) required the state to develop and adopt regulations that achieve the maximum feasible and cost-effective reduction of climate change emissions emitted by passenger vehicles and light duty trucks. Regulations were adopted by CARB in Sept. 2004.
Diesel Anti-Idling	In July 2004, CARB adopted a measure to limit diesel-fueled retail motor vehicle idling.
Other Light-Duty Vehicle Technology	New standards would be adopted to phase in beginning in the 2017 model year.
Alternative Fuels: Biodiesel Blends	CARB would develop regulations to require the use of 1% to 4% Biodiesel displacement of California diesel fuel.
Alternative Fuels: Ethanol	Increased use of ethanol fuel.
Heavy-Duty Vehicle Emission Reduction Measures	Increased efficiency in the design of heavy-duty vehicles and an educational program for the heavy-duty vehicle sector.

Not all of these measures are currently appropriate or applicable to the proposed Project. While future legislation could further reduce the Project's GHG footprint, the analysis of this is speculative and in accordance with CEQA Guidelines Section 15145, will not be further evaluated in this AQIA.

CEQA Guidelines Section 15130 notes that sometimes the only feasible mitigation for cumulative impacts may involve the adoption of ordinances or regulations rather than the imposition of conditions on a project-by-project basis. Global climate change is this type of issue. The causes and effects may not be just regional or statewide, they may also be worldwide. Given the uncertainties in identifying, let alone quantifying the impact of any single project on global warming and climate change, and the efforts made to reduce emissions of GHGs from the Project through design, in accordance with CEQA Section 15130, any further feasible emissions reductions would be accomplished through CARB regulations adopted pursuant to AB32. Given that the Project has a net negative impact on GHG emissions it can be assumed the Project will comply with any local and statewide air quality and climate plans.

5. CUMULATIVE IMPACTS

By its very nature, air pollution has a cumulative impact. The District's nonattainment status is a result of past and present development within the SJVAB. Furthermore, attainment of ambient air quality standards can be jeopardized by increasing emissions-generating activities in the region. No single project would be sufficient in size, by itself, to result in nonattainment of the regional air quality standards. Instead, a project's emissions may be individually limited, but cumulatively considerable when taken in combination with past, present, and future development within the San Joaquin Valley Air Basin. When assessing whether there is a new significant cumulative effect, the Lead Agency shall consider whether the incremental effects of the project are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects [CCR §15064(h)(1)]. Per CEQA Guidelines §15064(h)(3) a Lead Agency may determine that a project's incremental contribution to a cumulative effect is not cumulatively considerable if the project will comply with the requirements in a previously approved plan or mitigation program, including, but not limited to an air quality attainment or maintenance plan that provides specific requirements that will avoid or substantially lessen the cumulative problem within the geographic area in which the project is located. (SJVAPCD 2015)

Attachment A of Kern County's *Guidelines for Preparing an Air Quality Assessment for Use in Environmental Impact Reports* states "The following threshold[s] are defined for purposes of determining cumulative effects as the baseline for "considerable". Projects in the San Joaquin Valley Air Pollution Control District…will be subject to the following significance thresholds". The thresholds outlined in the guidelines mirror the individual project significance thresholds of 15 tons per year for PM_{10} and 10 tons per year for NO_X and ROG. Therefore, owing to the inherently cumulative nature of air quality impacts, the threshold for whether a project would make a cumulatively considerable contribution to a significant cumulative impact is simply whether the project would exceed project-level thresholds. This AQIA, however, also considered the impacts of the proposed Project in conjunction with the impacts of other projects previously proposed in the area. The following cumulative impacts were considered:

- Cumulative O_3 Impacts (ROG and NOx) from numerous sources within the region including transport from outside the region. O_3 is formed through chemical reactions of ROG and NOx in the presence of sunlight.
- Cumulative CO Impacts produced primarily by vehicular emissions.
- Cumulative PM_{10} Impacts from within the region and locally from the various projects. Such projects may cumulatively produce a significant amount of PM10 if several projects conduct grading or earthmoving activities at the same time; and
- Hazardous Air Pollutant (HAP) Impacts on sensitive receptors.

5.1 Cumulative Regional Air Quality Impacts

The most recent, certified SJVAB Emission Inventory data available from the SJVAPCD is based on data gathered for the 2020 annual inventory[1]. This data will be used to assist the SJVAPCD in demonstrating attainment of Federal 1-hour O_3 Standards (SJVAPCD 2007). **Table 5-1** provides a comparative look at the impacts proposed by the proposed Project to the SJVAB Emissions Inventory.

[1] SJVAPCD Emissions for Aggregated Stationary, Area-Wide, Mobile, and Natural Sources

Table 5-1. Comparative Analysis Based on SJV Air Basin 2020 Inventory - Tons per Year

	ROG	NOx	CO	SOx	PM_{10}	$PM_{2.5}$
Kern County - 2020	21,535	15,878	27,339	511	13,651	3,723
SJVAB - 2020	108,113	74,205	162,425	2,847	96,652	21,535
Proposed Project	1.06	0.01	0.22	0.001	0.005	0.002
Proposed Project's % of Kern	0.0049%	0.0001%	0.0008%	0.0002%	0.0000%	0.0001%
Proposed Project's % of SJVAB	0.0010%	0.0000%	0.0001%	0.0000%	0.0000%	0.0000%
Note: This is the latest inventory available as of May 2023 Source: CARB 2022b						

As shown in **Table 5-1** the proposed Project does not pose a substantial increase to basin emissions, as such basin emissions would be essentially the same if the Project is approved.

Table 5-1, **5-2**, and **5-3** provide CARB Emissions Inventory projections for the year 2025 for both the SJVAB and the Kern County portion of the air basin. Looking at the SJVAB Emissions predicted by the CARB year 2025 emissions inventory, the Kern County portion of the air basin is a moderate source of the emissions. The proposed Project produces a small portion of the total emissions in both Kern County and the entire SJVAB.

Table 5-2. Emission Inventory SJVAB 2025 Projection - Tons per Year

	ROG	NOx	CO	SOx	PM10	PM2.5
Total Emissions	107,347	52,451	145,964	2,920	95,922	21,280
Percent Stationary Sources	32.78%	19.28%	6.93%	85.00%	5.97%	15.44%
Percent Area-Wide Sources	52.70%	5.15%	13.30%	3.75%	89.38%	71.87%
Percent Mobile Sources	14.52%	75.57%	79.77%	11.25%	4.68%	12.86%
Total Stationary Source Emissions	35,186	10,111	10,111	2,482	5,731	3,285
Total Area-Wide Source Emissions	56,575	2,701	19,418	110	85,739	15,294
Total Mobile Source Emissions	15,586	39,639	116,435	329	4,490	2,738
Source: CARB 2022b Note: Total may not add due to rounding						

Table 5-3. Emission Inventory SJVAB - Kern County Portion 2025 Projection - Tons per Year

	ROG	NOx	CO	SOx	PM10	PM2.5
Total Emissions	21,353	10,804	24,674	475	13,651	3,687
Percent Stationary Sources	53.50%	25.68%	15.83%	84.62%	11.76%	31.68%
Percent Area-Wide Sources	34.70%	4.05%	7.69%	0.00%	82.62%	56.44%
Percent Mobile Sources	11.97%	70.27%	76.33%	15.38%	5.61%	10.89%
Total Stationary Source Emissions	11,425	2,774	3,906	402	1,606	1,168
Total Area-Wide Source Emissions	7,410	438	1,898	0	11,279	2,081
Total Mobile Source Emissions	2,555	7,592	18,834	73	767	402
Source: CARB 2022b Note: Total may not add due to rounding						

Table 5-4. 2025 Emissions Projections - Proposed Project, Kern County, and SJVAB

	ROG	NOx	PM_{10}
Proposed Project	1.06	0.01	0.005
Kern County	24,893	21,645	19,637
SJVAB	107,347	52,451	95,922
Proposed Project Percent of Kern County	0.0043%	0.00005%	0.00003%
Proposed Project Percent of SJVAB	0.0010%	0.00002%	0.00001%
Kern County Percent of SJVAB	23.19%	41.27%	20.47%
Source: CARB 2022b			

As shown above, the proposed Project would pose an inconsequential impact on regional O_3 and PM_{10} formation. The regional contribution to these cumulative impacts would be negligible and additionally, the Project would not exceed cumulatively considerable thresholds since the Project would be less than thresholds outlined in Kern County's *Guidelines for Preparing an Air Quality Assessment for Use in Environmental Impact Reports*. Therefore, this Project would not be considered cumulatively considerable in its contribution to regional O_3 and PM_{10} impacts.

5.2 Cumulative Local Air Quality Impacts

No tentative development projects within a one-mile radius of the proposed Project area were identified. The cumulative projects are typically listed only as geographical reference to demonstrate the construction activity within a one-mile radius of the proposed Project. The number and sizes of these projects are of no particular significance since the cumulative considerable thresholds established by Kern County are based on Project specific thresholds which are inherently cumulative in nature.

As no cumulative projects were identified within a one-mile radius, emissions estimates were not calculated. Additionally, any projects either currently under construction or, at a minimum, approved by the planning department for consistency with applicable regulation, for the purposes of this analysis, it is assumed that they are in conformance with the regional AQAP.

5.3 Cumulative Hazardous Air Pollutants

The GAMAQI also states that when evaluating potential impacts related to HAPs, "*impacts of local pollutants (CO, HAPs) are cumulatively significant when modeling shows that the combined emissions from the project and other existing and planned projects will exceed air quality standards*." Because the Project would not be a significant source of HAPs, the proposed Project would also *not be expected to pose a significant cumulative CO or HAPs impact*.

5.4 Cumulative Carbon Monoxide (CO) – Mobile Sources

The SJVAPCD's GAMAQI has identified CO impacts from impacted traffic intersections and roadway segments as being potentially cumulatively considerable. Traffic increases and added congestion caused by a project can combine to cause a violation of the SJVAPCD's CO standard also known as a "Hotspot". There are two criteria established by the GAMAQI by which CO "Hot Spot" modeling is required:

- A traffic study for the project indicates that the Level of Service (LOS) on one or more streets or at one or more intersections in the project vicinity will be reduced to LOS E or F; or
- A traffic study indicates that the project will substantially worsen an already existing LOS F on one or more streets or at one or more intersections in the project vicinity.

According to the traffic study (Ruettgers & Schuler 2023) that was prepared for this Project, due to the amount of peak hour trips being generally less than 50 trips in the peak hour a LOS analysis is not warranted. Therefore, due to the location and traffic increase anticipated from this Project, impacted intersections and roadway segments are anticipated to operate at a LOS of C or better. Therefore, CO "Hotspot" Modeling was not conducted for this Project and no concentrated excessive CO emissions are expected to be caused once the proposed Project is completed.

6. CONSISTENCY WITH THE AIR QUALITY ATTAINMENT PLAN

Air quality impacts from proposed projects within Kern County are controlled through policies and provisions of the SJVAPCD and the Kern County General Plan (KCPD 2009). In order to demonstrate that a proposed project would not cause further air quality degradation in either the SJVAPCD's plan to improve air quality within the air basin or the federal requirements to meet certain air quality compliance goals, each project should also demonstrate consistency with the SJVAPCD's adopted Air Quality Attainment Plans (AQAP) for O_3 and PM_{10}. The SJVAPCD is required to submit a "Rate of Progress" document to CARB that demonstrates past and planned progress toward reaching attainment for all criteria pollutants. The California Clean Air Act (CCAA) requires air pollution control districts with severe or extreme air quality problems to provide for a 5% reduction in non-attainment emissions per year. The AQAP prepared for the San Joaquin Valley by the SJVAPCD complies with this requirement. CARB reviews, approves or amends the document and forwards the plan to the EPA for final review and approval within the SIP.

Air pollution sources associated with stationary sources are regulated through the permitting authority of the SJVAPCD under the New and Modified Stationary Source Review Rule (SJVAPCD Rule 2201). Owners of any new or modified equipment that emits, reduces or controls air contaminants, except those specifically exempted by the SJVAPCD, are required to apply for an Authority to Construct and Permit to Operate (SJVAPCD Rule 2010). Additionally, best available control technology (BACT) is required on specific types of stationary equipment and are required to offset both stationary source emission increases along with increases in cargo carrier emissions if the specified threshold levels are exceeded (SJVAPCD Rule 2201, 4.7.1). Through this mechanism, the SJVAPCD would ensure that all stationary sources within the project area would be subject to the standards of the SJVAPCD to ensure that new developments do not result in net increases in stationary sources of criteria air pollutants.

6.1 Required Evaluation Guidelines

State CEQA Guidelines and the Federal Clean Air Act (Sections 176 and 316) contain specific references on the need to evaluate consistencies between the proposed project and the applicable AQAP for the project site. To accomplish this, CARB has developed a three-step approach to determine project conformity with the applicable AQAP:

1. *Determination that an AQAP is being implemented in the area where the project is being proposed*. The SJVAPCD has implemented the current, modified AQAP as approved by CARB.
2. *The proposed project must be consistent with the growth assumptions of the applicable AQAP*. The proposed Project land use type was not anticipated in the current growth assumptions. Therefore, growth assumptions in the Kern County General Plans will be modified with the approval of the proposed Project.
3. *The project must contain in its design all reasonably available and feasible air quality control measures*. The proposed project incorporates various policy and rule-required implementation measures that will reduce related emissions.

The CCAA and AQAP identify transportation control measures as methods to further reduce emissions from mobile sources. Strategies identified to reduce vehicular emissions such as reductions in vehicle trips, vehicle use, vehicle miles traveled, vehicle idling, and traffic congestion, in order to reduce vehicular emissions, can be implemented as control measures under the CCAA as well. Additional measures may also be implemented through the building process such as providing electrical outlets on exterior walls of structures to encourage use of electrical landscape maintenance equipment or measures such as electrical outlets for electrical systems on diesel trucks to reduce or eliminate idling time.

As the growth represented by the proposed Project will be updated in the Kern County General Plan and incorporated into the AQAP, conclusions may be drawn from the following criteria:

1. That, by definition, the proposed emissions from the Project are below the SJVAPCD's established emissions impact thresholds;
2. That the primary source of emissions from the Project will be motor vehicles that are licensed through the State of California and whose emissions are already incorporated into CARB's San Joaquin Valley Emissions Inventory.

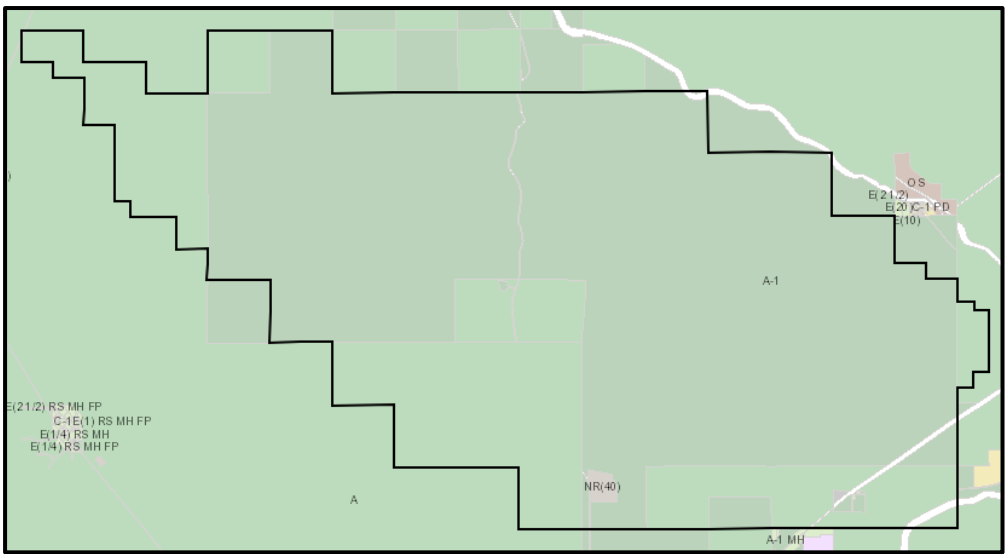
Based on these factors, the Project appears to be *consistent with the AQAP*.

6.2 Consistency with the Kern County Council of Government's Regional Conformity Analysis

The Kern Council of Governments (Kern COG) Regional Conformity Analysis (Kern COG 2018) Determination demonstrates that the regional transportation expenditure plans (Destination 2042 Regional Transportation Plan and Federal Transportation Improvement Program) in the Kern County portion of the San Joaquin Valley air quality attainment areas would not hinder the efforts set out in CARB's SIP for each area's non-attainment pollutants (CO, O_3, and PM_{10}). The analysis uses an adopted regional growth forecast, governed by both the adopted Kern COG Policy and Procedure Manual and a Memorandum of Understanding between the County of Kern and Kern COG (representing itself and outlying municipal member agencies).

The Kern COG Regional Conformity Analysis considers General Plan Amendments (GPA) and zone changes that were enacted at the time of the analysis as projected growth within the area based on land use designations incorporated within the Kern County General Plan. Land use designations that are altered based on subsequent GPAs that were not included in the Regional Conformity Analysis were not incorporated into the Kern COG analysis. Consequently, if a proposed project is not included in the regional growth forecast using the latest planning assumptions, it may not be said to conform to the regional growth forecast. Under the current Kern County Zoning, the Project site is designated as "A: Agricultural and A-1: Limited Agriculture" (see **Figure 6-1**).

Figure 6-1. Kern County Zoning



Item 2 under Section 3 – Model Maintenance Procedure, of the Kern COG Regional Transportation Modeling Policy and Procedure Manual states "*Land Use Data – General Plan land capacity data or "Build -out capacity" is used to distribute the forecasted County totals, and may be updated as new information becomes available, and is revised in regular consultation with local planning departments.*"

Under current policies, only after a General Plan Amendment (GPA) is approved, can housing and employment assumptions be updated to reflect the capacity changes. The proposed development does require a zone change , however, the zone change is consistent with the adopted General Plan Land Use, therefore, the existing growth forecast will not be modified to reflect these changes. In order to determine whether the forecasted growth for the Project area is sufficient to account for the projected increases in employment, an analysis based on Kern COG regional forecast was conducted.

The adopted growth forecast for the project site is distributed to Traffic Analysis Zones (TAZ) (see **Figure 6-2**). In order to evaluate the impacts to the proposed Project area, a one-mile radius analysis was conducted that included TAZ 412, 625, 1666, and 1667. This places the Project site at the center of the analysis area and provides a conservative evaluation of the TAZ data. Kern COG has predicted growth in population (10%), growth in housing (10%) and an increase in employment (10%) between 2020 and 2030. Employment forecast for the TAZ analysis area appears to be sufficient to account for 100% of the planned employment growth attributed to the proposed Project. In order to be considered "consistent" and, therefore, in conformance with the AQAP, these increases would need to occur over the same time as the adopted growth forecast. From 2020 through 2030, 142 new jobs are forecast to be added to the analysis area.

Figure 6-2. TAZ Analysis Map

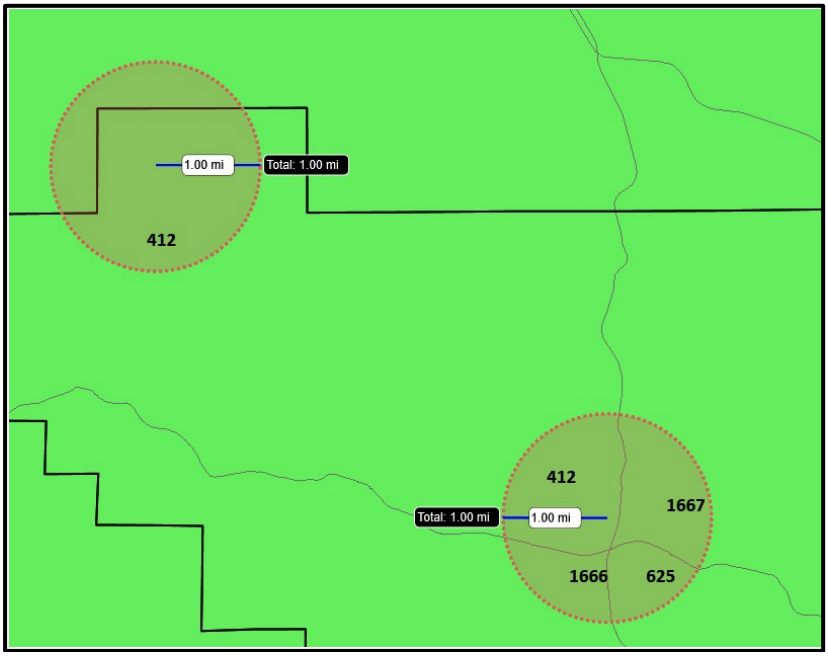


Table 6-1 provides the projected growth rates for the TAZ analysis area.

Table 6-1. TAZ Analysis Area Projected Growth Analysis[2]

Years	2017	2020	2030
Population	1,069	1,096	1,203
Households	349	360	397
Employment	1,338	1,379	1,521

Table 6-2 provides the percent increase/decrease for the analysis area population, households, and employment.

Table 6-2. Percent Increase/Decrease on TAZ Analysis Area

Years	Percent Increase / Decrease		
	Population	Households	Employment
2017*	0	0	0
2020	3%	3%	3%
2030	10%	10%	10%
*Baseline year of 2017 was valued at "0" to measure net percent increase/decrease.			

[2] Kern Council of Governments Regional Conformity Analysis Data, 2018

7. MITIGATION AND OTHER RECOMMENDED MEASURES

To ensure that Project is in compliance with all applicable SJVAPCD rules and regulations and emissions are further reduced, the applicant should implement and comply with a number of measures that are either recommended as a "good operating practice" for environmental stewardship or they are required by regulation. Some of the listed measures are regulatory requirements or construction requirements that would result in further emission reductions through their inclusion in Project construction and long-term design. The following measures either have been applied to the Project through the CalEEMod model and would be incorporated into the Project by design or would be implemented in conjunction with SJVAPCD rules as conditions of approval.

7.1 SJVAPCD Required PM_{10} Reduction Measures

As the Project would be completed in compliance with SJVAPCD Regulation VIII, dust control measures would be taken to ensure compliance specifically during grading and construction phases. The required Regulation VIII measures are as follows:

- Water previously exposed surfaces (soil) whenever visible dust is capable of drifting from the site or approaches 20% opacity.
- Water all unpaved haul roads a minimum of three-times/day or whenever visible dust from such roads is capable of drifting from the site or approaches 20% opacity.
- Reduce speed on unpaved roads to less than 15 miles per hour.
- Install and maintain a track out control device that meets the specifications of SJVAPCD Rule 8041 if the site exceeds 150 vehicle trips per day or more than 20 vehicle trips per day by vehicles with three or more axles.
- Stabilize all disturbed areas, including storage piles, which are not being actively utilized for production purposes using water, chemical stabilizers or by covering with a tarp or other suitable cover.
- Control fugitive dust emissions during land clearing, grubbing, scraping, excavation, leveling, grading, or cut and fill operations with application of water or by presoaking.
- When transporting materials offsite, maintain a freeboard limit of at least 6 inches and cover or effectively wet to limit visible dust emissions.
- Limit and remove the accumulation of mud and/or dirt from adjacent public roadways at the end of each workday. (Use of dry rotary brushes is prohibited except when preceded or accompanied by sufficient wetting to limit visible dust emissions and use of blowers is expressly forbidden).
- Stabilize the surface of storage piles following the addition or removal of materials using water or chemical stabilizer/suppressants.
- Remove visible track-out from the site at the end of each workday.
- Cease grading or other activities that cause excessive (greater than 20% opacity) dust formation during periods of high winds (greater than 20 mph over a one-hour period).

7.2 Recommended Measures to Reduce Equipment Exhaust

In addition, the GAMAQI guidance document lists the following measures as approved and recommended for construction activities. These measures are recommended:

- Maintain all construction equipment as recommended by manufacturer manuals.
- Shut down equipment when not in use for extended periods.
- Use electric equipment for construction whenever possible in lieu of diesel or gasoline powered equipment.

- Curtail use of high-emitting construction equipment during periods of high or excessive ambient pollutant concentrations.
- All construction vehicles shall be equipped with proper emissions control equipment and kept in good and proper running order to substantially reduce NOx emissions.
- On-Road and Off-Road diesel equipment shall use diesel particulate filters if permitted under manufacturer's guidelines.
- On-Road and Off-Road diesel equipment shall use cooled exhaust gas recirculation (EGR) if permitted under manufacturer's guidelines.
- All construction workers shall be encouraged to shuttle (car-pool) to retail establishments or to remain on-site during lunch breaks.
- All construction activities within the project area shall be discontinued during the first stage smog alerts.
- Construction and grading activities shall not be allowed during first stage O_3 alerts. First stage O_3 alerts are declared when the O_3 level exceeds 0.20 ppm (1-hour average).

7.3 Other Measures to Reduce Project Impacts

The following measures are recommended to further reduce the potential for long-term emissions from the Project. These measures are required as a matter of regulatory compliance:

- The Project design shall comply with applicable standards set forth in Title 24 of the Uniform Building Code to minimize total consumption of energy.
- Applicants shall be required to comply with applicable mitigation measures in the AQAP, SJVAPCD Rules, Traffic Control Measures, Regulation VIII and Indirect Source Rules for the SJVAPCD.
- The developer shall comply with the provisions of SJVAPCD Rule 4601 - Architectural Coatings, during the construction of all buildings and facilities. Application of architectural coatings shall be completed in a manner that poses the least emissions impacts whenever such application is deemed proficient.
- The applicant shall comply with the provisions of SJVAPCD Rule 4641 during the construction and pavement of all roads and parking areas within the project area. Specifically, the applicant shall not allow the use of:
  - Rapid cure cutback asphalt;
  - Medium cure cutback asphalt;
  - Slow cure cutback asphalt (as specified in SJVAPCD Rule 4641, Section 5.1.3); or Emulsified asphalt (as specified in SJVAPCD Rule 4641, Section 5.1.4).
  - The developer shall comply with applicable provisions of SJVAPCD Rule 9510 (Indirect Source Review).

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APPENDIX A. EXISTING AIR QUALITY MONITORING DATA

Top 4 Summary: Highest 4 Daily Maximum 8-Hour Ozone Averages

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	8-Hr Average	Date	8-Hr Average	Date	8-Hr Average
National 2015 Std (0.070 ppm):						
First High:	Jul 25	0.088	Aug 21	0.098	Aug 28	0.080
Second High:	Jun 4	0.085	Aug 22	0.094	Jun 17	0.079
Third High:	Jun 5	0.081	Aug 19	0.085	Aug 29	0.079
Fourth High:	Jun 18	0.081	Sep 5	0.083	Jun 18	0.077
California Std (0.070 ppm):						
First High:	Jul 25	0.088	Aug 21	0.098	Aug 28	0.081
Second High:	Jun 4	0.086	Aug 22	0.094	Aug 29	0.080
Third High:	Jun 5	0.082	Aug 19	0.086	Jun 17	0.079
Fourth High:	Jun 18	0.082	Sep 5	0.083	Jun 18	0.077
National 2015 Std (0.070 ppm):						
# Days Above the Standard:		24		25		11
Nat'l Standard Design Value:		0.087		0.085		0.080
National Year Coverage:		99		99		100
California Std (0.070 ppm):						
# Days Above the Standard:		28		25		11
California Designation Value:		0.096		0.094		0.088
Expected Peak Day Concentration:		0.096		0.095		0.090
California Year Coverage:		97		97		99

Notes:

Eight-hour ozone averages and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All averages expressed in parts per million.

An exceedance of a standard is not necessarily related to a violation of the standard.

State and national statistics may differ for the following reasons:

National 8-hour averages are truncated to three decimal places; State 8-hour averages are rounded to three decimal places.

State criteria for ensuring that data are sufficiently complete for calculating 8-hour averages are more stringent than the national criteria.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard exclude those 8-hour averages that have first hours between midnight and 6:00 am, Pacific Standard Time.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard include only those 8-hour averages from days that have sufficient data for the day to be considered valid.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum 8-Hour Ozone Averages

at Oildale-3311 Manor Street

iADAM

	2019		2020		2021	
	Date	8-Hr Average	Date	8-Hr Average	Date	8-Hr Average
National 2015 Std (0.070 ppm):						
First High:	Jul 25	0.086	Aug 21	0.096	Aug 29	0.095
Second High:	Aug 14	0.079	Aug 22	0.096	Aug 28	0.094
Third High:	Aug 6	0.077	Sep 5	0.085	Jul 27	0.087
Fourth High:	Aug 15	0.076	Aug 19	0.083	Aug 4	0.086
California Std (0.070 ppm):						
First High:	Jul 25	0.087	Aug 21	0.096	Aug 29	0.095
Second High:	Aug 14	0.080	Aug 22	0.096	Aug 28	0.094
Third High:	Aug 6	0.077	Sep 5	0.086	Jul 27	0.088
Fourth High:	Aug 15	0.077	Aug 19	0.083	Aug 4	0.086
National 2015 Std (0.070 ppm):						
# Days Above the Standard:		16		23		43
Nat'l Standard Design Value:		0.084		0.083		0.081
National Year Coverage:		99		99		99
California Std (0.070 ppm):						
# Days Above the Standard:		20		24		46
California Designation Value:		0.093		0.093		0.088
Expected Peak Day Concentration:		0.093		0.093		0.092
California Year Coverage:		98		99		97

Notes:

- Eight-hour ozone averages and related statistics are available at Oildale-3311 Manor Street between 1983 and 2021. Some years in this range may not be represented.
- All averages expressed in parts per million.
- An exceedance of a standard is not necessarily related to a violation of the standard.
- State and national statistics may differ for the following reasons:
  - National 8-hour averages are truncated to three decimal places; State 8-hour averages are rounded to three decimal places.
  - State criteria for ensuring that data are sufficiently complete for calculating 8-hour averages are more stringent than the national criteria.
- Daily maximum 8-hour averages associated with the National 0.070 ppm standard exclude those 8-hour averages that have first hours between midnight and 6:00 am, Pacific Standard Time.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard include only those 8-hour averages from days that have sufficient data for the day to be considered valid.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum 8-Hour Ozone Averages

at Maricopa-Stanislaus Street

	2019		2020		2021	
	Date	8-Hr Average	Date	8-Hr Average	Date	8-Hr Average
National 2015 Std (0.070 ppm):						
First High:	Nov 9	0.080	Aug 21	0.095	Jun 18	0.077
Second High:	Sep 14	0.077	Aug 22	0.095	Oct 2	0.076
Third High:	Oct 16	0.077	Aug 19	0.091	Oct 3	0.075
Fourth High:	Nov 7	0.077	Sep 6	0.091	Aug 29	0.073
California Std (0.070 ppm):						
First High:	Nov 9	0.080	Aug 21	0.096	Jun 18	0.077
Second High:	Sep 14	0.078	Aug 22	0.096	Oct 2	0.076
Third High:	Oct 16	0.078	Sep 6	0.092	Oct 3	0.076
Fourth High:	Nov 7	0.078	Aug 19	0.091	Aug 29	0.074
National 2015 Std (0.070 ppm):						
# Days Above the Standard:		41		38		10
Nat'l Standard Design Value:		0.083		0.085		0.080
National Year Coverage:		99		94		96
California Std (0.070 ppm):						
# Days Above the Standard:		45		40		11
California Designation Value:		0.085		0.093		0.091
Expected Peak Day Concentration:		0.089		0.094		0.091
California Year Coverage:		98		92		94

Notes:

Eight-hour ozone averages and related statistics are available at Maricopa-Stanislaus Street between 1987 and 2021. Some years in this range may not be represented.

All averages expressed in parts per million.

An exceedance of a standard is not necessarily related to a violation of the standard.

State and national statistics may differ for the following reasons:

National 8-hour averages are truncated to three decimal places; State 8-hour averages are rounded to three decimal places.

State criteria for ensuring that data are sufficiently complete for calculating 8-hour averages are more stringent than the national criteria.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard exclude those 8-hour averages that have first hours between midnight and 6:00 am, Pacific Standard Time.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard include only those 8-hour averages from days that have sufficient data for the day to be considered valid.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Ozone Measurements

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
First High:	Jul 25	0.097	Aug 21	0.110	Jun 29	0.090
Second High:	Jun 4	0.095	Aug 19	0.107	Aug 28	0.087
Third High:	Jun 11	0.092	Aug 22	0.107	Jul 27	0.083
Fourth High:	Jun 18	0.092	Aug 24	0.091	Sep 7	0.083
California:						
# Days Above the Standard:		2		3		0
California Designation Value:		0.10		0.10		0.10
Expected Peak Day Concentration:		0.102		0.101		0.095
National:						
# Days Above the Standard:		*0*		*0*		*0*
3-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
1-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
Nat'l Standard Design Value:		*0.104*		*0.107*		*0.097*
Year Coverage:		99		99		99

Notes:

Hourly ozone measurements and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per million.

The national 1-hour ozone standard was revoked in June 2005. Statistics related to the national 1-hour ozone standard are shown in or .

An exceedance of a standard is not necessarily related to a violation of the standard.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Ozone Measurements

at Oildale-3311 Manor Street

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
First High:	Jul 25	0.099	Aug 21	0.109	Aug 28	0.107
Second High:	Aug 6	0.091	Aug 22	0.107	Aug 29	0.102
Third High:	Aug 14	0.089	Aug 19	0.101	Aug 3	0.099
Fourth High:	Aug 31	0.086	Sep 5	0.093	Sep 9	0.099
California:						
# Days Above the Standard:		1		3		6
California Designation Value:		0.10		0.10		0.10
Expected Peak Day Concentration:		0.098		0.099		0.099
National:						
# Days Above the Standard:		*0*		*0*		*0*
3-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
1-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
Nat'l Standard Design Value:		*0.100*		*0.102*		*0.102*
Year Coverage:		99		99		98

Notes:

Hourly ozone measurements and related statistics are available at Oildale-3311 Manor Street between 1983 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per million.

The national 1-hour ozone standard was revoked in June 2005. Statistics related to the national 1-hour ozone standard are shown in or .

An exceedance of a standard is not necessarily related to a violation of the standard.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Ozone Measurements

at Maricopa-Stanislaus Street

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
First High:	Nov 7	0.086	Aug 19	0.122	Jun 18	0.083
Second High:	Nov 9	0.085	Aug 21	0.112	Oct 1	0.082
Third High:	Sep 14	0.084	Aug 22	0.103	Aug 7	0.080
Fourth High:	Oct 16	0.084	Sep 15	0.098	Oct 30	0.080
California:						
# Days Above the Standard:		0		7		0
California Designation Value:		0.09		0.10		0.10
Expected Peak Day Concentration:		0.092		0.099		0.096
National:						
# Days Above the Standard:		*0*		*0*		*0*
3-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
1-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
Nat'l Standard Design Value:		*0.096*		*0.098*		*0.098*
Year Coverage:		98		91		96

Notes:

Hourly ozone measurements and related statistics are available at Maricopa-Stanislaus Street between 1987 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per million.

The national 1-hour ozone standard was revoked in June 2005. Statistics related to the national 1-hour ozone standard are shown in or .

An exceedance of a standard is not necessarily related to a violation of the standard.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM10 Averages

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 5	116.3	Nov 5	193.8	Oct 11	437.5
Second High:	Nov 5	94.9	Oct 2	131.1	Oct 4	185.7
Third High:	Nov 11	75.9	Sep 12	118.6	Dec 13	164.7
Fourth High:	Oct 31	74.5	Aug 31	100.8	Aug 20	144.3
California:						
First High:	Jan 5	125.9	Nov 5	196.8	Oct 11	439.3
Second High:	Nov 5	96.5	Oct 2	128.2	Oct 4	183.1
Third High:	Nov 11	77.3	Sep 12	117.1	Dec 13	168.0
Fourth High:	Oct 31	76.4	Sep 18	97.7	Aug 20	140.8
National:						
Estimated # Days > 24-Hr Std:		0.0		*		*
Measured # Days > 24-Hr Std:		0		1		3
3-Yr Avg Est # Days > 24-Hr Std:		0.0		*		*
Annual Average:		*38.8*		*46.0*		*49.0*
3-Year Average:		*41*		*42*		*
California:						
Estimated # Days > 24-Hr Std:		108.1		*		*
Measured # Days > 24-Hr Std:		17		18		124
Annual Average:		39.0		*		*
3-Year Maximum Annual Average:		43		39		*
Year Coverage:		94		89		0

Notes:

Daily PM10 averages and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

The national annual average PM10 standard was revoked in December 2006 and is no longer in effect. Statistics related to the revoked standard are shown in *italics* or *italics* .

An exceedance of a standard is not necessarily related to a violation of the standard.

All values listed above represent midnight-to-midnight 24-hour averages and may be related to an exceptional event.

State and national statistics may differ for the following reasons:

- State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.
- State statistics for 1998 and later are based on local conditions (except for sites in the South Coast Air Basin, where State statistics for 2002 and later are based on local conditions). National statistics are based on standard conditions.
- State criteria for ensuring that data are sufficiently complete for calculating valid annual averages are more stringent than the national criteria.

Measurements are usually collected every six days. Measured days counts the days that a measurement was greater than the level of the standard; Estimated days mathematically estimates how many days concentrations would have been greater than the level of the standard had each day been monitored.

3-Year statistics represent the listed year and the 2 years before the listed year.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM10 Averages

iADAM

at Oildale-3311 Manor Street

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Oct 30	389.3	Sep 8	517.2	Oct 11	421.4
Second High:	Oct 27	382.7	Nov 6	277.8	Oct 4	164.3
Third High:	Nov 25	339.6	Aug 22	230.4	Oct 25	150.2
Fourth High:	Oct 28	233.7	Sep 14	225.3	Oct 1	137.6
California:						
First High:	Oct 30	392.1	Nov 6	277.3	Oct 11	423.0
Second High:	Oct 27	384.2	Aug 22	221.0	Oct 4	161.1
Third High:	Nov 25	344.1	Sep 15	219.6	Oct 25	149.3
Fourth High:	Oct 28	238.0	Sep 14	219.3	Oct 1	135.2
National:						
Estimated # Days > 24-Hr Std:		8.1		17.4		2.2
Measured # Days > 24-Hr Std:		8		15		2
3-Yr Avg Est # Days > 24-Hr Std:		*		10.0		9.0
Annual Average:		*46.6*		*57.3*		*50.0*
3-Year Average:		*52*		*53*		*51*
California:						
Estimated # Days > 24-Hr Std:		*		*		135.6
Measured # Days > 24-Hr Std:		118		123		129
Annual Average:		*		*		49.4
3-Year Maximum Annual Average:		*		*		49
Year Coverage:		0		0		0

Notes:

Daily PM10 averages and related statistics are available at Oildale-3311 Manor Street between 1988 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

The national annual average PM10 standard was revoked in December 2006 and is no longer in effect. Statistics related to the revoked standard are shown in *italics* or *italics* .

An exceedance of a standard is not necessarily related to a violation of the standard.

All values listed above represent midnight-to-midnight 24-hour averages and may be related to an exceptional event.

State and national statistics may differ for the following reasons:

- State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.
- State statistics for 1998 and later are based on local conditions (except for sites in the South Coast Air Basin, where State statistics for 2002 and later are based on local conditions). National statistics are based on standard conditions.
- State criteria for ensuring that data are sufficiently complete for calculating valid annual averages are more stringent than the national criteria.

Measurements are usually collected every six days. Measured days counts the days that a measurement was greater than the level of the standard; Estimated days mathematically estimates how many days concentrations would have been greater than the level of the standard had each day been monitored.

3-Year statistics represent the listed year and the 2 years before the listed year.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM2.5 Averages

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 27	59.1	Aug 22	150.7	Oct 30	72.3
Second High:	Jan 29	57.6	Jul 4	141.9	Oct 4	69.4
Third High:	Jan 28	53.1	Aug 21	130.2	Oct 29	66.4
Fourth High:	Jan 26	52.3	Aug 20	82.7	Nov 19	59.5
California:						
First High:	Jan 27	59.1	Aug 22	159.7	Oct 30	72.3
Second High:	Jan 29	57.6	Jul 4	143.9	Oct 4	70.5
Third High:	Jan 28	53.1	Aug 21	136.8	Oct 29	66.4
Fourth High:	Jan 26	52.3	Aug 23	88.9	Nov 19	59.5
National:						
'06 Estimated # Days > 24-Hr Std:		12.3		46.4		43.2
'06 Measured # Days > 24-Hr Std:		12		44		40
2006 24-Hr Std Design Value:		61		64		60
2006 24-Hr Std 98th Percentile:		43.4		79.2		56.9
2006 Annual Std Design Value:		15.2		16.4		16.1
2012 Annual Std Design Value:		15.2		16.4		16.1
'06 Annual Average:		11.8		19.7		16.5
California:						
Annual Std Designation Value:		16		20		20
Annual Average:		11.5		19.7		16.6
Year Coverage:		98		97		95

Notes:

Daily PM2.5 averages and related statistics are available at Bakersfield-5558 California Avenue between 1999 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

An exceedance of a standard is not necessarily related to a violation of the standard.

State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM2.5 Averages

at Bakersfield-Golden State Highway

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 27	66.1	Aug 22	150.2	Oct 4	78.5
Second High:	Jan 30	47.4	Sep 15	81.5	Dec 4	63.3
Third High:	Nov 8	44.3	Oct 3	76.9	Nov 19	59.1
Fourth High:	Nov 17	36.7	Aug 19	50.2	Nov 20	59.1
California:						
First High:	Jan 27	66.1	Aug 22	150.2	Oct 4	78.5
Second High:	Jan 30	47.4	Sep 15	81.5	Dec 4	63.3
Third High:	Nov 8	44.3	Oct 3	76.9	Nov 19	59.1
Fourth High:	Nov 17	36.7	Aug 19	50.2	Nov 20	59.1
National:						
'06 Estimated # Days > 24-Hr Std:		12.2		33.9		45.6
'06 Measured # Days > 24-Hr Std:		4		10		43
2006 24-Hr Std Design Value:		59		61		59
2006 24-Hr Std 98th Percentile:		44.3		76.9		54.3
2006 Annual Std Design Value:		15.5		16.6		16.6
2012 Annual Std Design Value:		15.5		16.6		16.6
'06 Annual Average:		12.3		19.4		17.8
California:						
Annual Std Designation Value:		18		18		*
Annual Average:		12.4		*		*
Year Coverage:		99		91		91

Notes:

Daily PM2.5 averages and related statistics are available at Bakersfield-Golden State Highway between 1999 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

An exceedance of a standard is not necessarily related to a violation of the standard.

State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM2.5 Averages

at Bakersfield-410 E Planz Road

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 27	83.7	Aug 22	158.6	Oct 4	70.5
Second High:	Oct 30	49.3	Sep 15	82.4	Jan 16	55.8
Third High:	Nov 8	46.7	Oct 3	81.4	Jan 19	54.8
Fourth High:	Nov 17	34.5	Aug 19	57.1	Jan 31	52.7
California:						
First High:	Jan 27	83.7	Aug 22	158.6	Oct 4	70.5
Second High:	Oct 30	49.3	Sep 15	82.4	Jan 16	55.8
Third High:	Nov 8	46.7	Oct 3	81.4	Jan 19	54.8
Fourth High:	Nov 17	34.5	Aug 19	57.1	Jan 31	52.7
National:						
'06 Estimated # Days > 24-Hr Std:		10.0		51.3		53.0
'06 Measured # Days > 24-Hr Std:		3		17		17
2006 24-Hr Std Design Value:		59		63		61
2006 24-Hr Std 98th Percentile:		46.7		81.4		54.8
2006 Annual Std Design Value:		16.9		17.6		17.8
2012 Annual Std Design Value:		16.9		17.6		17.8
'06 Annual Average:		13.0		20.3		20.0
California:						
Annual Std Designation Value:		13		13		13
Annual Average:		13.0		*		*
Year Coverage:		92		91		92

Notes:

Daily PM2.5 averages and related statistics are available at Bakersfield-410 E Planz Road between 2000 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

An exceedance of a standard is not necessarily related to a violation of the standard.

State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Nitrogen Dioxide Measurements

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
National:						
First High:	Nov 8	67.1	Nov 30	50.4	Oct 4	57.2
Second High:	Nov 12	63.8	Nov 5	50.3	Dec 1	56.2
Third High:	Nov 13	62.6	Dec 10	49.9	Dec 2	54.8
Fourth High:	Nov 4	60.4	Dec 2	47.8	Nov 30	54.6
California:						
First High:	Nov 8	67	Nov 5	50	Oct 4	57
Second High:	Nov 12	63	Nov 30	50	Dec 1	56
Third High:	Nov 13	62	Dec 10	49	Nov 30	54
Fourth High:	Nov 4	60	Dec 2	47	Dec 2	54
National:						
1-Hour Standard Design Value:		54		50		49
1-Hour Standard 98th Percentile:		53.9		44.9		48.4
# Days Above the Standard:		0		0		0
Annual Standard Design Value:		12		11		11
California:						
1-Hour Std Designation Value:		70		60		60
Expected Peak Day Concentration:		66		61		60
# Days Above the Standard:		0		0		0
Annual Std Designation Value:		12		12		11
Annual Average:		11		11		10
Year Coverage:		99		99		98

Notes:

Hourly nitrogen dioxide measurements and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per billion.
An exceedance of a standard is not necessarily related to a violation of the standard.
Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.
* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Nitrogen Dioxide Measurements

at Shafter-Walker Street

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
National:						
First High:	Nov 8	49.3	Dec 2	40.9	Dec 1	47.8
Second High:	Nov 1	45.8	Oct 30	39.7	Nov 30	46.0
Third High:	Nov 18	43.3	Nov 16	35.3	Dec 2	37.5
Fourth High:	Nov 9	40.8	Nov 28	34.2	Sep 30	36.7
California:						
First High:	Nov 8	49	Dec 2	40	Dec 1	47
Second High:	Nov 1	45	Oct 30	39	Nov 30	46
Third High:	Nov 18	43	Nov 16	35	Dec 2	37
Fourth High:	Nov 9	40	Nov 2	34	Sep 30	36
National:						
1-Hour Standard Design Value:		38		36		34
1-Hour Standard 98th Percentile:		36.9		32.5		32.9
# Days Above the Standard:		0		0		0
Annual Standard Design Value:		9		9		8
California:						
1-Hour Std Designation Value:		50		40		40
Expected Peak Day Concentration:		46		44		42
# Days Above the Standard:		0		0		0
Annual Std Designation Value:		9		9		8
Annual Average:		8		8		8
Year Coverage:		98		99		87

Notes:

Hourly nitrogen dioxide measurements and related statistics are available at Shafter-Walker Street between 1989 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per billion.
An exceedance of a standard is not necessarily related to a violation of the standard.
Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.
* means there was insufficient data available to determine the value.

Welcome to California

Air Resources Board

View a Different Site
View a Different Substance

Annual Toxics Summary

Bakersfield-5558 California Avenue

Lead

nanograms per cubic meter

iADAM FAQs

Read About Estimated Risk

Year	Months Present	Minimum	Median	Mean	90th Percentile	Maximum	Standard Deviation	Number of Observations	Detection Limit	Estimated Risk
2022	----------	0.65	3.6	*	5.4	6.1	1.80	15	1.3	*
2021	----------	0.65	2.8	*	5.8	9.9	2.28	24	1.3	*
2020	----------	1.5	*	*	*	5.7	1.38	9	1.3	*
2019	----------	0.65	3.5	3.70	6.3	8.5	1.91	34	1.3	0.1
2018	----------	0.65	3.6	3.92	7.0	11.7	2.38	37	1.3	0.1
2017	----------	0.65	3.5	*	7.5	12.6	2.60	29	1.3	*
2016	----------	0.65	4.3	*	6.9	19.8	3.57	33	1.3	*
2015	----------	0.65	3.2	3.34	7.6	9.5	2.50	33	1.3	0.1
2014	----------	0.85	3.6	*	8.8	14	3.78	16	1.7	*
2013	----------	0.5	2.9	*	5.3	6.7	1.71	21	1.0	*
2012	----------	1.7	3.4	4.02	8.2	14	2.74	32	1.5	0.1
2011	----------	0.75	4.0	*	9.1	11	2.90	20	1.5	*
2010	----------	0.75	2.5	*	5.7	8.2	2.07	18	1.5	*
2009	----------	1.5	4.5	5.27	11.2	14	3.22	29	1.5	0.2
2008	----------	*	*	*	*	*	*	0	*	*
2007	----------	0.75	7.1	*	11.7	13	3.23	24	1.5	*
2006	----------	*	*	*	*	*	*	0	*	*
2005	----------	*	*	*	*	*	*	0	*	*
2004	----------	*	*	*	*	*	*	0	*	*
2003	----------	4.0	*	*	*	7.0	1.64	5	3.0	*
2002	----------	1.5	7.0	6.78	10	17	3.34	36	3.0	0.2
2001	----------	2	5.0	5.83	9.2	26	4.41	39	4.0	0.2
2000	----------	2	5.0	5.92	14.1	22	4.76	40	4.0	0.2
1999	----------	2	5.0	5.70	11.2	25	4.55	39	4.0	0.2
1998	----------	2	7.0	9.43	14	78	11.8	42	4.0	0.3
1997	----------	2	7.0	7.92	14	20	4.40	34	4.0	0.3
1996	----------	2	7.0	7.69	14.5	35	6.10	36	4.0	0.3
1995	----------	2	8.0	8.68	15.1	21	5.14	30	4.0	0.3
1994	----------	2	10	*	16	39	7.11	25	4.0	*
1993	----------	*	*	*	*	*	*	0	*	*
1992	----------	*	*	*	*	*	*	0	*	*
1991	----------	*	*	*	*	*	*	0	*	*
1990	----------	*	*	*	*	*	*	0	*	*
1989	----------	*	*	*	*	*	*	0	*	*

Graph It!

Toxics Statistics Home

Notes: Values below the Limit of Detection (LoD) assumed to be ½ LoD.
Means and risks shown only for years with data in all 12 months.
"*" means there was insufficient or no data available to determine the value.

Data Descriptions Page

APPENDIX B. PROJECT EMISSION CALCULATIONS

Emission Statement - Calendar Year 2022 Emissions

Date 1/20/2023
Time 2:01:00 PM

UTM
Zone : 11
East : 274.98792
North : 3906.1353

Please return to:
San Joaquin Valley Unified APCD
1990 East Gettysburg Avenue
Fresno, CA 93726

Facility ID # : S-9168
TAD # : 15-9168
SIC : 1321
Facility Name : ELK HILLS POWER LLC
Toxic ID # :
Update Summary: Not Required
CTR: Required

Device ID #	Process Number	Equipment Type	Yearly Process Rate	Units / Source Classification Code	NOX lb / Unit	VOC Lb / Unit	SOX lb / Unit	CO lb / Unit	PM10 Lb / Unit	NH3* Lb / Unit	Please Note:
1	1	Inlet Gas System w/Electric Motor	0.37	PROCESS UNIT	0.00	745.85	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.37**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
2	1	Mercury Removal System w/Inlet Gas Filter Separator	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
3	1	Inlet Gas Treating w/Inlet Gas Amine Con	0.04	PROCESS UNIT	0.00	70.53	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.04**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
4	1	Inlet Gas Dehydration	0.28	PROCESS UNIT	0.00	557.19	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.28**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
5	1	NGL Recovery w/ Expander/Booster compressor	0.10	PROCESS UNIT	0.00	205.95	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.10**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
6	1	Residue Gas Compression	0.00	PROCESS UNIT	0.00	2.47	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
7	1	Deethanizer W/Reflux Condenser	0.14	PROCESS UNIT	0.00	273.34	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.14**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
8	1	Depropanizer W/Reflux Condensers & Reflux Drums	1.33	PROCESS UNIT	0.00	2663.81	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**1.33**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
9	1	Debutanizer W/Reflux Condensers & Reflux Drums	0.43	PROCESS UNIT	0.00	868.94	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.43**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
10	1	Refrigeration System	0.96	PROCESS UNIT	0.00	1921.97	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.96**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
11	1	Amine System w/Amine Regeneration Package	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
12	1	Glycol System W/Glycol Regeneration Package	0.04	PROCESS UNIT	0.00	71.06	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.04**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
13	1	NG Tank	0.37	PROCESS UNIT	0.00	748.70	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.37**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
14	1	Hot Oil Heater - 206.7 MMBtu/Hr	603.21	MILLION CUBIC FEET BURNED	1828.77	0.00	74.29	4971.96	4343.32	0.00	
				10200601	**0.91**	**0.00**	**0.04**	**2.49**	**2.17**	**0.00**	**Tons/Yr.**

14	2	Hot Oil Heater - 206.7 MMBtu/Hr	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				10200601	**0.91**	**0.00**	**0.04**	**2.49**	**2.17**	**0.00**	**Tons/Yr.**
15	1	Overhead Gas System with Fuel Gas Scrubber	0.00	PROCESS UNIT	0.00	6.19	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
16	1	Methanol Injection System	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
17	1	Amine Sump Tank	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
18	1	Glycol Sump Tank	19.00	1000 GALLONS THROUGHPUT	0.00	0.00	0.00	0.00	0.00	0.00	
				40301099	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
19	1	Amine Tank	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
20	1	Fresh Water Tank	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
21	1	Produced Water Tank	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
22	1	Slop Oil Tank	0.00	PROCESS UNIT	0.00	0.01	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
22	1	Oil Tank Vapor Recovery	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				31088801	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
23	1	700 bhp IC Engine - Testing - Diesel	1.04	1000 GALLONS BURNED	155.70	11.12	0.28	144.58	5.56	0.00	
				20200102	**0.08**	**0.01**	**0.00**	**0.08**	**0.00**	**0.00**	**Tons/Yr.**
23	2	700 bhp IC Engine - Emerg Use - Diesel	0.00	1000 GALLONS BURNED	0.00	0.00	0.00	0.00	0.00	0.00	
				20200102	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
24	1	Oxygen Removal System	0.00	PROCESS UNIT	0.00	0.00	0.00	0.00	0.00	0.00	
				30600105	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**Tons/Yr.**
Totals For the Facility (Tons/Year)					1.91	4.07	0.07	5.05	4.35	0.00	

Contact	Brandon Myers	*I certify that I am authorized by the owner or operator of the facility to submit the annual emissions report, and that to the best of my knowledge, all information submitted is true, complete, and correct. Additionally, if CTR required is indicated above, this information will be transmitted to the California Air Resources Board on my behalf pursuant to the Regulation for the Reporting of Criteria Air Pollutants and Toxic Air Contaminants (17 CCR Section 93400-93410)(CTR).*	
Company	ELK HILLS POWER LLC, 35R Gas Plant		
Address	4026 Skyline Road		
City,State,Zip	TUPMAN, CA 93276		
Telephone	(661) 765-1805		
Email Address	Brandon.Myers@crc.com		
Location of facility if different from above	35R GAS PLANT 4026 Skyline Road Tupman, CA 93276	**Responsible Official Signature and Date**	Brandon Myers / Plant Manager

Emission Statement - Calendar Year 2022 Emissions

Date 1/24/2023
Time 11:37:37 AM

UTM Zone: 11
UTM East : 275.273
UTM North : 3906.88

Please Sign and Return to:
San Joaquin Valley Unified APCD
1990 East Gettysburg Avenue
Fresno, CA 93726

Facility ID # : S - 3523
TAD # : 15 - 3523
SIC : 4911
Facility Name : ELK HILLS POWER, LLC
Toxic ID # :
Update Summary Not Required
CTR Required

CHECK BOX IF PROCESS RATES ARE CONFIDENTIAL : **N**

Device ID #	Process Number	Equipment Type	Yearly Process Rate	Units / Source Classification Code	NOX Lb/UNIT	VOC Lb/UNIT	SOX Lb/UNIT	CO Lb/UNIT	PM10 Lb/UNIT	NH3 Lb/UNIT	*Note:
1	1	TURBINE #1 WITH 250.5MMBTU/HR DUCT BURNER - NG	12048.8	MILLION CUBIC FEET	6.11	0.00	0.67	0.16	3.18	1.18	
				20100201	36.82	0.00	4.06	0.98	19.18	7.11	(Tons/Yr)
2	1	TURBINE #2 WITH 250.5MMBTU/HR DUCT BURNER - NG	12051.1	MILLION CUBIC FEET	6.19	0.00	0.67	0.21	3.65	1.98	
				20100201	37.32	0.00	4.01	1.25	22.02	11.94	(Tons/Yr)
3	1	COOLING TOWER	646.15	MILLION GAL THRGHPUT	0	0	0	0	5.12	0	
				38500101	0	0	0	0	1.65	0	(Tons/Yr)
6	1	240 BHP DIESEL EMERG IC ENGINE-**TESTING**	0.23	1000 GALLONS BURNED	172.45	43.91	0.20	118.76	9.80	0	
				20100102	0.02	0.01	0.00	0.01	0.00	0	(Tons/Yr)
6	2	240 BHP DIESEL EMERG IC ENGINE-**EMERGENCY**	0.00	1000 GALLONS BURNED	0	0	0	0	0	0	
				20100102	0	0	0	0	0	0	(Tons/Yr)
			Totals For the Facility (Tons/Year)		74.16	0.01	8.08	2.24	42.85	19.05	

Contact Sonnie Pineda
Company ELK HILLS POWER, LLC
Adress 900 Old River Road
City,State,Zip Bakersfield, CA 93311
Telephone (661) 765-1805
Email Address Sonnie.PIneda@crc.com
Location of facility if different from above ELK HILLS POWER, LLC
4026 SKYLINE RD
TUPMAN, CA 93276

Name and Title of Responsible Official

Brandon Myers / Plant Manager

I certify that I am authorized by the owner or operator of the facility to submit the annual emissions report, and that to the best of my knowledge, all information submitted is true, complete, and correct. Additionally, if CTR required is indicated above, this information will be transmitted to the California Air Resources Board on my behalf pursuant to the Regulation for the Reporting of Criteria Air Pollutants and Toxic Air Contaminants (17 CCR Section 93400-93410)(CTR).

Signature of Responsible Official and Date

Source: EMFAC2021 (v1.0.2) Emission Rates
Region Type: County
Region: Kern
Calendar Year: 2022, 2025
Season: Annual
Vehicle Classification: EMFAC202x Categories
Units: miles/day for CVMT and EVMT, trips/day for Trips, g/mile for RUNEX, PMBW and PMTW, g/trip for STREX, HOTSOAK and RUNLOSS, g/vehicle/day for IDLEX and DIURN. PHEV calculated based on total VMT.

Region	Calendar Year	Vehicle Category	Model Year	Speed	Fuel	ROG_RUNEX	NOx_RUNEX	CO_RUNEX	SOx_RUNEX	PM10_TOT	PM2.5_TOT	CO2_RUNEX	CH4_RUNEX	N2O_RUNEX	NH3_RUNEX
Kern	2022	LDA	Aggregate	Aggregate	Gasoline	0.011232822	0.052801641	0.88040352	0.002911525	0.015351771	0.005311	294.5094	0.002837	0.005333	0.03276
Kern	2022	LDT1	Aggregate	Aggregate	Gasoline	0.048796386	0.231562659	2.35104999	0.003478532	0.01789444	0.006845	351.8638	0.010666	0.015244	0.037979
Kern	2022	LDT2	Aggregate	Aggregate	Gasoline	0.014499028	0.094740554	1.04550945	0.003608728	0.016422219	0.005721	365.0335	0.003566	0.007327	0.03482
Kern	2025	LDA	Aggregate	Aggregate	Gasoline	0.007807997	0.03831521	0.728782641	0.002743576	0.015263194	0.005206	277.5209	0.002094	0.004429	0.035545
Kern	2025	LDT1	Aggregate	Aggregate	Gasoline	0.033334866	0.162266722	1.748074221	0.003294996	0.017395394	0.006387	333.2986	0.007449	0.011386	0.038056
Kern	2025	LDT2	Aggregate	Aggregate	Gasoline	0.01014159	0.064191016	0.838277345	0.0033495	0.016323567	0.005604	338.8119	0.002627	0.005701	0.037222

Region	Calendar Year	Vehicle Category	Model Year	Speed	Fuel	ROG_RUNEX	NOx_RUNEX	CO_RUNEX	SOx_RUNEX	PM10_TOT	PM2.5_TOT	CO2_RUNEX	CH4_RUNEX	N2O_RUNEX	NH3_RUNEX
KERN	2022	AVG	Aggregate	Aggregate	Gasoline	0.024842745	0.126368285	1.42565432	0.003332928	0.016556143	0.005959	337.1356	0.00569	0.009301	0.035186
KERN	2025	AVG	Aggregate	Aggregate	Gasoline	0.017094818	0.088257649	1.105044736	0.003129357	0.016327385	0.005733	316.5438	0.004057	0.007172	0.036941

Baseline Mobile Emissions

Trips/day:	26	(13 dedicated employees making 2 trips per day)
Trips/year:	9,490	(7 days a week)
Miles/trip:	40	(Estimated one-way trip distance from Project site to Bakersfield, CA)
Total Miles/year:	379,600	

Baseline Mobile Emissions	**ROG**	**NO_X**	**CO**	**SO_X**	**PM_{10}[1]**	**$PM_{2.5}$[1]**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
Em. Factor (grams/mile)[2]	0.025	0.126	1.426	0.003	0.017	0.006	337.136	0.006	0.009	
Lbs/Mile	5.48E-05	2.79E-04	3.14E-03	7.35E-06	3.65E-05	1.31E-05				
Lbs/Year	20.790	105.754	1,193.094	2.789	13.855	4.987				
lbs/day	0.057	0.290	3.269	0.008	0.038	0.014				
Tons/year	**0.010**	**0.053**	**0.597**	**0.001**	**0.007**	**0.002**				
MT/year							**127.977**	**0.002**	**0.004**	**129.117**

Post-Project Mobile Emissions

Trips/day:	46	(23 dedicated employees making 2 trips per day)
Trips/year:	16,790	(7 days a week)
Miles/trip:	40	(Estimated one-way trip distance from Project site to Bakersfield, CA)
Total Miles/year:	671,600	

Baseline Mobile Emissions	**ROG**	**NO_X**	**CO**	**SO_X**	**PM_{10}[1]**	**$PM_{2.5}$[1]**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
Em. Factor (grams/mile)[2]	0.017	0.088	1.105	0.003	0.016	0.006	316.544	0.004	0.007	
Lbs/Mile	3.77E-05	1.95E-04	2.44E-03	6.90E-06	3.60E-05	1.26E-05				
Lbs/Year	25.311	130.676	1,636.156	4.633	24.175	8.488				
lbs/day	0.069	0.358	4.483	0.013	0.066	0.023				
Tons/year	**0.013**	**0.065**	**0.818**	**0.002**	**0.012**	**0.004**				
MT/year							**212.591**	**0.003**	**0.005**	**214.141**

Increase Mobile Emissions

Baseline Mobile Emissions	**ROG**	**NO_X**	**CO**	**SO_X**	**PM_{10}[1]**	**$PM_{2.5}$[1]**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
Tons/year	**0.002**	**0.012**	**0.222**	**0.001**	**0.005**	**0.002**				
MT/year							**84.614**	**0.001**	**0.001**	**85.025**

FACILITY NAME
Project # , Permit Unit #

Fugitive Emissions Using Screening Emission Factors

California Implementation Guidelines for Estimating Mass Emissions
of Fugitive Hydrocarbon Leaks at Petroleum Facilities
Table IV-2c. Oil and Gas Production
Screening Value Ranges Emission Factors

Percentage of components with ≥ 10,000 ppmv leaks allowed?	0	%
Weight percentage of VOC in the total organic compounds in gas (neglect non-organics)?	100	%
Weight percentage of VOC in the total organic compounds in oil (neglect non-organics)?	100	%

Equipment Type	Service	Component Count	Total allowable leaking components	Screening Value EF - TOC < 10,000 ppmv (lb/day/source)	Screening Value EF - TOC ≥ 10,000 ppmv (lb/day/source)	VOC emissions (lb/day)
Valves	Gas/Light Liquid	560	0	1.852E-03	7.333E+00	1.04
	Light Crude Oil	0	0	1.005E-03	3.741E+00	0.00
	Heavy Crude Oil	0	0	7.408E-04	N/A*	0.00
Pump Seals	Gas/Light Liquid	4	0	5.270E-02	4.709E+00	0.21
	Light Crude Oil	0	0	1.402E-02	4.709E+00	0.00
	Heavy Crude Oil	0	0	N/A	N/A	N/A
Others	Gas/Light Liquid	60	0	7.778E-03	7.281E+00	0.47
	Light Crude Oil	0	0	6.931E-03	3.757E-01	0.00
	Heavy Crude Oil	0	0	3.016E-03	N/A*	0.00
Connectors	Gas/Light Liquid	560	0	6.349E-04	1.370E+00	0.36
	Light Crude Oil	0	0	5.291E-04	1.238E+00	0.00
	Heavy Crude Oil	0	0	4.233E-04	4.233E-04	0.00
Flanges	Gas/Light Liquid	560	0	1.482E-03	3.228E+00	0.83
	Light Crude Oil	0	0	1.270E-03	1.376E+01	0.00
	Heavy Crude Oil	0	0	1.217E-03	N/A*	0.00
Open-ended Lines	Gas/Light Liquid	0	0	1.270E-03	2.905E+00	0.00
	Light Crude Oil	0	0	9.524E-04	1.175E+00	0.00
	Heavy Crude Oil	0	0	7.937E-04	3.762E+00	0.00

* Emission factor not available. All components from equipment type and service will be assessed as < 10,000 ppmv

Total VOC Emissions = 2.9 lb/day

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Facilities Construction

Kern-San Joaquin County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
User Defined Industrial	7,385.67	User Defined Unit	7,385.67	0.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.7	**Precipitation Freq (Days)**	32
Climate Zone	3			**Operational Year**	2024
Utility Company	Pacific Gas and Electric Company				
CO2 Intensity (lb/MWhr)	203.98	**CH4 Intensity (lb/MWhr)**	0.033	**N2O Intensity (lb/MWhr)**	0.004

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use - Acrage of CCS Facility

Construction Phase - 2- year estiimate for facilities construction

Off-road Equipment - Estimated Off Road Equipment

Trips and VMT - According to traffic study

Consumer Products - x

Area Coating - x

Landscape Equipment - x

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblAreaCoating	ReapplicationRatePercent	10	0

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

tblConstDustMitigation	WaterUnpavedRoadVehicleSpeed	0	15
tblConstructionPhase	NumDays	155,000.00	523.00
tblConsumerProducts	ROG_EF	2.14E-05	0
tblConsumerProducts	ROG_EF_Degreaser	3.542E-07	0
tblConsumerProducts	ROG_EF_PesticidesFertilizers	5.152E-08	0
tblLandscapeEquipment	NumberSummerDays	180	0
tblLandUse	LotAcreage	0.00	7,385.67
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	1.00	5.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	1.00	3.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	7.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	4.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	1.00	8.00
tblOffRoadEquipment	UsageHours	7.00	3.80
tblOffRoadEquipment	UsageHours	7.00	0.50
tblOffRoadEquipment	UsageHours	8.00	3.80
tblOffRoadEquipment	UsageHours	7.00	3.80
tblOffRoadEquipment	UsageHours	8.00	3.80
tblTripsAndVMT	WorkerTripLength	10.80	40.00
tblTripsAndVMT	WorkerTripNumber	0.00	160.00

2.0 Emissions Summary

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2024	0.6087	3.9897	5.1378	0.0132	0.6250	0.1687	0.7937	0.1660	0.1582	0.3241	0.0000	1,157.0781	1,157.0781	0.1915	0.0103	1,164.9217
2025	0.5674	3.6468	4.9696	0.0129	0.6226	0.1477	0.7703	0.1653	0.1384	0.3037	0.0000	1,136.5261	1,136.5261	0.1892	9.4600e-003	1,144.0770
Maximum	**0.6087**	**3.9897**	**5.1378**	**0.0132**	**0.6250**	**0.1687**	**0.7937**	**0.1660**	**0.1582**	**0.3241**	**0.0000**	**1,157.0781**	**1,157.0781**	**0.1915**	**0.0103**	**1,164.9217**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2024	0.6087	3.9897	5.1378	0.0132	0.6250	0.1687	0.7937	0.1660	0.1582	0.3241	0.0000	1,157.0772	1,157.0772	0.1915	0.0103	1,164.9209
2025	0.5674	3.6468	4.9696	0.0129	0.6226	0.1477	0.7703	0.1653	0.1384	0.3037	0.0000	1,136.5253	1,136.5253	0.1892	9.4600e-003	1,144.0762
Maximum	**0.6087**	**3.9897**	**5.1378**	**0.0132**	**0.6250**	**0.1687**	**0.7937**	**0.1660**	**0.1582**	**0.3241**	**0.0000**	**1,157.0772**	**1,157.0772**	**0.1915**	**0.0103**	**1,164.9209**

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Quarter	Start Date	End Date	Maximum Unmitigated ROG + NOX (tons/quarter)	Maximum Mitigated ROG + NOX (tons/quarter)
1	**1-1-2024**	**3-31-2024**	1.1459	1.1459
2	**4-1-2024**	**6-30-2024**	1.1419	1.1419
3	**7-1-2024**	**9-30-2024**	1.1544	1.1544
4	**10-1-2024**	**12-31-2024**	1.1585	1.1585
5	**1-1-2025**	**3-31-2025**	1.0427	1.0427
6	**4-1-2025**	**6-30-2025**	1.0505	1.0505
7	**7-1-2025**	**9-30-2025**	1.0621	1.0621
		Highest	1.1585	1.1585

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Building Construction	Building Construction	1/1/2024	12/31/2025	5	523	

Acres of Grading (Site Preparation Phase): 0

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Building Construction	Air Compressors	20	0.50	78	0.48
Building Construction	Cranes	5	3.80	231	0.29
Building Construction	Cranes	3	0.50	231	0.29
Building Construction	Excavators	1	3.80	158	0.38
Building Construction	Forklifts	7	3.80	89	0.20
Building Construction	Off-Highway Trucks	2	3.80	402	0.38
Building Construction	Rubber Tired Dozers	1	3.80	247	0.40
Building Construction	Rubber Tired Loaders	3	0.50	203	0.36
Building Construction	Tractors/Loaders/Backhoes	4	3.80	97	0.37
Building Construction	Welders	8	3.80	46	0.45

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Building Construction	54	160.00	0.00	0.00	40.00	7.30	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

Reduce Vehicle Speed on Unpaved Roads

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Building Construction - 2024

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.4677	3.8772	3.7111	7.9500e-003		0.1658	0.1658		0.1554	0.1554	0.0000	679.2140	679.2140	0.1840	0.0000	683.8150
Total	**0.4677**	**3.8772**	**3.7111**	**7.9500e-003**		**0.1658**	**0.1658**		**0.1554**	**0.1554**	**0.0000**	**679.2140**	**679.2140**	**0.1840**	**0.0000**	**683.8150**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.1410	0.1124	1.4267	5.2100e-003	0.6250	2.9700e-003	0.6280	0.1660	2.7300e-003	0.1687	0.0000	477.8641	477.8641	7.4800e-003	0.0103	481.1067
Total	**0.1410**	**0.1124**	**1.4267**	**5.2100e-003**	**0.6250**	**2.9700e-003**	**0.6280**	**0.1660**	**2.7300e-003**	**0.1687**	**0.0000**	**477.8641**	**477.8641**	**7.4800e-003**	**0.0103**	**481.1067**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Building Construction - 2024

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.4677	3.8772	3.7111	7.9500e-003		0.1658	0.1658		0.1554	0.1554	0.0000	679.2132	679.2132	0.1840	0.0000	683.8142
Total	**0.4677**	**3.8772**	**3.7111**	**7.9500e-003**		**0.1658**	**0.1658**		**0.1554**	**0.1554**	**0.0000**	**679.2132**	**679.2132**	**0.1840**	**0.0000**	**683.8142**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.1410	0.1124	1.4267	5.2100e-003	0.6250	2.9700e-003	0.6280	0.1660	2.7300e-003	0.1687	0.0000	477.8641	477.8641	7.4800e-003	0.0103	481.1067
Total	**0.1410**	**0.1124**	**1.4267**	**5.2100e-003**	**0.6250**	**2.9700e-003**	**0.6280**	**0.1660**	**2.7300e-003**	**0.1687**	**0.0000**	**477.8641**	**477.8641**	**7.4800e-003**	**0.0103**	**481.1067**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Building Construction - 2025

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.4366	3.5478	3.6568	7.9200e-003		0.1449	0.1449		0.1358	0.1358	0.0000	676.6217	676.6217	0.1826	0.0000	681.1863
Total	**0.4366**	**3.5478**	**3.6568**	**7.9200e-003**		**0.1449**	**0.1449**		**0.1358**	**0.1358**	**0.0000**	**676.6217**	**676.6217**	**0.1826**	**0.0000**	**681.1863**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.1308	0.0989	1.3128	5.0200e-003	0.6226	2.8000e-003	0.6254	0.1653	2.5800e-003	0.1679	0.0000	459.9044	459.9044	6.6400e-003	9.4600e-003	462.8907
Total	**0.1308**	**0.0989**	**1.3128**	**5.0200e-003**	**0.6226**	**2.8000e-003**	**0.6254**	**0.1653**	**2.5800e-003**	**0.1679**	**0.0000**	**459.9044**	**459.9044**	**6.6400e-003**	**9.4600e-003**	**462.8907**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Building Construction - 2025

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.4366	3.5478	3.6568	7.9200e-003		0.1449	0.1449		0.1358	0.1358	0.0000	676.6209	676.6209	0.1826	0.0000	681.1855
Total	**0.4366**	**3.5478**	**3.6568**	**7.9200e-003**		**0.1449**	**0.1449**		**0.1358**	**0.1358**	**0.0000**	**676.6209**	**676.6209**	**0.1826**	**0.0000**	**681.1855**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.1308	0.0989	1.3128	5.0200e-003	0.6226	2.8000e-003	0.6254	0.1653	2.5800e-003	0.1679	0.0000	459.9044	459.9044	6.6400e-003	9.4600e-003	462.8907
Total	**0.1308**	**0.0989**	**1.3128**	**5.0200e-003**	**0.6226**	**2.8000e-003**	**0.6254**	**0.1653**	**2.5800e-003**	**0.1679**	**0.0000**	**459.9044**	**459.9044**	**6.6400e-003**	**9.4600e-003**	**462.8907**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
User Defined Industrial	0.00	0.00	0.00		
Total	0.00	0.00	0.00		

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
User Defined Industrial	9.50	7.30	7.30	0.00	0.00	0.00	0	0	0

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
User Defined Industrial	0.480055	0.053153	0.177436	0.165193	0.030848	0.009491	0.014052	0.037969	0.000584	0.000238	0.025005	0.001479	0.004498

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaturalGas Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaturalGas Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

5.3 Energy by Land Use - Electricity

Unmitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

6.0 Area Detail

6.1 Mitigation Measures Area

Facilities Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

6.2 Area by SubCategory

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

7.0 Water Detail

7.1 Mitigation Measures Water

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
User Defined Industrial	0 / 0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

7.2 Water by Land Use

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
User Defined Industrial	0 / 0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			
Mitigated	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Pipelines Construction

Kern-San Joaquin County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
User Defined Industrial	7,385.67	User Defined Unit	7,385.67	0.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.7	**Precipitation Freq (Days)**	32
Climate Zone	3			**Operational Year**	2024
Utility Company	Pacific Gas and Electric Company				
CO2 Intensity (lb/MWhr)	203.98	**CH4 Intensity (lb/MWhr)**	0.033	**N2O Intensity (lb/MWhr)**	0.004

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use - Acrage of CCS Facility

Construction Phase - 1- year estiimate for facilities construction

Off-road Equipment - Estimated Off Road Equipment

Off-road Equipment - x

Off-road Equipment - estimated construction equipment

Trips and VMT - According to traffic study

Grading -

Consumer Products - x

Area Coating - x

Landscape Equipment - x

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Table Name	Column Name	Default Value	New Value
tblAreaCoating	ReapplicationRatePercent	10	0
tblConstructionPhase	NumDays	15,500.00	262.00
tblConstructionPhase	NumDays	15,500.00	262.00
tblConsumerProducts	ROG_EF	2.14E-05	0
tblConsumerProducts	ROG_EF_Degreaser	3.542E-07	0
tblConsumerProducts	ROG_EF_PesticidesFertilizers	5.152E-08	0
tblGrading	MaterialExported	0.00	79,200.00
tblGrading	MaterialImported	0.00	79,200.00
tblLandscapeEquipment	NumberSummerDays	180	0
tblLandUse	LotAcreage	0.00	7,385.67
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	0.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	1.00	0.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	1.00	0.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	0.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	0.00
tblTripsAndVMT	HaulingTripLength	20.00	40.00
tblTripsAndVMT	HaulingTripNumber	19,800.00	20.00
tblTripsAndVMT	VendorTripLength	7.30	20.00
tblTripsAndVMT	WorkerTripLength	10.80	40.00
tblTripsAndVMT	WorkerTripNumber	90.00	32.00

2.0 Emissions Summary

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2024	0.7362	6.0735	7.0644	0.0128	0.1370	0.2823	0.4194	0.0351	0.2661	0.3011	0.0000	1,101.9715	1,101.9715	0.2397	2.2200e-003	1,108.6243
Maximum	**0.7362**	**6.0735**	**7.0644**	**0.0128**	**0.1370**	**0.2823**	**0.4194**	**0.0351**	**0.2661**	**0.3011**	**0.0000**	**1,101.9715**	**1,101.9715**	**0.2397**	**2.2200e-003**	**1,108.6243**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2024	0.7362	6.0735	7.0644	0.0128	0.1370	0.2823	0.4194	0.0351	0.2661	0.3011	0.0000	1,101.9703	1,101.9703	0.2397	2.2200e-003	1,108.6231
Maximum	**0.7362**	**6.0735**	**7.0644**	**0.0128**	**0.1370**	**0.2823**	**0.4194**	**0.0351**	**0.2661**	**0.3011**	**0.0000**	**1,101.9703**	**1,101.9703**	**0.2397**	**2.2200e-003**	**1,108.6231**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Quarter	Start Date	End Date	Maximum Unmitigated ROG + NOX (tons/quarter)	Maximum Mitigated ROG + NOX (tons/quarter)
1	1-1-2024	3-31-2024	1.6905	1.6905
2	4-1-2024	6-30-2024	1.6896	1.6896
3	7-1-2024	9-30-2024	1.7082	1.7082
		Highest	1.7082	1.7082

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Construction	Grading	1/1/2024	12/31/2024	5	262	
2	Const1	Grading	1/1/2024	12/31/2024	5	262	

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Construction	Air Compressors	4	5.00	78	0.48
Construction	Air Compressors	1	2.50	78	0.48
Construction	Cranes	3	5.00	231	0.29
Construction	Cranes	3	2.50	231	0.29
Construction	Generator Sets	4	2.50	84	0.74
Construction	Other Construction Equipment	9	5.00	172	0.42
Construction	Other Construction Equipment	2	2.50	172	0.42
Construction	Other Material Handling Equipment	1	2.50	168	0.40
Construction	Trenchers	1	2.50	78	0.50
Construction	Welders	8	5.00	46	0.45
Const1	Excavators	0	8.00	158	0.38
Const1	Graders	0	8.00	187	0.41
Const1	Rubber Tired Dozers	0	8.00	247	0.40
Const1	Scrapers	0	8.00	367	0.48
Const1	Tractors/Loaders/Backhoes	0	8.00	97	0.37

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Construction	36	32.00	0.00	0.00	40.00	7.30	20.00	LD_Mix	HDT_Mix	HHDT

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Const1		0	0.00	0.00	20.00	10.80	20.00	40.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

3.2 Construction - 2024

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.7080	6.0487	6.7787	0.0118		0.2817	0.2817		0.2655	0.2655	0.0000	1,005.3280	1,005.3280	0.2382	0.0000	1,011.2820
Total	**0.7080**	**6.0487**	**6.7787**	**0.0118**	**0.0000**	**0.2817**	**0.2817**	**0.0000**	**0.2655**	**0.2655**	**0.0000**	**1,005.3280**	**1,005.3280**	**0.2382**	**0.0000**	**1,011.2820**

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Construction - 2024

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.0282	0.0225	0.2853	1.0400e-003	0.1250	5.9000e-004	0.1256	0.0332	5.5000e-004	0.0337	0.0000	95.5728	95.5728	1.5000e-003	2.0500e-003	96.2213
Total	**0.0282**	**0.0225**	**0.2853**	**1.0400e-003**	**0.1250**	**5.9000e-004**	**0.1256**	**0.0332**	**5.5000e-004**	**0.0337**	**0.0000**	**95.5728**	**95.5728**	**1.5000e-003**	**2.0500e-003**	**96.2213**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.7080	6.0487	6.7787	0.0118		0.2817	0.2817		0.2655	0.2655	0.0000	1,005.3268	1,005.3268	0.2382	0.0000	1,011.2808
Total	**0.7080**	**6.0487**	**6.7787**	**0.0118**	**0.0000**	**0.2817**	**0.2817**	**0.0000**	**0.2655**	**0.2655**	**0.0000**	**1,005.3268**	**1,005.3268**	**0.2382**	**0.0000**	**1,011.2808**

Pipelines Construction - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Construction - 2024

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.0282	0.0225	0.2853	1.0400e-003	0.1250	5.9000e-004	0.1256	0.0332	5.5000e-004	0.0337	0.0000	95.5728	95.5728	1.5000e-003	2.0500e-003	96.2213
Total	**0.0282**	**0.0225**	**0.2853**	**1.0400e-003**	**0.1250**	**5.9000e-004**	**0.1256**	**0.0332**	**5.5000e-004**	**0.0337**	**0.0000**	**95.5728**	**95.5728**	**1.5000e-003**	**2.0500e-003**	**96.2213**

3.3 Const1 - 2024

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					0.0117	0.0000	0.0117	1.7700e-003	0.0000	1.7700e-003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0117**	**0.0000**	**0.0117**	**1.7700e-003**	**0.0000**	**1.7700e-003**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

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EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.3 Const1 - 2024

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	3.0000e-005	2.2700e-003	3.7000e-004	1.0000e-005	3.4000e-004	2.0000e-005	3.7000e-004	9.0000e-005	2.0000e-005	1.2000e-004	0.0000	1.0707	1.0707	0.0000	1.7000e-004	1.1210
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**3.0000e-005**	**2.2700e-003**	**3.7000e-004**	**1.0000e-005**	**3.4000e-004**	**2.0000e-005**	**3.7000e-004**	**9.0000e-005**	**2.0000e-005**	**1.2000e-004**	**0.0000**	**1.0707**	**1.0707**	**0.0000**	**1.7000e-004**	**1.1210**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					0.0117	0.0000	0.0117	1.7700e-003	0.0000	1.7700e-003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0117**	**0.0000**	**0.0117**	**1.7700e-003**	**0.0000**	**1.7700e-003**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

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EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.3 Const1 - 2024

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	3.0000e-005	2.2700e-003	3.7000e-004	1.0000e-005	3.4000e-004	2.0000e-005	3.7000e-004	9.0000e-005	2.0000e-005	1.2000e-004	0.0000	1.0707	1.0707	0.0000	1.7000e-004	1.1210
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**3.0000e-005**	**2.2700e-003**	**3.7000e-004**	**1.0000e-005**	**3.4000e-004**	**2.0000e-005**	**3.7000e-004**	**9.0000e-005**	**2.0000e-005**	**1.2000e-004**	**0.0000**	**1.0707**	**1.0707**	**0.0000**	**1.7000e-004**	**1.1210**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
User Defined Industrial	0.00	0.00	0.00		
Total	0.00	0.00	0.00		

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
User Defined Industrial	9.50	7.30	7.30	0.00	0.00	0.00	0	0	0

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
User Defined Industrial	0.480055	0.053153	0.177436	0.165193	0.030848	0.009491	0.014052	0.037969	0.000584	0.000238	0.025005	0.001479	0.004498

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaturalGas Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaturalGas Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

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EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

5.3 Energy by Land Use - Electricity

Unmitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

6.0 Area Detail

6.1 Mitigation Measures Area

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EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

6.2 Area by SubCategory

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

7.0 Water Detail

7.1 Mitigation Measures Water

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EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
User Defined Industrial	0 / 0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

7.2 Water by Land Use

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
User Defined Industrial	0 / 0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			
Mitigated	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
User Defined Industrial	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

2021 ORIGINAL

Facility	CO2 (MT/yr)	CH4 (MT/yr)	N2O (MT/yr)	CO2e (MT/yr)	Thermal CO2e (MT/yr)	Non-Thermal CO2e (MT/yr)	Subpart C CO2e (MT/yr)	Subpart W CO2e (MT/yr)	Subpart NN CO2e (MT/yr)
35R Gas Plant	2,759,428.6767	275.3343	12.8649	2,770,145.7744	0.0000	2,770,145.7744	1,681,919.0777	23,727.3584	1,064,499.3383
35R Gas Plant (Not including De minimis			Calculated	2,750,798.3616			1,705,646.4361		
			Previous Year	2,877,818.1007		Tool	1,705,647.20		1,064,499.50
			% Change	-4%			0%		0%

De minimis Emissions	CO2e (MT/yr)
De minimis remaining	652.5872
De minimis applied	19,347.4128
De minimis Threshold	20,000.0000

Facility	CO2 (MT/yr)	CH4 (MT/yr)	N2O (MT/yr)	CO2e (MT/yr)	Thermal CO2e (MT/yr)	Non-Thermal CO2e (MT/yr)	Subpart C CO2e (MT/yr)	Subpart W CO2e (MT/yr)	Subpart NN CO2e (MT/yr)	Total CO2e (no De Minimis) (MT/yr)	Covered Emissions CO2e (MT/yr)	Non- Covered Emissions CO2e (MT/yr)
35R Gas Plant	2,759,428.6767	275.3343	12.8649	2,770,145.7744	0.0000	2,770,145.7744	1,681,919.0777	23,727.3584	1,064,499.3383	2,750,798.3616	2,001,529.10851517	6,031.4849
										Tool	2,035,907.50	
											-2%	

Facility Total	35R Gas Plant								
Source Category	CO2 (MT/yr)	CH4 (MT/yr)	N2O (MT/yr)	CO2e (MT/yr)	Percent Thermal	Thermal CO2e (MT/yr)	Non-Thermal CO2e (MT/yr)	Covered Emission	Citation
Natural gas pneumatic device venting (LB	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Natural gas pneumatic device venting (IB	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	No	§95852.2(b)(7)
Natural gas pneumatic device venting (HB	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Natural gas driven pneumatic pump ventin	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Acid gas removal vents	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Dehydrator vents	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Well venting for liquids unloadin	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Gas well venting during well completions without hydraulic fracturing	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Gas well venting during well completions with hydraulic fracturing	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Gas well venting during well workovers without hydraulic fracturing	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Gas well venting during well workovers with hydraulic fracturing	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Equipment and pipeline blowdowns	0.1523	0.6404	0.0000	16.1623	0.0000	0.0000	16.1623	Yes	
Dump Valves	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Well testing venting and flarin	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Associated gas venting and flaring from produced hydrocarbons	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Flare stack emissions	18,767.9908	74.9410	0.0315	20,650.9028	0.0000	0.0000	20,650.9028	Yes	
Centrifugal Compressors (< 250 HP)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	No	§95852.2(b)(8)
Centrifugal Compressors (>= 250 HP)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Reciprocating Compressors (>= 250 HP)	1.1456	5.2023	0.0000	131.2031	0.0000	0.0000	131.2031	Yes	
Reciprocating Compressors (< 250 HP)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	No	§95852.2(b)(8)
Equipment leaks (Fugitives)	25.3302	116.1504	0.0000	2,929.0902	0.0000	0.0000	2,929.0902	No	§95852.2(b)(9)
EOR injection pump blowdowr	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Storage tanks vented emissions from produced hydrocarbons	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	No	§95852.2(b)(2)
Produced Water Dissolved CO2 and CH4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	No	§95852.2(b)(4)
Stationary Combustion Equipment (Covered	1,680,359.2678	28.4645	2.8463	1,681,919.0777	0.0000	0.0000	1,681,919.0777	Yes	
Stationary Combustion Equipment (Not Covered)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	No	§95852(a)(2)
Portable Combustion Equipment (Covered	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	Yes	
Portable Combustion Equipment (Not Covered	0.0000	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	No	§95852(a)(2)
Supplier 95122	1,060,274.7900	49.9357	9.9871	1,064,499.3383	0.0000	0.0000	1,064,499.3383	Yes	

Elk Hills Power Plant Amine Project Emissions CO2 Reduction Estimates

Year	Base Case	1	2	3	4	5	6	7	8	9	10
EHPP Nameplate Capacity, Gross MW	550	550	550	550	550	550	550	550	550	550	550
EHPP Average Output, Net MW	455	455	455	455	455	455	455	455	455	455	455
Hours Per Year	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760
Capacity Factor	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Electricity Generated, Net MWh	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794
Baseline CO2e Emissions, mllion metric tons CO2e/Yr	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853
!st Amine Unit Removal, MMSCFD CO2		5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
!st Amine Unit Removal, MT CO2/Yr		101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743
2nd Amine Unit Removal, MMSCFD CO2			5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
2nd Amine Unit Removal, MT CO2/Yr			101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743
Total Amine Unit Removals		101,743	203,485	203,485	203,485	203,485	203,485	203,485	203,485	203,485	203,485
Cumulative Total CO2 Injected, MT CO2		101,743	305,228	508,713	712,198	915,683	1,119,168	1,322,653	1,526,139	1,729,624	1,933,109
EHPP Emissions, MT CO2e	1,556,853	1,455,111	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368

Elk Hills Power Plant Amine Project Emissions CO2 Reduction Estimates

Year	11	12	13	14	15	16	17	18	19	20
EHPP Nameplate Capacity, Gross MW	550	550	550	550	550	550	550	550	550	550
EHPP Average Output, Net MW	455	455	455	455	455	455	455	455	455	455
Hours Per Year	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760
Capacity Factor	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Electricity Generated, Net MWh	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794	3,706,794
Baseline CO2e Emissions, mllion metric tons CO2e/Yr	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853	1,556,853
!st Amine Unit Removal, MMSCFD CO2	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
!st Amine Unit Removal, MT CO2/Yr	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743
2nd Amine Unit Removal, MMSCFD CO2	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
2nd Amine Unit Removal, MT CO2/Yr	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743	101,743
Total Amine Unit Removals	203,485	203,485	203,485	203,485	203,485	203,485	203,485	203,485	203,485	203,485
Cumulative Total CO2 Injected, MT CO2	2,136,594	2,340,079	2,543,564	2,747,049	2,950,535	3,154,020	3,357,505	3,560,990	3,764,475	3,967,960
EHPP Emissions, MT CO2e	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368	1,353,368

APPENDIX C. CARB 2020 AND 2025 ESTIMATED EMISSION INVENTORIES

2016 SIP Emission Projection Data

2020 Estimated Annual Average Emissions

KERN COUNTY

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

KERN COUNTY COUNTY - MOJAVE DESERT AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	0.5	0.1	0.8	2.4	0.2	0.4	0.4	0.4	0.0
WASTE DISPOSAL	8.4	0.1	0.0	-	0.0	0.0	0.0	0.0	0.1
CLEANING AND SURFACE COATINGS	0.9	0.8	-	-	-	0.0	0.0	0.0	-
PETROLEUM PRODUCTION AND MARKETING	0.1	0.1	-	-	-	-	-	-	-
INDUSTRIAL PROCESSES	0.1	0.1	10.2	18.4	8.1	3.7	2.9	1.7	0.1
*** TOTAL STATIONARY SOURCES**	**10.2**	**1.3**	**11.0**	**20.8**	**8.3**	**4.1**	**3.3**	**2.1**	**0.1**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	1.6	1.4	-	-	-	-	-	-	1.3
MISCELLANEOUS PROCESSES	3.5	1.2	11.0	0.6	0.0	18.6	9.7	2.6	0.7
*** TOTAL AREAWIDE SOURCES**	**5.0**	**2.6**	**11.0**	**0.6**	**0.0**	**18.6**	**9.7**	**2.6**	**2.0**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	1.1	1.1	7.2	4.1	0.0	0.3	0.3	0.1	0.1
OTHER MOBILE SOURCES	5.0	4.9	23.8	5.5	0.3	3.0	2.9	2.9	0.0
*** TOTAL MOBILE SOURCES**	**6.2**	**5.9**	**31.0**	**9.6**	**0.3**	**3.3**	**3.2**	**3.0**	**0.1**
TOTAL KERN COUNTY IN MOJAVE DESERT	**21.4**	**9.8**	**53.0**	**31.0**	**8.6**	**26.0**	**16.2**	**7.7**	**2.3**

KERN COUNTY COUNTY - SAN JOAQUIN VALLEY AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	12.6	1.8	9.9	7.6	0.7	2.7	2.6	2.5	1.6
WASTE DISPOSAL	224.6	12.2	0.2	0.1	0.0	0.1	0.0	0.0	5.4
CLEANING AND SURFACE COATINGS	3.0	2.7	-	-	-	0.0	0.0	0.0	
PETROLEUM PRODUCTION AND MARKETING	46.2	11.8	0.9	0.3	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	2.4	2.3	0.1	0.1	0.1	3.7	1.6	0.6	0.2

* TOTAL STATIONARY SOURCES	288.8	30.7	11.1	8.0	1.1	6.7	4.4	3.3	7.2
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	10.9	10.0	-	-	-	-	-	-	26.5
MISCELLANEOUS PROCESSES	63.6	9.9	5.2	1.2	0.0	61.8	30.9	5.7	17.1
* TOTAL AREAWIDE SOURCES	74.5	19.9	5.2	1.2	0.0	61.8	30.9	5.7	43.6
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	5.4	4.9	31.4	23.5	0.1	1.7	1.6	0.7	0.8
OTHER MOBILE SOURCES	4.0	3.5	27.2	10.8	0.0	0.6	0.5	0.5	0.0
* TOTAL MOBILE SOURCES	9.4	8.4	58.6	34.2	0.2	2.2	2.2	1.2	0.8
TOTAL KERN COUNTY IN SAN JOAQUIN VALLEY	372.7	59.0	74.9	43.5	1.4	70.7	37.4	10.2	51.7
GRAND TOTAL FOR KERN COUNTY	394.0	68.8	127.9	74.4	10.0	96.7	53.6	17.9	54.0

Start a new query.

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California Governor
Gavin Newsom
Visit Governor's Website

Secretary for Environmental Protection
Jared Blumenfeld
Visit his Website

Chair, California Air Resources Board
Liane M. Randolph
Visit her Website

ACCESSIBILITY
PRIVACY POLICY
CONDITIONS OF USE
LOCAL AIR DISTRICTS
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2016 SIP Emission Projection Data

2020 Estimated Annual Average Emissions

SAN JOAQUIN VALLEY AIR BASIN

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	17.9	3.2	24.7	24.1	2.4	4.8	4.7	4.6	2.2
WASTE DISPOSAL	527.3	26.9	0.6	0.3	0.2	0.9	0.3	0.2	11.2
CLEANING AND SURFACE COATINGS	27.8	25.2	-	-	-	0.3	0.3	0.3	0.0
PETROLEUM PRODUCTION AND MARKETING	111.0	16.6	1.0	0.4	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	20.6	19.5	1.4	3.9	3.6	20.9	9.5	3.6	1.7
*** TOTAL STATIONARY SOURCES**	**704.7**	**91.3**	**27.7**	**28.6**	**6.5**	**27.2**	**14.9**	**8.7**	**15.2**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	55.0	49.9	-	-	-	-	-	-	113.1
MISCELLANEOUS PROCESSES	761.8	103.0	53.2	7.9	0.3	473.4	236.8	41.8	193.9
*** TOTAL AREAWIDE SOURCES**	**816.8**	**152.8**	**53.2**	**7.9**	**0.3**	**473.4**	**236.8**	**41.8**	**307.0**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	27.3	24.9	167.9	96.9	0.6	7.8	7.6	3.4	3.6
OTHER MOBILE SOURCES	30.6	27.2	196.2	69.8	0.3	5.6	5.5	5.0	0.0
*** TOTAL MOBILE SOURCES**	**57.9**	**52.0**	**364.1**	**166.8**	**1.0**	**13.4**	**13.1**	**8.5**	**3.6**
GRAND TOTAL FOR SAN JOAQUIN VALLEY AIR BASIN	**1579.4**	**296.2**	**445.0**	**203.3**	**7.8**	**514.0**	**264.8**	**59.0**	**325.9**

Start a new query.

Secretary for Environmental Protection
Jared Blumenfeld
Visit his Website

Chair, California Air Resources Board
Liane M. Randolph
Visit her Website

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2016 SIP Emission Projection Data

2025 Estimated Annual Average Emissions

KERN COUNTY

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

KERN COUNTY COUNTY - MOJAVE DESERT AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	0.5	0.1	0.8	2.5	0.2	0.4	0.4	0.4	0.0
WASTE DISPOSAL	9.3	0.1	0.0	-	0.0	0.0	0.0	0.0	0.1
CLEANING AND SURFACE COATINGS	1.0	0.9	-	-	-	0.0	0.0	0.0	-
PETROLEUM PRODUCTION AND MARKETING	0.1	0.1	-	-	-	-	-	-	-
INDUSTRIAL PROCESSES	0.1	0.1	11.0	19.7	8.6	3.9	3.2	1.9	0.1
*** TOTAL STATIONARY SOURCES**	**11.1**	**1.4**	**11.8**	**22.2**	**8.8**	**4.4**	**3.5**	**2.2**	**0.1**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	1.7	1.5	-	-	-	-	-	-	
MISCELLANEOUS PROCESSES	3.5	1.2	11.1	0.6	0.0	18.5	9.7	2.6	0.7
*** TOTAL AREAWIDE SOURCES**	**5.2**	**2.7**	**11.1**	**0.6**	**0.0**	**18.5**	**9.7**	**2.6**	**2.0**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	0.9	0.8	5.0	2.3	0.0	0.3	0.3	0.1	0.1
OTHER MOBILE SOURCES	5.0	4.8	24.2	4.6	0.3	3.0	2.9	2.9	0.0
*** TOTAL MOBILE SOURCES**	**5.8**	**5.6**	**29.2**	**6.9**	**0.3**	**3.3**	**3.2**	**3.0**	**0.1**
TOTAL KERN COUNTY IN MOJAVE DESERT	**22.1**	**9.7**	**52.1**	**29.7**	**9.2**	**26.1**	**16.4**	**7.8**	**2.3**

KERN COUNTY COUNTY - SAN JOAQUIN VALLEY AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	12.4	1.7	9.6	7.2	0.6	2.6	2.5	2.4	1.7
WASTE DISPOSAL	247.0	13.4	0.2	0.1	0.0	0.1	0.0	0.0	6.0
CLEANING AND SURFACE COATINGS	3.3	3.0	-	-	-	0.0	0.0	0.0	-
PETROLEUM PRODUCTION AND MARKETING	45.0	10.8	0.8	0.3	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	2.6	2.4	0.1	0.1	0.1	4.0	1.7	0.6	0.2

* TOTAL STATIONARY SOURCES	310.3	31.3	10.7	7.6	1.1	6.9	4.4	3.2	7.8
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	11.4	10.3	-	-	-	-	-	-	25.1
MISCELLANEOUS PROCESSES	63.7	9.9	5.2	1.2	0.0	61.8	30.9	5.7	17.2
* TOTAL AREAWIDE SOURCES	75.0	20.3	5.2	1.2	0.0	61.8	30.9	5.7	42.3
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	4.3	3.9	23.7	12.7	0.1	1.7	1.7	0.7	0.8
OTHER MOBILE SOURCES	3.5	3.1	28.0	8.1	0.0	0.4	0.4	0.4	0.0
* TOTAL MOBILE SOURCES	7.8	7.0	51.6	20.8	0.2	2.1	2.1	1.1	0.8
TOTAL KERN COUNTY IN SAN JOAQUIN VALLEY	393.1	58.5	67.6	29.6	1.3	70.8	37.4	10.1	51.0
GRAND TOTAL FOR KERN COUNTY	415.2	68.2	119.7	59.3	10.5	97.0	53.8	17.8	53.2

Start a new query.

CONTACT US

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2016 SIP Emission Projection Data

2025 Estimated Annual Average Emissions

SAN JOAQUIN VALLEY AIR BASIN

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	17.7	3.0	24.6	23.0	2.4	4.7	4.6	4.5	2.3
WASTE DISPOSAL	572.3	29.2	0.6	0.3	0.2	1.0	0.3	0.2	12.2
CLEANING AND SURFACE COATINGS	30.8	27.9	-	-	-	0.4	0.4	0.3	0.0
PETROLEUM PRODUCTION AND MARKETING	109.5	15.1	0.9	0.3	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	22.4	21.1	1.6	4.2	3.8	22.6	10.3	3.9	1.9
*** TOTAL STATIONARY SOURCES**	**752.7**	**96.4**	**27.7**	**27.7**	**6.8**	**28.9**	**15.7**	**9.0**	**16.4**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	57.5	52.0	-	-	-	-	-	-	109.9
MISCELLANEOUS PROCESSES	761.9	103.0	53.2	7.4	0.3	469.2	234.9	41.9	194.5
*** TOTAL AREAWIDE SOURCES**	**819.4**	**155.0**	**53.2**	**7.4**	**0.3**	**469.2**	**234.9**	**41.9**	**304.4**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	20.5	18.8	118.9	54.2	0.6	7.9	7.7	3.2	3.4
OTHER MOBILE SOURCES	26.8	23.9	200.1	54.4	0.3	4.7	4.6	4.2	0.0
*** TOTAL MOBILE SOURCES**	**47.3**	**42.7**	**319.0**	**108.6**	**0.9**	**12.6**	**12.3**	**7.5**	**3.5**
GRAND TOTAL FOR SAN JOAQUIN VALLEY AIR BASIN	**1619.4**	**294.1**	**399.9**	**143.7**	**8.0**	**510.7**	**262.8**	**58.3**	**324.3**

Start a new query.

Secretary for Environmental Protection
Jared Blumenfeld
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APPENDIX D. HEALTH RISK ASSESSMENT MODELING FILES

(Electronic Files)

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B.2 Failure Investigation Report

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DOT	US Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety – Accident Investigation Division

Principal Investigator	Wesley Mathews
Acting Accident Investigation Director	Chris Ruhl
Date of Report	May 26, 2022
Subject	Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC – Pipeline Rupture/ Natural Force Damage

Operator, Location, & Consequences

Date of Failure	February 22, 2020
Commodity Released	Carbon Dioxide
City, County and State	Satartia, Yazoo County, MS
OpID and Operator Name	32545, Denbury Gulf Coast Pipelines, LLC
Unit # and Unit Name	75379 – MS-2
WMS Activity ID	20-176125
Milepost (MP) / Location	MP 6.6 / Pipeline Stationing 348+63
Type of Failure	Natural Force Damage
Fatalities	None
Injuries	None
Description of Area Impacted	Rural, “Could Affect” High Consequence Area (HCA) - Other Populated Area
Total Costs	$ 3,947,009

Key Points

- On February 22, 2020, a carbon dioxide (CO_2) pipeline operated by Denbury Gulf Coast Pipelines LLC (Denbury) ruptured in proximity to the community of Satartia, Mississippi. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld.
- Carbon dioxide is considered minimally toxic by inhalation and is classified as an asphyxiant, displacing the oxygen in air. Symptoms of CO_2 exposure may include headache and drowsiness. Individuals exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.
- When CO_2 in a super-critical phase (which is common for CO_2 pipelines) releases into open air, it naturally vaporizes into a heavier than air gas and dissipates. During the February 22 event, atmospheric conditions and unique topographical features of the accident site significantly delayed dissipation of the heavier-than-air vapor cloud. Pipeline operators are required to establish atmospheric models to prepare for emergencies—Denbury's model did not contemplate a release that could affect the Village of Satartia.
- Local emergency responders were not informed by Denbury of the rupture and the nature of the unique safety risks of the CO_2 pipeline. As a result, responders had to guess the nature of the risk, in part making assumptions based on reports of a "green gas" and "rotten egg smell" and had to contemplate appropriate mitigative actions. Fortunately, responders decided to quickly isolate the affected area by shutting down local highways and evacuating people in proximity to the release. Denbury reported on its PHMSA F 7000.1 accident report that 200 residents surrounding the rupture location were evacuated, and forty-five people were taken to the hospital. Denbury also reported that to the company's knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure. No fatalities were reported.
- This event demonstrated the need for:
    - Pipeline company awareness and mitigation efforts directed at addressing integrity threats due to changing climate, geohazards, and soil stability issues.
    - Improved public engagement efforts to ensure public and emergency responder awareness of nearby CO_2 pipeline and pipeline facilities and what to do if a CO_2 release occurs. This is especially important for communities in low-lying areas, with certain topographical features such as rivers and valleys.

Executive Summary

On February 22, 2020, at 7:06 p.m. Central Standard Time (CST[1]), Denbury's 24-inch Delhi (Delhi) Pipeline ruptured, releasing liquid CO_2 that immediately began to vaporize at atmospheric conditions. The site of the rupture was on the northeast side of Highway 433 (HWY 433), approximately one mile southeast of Satartia, Mississippi. Denbury subsequently reported the rupture released an estimated total of 31,405[2] barrels of CO_2. Following the accident, investigators from the Pipeline and Hazardous Material Safety Administration's (PHMSA's) Accident Investigation Division (AID) and Southwest Regional Office, conducted an investigation, including an onsite investigation.

Liquid CO_2 vaporizes when released to the atmosphere. Carbon dioxide vapor is 1.53 times heavier than air, and displaces oxygen, so it can act as an asphyxiant to humans and animals. The National Institute for Occupational Safety and Health has established that concentrations of 40,000 parts per million (ppm) are immediately dangerous to life and health. The Occupational Safety and Health Administration has established 5000 ppm as a permissible exposure limit, which is an 8-hour time-weighted average. The weather conditions and unique topography of the accident site prevented the CO_2 vapor from rapidly dispersing and allowing a plume to form that migrated toward Satartia. Upon learning of the pipeline rupture, Yazoo County Office of Emergency Management (Yazoo County OEM) shut down HWY 433 to all traffic and evacuated the area. Local authorities evacuated approximately 200 people near the rupture, including the entire town of Satartia (around 50 residents), and three homes across the Yazoo River. According to Denbury's PHMSA F 7000.1 accident report, forty-five people sought medical attention at local hospitals, including individuals who were caught in the vapor cloud while driving a vehicle. One individual was admitted to the hospital for reasons unrelated to the pipeline failure. There were no fatalities.

The pipeline failed on a steep embankment adjacent to HWY 433, which had recently subsided. Heavy rains are believed to have led to a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure. After the accident, Denbury, under PHMSA's oversight, cut out the failed sections of pipe and sent them to Det Norske Veritas' (DNV) Columbus, Ohio laboratory for metallurgical analysis. DNV confirmed the initial onsite observations of a girth weld failure.

PHMSA's investigation also revealed several contributing factors to the accident, including but not limited to, Denbury not addressing the risks of geohazards in its plans and procedures, underestimating the potential affected areas that could be impacted by a release in its CO_2 dispersion model, and not notifying local responders to advise them of a potential failure.

System Details

Denbury's Delhi Pipeline, on which the failure occurred, consists of 77 miles of 24-inch diameter pipeline, the majority of which is located within Mississippi. The entire Delhi Pipeline system flows east to west, beginning at the Jackson Dome in Mississippi and terminating in Delhi, Louisiana. Denbury primarily uses the CO_2 for enhanced oil recovery (EOR) for Denbury Resources Inc. onshore oil wells. The pipeline is controlled from the Denbury control room located in Plano, Texas.

[1] All times are reported in CST unless otherwise noted.

[2] Denbury reported a total release volume of 31,405 barrels in Form PHMSA F-7000.1, Accident Report – Hazardous Liquid Pipeline Systems, dated November 25, 2020. The actual release volume likely exceeded this amount due to a valve operation error, however, Denbury has not confirmed and reported any new release volume to PHMSA.

Following the Delhi Pipeline rupture, two of Denbury's local oilfields were cut off from its CO_2 supply and assumed non-EOR operation while the pipeline remained out of service. One oilfield returned to full EOR operation before repairs were made to the Delhi Pipeline as the oilfield had an alternate supply of CO_2. The other oilfield conducted non-EOR operations until the pipeline was repaired and returned to service in October 2020.

Stupp Corporation manufactured the pipe in 2007 and Denbury installed it in 2009. The pipe was manufactured to API 5L X80 grade, with an electric resistance welded (ERW) longitudinal weld seam, a 0.469-inch wall thickness on the mainline pipe, 0.540-inch wall thickness on the bored pipe section under roads, which was 240 feet in length and more than 30 feet below HWY 433. The pipe is coated with fusion bonded epoxy (FBE) and was installed by horizontal directional drill. During construction, Denbury welded the pipe joints using an API 1104 qualified welding procedure. The procedure specified using an E6010 electrode root pass, followed by an E9018 electrode hot pass, then E10045 electrode for subsequent passes.

The maximum operating pressure of the Delhi Pipeline is 2160 pounds per square inch gauge (psig). At the time of the rupture, Denbury was operating the Delhi Pipeline at an estimated pressure of 1400 psig, which was above the 1070 psig needed to maintain CO_2 in a supercritical state.

Denbury's control room isolated the failed pipeline section by remotely operating the mainline block valves (MLBVs) at Redwood, Satartia, and Tinsley. There is approximately 9.55 miles of pipe between the Tinsley and Satartia MLBVs, which are the two MLBVs closest to the rupture.

Events Leading up to the Failure

According to the National Weather Service (NWS), accumulated rainfall data between January 1, 2020, through February 29, 2020 (60 days) for each of the cities of Greenville, Greenwood, Vicksburg, and Jackson, Mississippi – which form a relative square (Figure 1) around Satartia and Yazoo County[3] – was 17.43 inches, 19.41 inches, 23.2 inches, and 23.36 inches of rain, respectively. The amount of rain recorded in these four cities was between 7.44 and 13.63 inches above the annual historical average for the same 60-day timespan. Significant variations in environmental/climate conditions such as ambient temperatures and rainfall can impact soil stability and erosion patterns. Landslides are typically associated with periods of heavy rain, particularly in susceptible areas with the right combination of slope and soil-type. On May 26, 2022, PHMSA issued an updated Advisory Bulletin to remind operators of gas and hazardous liquid pipelines of the importance of identifying and mitigating risks caused by changes in environmental and geological conditions on their pipeline facilities.

[3] Neither Yazoo City, Satartia, nor Yazoo County had historic NWS data for the desired date range.

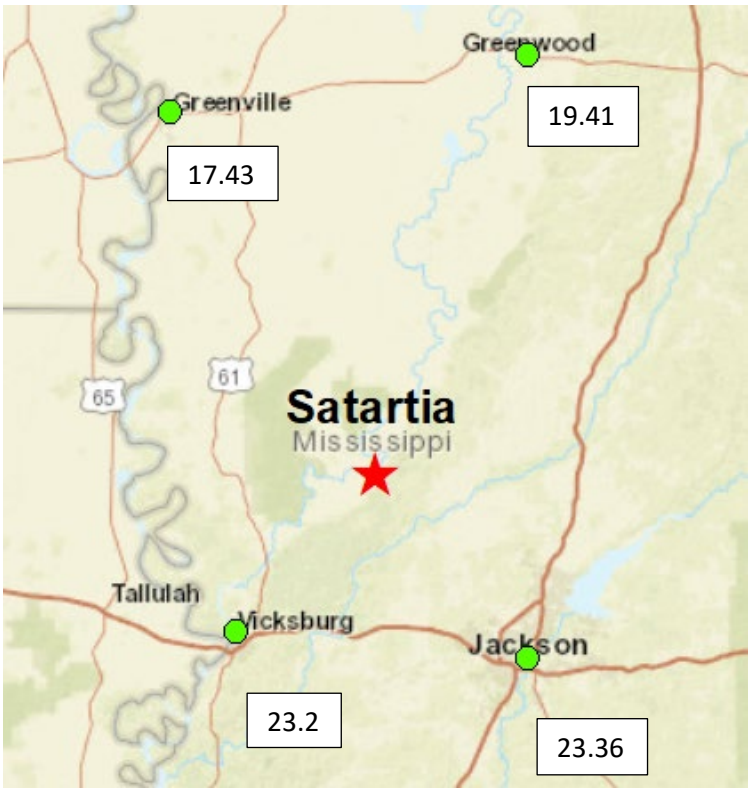

Figure 1: Map of Cities Relative to Satartia and Their Respective Rain Totals Between January 1, 2020, and February 29, 2020

On November 9, 2018, the Delhi Pipeline experienced a girth weld rupture at a valve location during pipeline reloading activities, and not attributed to natural force damage. Laboratory analysis indicated the release was the result of large thermal differential stresses being exerted on the pipeline from CO_2 loading at two different locations at the same time. The pipe between the two loading points shrank due to chilling from the CO_2, causing the girth weld connecting the pipeline to the valve body to rupture. The report found no evidence of inadequate mechanical properties or chemical composition anomalies in the ruptured weld. Denbury updated their procedure to prevent similar occurrences.

Prior to the accident, on November 8, 2019, Yazoo County first responders practiced a full-scale county response during a drill for a rail accident, however Denbury was not a participant in the drill. Local responders believe that the drill prepared them to respond to this event. Denbury had not conducted any drills with local responders since Denbury's modeling had not identified that Satartia would be impacted by a rupture of the pipeline.

Emergency Response

The Delhi Pipeline was operating normally prior to the February 22, 2020 accident.

Approximated Timeline

The following timeline was developed utilizing information provided by the Yazoo County OEM, [4] Denbury, and PHMSA investigator notes.

On February 22, 2020:

- 7:06 p.m. – Denbury's 24-inch pipeline ruptured.
- 7:07 p.m. – Denbury's control room was alerted by its supervisory control and data acquisition (SCADA) system of a pressure drop.
- 7:14 p.m. – Denbury control room remotely closed three MLBVs (one MLBV at Tinsley Station, which is upstream of the rupture site, and two MLBVs at Satartia and Redwood, which are downstream of the rupture).
- 7:15 p.m. – Denbury control room received SCADA confirmation that the MLBVs were closed.
- 7:15 p.m. – Yazoo County OEM dispatcher received an initial report of a "foul smell and green fog across the highway." Based on that information, responders responded under the assumption there was a possible chlorine leak and began contacting people from the local water utility company.
- 7:17 p.m. – Yazoo County OEM dispatcher received a call regarding a person possibly having a seizure. Responders began contacting personnel responsible for a nearby water well as the description of the report indicated chlorine gas.
- 7:19 p.m. – Denbury dispatched personnel to attempt to confirm MLBVs were closed successfully and to identify the location of the release.
- 7:26 p.m. – HWY 433 was ordered closed by local officials due to belief a chlorine leak was occurring.
- 7:30 p.m. – A responder commented that it sounded like a gas line had erupted. It was around this same time that another responder fielded a call from someone in the area who could hear a loud roar. This led the responders to believe that the accident was not chlorine gas related. First responders redirected their efforts to a possible CO_2 and hydrogen sulfide release, based on the initial first-hand reports from community members.
- 7:30 p.m. – First responders accessed a plume model generated by the NWS correlating local meteorological data with product type which indicated the CO_2 would move from the release site directly toward Satartia. Responders then called for the evacuation of Satartia. The scope of the response expanded as the CO_2 cloud dispersed, requiring an Incident Command (IC), commanded by the Chief of the District Three Volunteer Fire Department.
- 7:39 p.m. – Yazoo County OEM closed Highway 3 to traffic (intersection with HWY 433 is about 2/3-mile northwest of the rupture site).
- 7:43 p.m. – IC confirmed Denbury's CO_2 pipeline had ruptured; however, no one could get close to the release site due to the ongoing release of CO_2.
- 7:48 p.m. – Denbury's Tinsley Station Manager was contacted by IC and informed that Denbury's pipeline had ruptured. IC made Denbury aware of the response measures being taken. Denbury informed the IC that the Jackson Dome formation was shut down and that company personnel had been dispatched to check that the MLBVs were closed.

[4] The events entered in the Yazoo County OEM recording system are time stamped upon entry and may be delayed by seconds or minutes from the actual time of the event.

- 7:57 p.m. – Yazoo County OEM blocked off Mechanicsburg Road (around two miles southeast of the rupture site; intersects with HWY 433).
- 7:58 p.m. – According to Yazoo County OEM records, the Mississippi Department of Environmental Quality (MDEQ) contacted the Center for Toxicology & Environmental Health (CTEH) requesting technicians be dispatched to the rupture site with air monitoring equipment.
- 8:06 p.m. – The first Denbury representative arrived near the rupture site after confirming MLBV closures.
- 8:24 p.m. – Yazoo County OEM dispatch confirmed the second Denbury representative arrived near the rupture site.
- 9:06 p.m. – A Denbury representative from the Plano, Texas office called the National Response Center (NRC) to report their Delhi Pipeline had ruptured, releasing an estimated 222 barrels of liquid carbon dioxide (Report No. 1271847).
- 9:25 p.m. – Representatives from the CTEH and Denbury's environmental contractor E3 Environmental (E3) arrived on scene to conduct air monitoring to support the IC.
- 10:25 p.m. – Tinsley MLBV was completely closed.[5]
- 10:30 p.m. – CTEH initiated real-time air monitoring.

On February 23, 2020:

- 1:49 a.m. – The IC established a warming shelter at a local middle school for evacuees.
- 8:00 a.m. – Evacuees were allowed to return home. Air monitoring services were extended to anyone who requested the service. Evacuees were encouraged to vent their homes by opening doors and windows. The closure of HWY 433 was lifted after heavy equipment was used to clear mud that was deposited by the rupture.
- 11:34 a.m. – Real-time air monitoring concluded.

On February 24, 2020:

- 6:56 p.m., Denbury called the NRC and made the PHMSA required 48-hour update (Report No. 1272001). The update stated 21,873 barrels of liquid CO_2 had been released.[5]

Personnel from the Vicksburg Fire Department, including paramedics, District Three Volunteer Fire Department, Pafford EMS, Mississippi Emergency Management Agency, CF Industries, MDEQ, Madison County Fire Department, Warren County Fire Department, NWS, Local Police Departments, Yazoo County OEM, CTEH, E3, and Denbury participated in the emergency response efforts.

Local emergency responders utilized regular media, social media posts, phone calls, and door-to-door checks to notify homeowners and affected individuals of the CO_2 release.

A total of approximately 200 people were evacuated, which included those who were evacuated out of the area and those who were not allowed to pass through the area. During post-accident interviews, PHMSA learned that individuals on HWY 433 and in the area nearest to the migrating CO_2 vapor cloud experienced vehicle engine issues. This included individuals in a vehicle off of HWY 433, who succumbed to the effects of exposure to the released CO_2 and required emergency assistance to be evacuated. PHMSA also learned that one of two residents living in a dwelling in closest proximity to the pipeline rupture

[5] Denbury reported an updated estimate of 31,405 barrels to PHMSA on November 25, 2020.

passed out upon investigating the cloud. She later came-to and was able to evacuate to safety with her partner. Denbury reported a total of forty-five people sought medical attention at local hospitals.

Emergency Response Air Monitoring Plan

CTEH (Denbury's third-party contractor) in consultation with the IC developed an air monitoring plan to ensure the safety of response personnel, the community, and site characterization. CTEH implemented the plan to monitor for concentrations of CO_2, hydrogen-sulfide (H_2S), and oxygen (O_2) using handheld real-time instrumentation throughout the community and within homes of residents who requested monitoring. Air monitoring was conducted from 10:30 p.m. on February 22, 2020, until approximately 11:30 a.m. on February 23, 2020. Monitoring was performed using calibrated RAE Systems instruments made by Honeywell.

Carbon dioxide is considered minimally toxic by inhalation, unless in higher concentrations. CO_2 is classified as an asphyxiant, displacing the oxygen in breathing air. Symptoms of CO_2 exposure may include headache and drowsiness. Those exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.

In the hours after the rupture, after outdoor ambient air CO_2 levels continuously measured below 5,000 ppm, responders performed initial indoor assessment monitoring within residences and church buildings potentially impacted by the accident. During initial indoor assessments, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows to allow ventilation to dissipate the concentration of CO_2 and not to enter prior to re-assessment. No subsequent CO_2 readings in the hours after the accident were recorded above 3,500 ppm during re-assessments.

According to firsthand accounts, as well as secondhand accounts from first responders, there was a "rotten eggs" odor associated with the CO_2 release and gas plume. A rotten eggs odor can be attributed to the presence of H_2S, which is naturally occurring in the geologic formation that serves as a source of the CO_2 in the pipeline. PHMSA reviewed the CTEH air monitoring results and did not identify any observed readings of H_2S by monitoring equipment. The monitoring equipment's detection limit for H_2S was 0.1 ppm.

Summary of Return-to-Service

Prior to repairing the pipeline, Denbury contracted an engineering firm to develop plans to cutout the failed section of pipe and to mitigate potential future land movement. Denbury installed soil shoring along HWY 433 to stabilize the area. PHMSA evaluated the repair plan and monitored its execution.

On September 1, 2020, Denbury began replacing the failed pipe section, and on September 26, Denbury welded the new sections of pipe into the pipeline at the accident location. Mannesmann Line Pipe manufactured the newly installed 80-foot section of 24-inch nominal diameter pipe in 2019. The pipe is API 5L X70 grade, has 0.562-inch wall thickness and an ERW longitudinal weld seam, and is coated with FBE.

Denbury restarted the pipeline on October 26, 2020. Prior to the restart of the pipeline, Denbury provided PHMSA with a proposed restart plan for review and approval. Concurrently with Denbury's repair and restart efforts, PHMSA conducted an inspection of Denbury's pipeline operations, which resulted in the

issuance of various enforcement actions, including a Notice of Probable Violation in connection with this accident.[6]

Investigation Details

On February 23, 2020, at 10:09 a.m., a PHMSA AID investigator from Oklahoma City arrived at the intersection of HWY 433 and Highway 3 to meet with Denbury representatives and emergency response organizations. The group then proceeded to the site of the rupture (Figure 2). By that time, the IC had demobilized, and roadblocks had been removed. Denbury crews were in the process of setting up caution fencing and slowing traffic on HWY 433 for public and worker safety. The rupture crater was on the northeast side of HWY 433 (Figure 2).



Figure 2: Vehicle is Parked on HWY 433 - The White is Ice Generated by the Release of CO_2 - The Blue Arrow Points North (Aerial Drone Photograph Courtesy of the Mississippi Emergency Management Agency)

[6] CPF 4-2022-017-NOPV, dated May 26, 2022.

The topography along the pipeline right-of-way (ROW) in this area is a steep hill that rises from the valley containing the Big Black River to the east, goes relatively flat across the crest of the hill containing HWY 433, and then slopes downward toward the valley containing the Yazoo River to the west.



Figure 3: Crater Created by the Rupture Containing Fallen Debris (dry ice, and the failed pipe sections) (Blue Arrow is Pointing at the Pipeline Separation)

The pipeline separated at a girth weld. The pipeline self-excavated due to the discharge of CO_2. The auto refrigeration generated by the CO_2 discharge and accompanying chance in phase covered the area with a thick layer of ice (Figures 2, 3, and 4). The upstream section of pipe was not covered in ice, and a slightly jagged edge was observed on the rupture edge (Figure 4). The crater was an estimated 40-feet-deep on the downstream (HWY 433) side and about four-feet-deep on the upstream side.



Figure 4: The failed pipe sections shown separated by a few inches.

Upon release, the CO_2 transitioned from a liquid to a gaseous phase resulting in a refrigeration effect. Although the pipeline was shut down by 7:15 pm, the remaining contents of the pipe continued to vent to the atmosphere for several hours. The CO_2 was heavier than air[7] and followed a path downhill. CO_2 moved down the slope to the east and remained in the bowl of the crater. As the discharged volume increased, and without significant winds to disperse the CO_2, the CO_2 moved over the crest of the hill then west into the valley, reaching Satartia.

Plume Model

First responders utilized a plume model generated by the NWS to base the decision to evacuate Satartia (Figure 5).

[7] CO_2 has a density approximately 1.53 times that of air in standard atmospheric conditions.

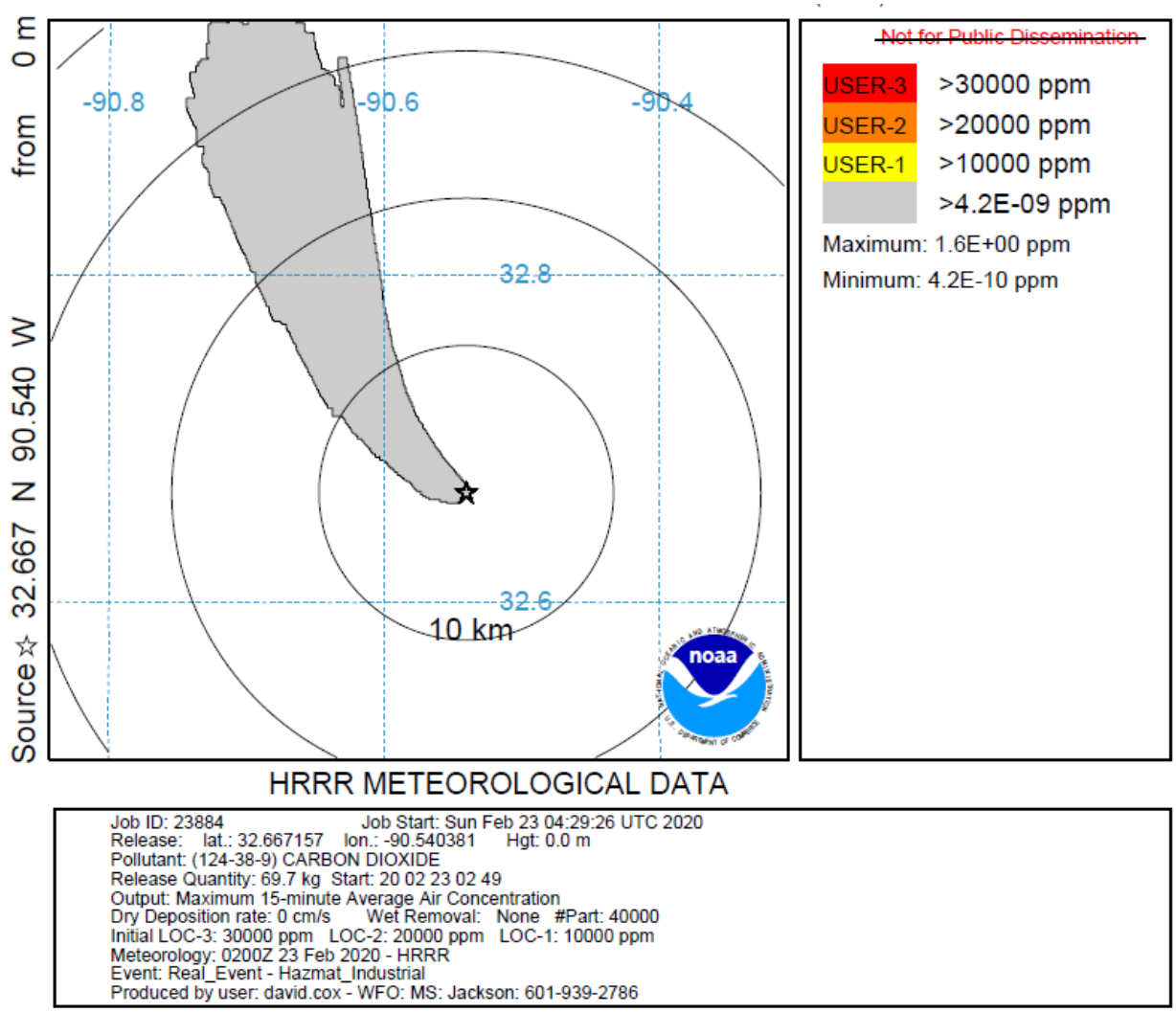

Figure 5: This Chart Shows the Plume Model Data Generated by the National Weather Service/NOAA - The Model Indicates the Direction a Plume or Cloud of CO_2 Would Have Followed from Ground Level While Dissipating, According to Atmospheric Data at the Time of the Release - Each Ring is 10 Kilometers (Satartia is Less Than Two Kilometers Northwest of Release Site, Indicated by the Star)[8]

Prior to the accident in 2011, Denbury had contracted a third-party company to generate an affected radius model for a potential CO_2 release. Denbury used the model to generate a zone along the pipeline ROW to identify pipeline segments which were within or "could affect" an HCA and to develop its Public Awareness Program (PAP).[9] The model established a zone for the Delhi Pipeline (Figure 6) that left Satartia outside of the affected radius, and therefore the pipeline segment was not identified by Denbury as a "could affect" HCA. Additionally, Satartia was not included in Denbury's PAP or considered in any local

[8] The NWS approved inclusion of the chart within this report and clarified that "Not for Public Dissemination" (in the upper right-hand corner) pertains to real-time emergency response utilization, due to inherent uncertainties with several variables.
[9] Required by 49 CFR § 195.440.

emergency response plans. The rupture location was one mile from the center of Satartia, where the entire town was evacuated.



Figure 6: Topographical Map Showing the Delhi Pipeline (Green) and Denbury's Buffer Zone (Red) on Either Side of the Pipeline and the Proximity to Satartia (Blue Star Indicates the Rupture Site)

Soil and Geohazards

The soil at the failure location is identified as a loess soil typical to the area and was relatively saturated due to the recent heavy rainfall. Dry patches of the soil observed later were powdery, confirming the loess to be silty and clayey, indicating the soil would be prone to absorb water as well as collapse or slump under the right conditions.[10] Vertical erosion of the steeply sloped hillside, made heavier by water saturation, produced enough axial loading on the pipeline to cause the girth weld to fail.

On February 23, 2020, representatives from the Mississippi Department of Transportation assessed the condition of the crater's edge along HWY 433. They determined the highway was at risk of further land movement due to current and future soil saturation from rainfall, the weight of the trees at the edge of the crater, and the HWY 433 ROW was impinged upon by the rupture. Crews were dispatched to cut down the trees and mitigate the risk of additional land movement. Soil instability along roads is not unusual in the region. The PHMSA AID investigator observed road damage from unstable soil slumping away from a road along roadways leading to the accident site. Denbury representatives mentioned that, along the Delhi pipeline, they experience two to three issues per year involving land movement. Denbury's Integrity Management Program (IMP)[11] identified "geo-technical hazards" (geohazards) as a potential risk to its pipelines but lacked additional details concerning threat assessment or preventative/mitigative measures for its operational pipelines such as: using in-line inspection tools with inertial measurement unit sensors, conducting bending strain analysis, or conducting geohazard assessments. Denbury's operations and

[10] Loess soil has a relatively high porosity (typically around 50-55%) and often contains vertical capillaries that allow the sediment to fracture and form vertical bluffs. The loess bluffs tend to erode vertically.
[11] Required by 49 CFR § 195.452.

maintenance (O&M) procedures also lacked substantive information regarding geohazard identification, assessment, remediation, and training for employees. Additionally, Denbury's pipeline patrolling program to address federal regulations[12] was commonly performed by aerial patrol. Records indicate that patrols were made at regular intervals, but no geohazards were identified at the rupture location.

In response to this rupture, PHMSA initiated a specialized review of Denbury's IMP and O&M activities. PHMSA's investigation identified that Denbury did not address the risk of geohazards to the pipeline and take adequate preventive and mitigative measures prior to the accident. PHMSA has made specific recommendations for the development of the company's geohazards program, which the company has initiated.

Welding Procedure

Denbury hired DNV prior to the construction of the pipeline to develop its welding procedure. The welding procedure was developed to API 1104, 20th edition and was qualified. The procedure utilized an E6010 electrode root pass, an E9018G electrode hot pass and E10045 electrode filler and cap pass. In 2009, a welding procedure utilizing an E10045 electrode was a pipeline construction industry leading development. Prior industry practice was to utilize cellulosic-type electrodes.

Laboratory and Root Cause Analyses

Once shoring was installed at the rupture site, the upstream pipe was excavated, and two failed pipe sections were cut out. On March 11, 2020, the two failure samples were secured and shipped to DNV's laboratory in Columbus, Ohio for metallurgical analysis. Denbury worked with Mears to provide DNV with a testing protocol to facilitate analysis. Mott MacDonald performed a site-specific soil movement analysis to estimate soil loading on the pipeline and perform a stress analysis. Mears performed a Root Cause Analysis utilizing the above information, coupled with information from original construction documentation, site observations, operating and maintenance records, and related information.

Denbury reported the results of the metallurgical findings and stress evaluations in a written accident report on the PHMSA Form 7000.1 and indicated soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition, and the soil movement was promoted by unusually heavy rainfall. There were no material defects observed with the pipe or the failed weld which could have contributed to the failure.

PHMSA notes the failed girth weld exhibited both ductile and brittle fracture appearances. A typical overload condition in these circumstances is expected to be ductile, unless the grain structure of the steel is susceptible to brittle failure, or the material has been chilled below its transition temperature from ductile to brittle behavior. A failure scenario whereby a leak initiates, and the refrigeration effect associated with vaporization of the liquid CO_2 results in a brittle failure is plausible, although a distinct failure origin within the girth weld was not identified.

Findings and Contributing Factors

PHMSA has determined that the failure of the Delhi Pipeline was a result of soil movement which caused excessive axial loading leading to failure at the girth weld. Area topography, soil type, and large amounts of rain over the preceding months saturated and vertically eroded the loess soil on the side of the hill above the pipeline. It is unclear whether prevalent warmer temperatures in the two months preceding the heavy rainfall could have contributed to the soil instability as well.

[12] Required by 49 CFR § 195.412.

Contributing factors include:

- Denbury's O&M procedures did not appear to address the potential for pipeline damage due to soil instability despite having prior experience with and knowledge of land movement risks.
- Denbury's IMP did not appear to address integrity threat identification and/or assessment for geohazards or preventative or mitigative measures.
- Denbury's aerial patrols did not identify a geohazard at the failure location prior to the accident.
- Denbury's CO_2 dispersion model underestimated the potential affected area that could be impacted by a release. As a result, the pipeline segment was not identified as a "could affect" HCA, and Satartia was not included in Denbury's PAP.
- Denbury did not notify local responders advising them of a potential failure. Local responders contacted Denbury approximately 40-minutes after the rupture. This led to confusion in understanding circumstances associated with the emergency and hindered the ability of first responders and community members to safely navigate the emergency.

Appendices

Appendix A Map

Appendix B NRC Reports Nos. 1271847 and 1272001

Appendix C PHMSA 7000.1 Final Report

Appendix D Mears Metallurgical and Root Cause Failure Analysis

Appendix E CTEH Air Monitoring Summary Report

Appendix A Map



Figure 7: An ArcGIS-generated Satellite Map with the Site of the Rupture Marked by the Red Star (the Insert Map on the Bottom Right Shows the Rupture Site Location Within the State of Mississippi)

Appendix B NRC Report No. 1271847

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:28 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1271847

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1271847

INCIDENT DESCRIPTION

*Report taken by NRC on 22-FEB-20 at 22:06 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 19:07 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

32.658 County: YAZOO
-90.537
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: SE
OFF HWY 433

RELEASED MATERIAL(S)

CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 222 BARREL(S)

DESCRIPTION OF INCIDENT

CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Sent to Hospital: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: UNKNOWN

Closure Type	Description of Closure	Hours Closed	Direction of Closure

Air: NO

Road: YES HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD — Major Artery:YES
Waterway:NO

Track: NO

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: NONE

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local:
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

CENTERS FOR DISEASE CONTROL (GRASP)
22-FEB-20 22:14

DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
22-FEB-20 22:14
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
22-FEB-20 22:14
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
22-FEB-20 22:14
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
22-FEB-20 22:14
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
22-FEB-20 22:14
U.S. EPA IV (MAIN OFFICE)
22-FEB-20 22:17
U.S. EPA IV (EPA RRT4)
22-FEB-20 22:14
GULF STRIKE TEAM (MAIN OFFICE)
22-FEB-20 22:14
JFO-LA (COMMAND CENTER)
22-FEB-20 22:14
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
22-FEB-20 22:14
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
22-FEB-20 22:14
NOAA RPTS FOR MS (MAIN OFFICE)
22-FEB-20 22:14
NTSB PIPELINE (MAIN OFFICE)
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
22-FEB-20 22:14
DOI FOR REGION 4 (MAIN OFFICE)
22-FEB-20 22:14
REPORTING PARTY (RP SUBMITTER)
22-FEB-20 22:14
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
22-FEB-20 22:14
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
22-FEB-20 22:14
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
22-FEB-20 22:14
TEXAS FUSION CENTER (COUNTER TERRORISM)
22-FEB-20 22:14
USCG DISTRICT 8 (MAIN OFFICE)
22-FEB-20 22:14
USCG DISTRICT 8 (PLANNING)
22-FEB-20 22:14

ADDITIONAL INFORMATION

THE ROAD CLOSURES ARE STILL ONGOING.

*** END INCIDENT REPORT #1271847 ***

Report any problems by calling 1-800-424-8802

PLEASE VISIT OUR WEB SITE AT

https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb811754707c84b89d3e308d7fdabecad%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256787161489692&sdata=MzcfYqeN1ZIbmwqa6VXKF9L%2FqieIW0kTmcl30E8JTvk%3D&reserved=0

Appendix B NRC Report No. 1272001

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:30 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1272001

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
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applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1272001

INCIDENT DESCRIPTION

*Report taken by NRC on 24-FEB-20 at 19:56 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 22:06 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION
OFF HWY 433 County: YAZOO
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: Latitude: 32° 39' 28" N

Longitude: 090° 32' 13" W

RELEASED MATERIAL(S)
CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 21873 BARREL(S)

DESCRIPTION OF INCIDENT
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

UPDATE: THE CORRECT LAT/LONG FOR THE INCIDENT IS 32.65785 NORTH AND
-90.53695 WEST.
TWO HUNDRED PRIVATE CITIZENS WERE EVACUATED FROM THEIR HOMES IN THE

AREA OF THE RELEASE.
FORTY FIVE PEOPLE WERE TAKEN TO A HOSPITAL. THE NUMBER OF PEOPLE TAKEN TO A HOSPITAL DUE TO INJURIES IS UNKNOWN
TWO PEOPLE ARE STILL AT THE HOSPITAL AS OF 24-FEB-20. THE RELEASE WAS COMPLETELY SECURED AT 23:08HRS ON SATURDAY THE 22-FEB-20. ROAD CLOSURES AND EVACUATION ORDER WAS LIFTED AT 08:00AM ON SUNDAY FEBRUARY 23RD. THE TOTAL AMOUNT OF THE RELEASE WAS DETERMINED TO BE 21,873 BARRELS OF CARBON DIOXIDE GAS. THE EVACUATION RADIUS WAS .25 MILES. TV NEWS AND POSSIBLY NEWSPAPERS IN THE LOCAL AREA AS WELL AS NATIONAL NEWS REPORTED THE INCIDENT. RELEASE DURATION WAS 4 HOURS. PHMSA, MS OIL AND GAS, MS DEQ WERE NOTIFIED. MS DEQ, STATE POLICE, LOCAL FD, LOCAL PD, EMS AND HWY PATROL WERE ALL ON SCENE.

ORIGINAL REPORT: CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: YES 45 Sent to Hospital:45 Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:YES 200 Who Evacuated: EVERYONE Radius/Area:.25 Mile(s)

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure

Air: NO

Road: YES HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD Major Artery:YES

Waterway:NO

Track: NO

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: HIGH

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal: PHMSA
State/Local: MS DEQ, MS OIL AND GAS, SATATE POLICE
State/Local On Scene: MS DEQ, STATE POLICE, PD, FD, EMS
State Agency Number:

NOTIFICATIONS BY NRC

AGCY TOXIC SUBST & DISEASE REGISTRY (HHS)
24-FEB-20 20:22
CENTERS FOR DISEASE CONTROL (GRASP)
24-FEB-20 20:22
DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
24-FEB-20 20:22
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
24-FEB-20 20:22
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
24-FEB-20 20:22
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
24-FEB-20 20:22
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (MAIN OFFICE (AUTO))
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (AFTER HOURS SECONDARY)
24-FEB-20 20:36
U.S. EPA IV (MAIN OFFICE)
24-FEB-20 20:32
U.S. EPA IV (EPA RRT4)
24-FEB-20 20:22
GULF STRIKE TEAM (MAIN OFFICE)
24-FEB-20 20:22
INFO ANALYSIS AND INFRA PROTECTION (MAIN OFFICE)
24-FEB-20 20:22
JFO-LA (COMMAND CENTER)
24-FEB-20 20:22
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
24-FEB-20 20:22
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
24-FEB-20 20:22
NOAA RPTS FOR MS (MAIN OFFICE)
24-FEB-20 20:22
NRC COMMAND DUTY OFFICER (MAIN OFFICE)

24-FEB-20 20:50
NTSB PIPELINE (MAIN OFFICE)
24-FEB-20 20:22
OCCUPATIONAL SAFETY & HEALTH ADMIN (MAIN OFFICE)
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY WEEKDAYS (VERBAL))
24-FEB-20 20:34
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
24-FEB-20 20:22
DOI FOR REGION 4 (MAIN OFFICE)
24-FEB-20 20:22
REPORTING PARTY (RP SUBMITTER)
24-FEB-20 20:22
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
24-FEB-20 20:22
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
24-FEB-20 20:22
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
24-FEB-20 20:22
TEXAS FUSION CENTER (COUNTER TERRORISM)
24-FEB-20 20:22
USCG DISTRICT 8 (MAIN OFFICE)
24-FEB-20 20:22
USCG DISTRICT 8 (PLANNING)
24-FEB-20 20:22

ADDITIONAL INFORMATION
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

*** END INCIDENT REPORT #1272001 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT
https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb126276307c640ca447f08d7fdab7b17%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256785273758601&sdata=wEB2Wbm6RWfQw9nm5l8g20CXFahn0HprioWivv3i1Uo%3D&reserved=0

Appendix C PHMSA 7000.1 Final Report

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0047 EXPIRATION DATE: 8/31/2020
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	03/21/2020
	No.	20200087 - 34574 --- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**
Last Revision Date:	11/25/2020		
1. Operator's OPS-issued Operator Identification Number (OPID):	32545		
2. Name of Operator	DENBURY GULF COAST PIPELINES, LLC		
3. Address of Operator:			
3a. Street Address	5851 LEGACY CIRCLE SUITE 1200		
3b. City	PLANO		
3c. State	Texas		
3d. Zip Code	75024		
4. Local time *(24-hr clock)* and date of the Accident:	02/22/2020 19:07		
5. Location of Accident:			
Latitude / Longitude	32.65785, -90.53695		
6. National Response Center Report Number (if applicable):	1271847		
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	02/22/2020 20:51		
8. Commodity released: *(select only one, based on predominant volume released)*	CO2 (Carbon Dioxide)		
- Specify Commodity Subtype:			
- If "Other" Subtype, Describe:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend e.g. B2, B20, B100			
9. Estimated volume of commodity released unintentionally (Barrels):	9,532.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	21,873.00		
11. Estimated volume of commodity recovered (Barrels):			
12. Were there fatalities?	No		
- If Yes, specify the number in each category:			
12a. Operator employees			
12b. Contractor employees working for the Operator			
12c. Non-Operator emergency responders			
12d. Workers working on the right-of-way, but NOT associated with this Operator			
12e. General public			
12f. Total fatalities (sum of above)			
13. Were there injuries requiring inpatient hospitalization?	No		
- If Yes, specify the number in each category:			
13a. Operator employees			
13b. Contractor employees working for the Operator			
13c. Non-Operator emergency responders			
13d. Workers working on the right-of-way, but NOT associated with this Operator			
13e. General public			
13f. Total injuries (sum of above)			

14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	02/22/2020 19:15
14b. Local time pipeline/facility restarted:	10/26/2020 12:30
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	200
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident - effective 7- 2014 changed to "Local time Operator identified failure":	02/22/2020 20:20
18b. Local time Operator resources arrived on site:	02/22/2020 20:20

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Mississippi
3. Zip Code:	39194
4. City	Not Within a Municipality
5. County or Parish	Yazoo County
6. Operator-designated location:	Milepost/Valve Station
Specify:	6.6
7. Pipeline/Facility name:	Delhi
8. Segment name/ID:	Delhi
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	360
12. Did Accident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Weld, including heat-affected zone
- If Pipe, specify:	
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.540

3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	80,000
3d. Pipe specification:	API 5L
3e. Pipe Seam , specify:	Longitudinal ERW - High Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Stupp Corporation
3g. Year of manufacture:	2007
3h. Pipeline coating type at point of Accident, specify:	Field Applied Epoxy
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	Pipe Girth Weld
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	2009
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Other
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	Guillotine Type Failure

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	No
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	No
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	
- Vegetation	
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	No
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	

- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	No
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated cost to Operator – effective 12-2012, changed to "Estimated Property Damage":	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 12-2012, "paid/reimbursed by the Operator" removed	$ 225,899
8b. Estimated cost of commodity lost	$ 11,130
8c. Estimated cost of Operator's property damage & repairs	$ 3,504,518
8d. Estimated cost of Operator's emergency response	$ 205,462
8e. Estimated cost of Operator's environmental remediation	$ 0
8f. Estimated other costs	$ 0
Describe:	
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 3,947,009

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	1,402.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	2,160.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f below)* effective 12-2012, changed to *"(Complete 5.a – 5.e below)"*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	50,406
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	Yes
- If Yes, Which operational factors complicate execution? (*select all that apply*)	
- Excessive debris or scale, wax, or other wall buildup	

- Low operating pressure(s)	
- Low flow or absence of flow	Yes
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm (s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm (s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	

1b. Specify how many failed:	
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G2 - Natural Force Damage

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

Corrosion Failure – Sub-Cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	

- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column

Natural Force Damage – Sub-Cause:	Heavy Rains/Floods
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	

- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	Other
- If Other, Describe:	,Soil movement, promoted by unusually high rainfall averages and not a singular event, induced axial stresses sufficient to cause an overload condition.,,
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	No
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Previous Damage due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	

Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	

3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	

G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column

Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause shown above is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation	

(Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	

Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	

- If Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

On 2/22/2020 at 19:07, the Denbury Control Center (DCC) observed a low-pressure alarm at the Satartia motor operated valve (MOV) location on the Delhi segment. The Control Center Supervisor was notified and at 19:15 the upstream MOV, downstream MOV, and the Satartia MOV were closed by the DCC. Denbury operations personnel were immediately notified by the DCC of low-pressure alarms and valve closures and were mobilized to the area in addition to emergency response contractors. While mobilization of personnel occurred, the DCC closed all CO2 sources to Delhi segment between 19:26 and 19:28. At 19:54, a Denbury representative contacted the Tri-Community Fire Chief, who was on-site and identified himself as the Incident Commander on location acknowledging the incident was being managed in the Unified Command. Denbury personnel arrived on-site at 20:20 to confirm the Delhi segment had experienced a pipeline failure upstream of the Hwy 433 road crossing. At 20:21, a Denbury representative contacted the Yazoo County EMA, who was directing the Yazoo County Sheriffs Department, MS Highway Patrol, and MDOT. The Yazoo County EMA confirmed that they began facilitating the evacuation of residence near Satartia, MS at approximately 19:20. MSDEQ was notified at 19:58. Both MSDEQ and MEMA were on-scene and performing supporting agency roles during the emergency phase of the response (4 hours). At 20:51, the NRC was notified, and the CO2 leak was reported (NRC #1271847). At 21:36 emergency response contractors arrived on-site and began conducting preliminary air-monitoring for response personnel. At 21:55 additional emergency response contractors arrived on-site and began conducting community air monitoring and atmospheric testing in and around the failure site and the City of Satartia and the surrounding area. Air monitoring and atmospheric testing continued throughout the night. At 23:06, Denbury personnel observed no product coming from the failure location. At 0:00 on 2/23/2020, an Operation Period Briefing was conducted by the Unified Command. During the briefing, the incident command team instructed responders to continue air monitoring, conduct reconnaissance within the evacuated areas to ensure no people were left behind, clear the debris and soil off of HWY 433, and begin developing a plan to lift the evacuation. At 06:00 a planning meeting was conducted by the Unified Command. The recon team confirmed all personnel had been evacuated and reported seeing live cows, dogs, and cats throughout the evacuated area. The air monitoring team also reported that CO2 levels were down to ambient levels and the evacuation could be lifted. At 08:00 the Unified Command gave the All Clear, and the roads were opened and residents in the surrounding area were allowed to return to their homes. Personnel and a toxicologist from CTEH were made available to inspect homes prior to the residence re-entry. At 18:39 on 2/24/2020, the NRC was contacted and given a 48-hour update report (NRC #1272001). A total of 200 residents were evacuated and 45 residents were taken to the hospital. To Denburys knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure.

On 3/9/2020 pipeline samples of the failure location were removed, prepared for shipment, and sent to a testing laboratory on 3/11/2020. The results from the laboratory testing were received and shared with PHMSA on 6/26/2020.

Based on the findings of metallurgical and stress evaluations and the evidence of a code compliant pipeline, it is concluded that soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition and resulted in the pipeline rupture. Soil movement was promoted by unusually high rainfall averages and not a singular rainfall event.

The pipeline segment was repaired and on 10/26/2020 at 12:30 the pipeline was restarted with no issues.

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Date	11/24/2020

Appendix D Mears Metallurgical and Root Cause Failure Analysis



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Study of Root Cause and Contributing Factors

Denbury – Yazoo County

Failure Investigation

Final Report

Revised 9/02/2021

Prepared for:

Denbury Resources Inc.

Prepared by:

Mears Group, Inc.

~~Privileged and Confidential~~

September 2, 2021

Denbury Resources Inc.
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Attention: Chad Docekal

Subject: Denbury Delhi 24-inch Transmission Line failure Root Cause Analysis – Final Report, Revised 9/02/2021

Thank you for the opportunity to provide Denbury Resources with root cause investigation and analysis for the Denbury Delhi 24-inch transmission line near Satartia, Mississippi. This revision includes additional appendices providing supporting information and responses to questions provided to Mears 4/7/2021. If you have any questions or comments, please call me at (614) 832-3896.

Sincerely,

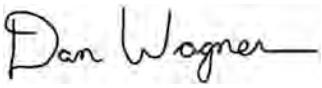
Kevin Garrity
Executive Vice President

Cc: Dan Wagner
Aida Lopez-Garrity
Kurt Lawson

SIGNATURE FORM

Study of Root Cause and Contributing Factors
Denbury – Yazoo County
Failure Investigation
Final Report

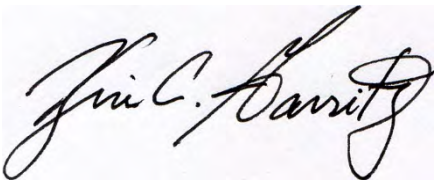
Prepared by:



Dan Wagner – Principal Technical Advisor — 9/02/2021 Date



Aida Lopez-Garrity – Executive Director – Special Projects — 9/2/2021 Date



Kevin C. Garrity, P.E., FNACE – Executive Vice President — 9/2/2021

Executive Summary

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The failure is reported to have occurred February 22, 2020, with a rupture approximately 6.59 miles (stationing 348+26) downstream of the Tinsley, MS station.

The investigation into the cause and contributing factors to the Delhi 24-inch failure has been undertaken through the following activities:

- In-Situ investigations at the incident location,
- Corrosion and coating related assessments,
- A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
- Laboratory Analysis of the Failure.

Metallurgical Testing and Failure Analysis was performed on three samples of pipe from the failure site. The metallurgical testing laboratory completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

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The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.

Based on the findings presented, the pipeline failure occurred at the girth weld due to an overload of axial stress on the weld. A possible contributing factor to the failure may have been axial stresses introduced by movement. These findings are supported by the following:

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.
4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X-80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

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Acronyms and Abbreviations

API	American Petroleum Institute
ARO	Abrasion Resistant Overlay
CP	Cathodic Protection
CVN	Charpy V-Notch
D/S	Downstream
EDS	Energy-Dispersive Spectroscopy
ERW	Electric Resistance Welding
FATT	Fracture Appearance Transition Temperature
FBE	Fusion Bonded Epoxy
GW	Girth Weld
HAZ	Heat Affected Zone
HDD	Horizontal Directional Drilling
HF-ERW	High Frequency Electric Resistance Welding
HV	Hardness Value
ID	Inside Diameter
MAOP	Maximum Allowable Operating Pressure
MPI	Magnetic Particle Inspection
NWT	Nominal Wall Thickness
OD	Outside Diameter
PS	Pipe Sample
PSIG	Pounds per Square Inch Gauge
PSL	Product Specification Levels
RCA	Root Cause Analysis
SEM	Scanning Electron Microscope
SMYS	Specified Minimum Yield Strength
TS	Tensile Strength
U/S	Upstream
UTS	Ultimate Tensile Strength

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WT	Wall Thickness
YS	Yield Strength

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1.0 INTRODUCTION

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The incident is reported to have occurred on February 22, 2020, when a failure occurred on the 24-inch Delhi Transmission Line, resulting a rupture of the pipeline.

The information, material and documentation reviewed and relied upon in the formation of the findings expressed include:

- Pipe and coating data,
- Alignment Sheets,
- Indirect inspection results,
- Google Earth™ imagery,
- As-built drawings and sketches,
- Onsite inspections,
- Field and laboratory test results,
- Metallurgical examination reports,
- Welding Procedures,
- Stress Analysis Report, and
- Personnel interviews.

The findings expressed are based upon the information reviewed to date and analyses performed to date and may be modified as new or additional information/analysis are considered.

2.0 BACKGROUND

The Delhi 24-inch Transmission Line serves as a carrier of carbon dioxide and is approximately 77.4 miles in length. The pipeline segment begins at the Denbury Tinsley Station in Yazoo County, Mississippi and continues to a meter station near Delhi, Louisiana. An overview of the pipeline segment is provided in Figure 1.

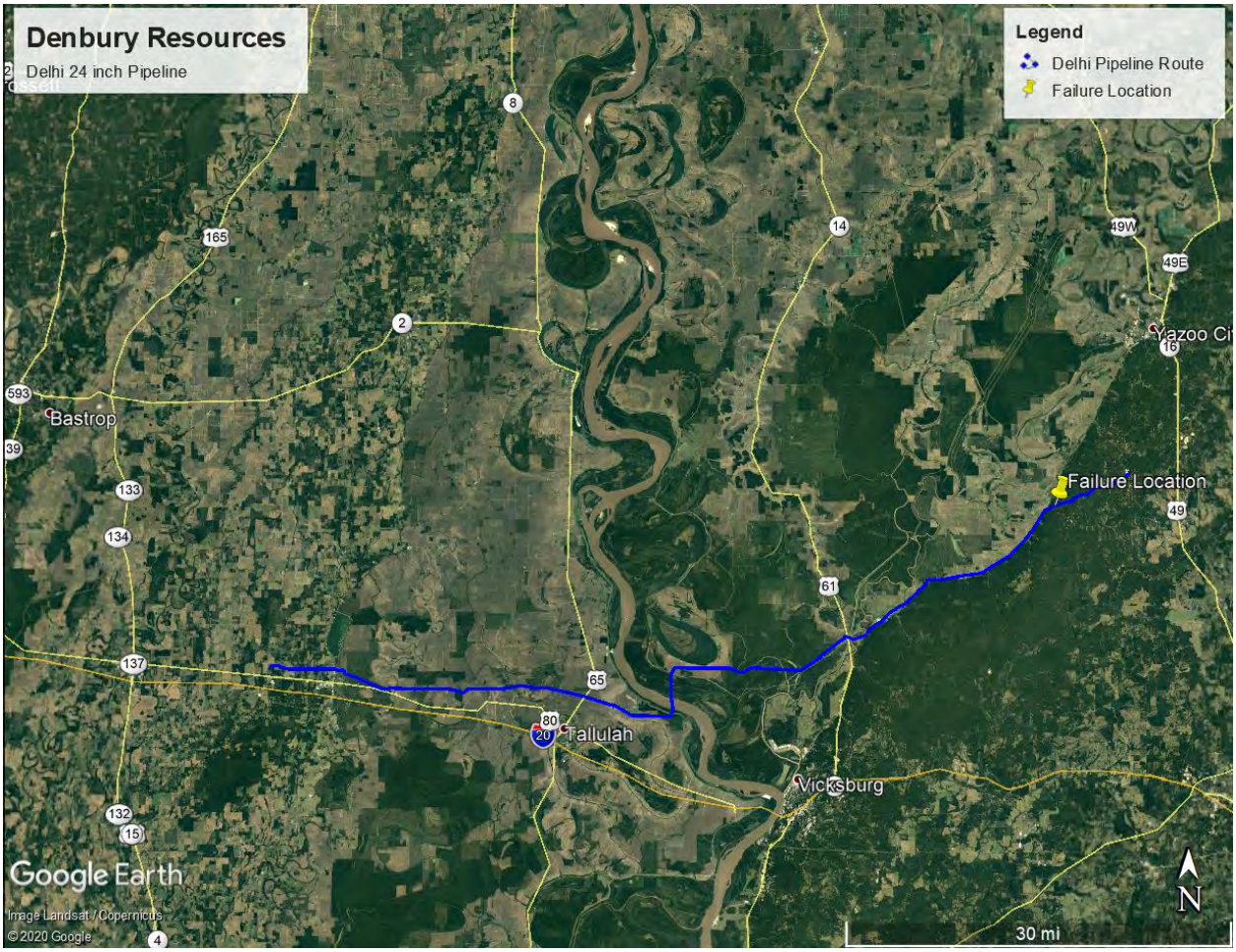

Figure 1. Delhi 24-inch Transmission Pipeline Route

2.1 Pipeline Construction Data

The Delhi 24-inch Transmission Line is documented as installed in 2009, primarily of 0.469-inch wall thickness, API 5L Grade X-80M PSL 2 piping, with a high frequency electric resistance welded (HF-ERW) seam, coated with fusion-bonded epoxy (FBE). Sections of piping installed using slick bore were constructed of 0.540-inch X-80 coated with FBE and an additional layer of abrasion-resistant overcoat (ARO). The pipeline has a diameter of 24 inches. A simplified overview of the pipeline segment is provided in Figure 2.

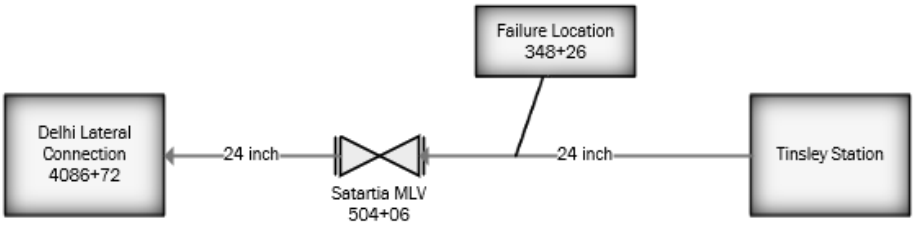

Figure 2. Simplified Delhi 24-inch Transmission Line Diagram

A summary of pipeline information for the Delhi 24-inch Transmission Line in included in Table 1.

Table 1. Pipeline Data

Pipeline Information	Delhi 24-inch Transmission Line
Line Length (miles)	77.4
Pipe Outside Diameter (inches)	24
Pipe Wall Thickness (inches)	0.469, 0.540
Pipe Grade	X-80
Maximum Allowable Operating Pressure (MAOP, psi)	2,160
Normal Operating Stress Level (psi)	1,200-1,450
Pressure at Time of Failure (psi)	1,336
Pipe Seam Type	ERW
Product Carried	Carbon Dioxide (dry)
Pipe Construction Date	2009
Pipe Coatings (type/thickness)	FBE 14-16 mils and ARO 40 mils
Girth Weld Coatings	Liquid Epoxy – SPC-2888

A post-construction hydrostatic pressure test was reported to have been conducted on the piping in January 2009 to a minimum test pressure of 2,908 psig at the Dead Weight Location for 8 hours.

The pipeline is reported to have had impressed current cathodic protection applied since the date of construction with no interference bonds and two continuity bonds at the start and end of the pipeline section.

2.2 Incident Summary

The incident is reported to have occurred after 7:00 p.m. local time, based on resident reports and an evacuation order, on February 22, 2020 near Satartia Mississippi, when a failure occurred at a girth weld, resulting in a rupture of the pipe near a crossing of Mississippi Highway 433 approximately 1 mile southeast of Satartia. The line was shut down and valves closed at approximately 7:17 p.m. as reported by Denbury.

The failure occurred on a pipe section consisting of 24-inch diameter by 0.540-inch wall thickness API 5L Grade X-80M PSL 2 line pipe with a high frequency electric resistance welded (HF ERW) seam. The pipe at the site of the failure was installed using slick bore, coated with FBE/ARO on the pipe and liquid epoxy coating applied on the girth welds. The failure occurred at approximate stationing 348+26, about 6.59 miles downstream of the Tinsley Station at the base of a hill, significantly lower in elevation than the surface of Highway 433. The pipeline normally operates between 1,200 psig and 1,450 psig. At the time of the failure, the pressure at the Tinsley Meter Station (0+00) was 1,336 psig.

A Google Earth™ overview of the failure location is provided in Figure 3.

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Figure 3. Delhi 24-inch Transmission Failure Location

A photo of the failure location post-incident is included in Figure 4.

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Figure 4. Post-Incident Photo of Failure Location (Downstream to Upstream)

3.0 ROOT CAUSE ANALYSIS PROCESS

A failure action sequence was used for the purposes of performing the Root Cause Analysis.

The basic role of a root cause analysis is as follows:

- Collect information.
- Understand what happened.
- Identify the problems that caused the incident.
- Analyze each problem's root causes.
- Look beyond root causes for systemic, cultural, and organizational factors.
- Develop recommendations for remediation to improve performance and prevent repeat incidents.

Since root cause analyses are normally associated with incidents or accidents, much of the existing terminology in use refers to "incidents".

A typical Failure Action Response Sequence adapted from Guidance for Plant Personnel on Gathering Data and Samples for Materials Failure Analysis MTI catalog MTI 9539 is shown in Figure 5.

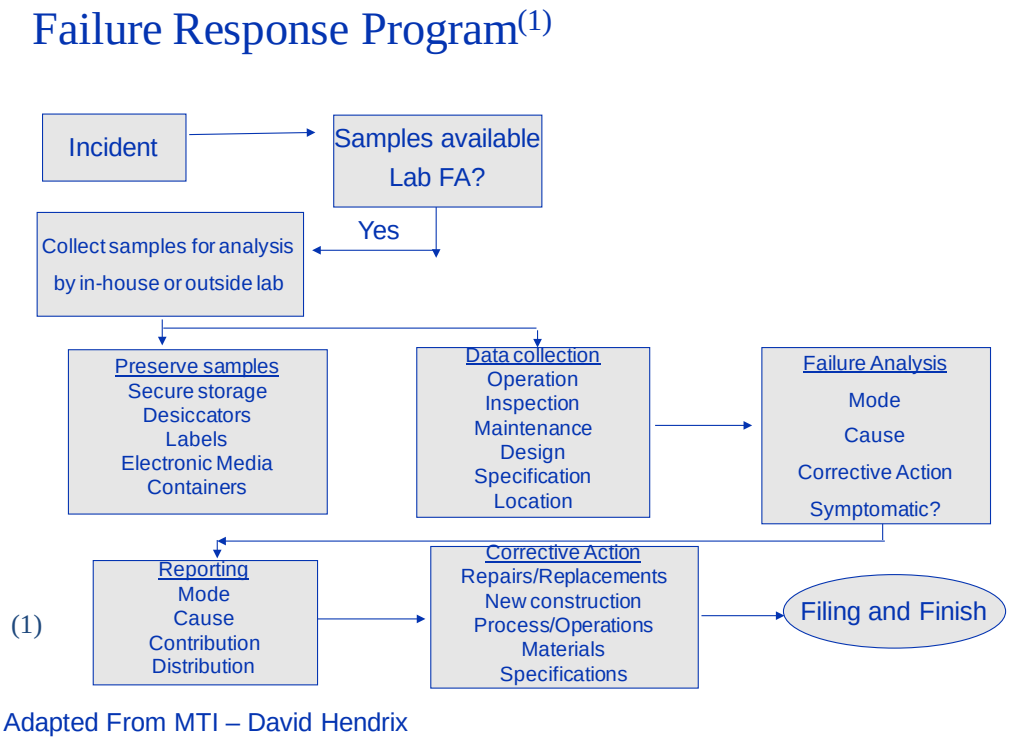

Figure 5. Failure Response Sequence

The root cause analysis focused on identifying the root cause(s) of the pipeline failure and contributing factors.

4.0 DESCRIPTION OF INVESTIGATIVE PROCESS

The investigation into the cause and contributing factors to the Delhi 24-inch Transmission line failure has been undertaken through the following activities:

1. In-Situ investigations at the release location,
2. Corrosion and coating related assessments,
3. A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
4. Laboratory failure analysis of the failure.

Metallurgical testing and a failure analysis were performed on three samples of pipe from the release site. The metallurgical testing lab completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.
The available information related to construction, prior integrity assessments and cathodic protection was analyzed to assist in establishing the root cause and contributing factors of the failure.

4.1 In-Situ Investigation Findings

On February 27, Mears mobilized to the release location to secure the failed pipe sections for laboratory investigation, perform initial site investigations, and collect information to support the root cause analysis.

Upon arrival, significant response and operational activities had been undertaken to secure the site and prepare for excavation and removal of the pipe section.

From initial visual examination, the failure appeared to have occurred at least 40 feet in elevation below the roadway, with indications of soil subsidence in the vicinity of the failure. The release crater included trees and root debris, but based on the pipeline alignment sheet elevation profile, a significant volume of soil in the slick bore section between the failure and MS Highway 433 had collapsed. The soil in the vicinity of the failure appeared to be extremely wet.

Figure 6 and Figure 7 show the view of the release location as-found on February 27, 2020.



Figure 6. Failure Location (Upstream to Downstream)

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Figure 7. Failure Location (Upstream to Downstream)

Personnel were unable to access the pipe at the failure location due to the depth of the crater and instability of the soil on the downstream side of the crater.

In-situ visual inspection of the exterior surface of the pipe identified a separation of the piping at a girth weld of approximately 8 inches, with slight misalignment between the upstream and downstream joints. Figure 8 provides a close-up of the as-found pipe and coating condition at the separation.



Figure 8. Delhi 24-inch Transmission Line Failure - As-Found Condition at Girth Weld

A protocol was developed for removal of pipe samples in the vicinity of the failure, to include the upstream and downstream sections of the failure and an intact girth weld near the failure location. A copy of the Pipe Collection Protocol is provided in Appendix A.

Removal of the samples began on March 9, 2020. Excavation and removal of an upstream section of piping included the upstream half of the failure and the intact girth weld noted above. This section was approximately 68 feet 5 ½ inches in length.

Figure 9 shows the upstream pipe section being removed from the site.



Figure 9. Upstream Pipe Section During Removal

Following removal of the upstream section, limited excavation and backfill was conducted to allow access to the downstream side of the failure. A section of pipe containing the downstream section of the failure was then removed using a magnesium torch attached to the bucket of an excavator.

Once moved to an accessible location, the pipe sections were documented, samples were cut and prepared for shipment to the laboratory. Figure 10 provides an overview of the pipe sections as removed and prepared for shipment.

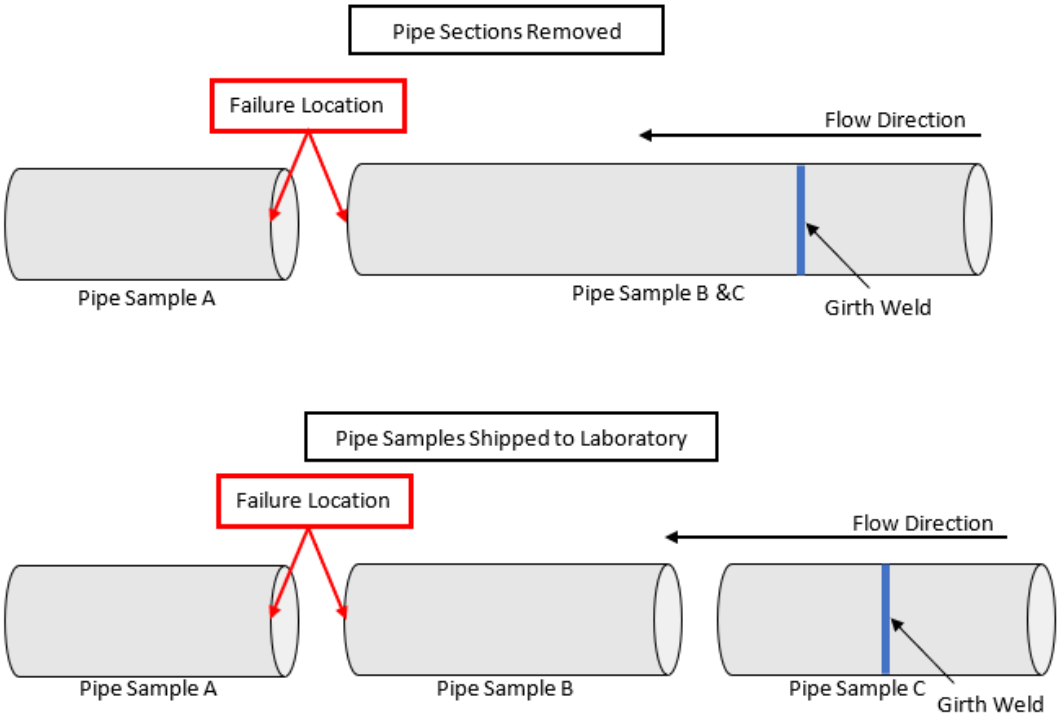

Figure 10. Overview of Pipe Sections and Samples

Visual inspection of the external surface of the pipe sections identified an area of coating damage near the failure, which appeared to have occurred as a result of the failure (no pitting, attached solids, and apparent adhesive failure). No external corrosion was observed and the pipe coating on the remainder of the section appeared to be in excellent condition.

Initial visual inspection of the internal surface of the piping showed no accumulated solids or liquids in the pipe sample and no indications of pitting or corrosion. A view of the internal condition of the pipe section containing samples B & C after removal is provided in Figure 11.

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Figure 11. Internal Condition of Pipe Sample During Removal

Soil samples were collected from the area around the pipe for chemical and microbiological analysis, the failure surfaces were protected with foam insulation, then the pipe samples were wrapped, crated and shipped to the laboratory for metallurgical testing on March 10, 2020. The approximate lengths of the pipe samples were PS A – 6 feet, PS B – 6 feet and PS C – 8 feet.

5.0 LABORATORY INVESTIGATION FINDINGS

Metallurgical Testing and a Failure Analysis was performed on a multiple pipe samples from the release site. The work was conducted under Mears direction by a third-party independent laboratory (DNV GL). The metallurgical testing consisted of the following tests and examinations:

- Physical Examination,
- Photographic documentation and videography,
- Scanning electron microscopy
- Metallographic Analysis,

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- Hardness testing, and
- Chemical analysis.

The metallurgical sampling and testing protocol utilized for the laboratory investigations is included in Appendix B.

5.1 Visual and Nondestructive Examination

The pipe sections were removed from the shipping crates, visually inspected and photographed. As noted above, some of the pipe coating adjacent to the failed girth weld was missing on PS A and PS B. This may be due to the fact that CO2 is in a supercritical state at about 1,000 psig and about 60°F during the transportation before the rupture. The release of CO2 after the rupture from the actual operating conditions to the atmospheric conditions commonly results in an accumulation and flow of dry ice (i.e. -70°F or colder) which may have impacted adhesion to the pipe.

The mill-applied pipe coating (FBE/ARO) was brown in color, with a light blue liquid epoxy applied to the girth welds. Black residue was found adjacent to ends of the pipe samples cut in the field using an acetylene torch. Figure 12, Figure 13 and Figure 14 show the as-received pipe samples after removal from the crates and protective wrappings.

The pipe adjacent to the fracture surfaces and failed girth weld were visually inspected. The fractured surface was flat and generally at a 180-degree angle with no thinning and/or reduction of the affected area. The fracture path traversed or crossed over the weld at various locations.

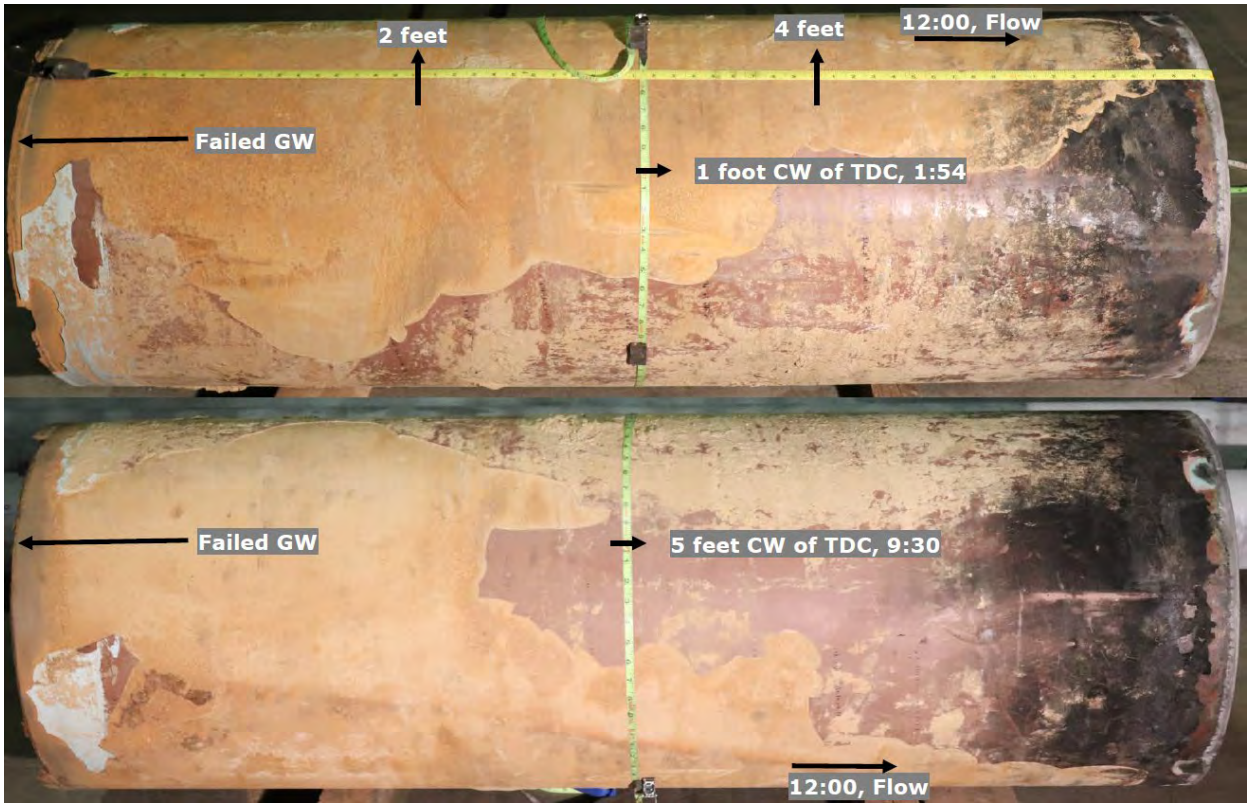

Figure 12. Pipe Sample A (PS A)



Figure 13. Pipe Sample B (PS B)

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Figure 14. Pipe Sample C (PS C)

A photograph of the fracture surface of PS A is provided in Figure 15.

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Figure 15. PS A Fracture Surface (Upstream to Downstream)

Pipe circumferences and diameters were measured at the field-cut ends of the pipe sections, finding no measurable ovality and diameters meeting API 5L tolerances for the 24-inch diameter pipe. Wall thicknesses were between 0.530 inches and 0.540 inches, which meet API 5L tolerances for pipe with a nominal wall thickness (NWT) of 0.540 inches.

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The intact girth weld (PS C) was grit blasted and MPI was conducted on the external and internal surfaces. No crack-like indications were identified.

After detailed visual inspection and measurements were collected, the pipe samples were aligned and evaluated to identify locations for further sampling and metallurgical analyses. An overview of the locations selected for metallography (M, MU), fractography (S), mechanical and chemical analyses is provided in Figure 16.

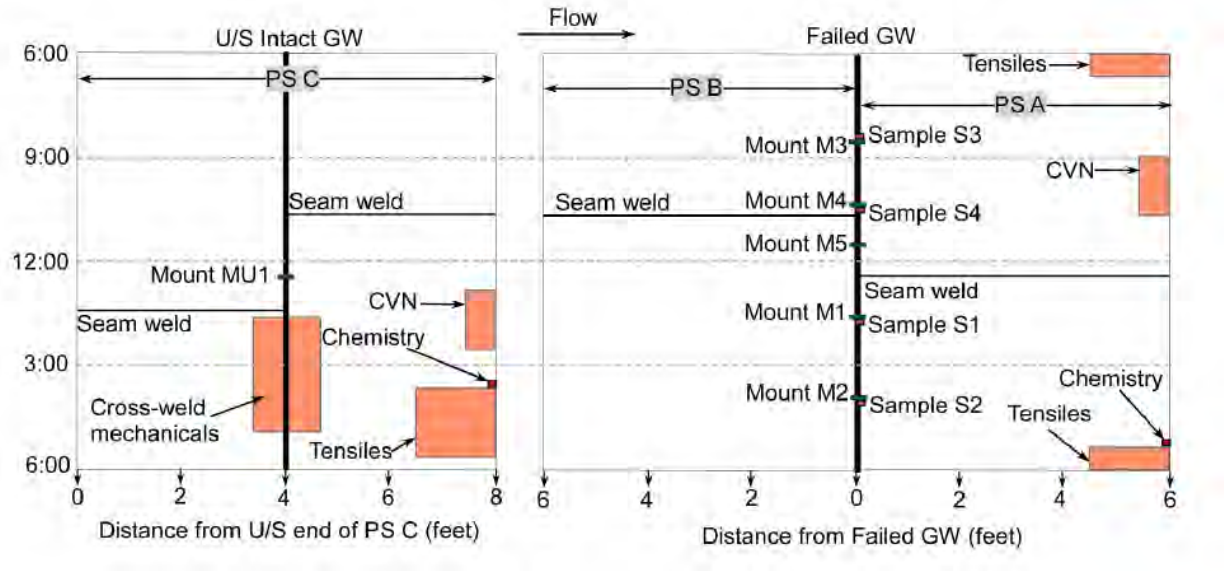

Figure 16. Laboratory Testing and Sample Schematic

5.2 Defect Examination

The internal and external surfaces of the failed girth weld were cleaned with a soft bristle brush to for more detailed examination. Five areas were selected for metallurgical analyses of the failed girth weld (PS A, PS B) and one area from the intact girth weld in PS C. The fracture surface consisted of smooth regions and rougher surfaces that varied in thickness throughout the rupture face. An example of these regions is provided in Figure 17. There was no evidence of pre-existing manufacturing flaws. It was not possible to determine the exact location of the failure initiation process due to the lack of chevrons on the fracture surface.

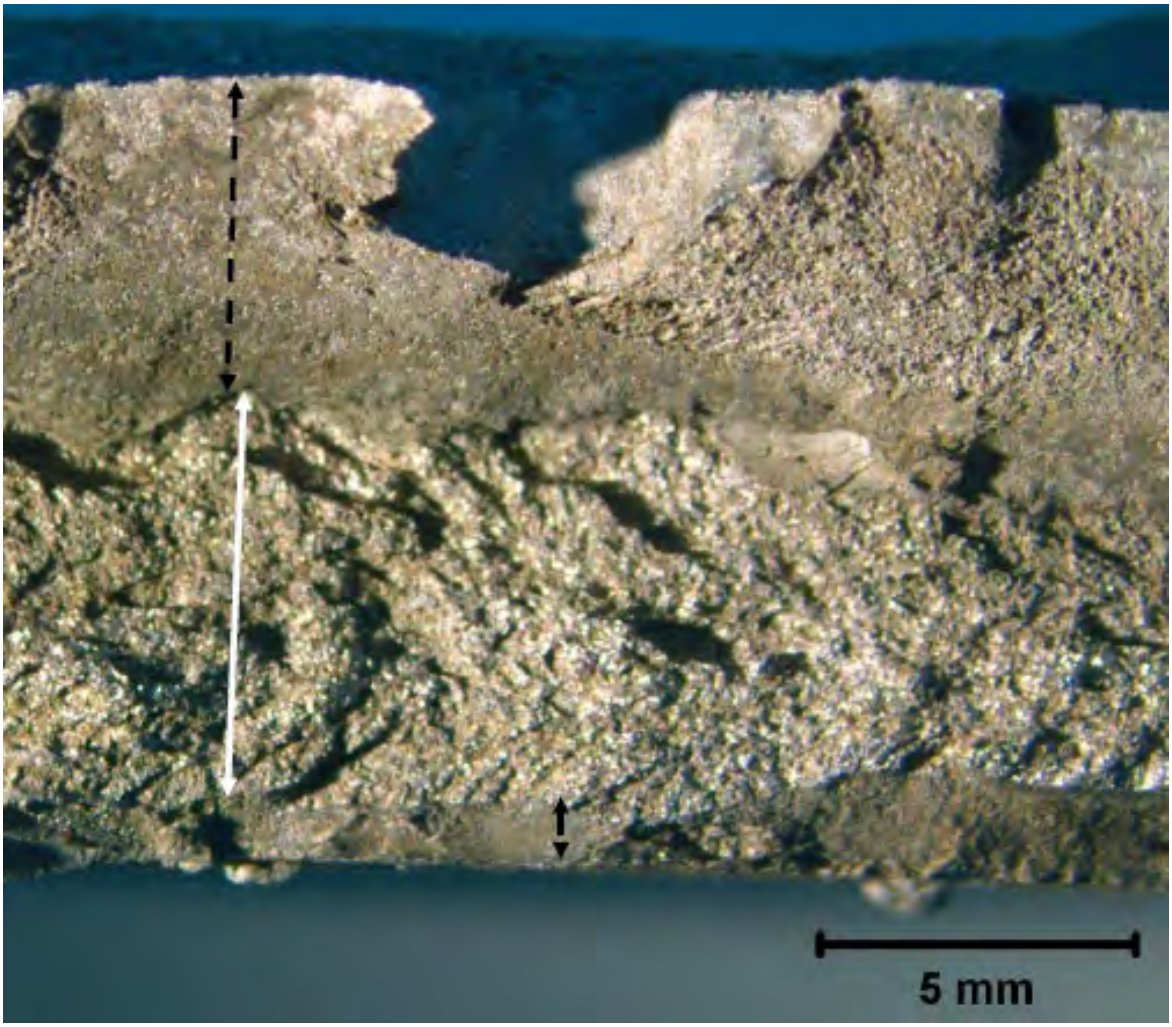

Figure 17. Image of Sample S2 - Smooth (Black Arrow) and Rough (White Arrow) Regions

5.3 Metallography and Fractographic Examination

Upon removal of the samples discussed above, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough).

These samples are shown in Figure 18.

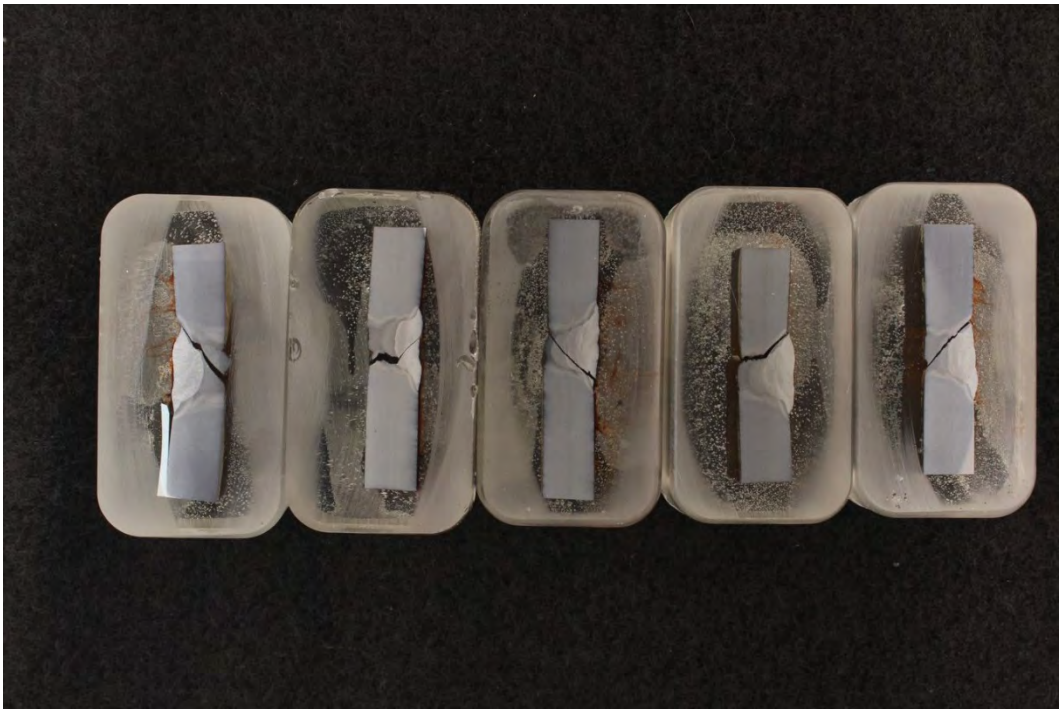

Figure 18. Metallurgical samples M1 through M5

5.3.1 Metallurgical Sample 1

Sample M1 contains a fracture path at a shear angle. This sample was removed from the girth weld at the 1:35 o'clock orientation (see Figure 19).

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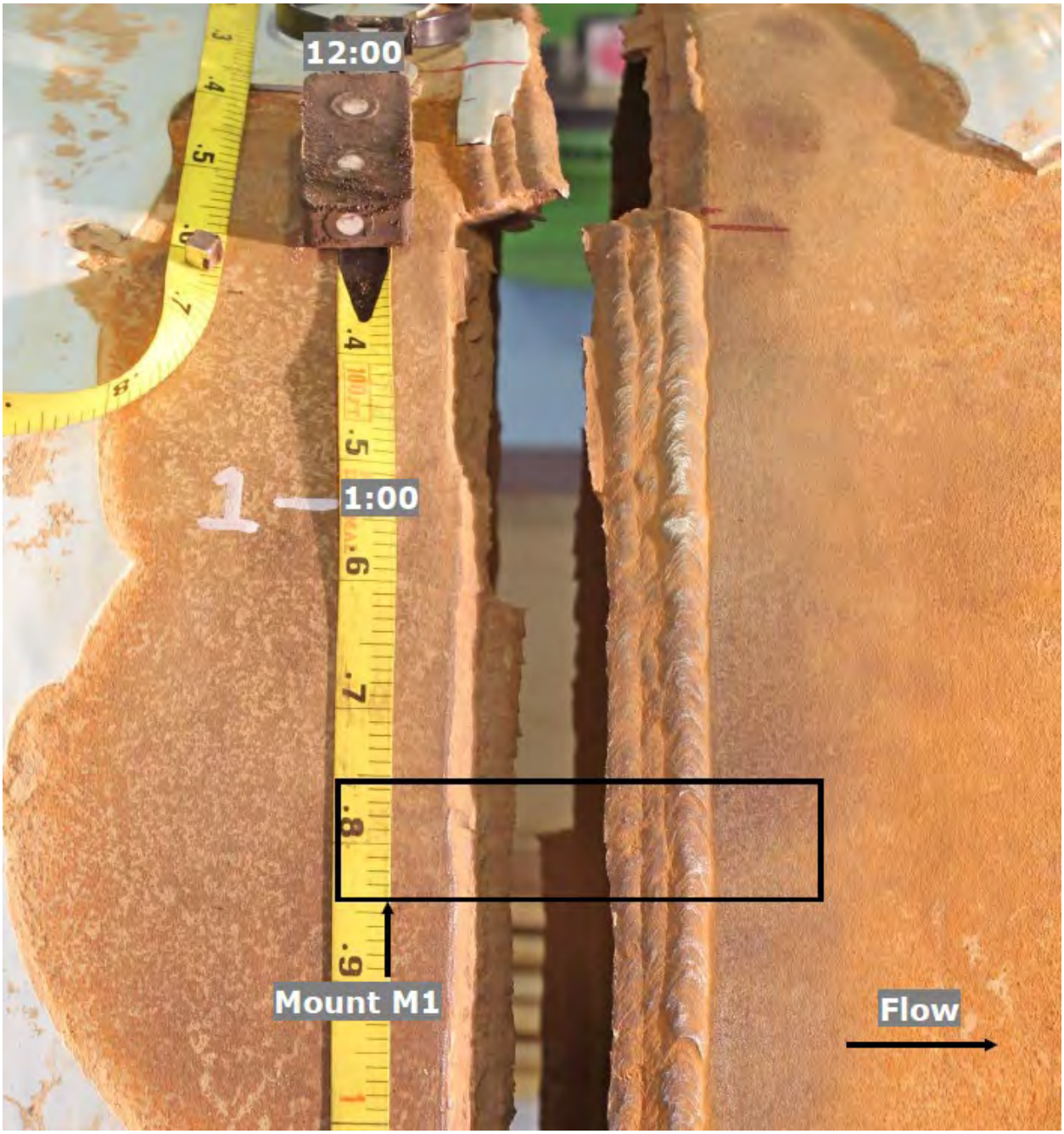

Figure 19. Overview of Mount M1

The fracture path of this sample is located in the HAZ near the toe of the weld at the OD surface. An image of the cross section of sample M1 is provided in Figure 20.

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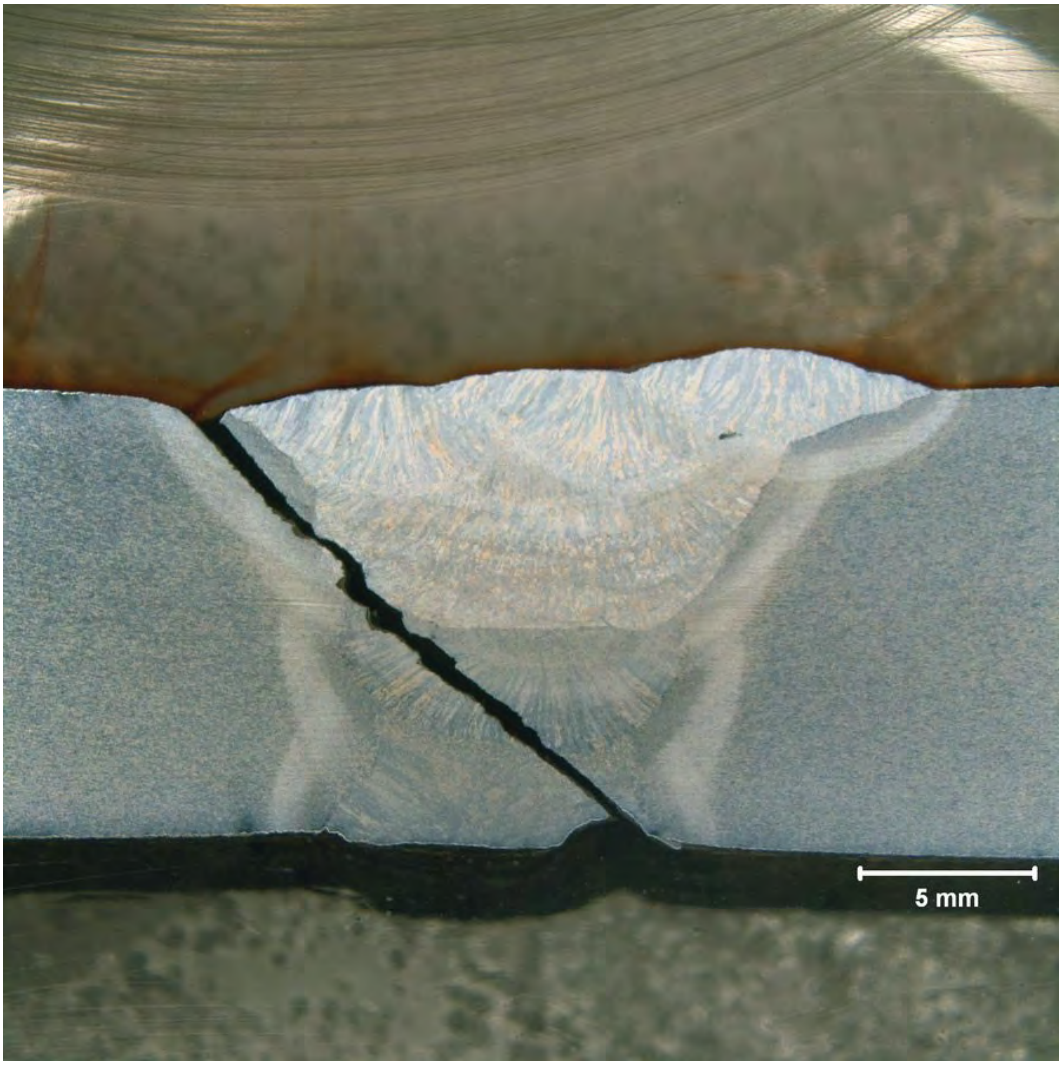

Figure 20. Representative Cross-Section from Sample M1

There is no indication of excessive porosity and/or inclusions. It shows a slight misalignment of the high-low weld of approximately 4.3% of the NWT. Higher magnifications are provided in the laboratory report which show grain elongation due to the cold work that took place during the rupture process. This is consistent with ductile overloading. The microstructure is typical of modern X80 line pipe. A close-up of sample M1 is provided in Figure 21.

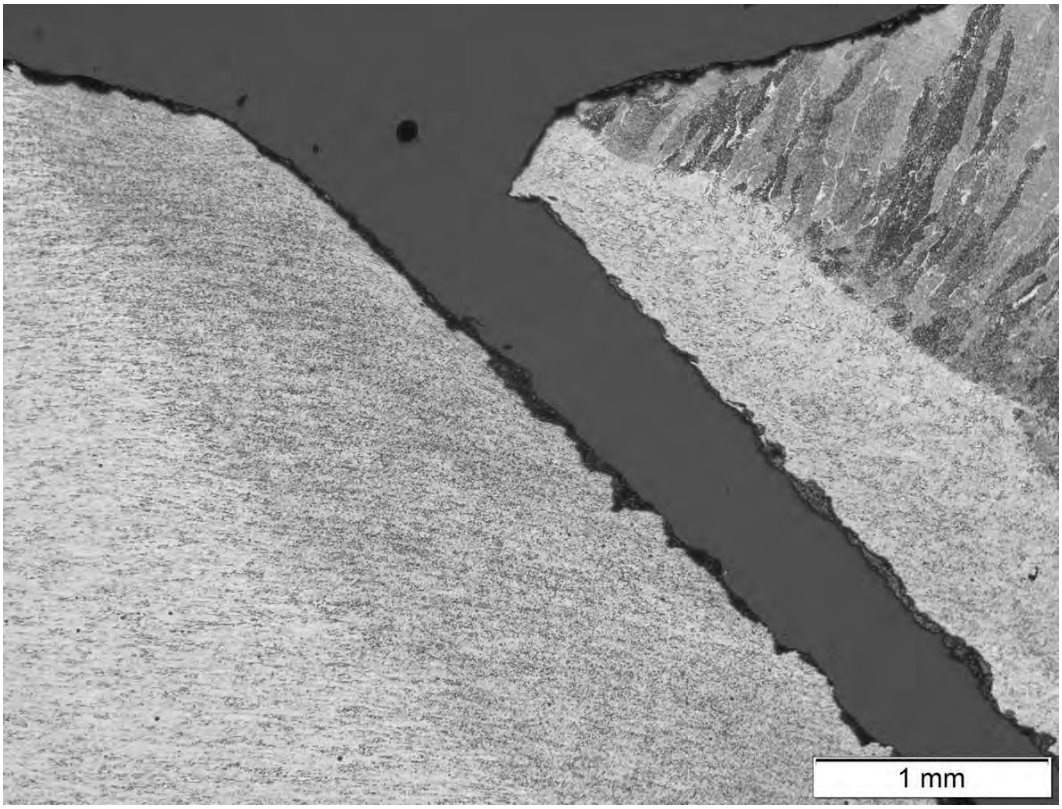

Figure 21. Close-Up of Sample M1

5.3.2 Metallurgical Sample 2

Sample 2 contains regions where the fracture path is perpendicular to the free surface and regions of shear failure. This sample was taken from the GW at the 3:55 o'clock orientation (see Figure 22).

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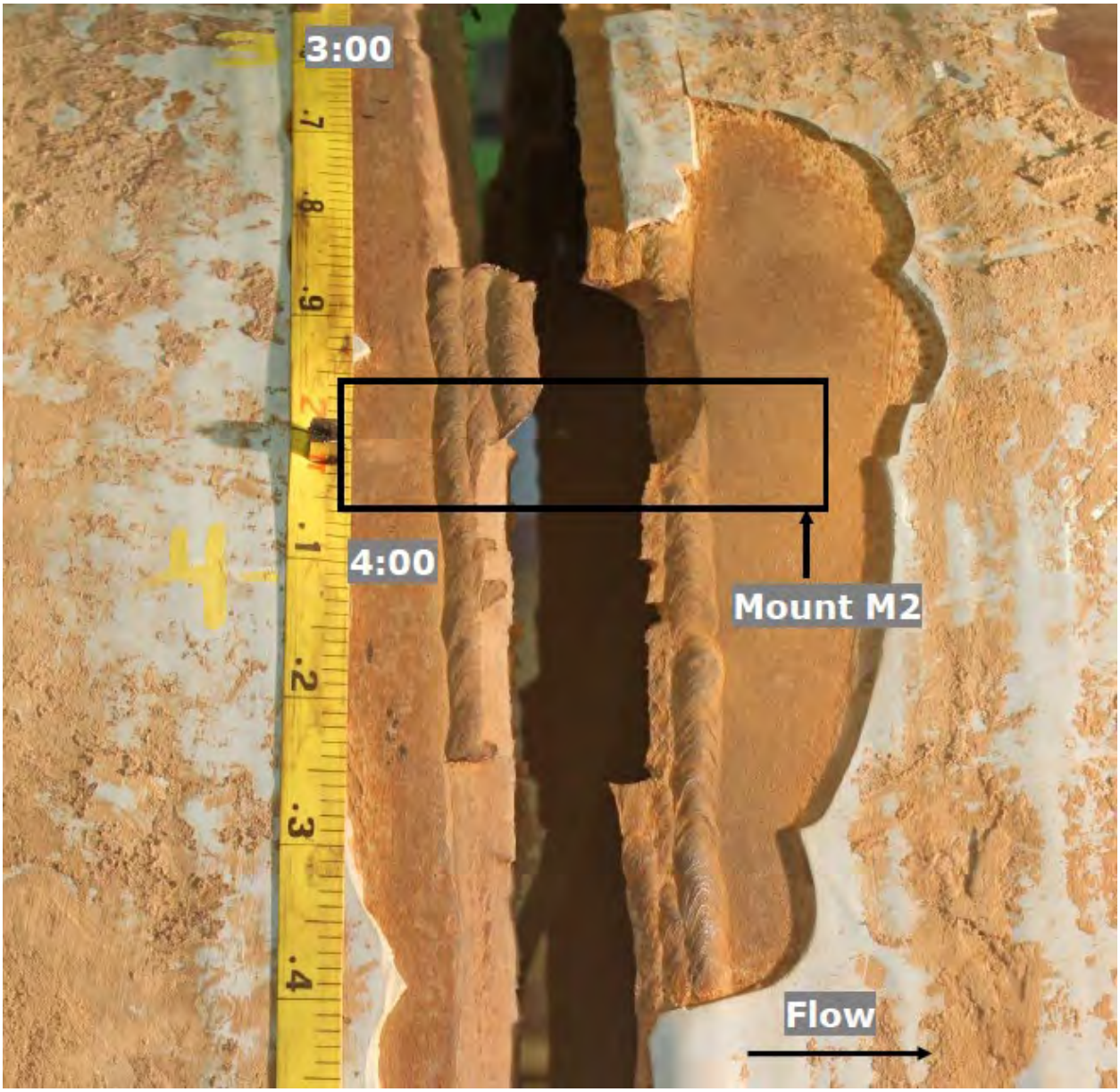

Figure 22. Overview of Mount M2

The cross section of M2 includes both the weld metal and HAZ. The cross section of sample M2 is provided in Figure 23.

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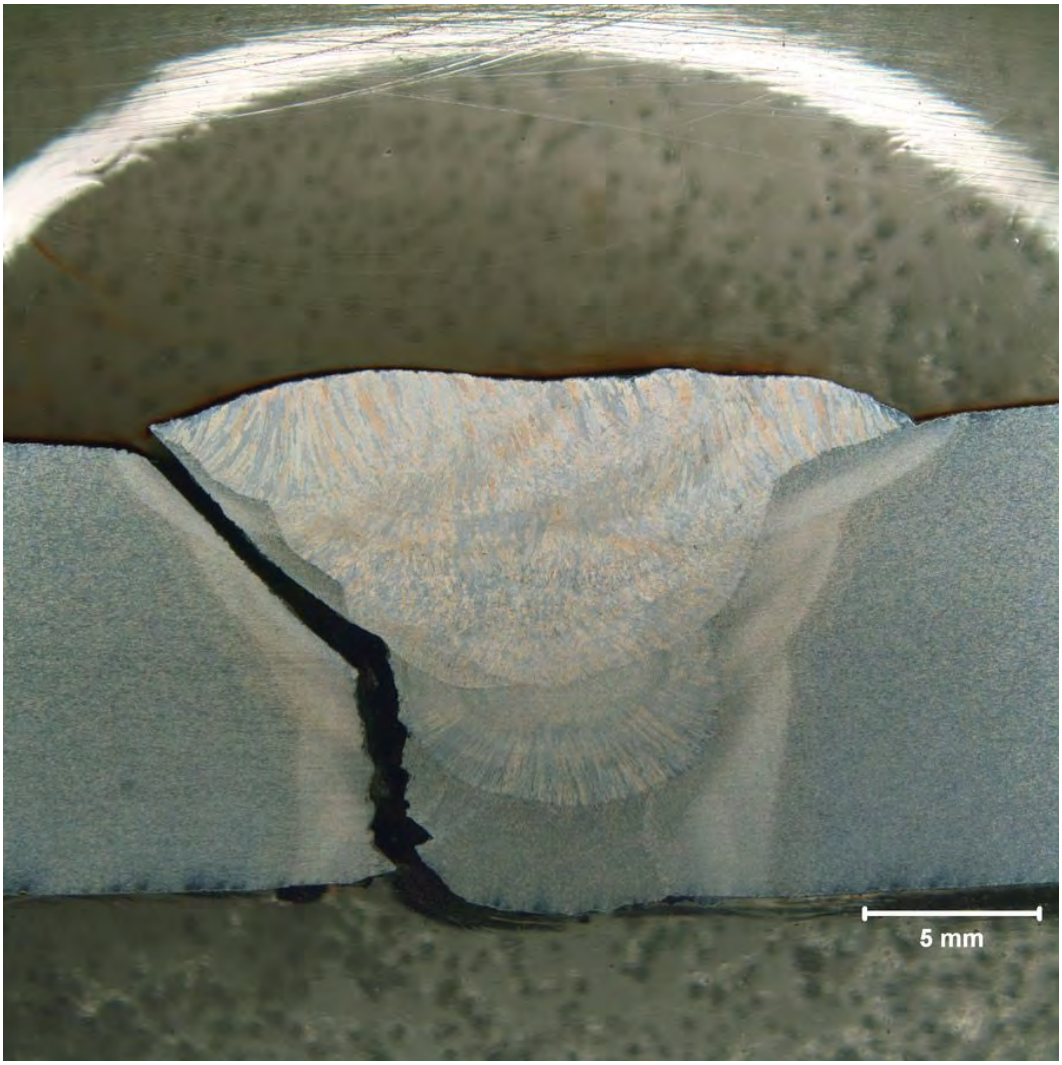

Figure 23. Representative Cross-Section from Sample M2

There are both smooth and rough regions in this sample. The high-low weld misalignment at this location is approximately 6.9% of the NWT. The fracture path at this location was mainly located at the HAZ. Fractography in the SEM shows the presence of a smooth region containing dimples (typical of ductile behavior) and cleavage facets (typical of brittle behavior) in the rough region. Some fissures were also found in the area where cleavage facets were located. These fissures are usually seen in girth weld overload areas (see Figure 24).

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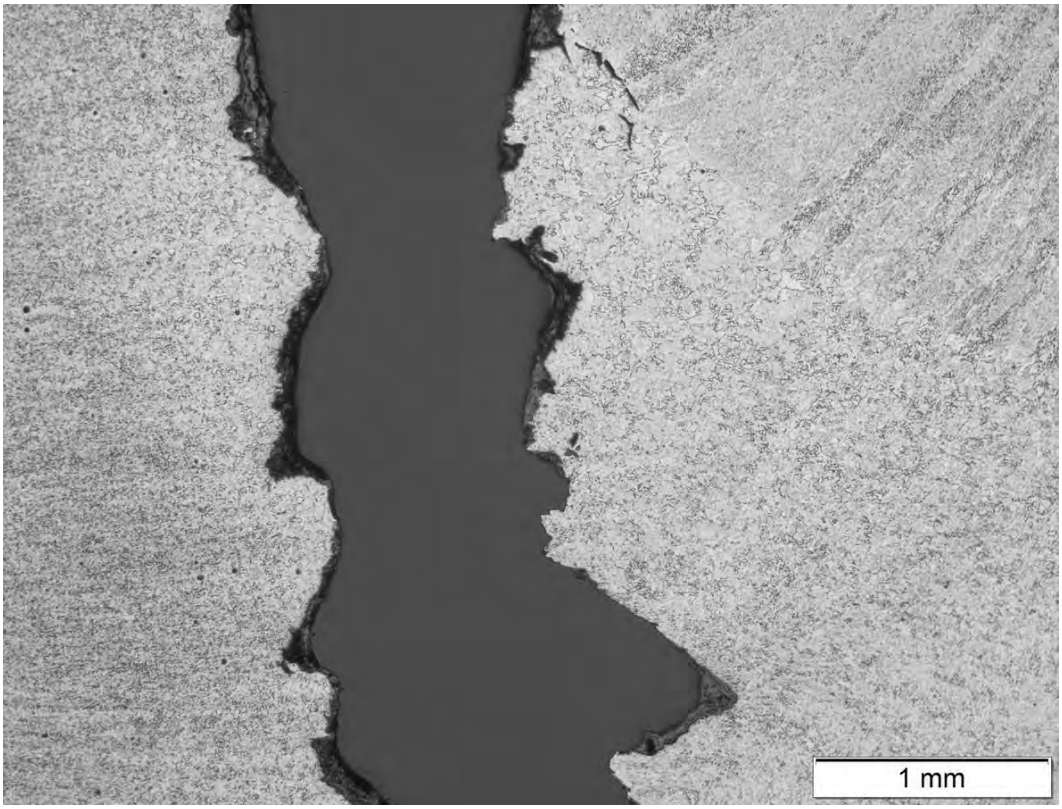

Figure 24. Close-Up of Sample M2

5.3.3 Metallurgical Sample 3

This sample was removed from the failed GW at the 8:35 o'clock orientation (Figure 25).

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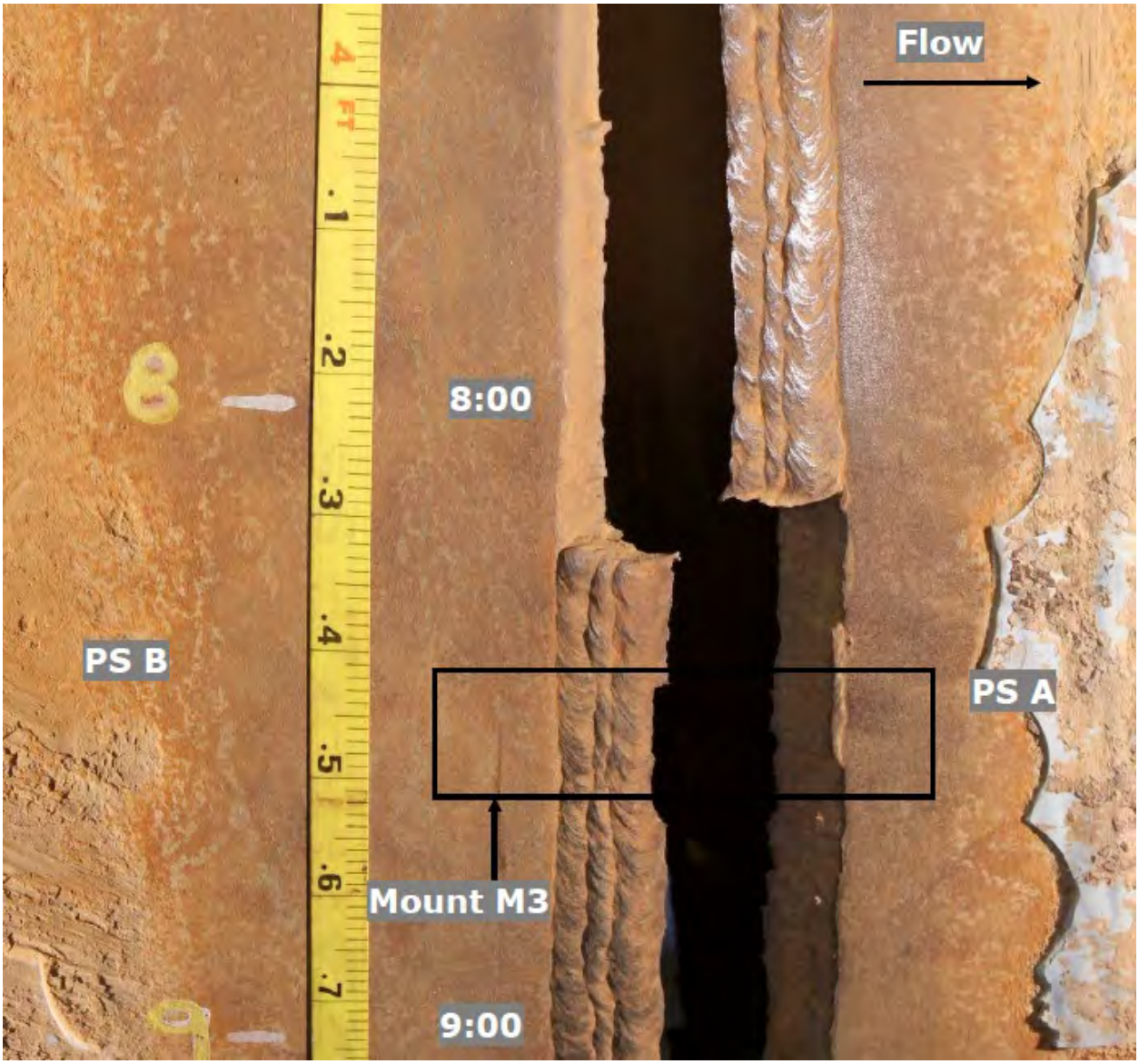

Figure 25. Overview of Mount M3

The fracture path is at a shear angle and mainly located in the weld metal. The morphology of the weld is similar to samples M1 and M2. The high-low weld misalignment at this location was approximately 2.6% of the NWT. The microstructure is consistent with the findings in samples M1 and M2 (see Figure 26 and Figure 27).

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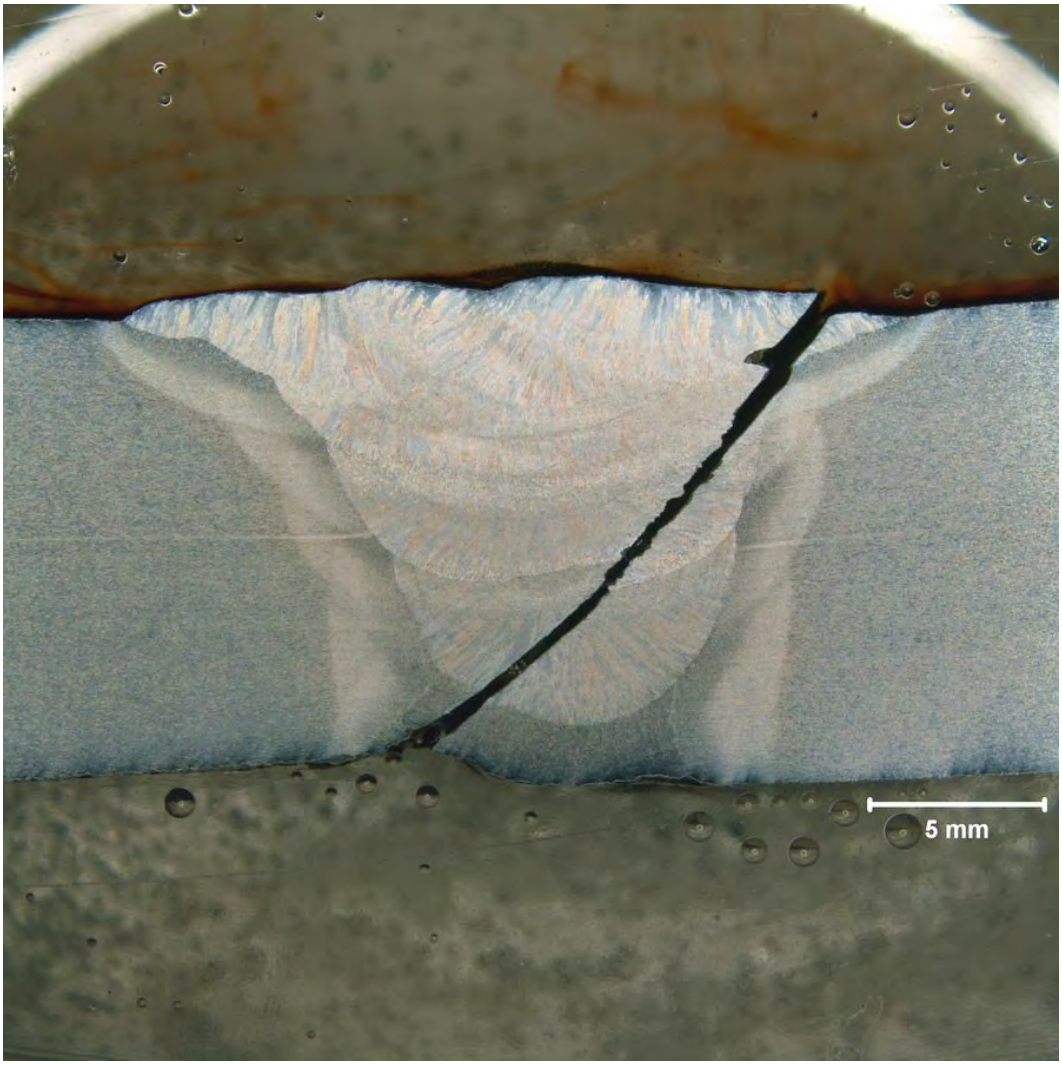

Figure 26. Location of Mount M3

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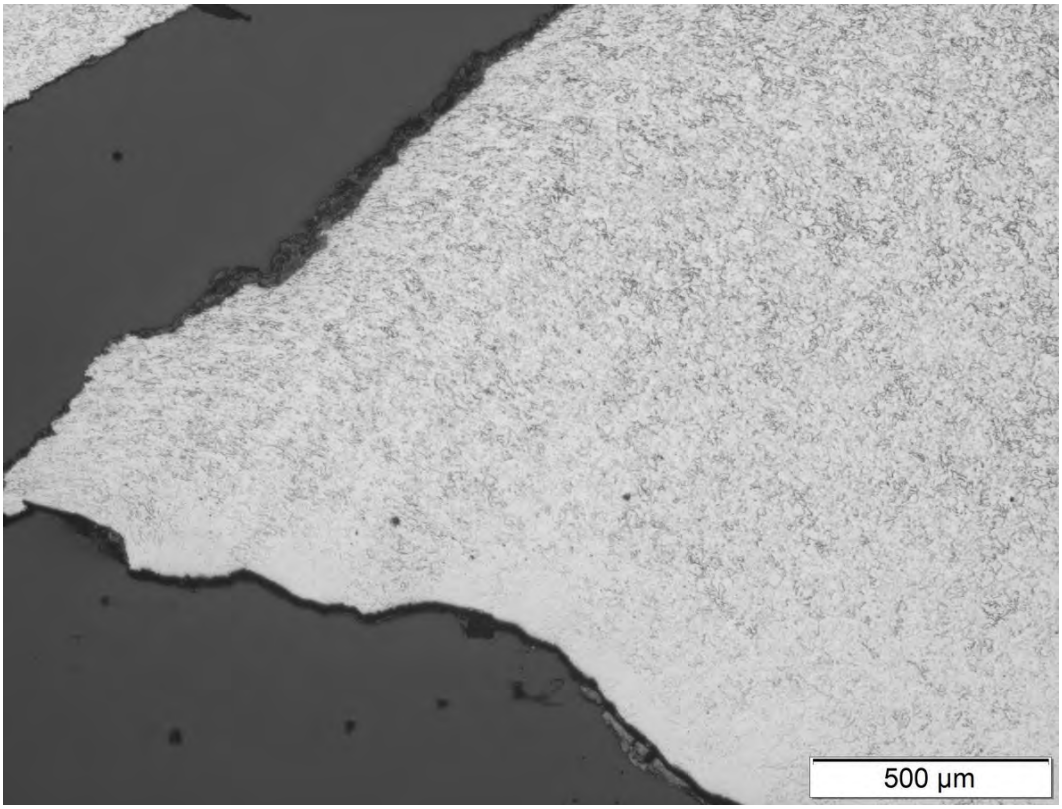

Figure 27. Close-Up of Sample M3

5.3.4 Metallurgical Sample 4

Sample M4 was removed from the failed GW at the 10:24 o'clock orientation. An overview of sample M4 is provided in Figure 28.

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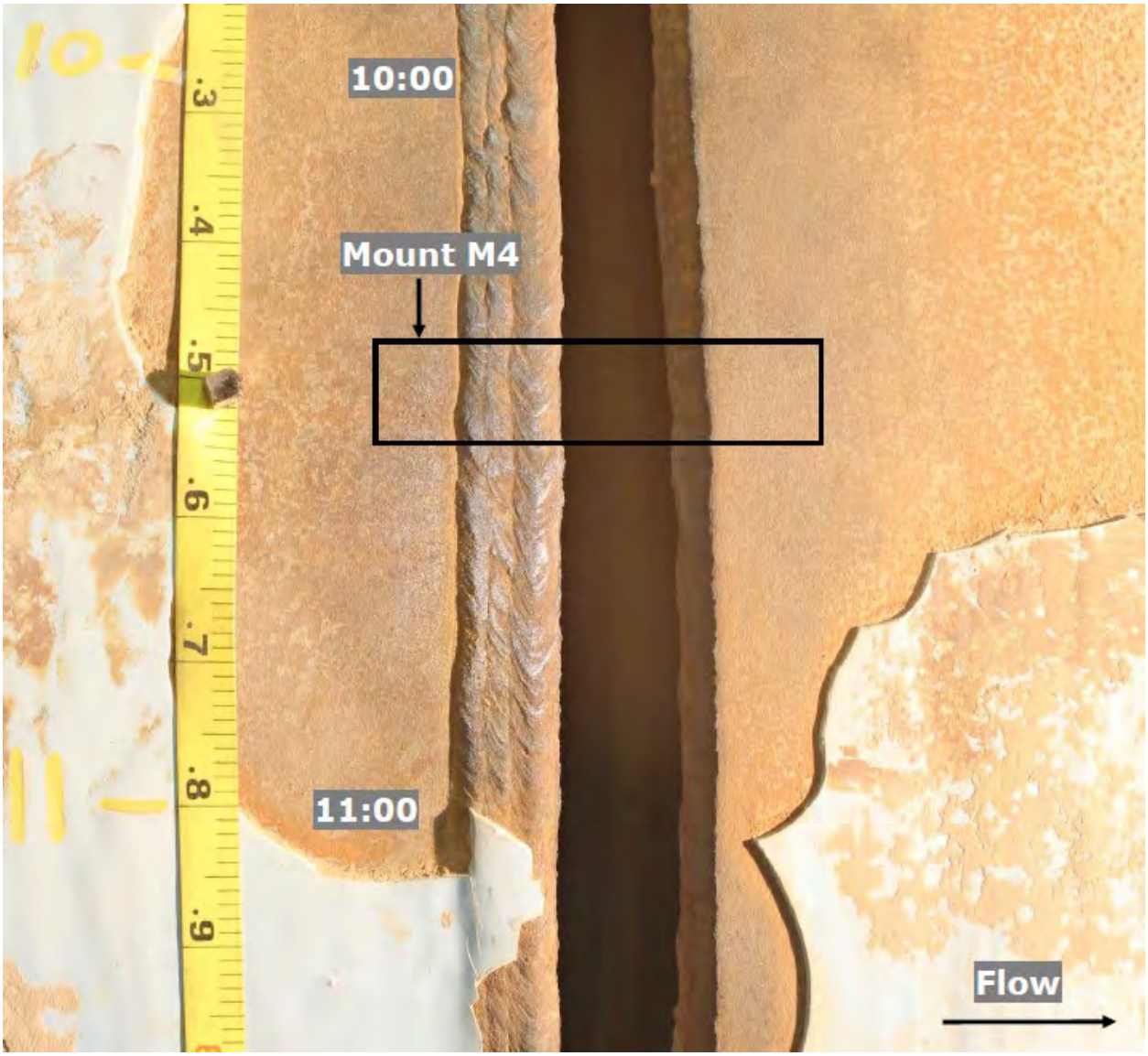

Figure 28. Overview of Mount M4

There is a smooth shear angle region and a rough region. The fracture path at this location is mainly in the HAZ. (see Figure 29).

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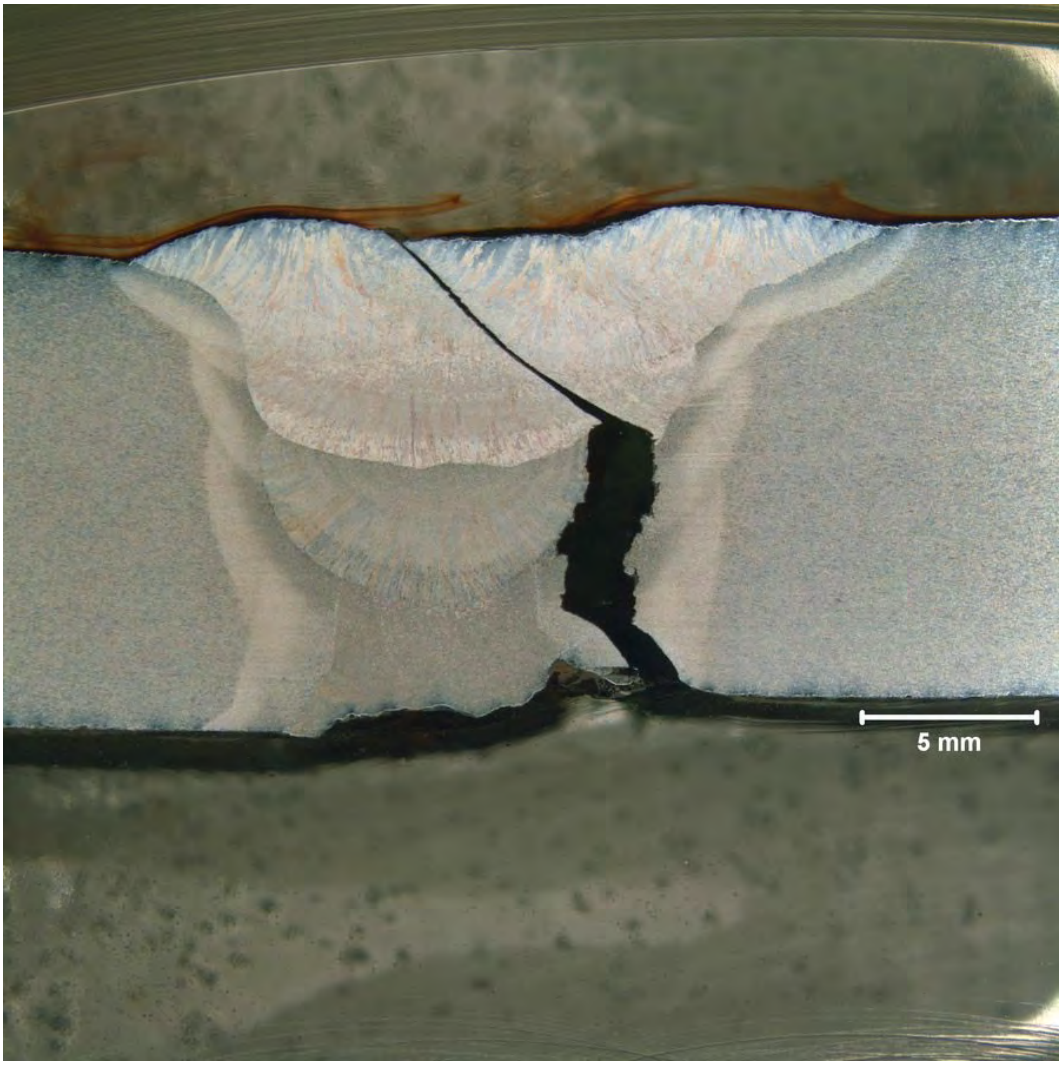

Figure 29. Representative Cross-Section from Sample M4

The sample shows grain elongation and an inclusion orientated parallel to the fracture surface which is consistent with ductile overload. There are also fissures in this sample that have the same morphology shown in M2 sample. A close-up of the M4 sample is provided in Figure 30.

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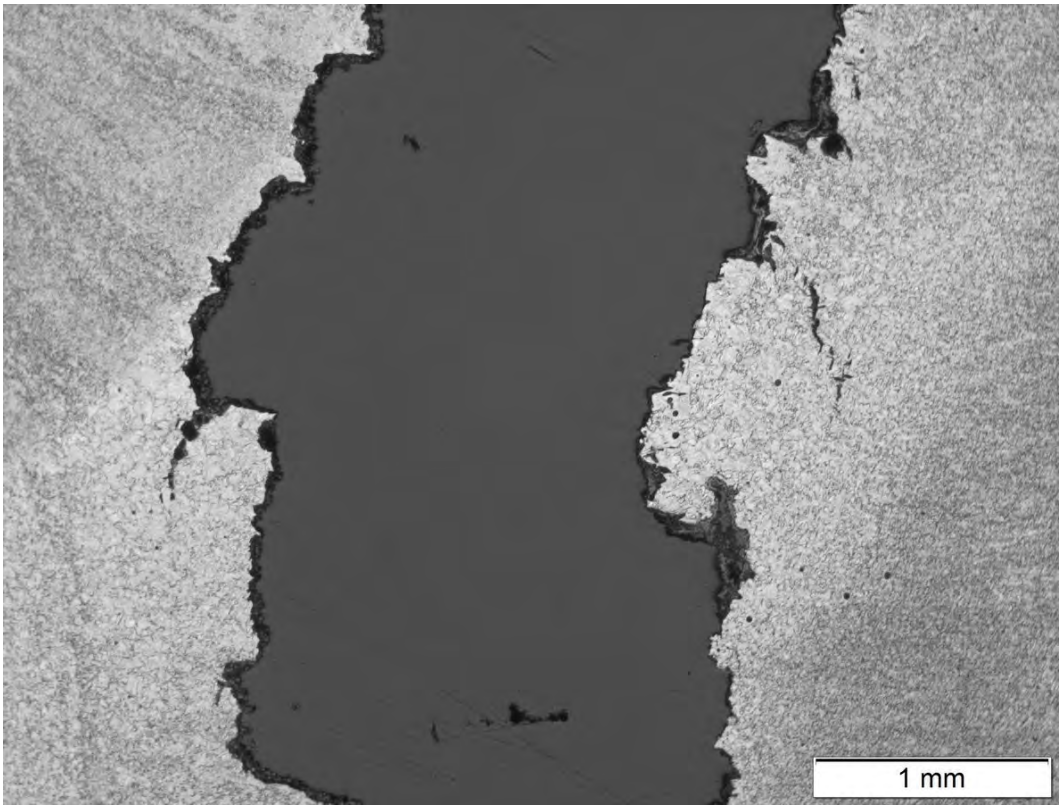

Figure 30. Close-Up of Sample M4

5.3.5 Metallurgical Sample 5

Sample 5 was removed from the failed GW at the 11:37 o'clock orientation (see Figure 31).

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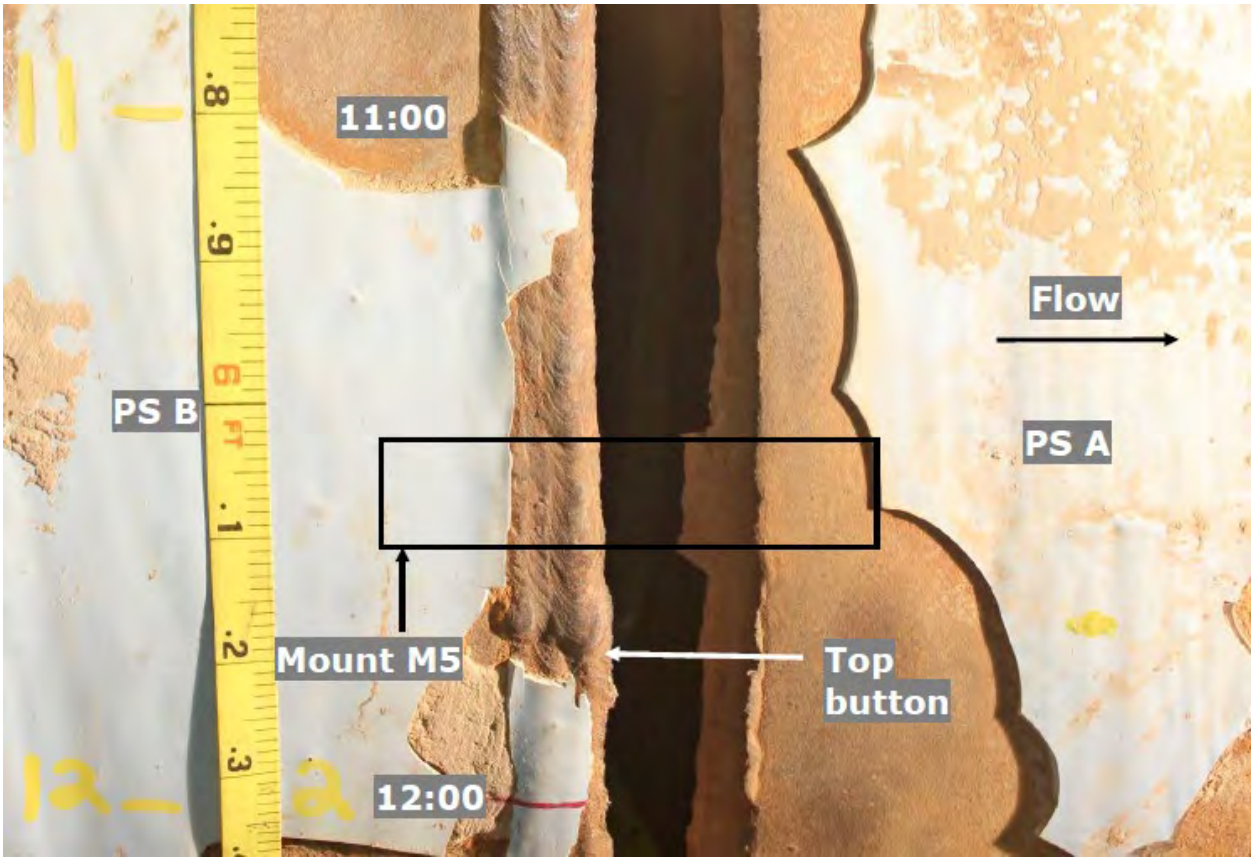

Figure 31. Overview of Mount M5

This sample has a smooth shear region on most of the fracture surface, located in both the weld metal and base metal. There is a shallow flaw between the weld metal and HAZ which is consistent with incomplete fusion. The high-low weld misalignment at this location was approximately 4.6% of the NWT. There is no evidence of crack extension at the flaw in this sample. A view of the cross section of sample M5 is provided in Figure 32.

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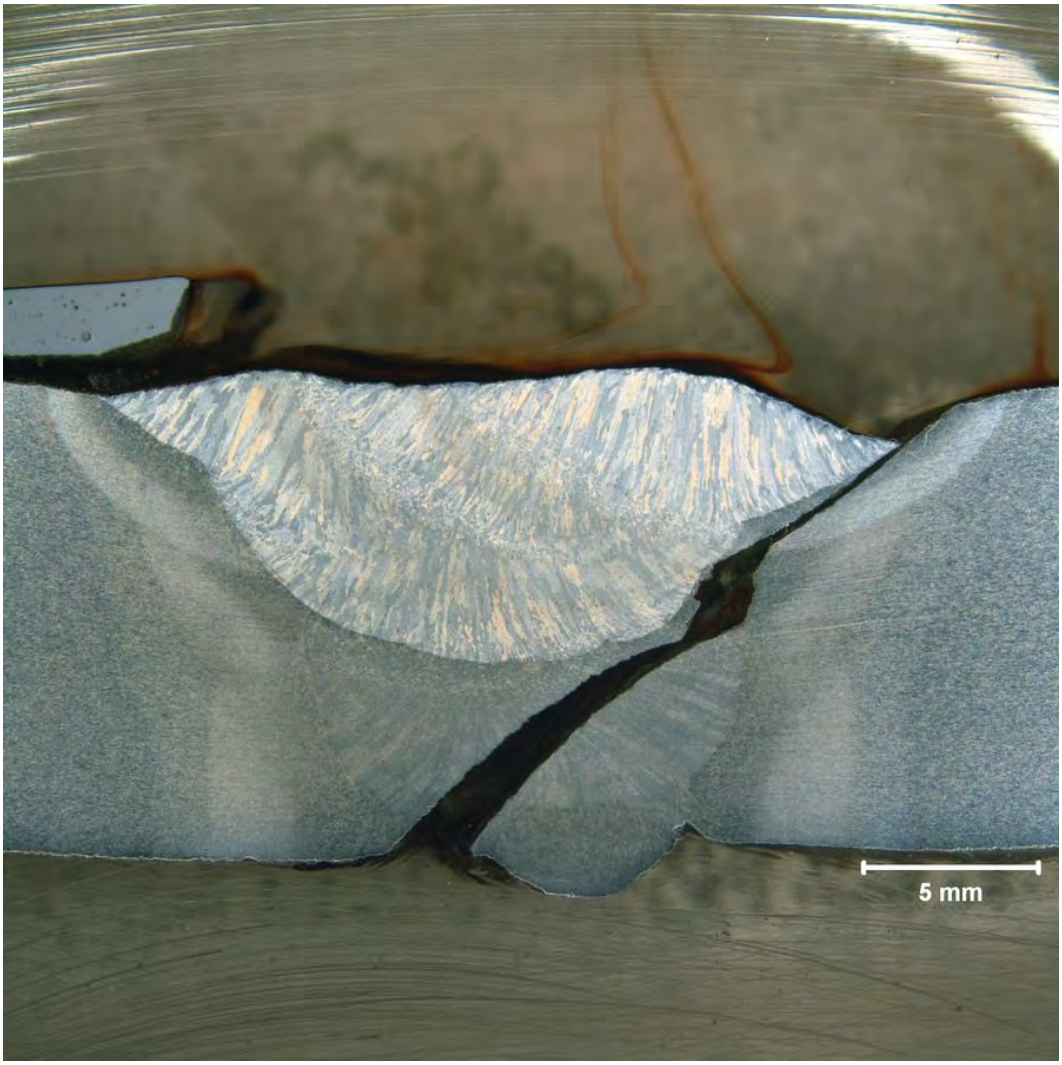

Figure 32. Representative Cross-Section from Sample M5

5.3.6 Metallurgical Sample MU1

Sample MU1 was removed from the intact girth weld. An overview of this sample is provided in Figure 33.

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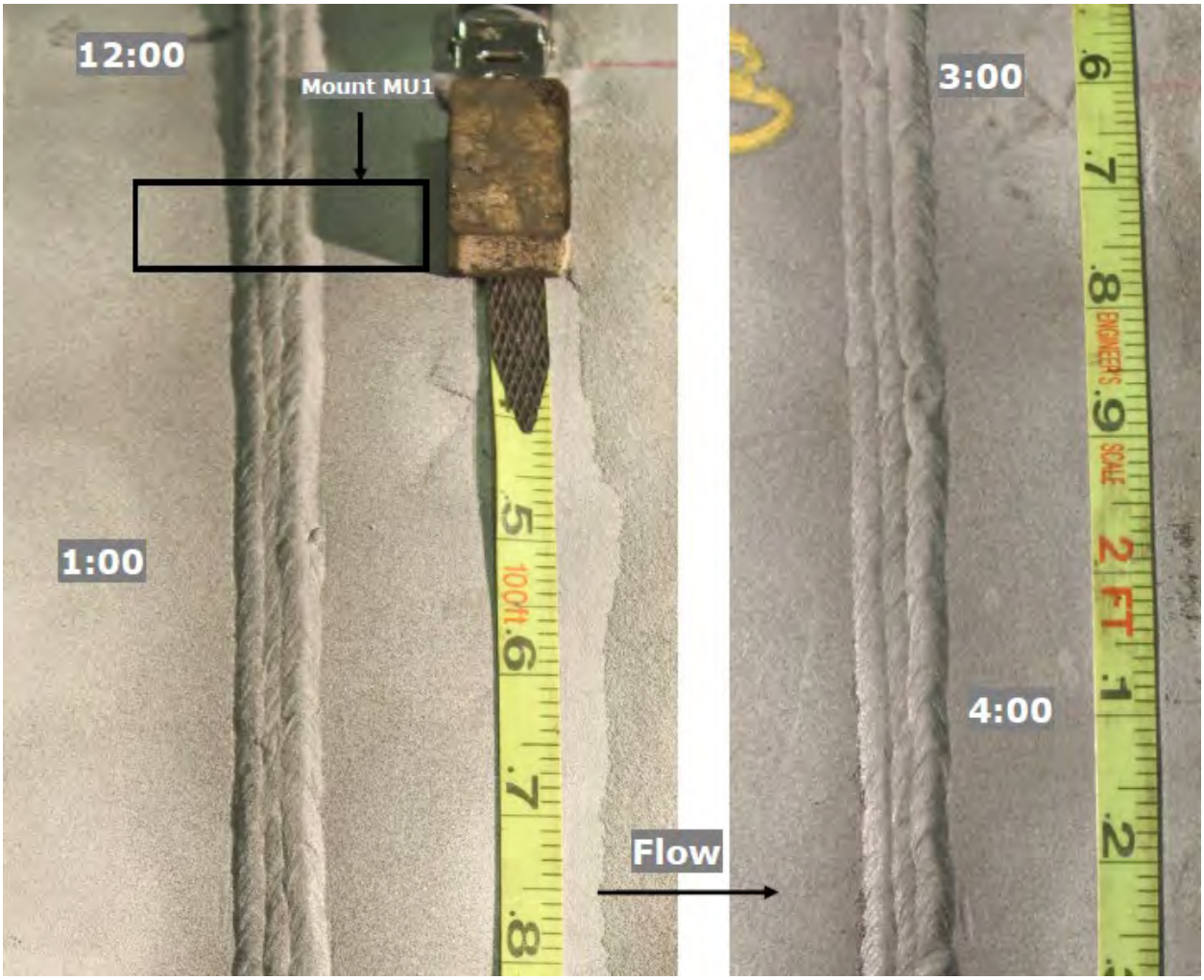

Figure 33. Overview of Mount MU1

This sample was removed from the intact GW at the 12:24 o'clock position. The morphology is similar to the previous mounts. The high-low weld misalignment at this location is approximately 4.6% of the NWT. The figure shows a shallow incomplete fusion flaw (1.9% of the NWT) between the weld metal and the HAZ. An image of the cross section of sample MU1 is provided in Figure 34.

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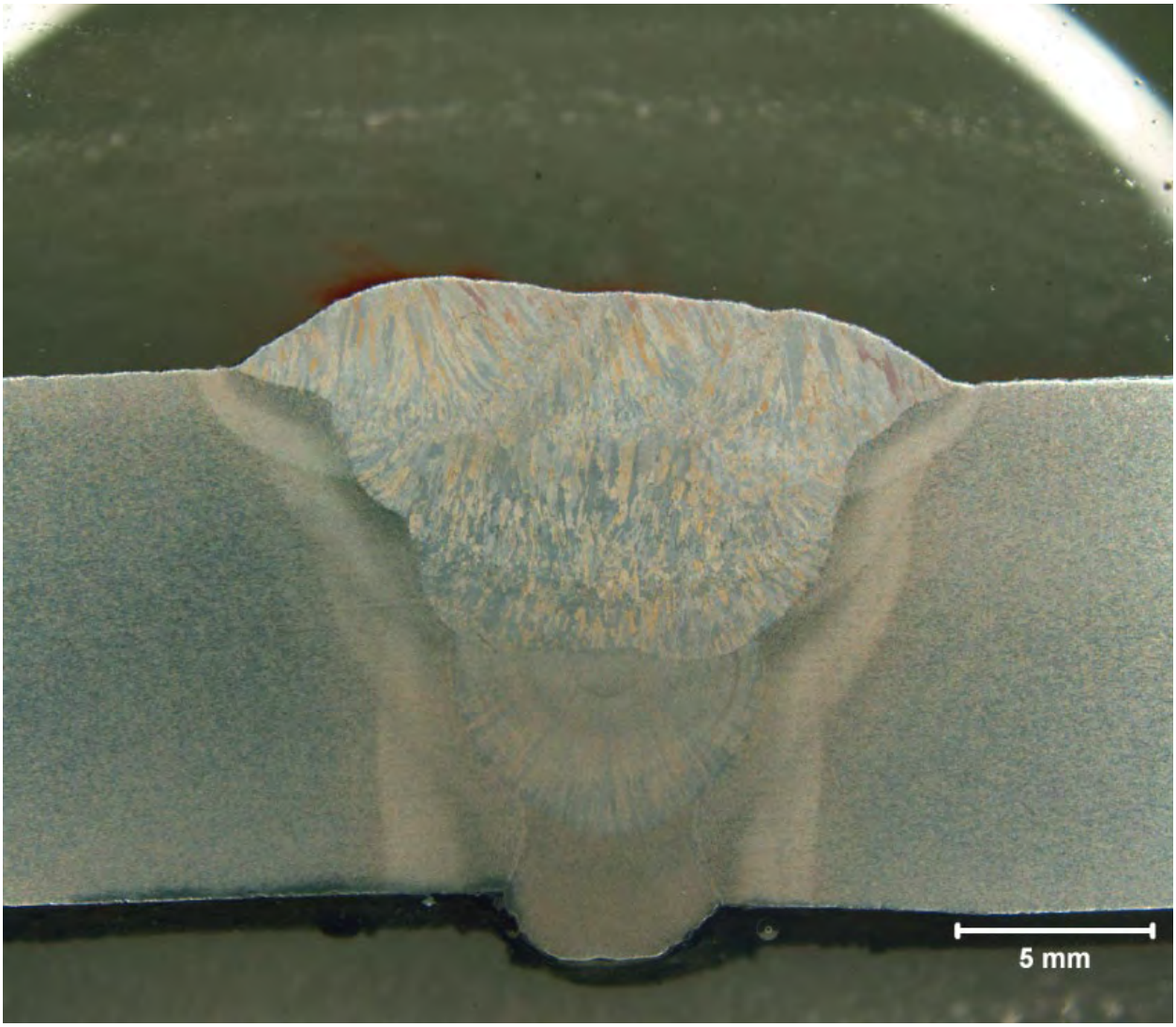

Figure 34. Cross Section of Mount MU1

A shallow flaw was identified between the weld metal and HAZ, with no evidence of cracking or extension of the flaw. A close up view of the flaw is provided in Figure 35.

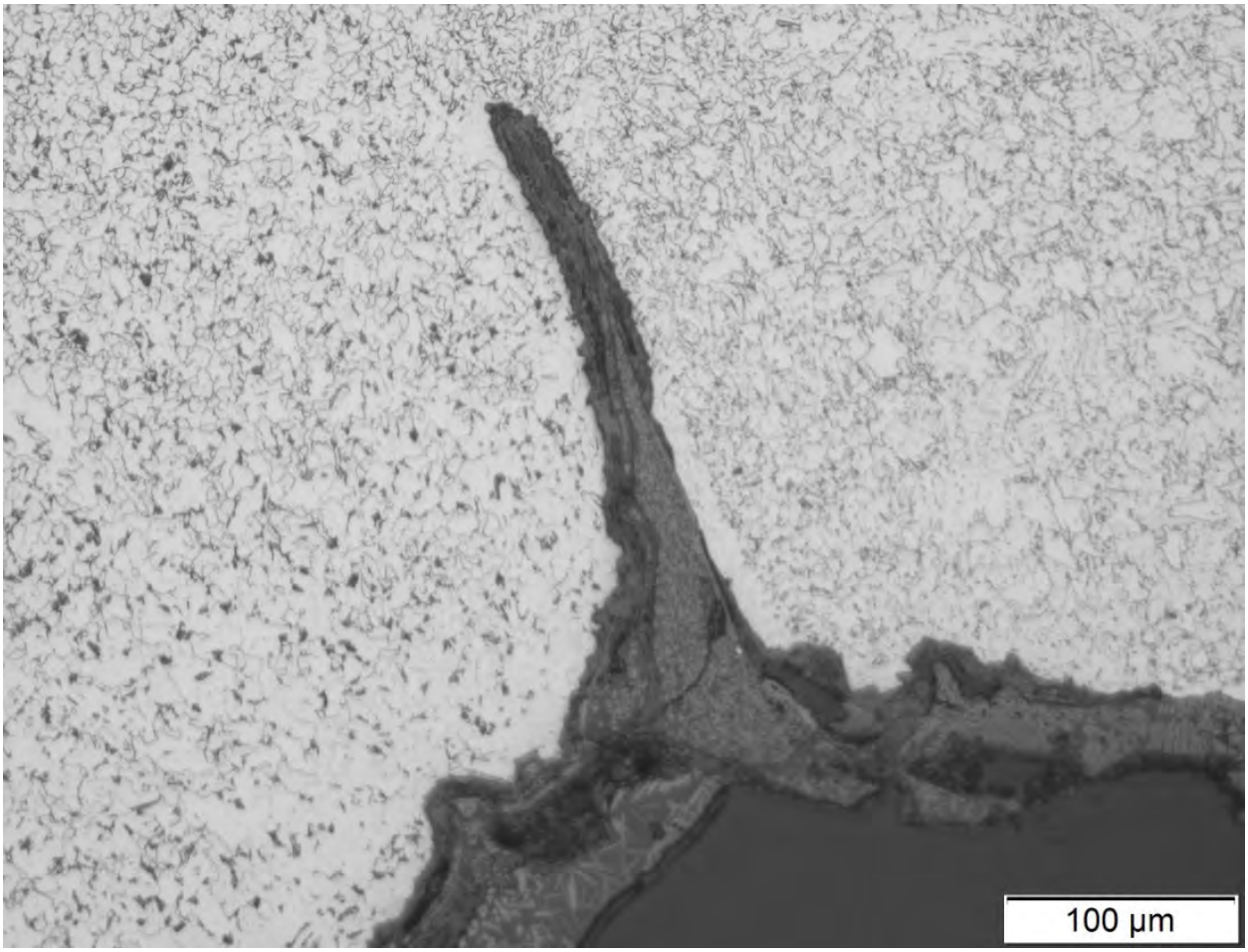

Figure 35. Close Up View of Sample MU1 Flaw

5.4 Scanning Electron Microscopy

As noted above, 4 samples were removed from PS A adjacent to the metallographic samples. No evidence of pre-existing flaws or fatigue were identified. SEM images (Figure 36, Figure 37, Figure 38) provide examples of dimples and mid-wall tears associated with ductile fracture, and cleavage facets associated with brittle fracture.

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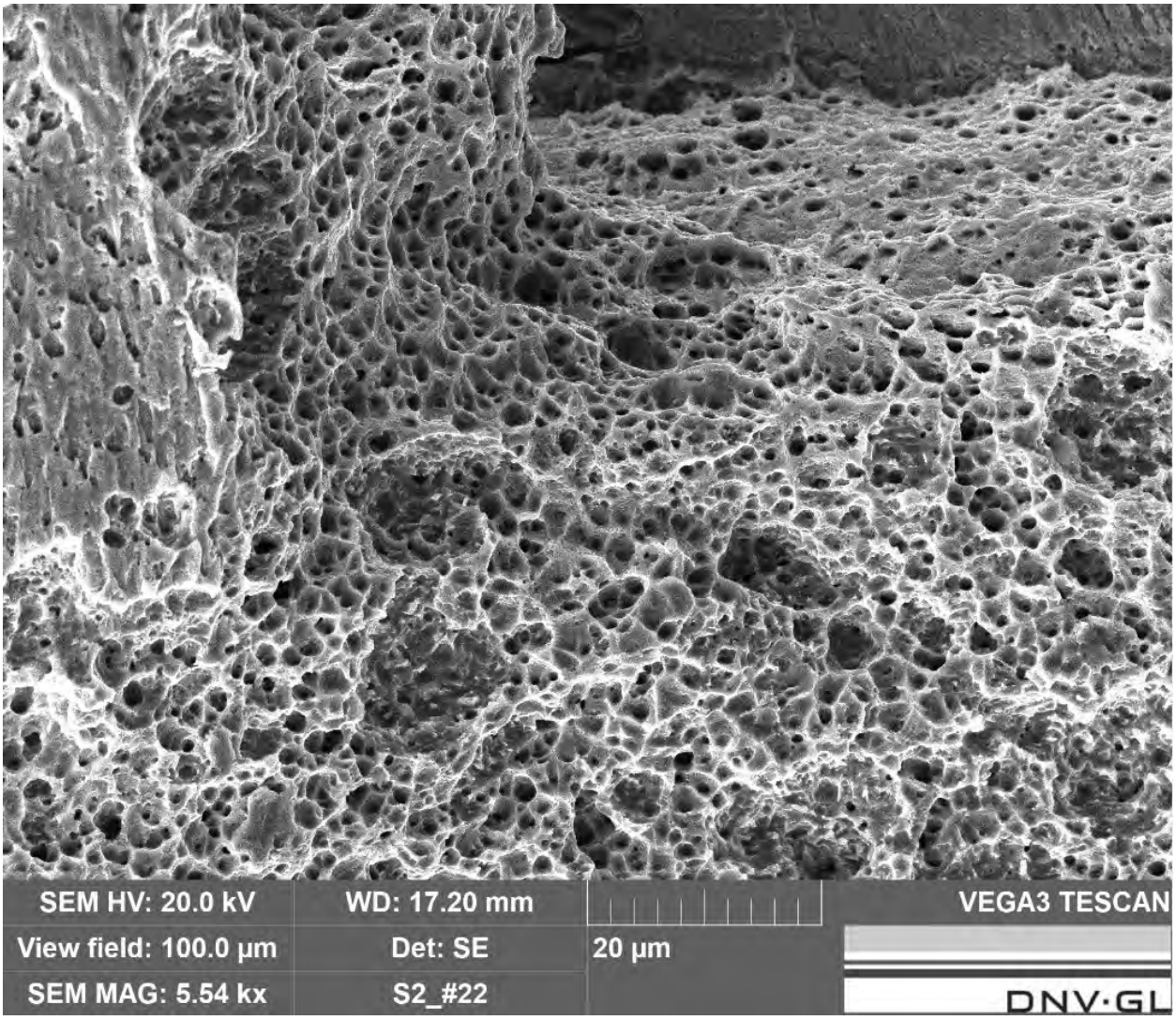

Figure 36. Sample S2 – Dimples Associated with Ductile Fracture

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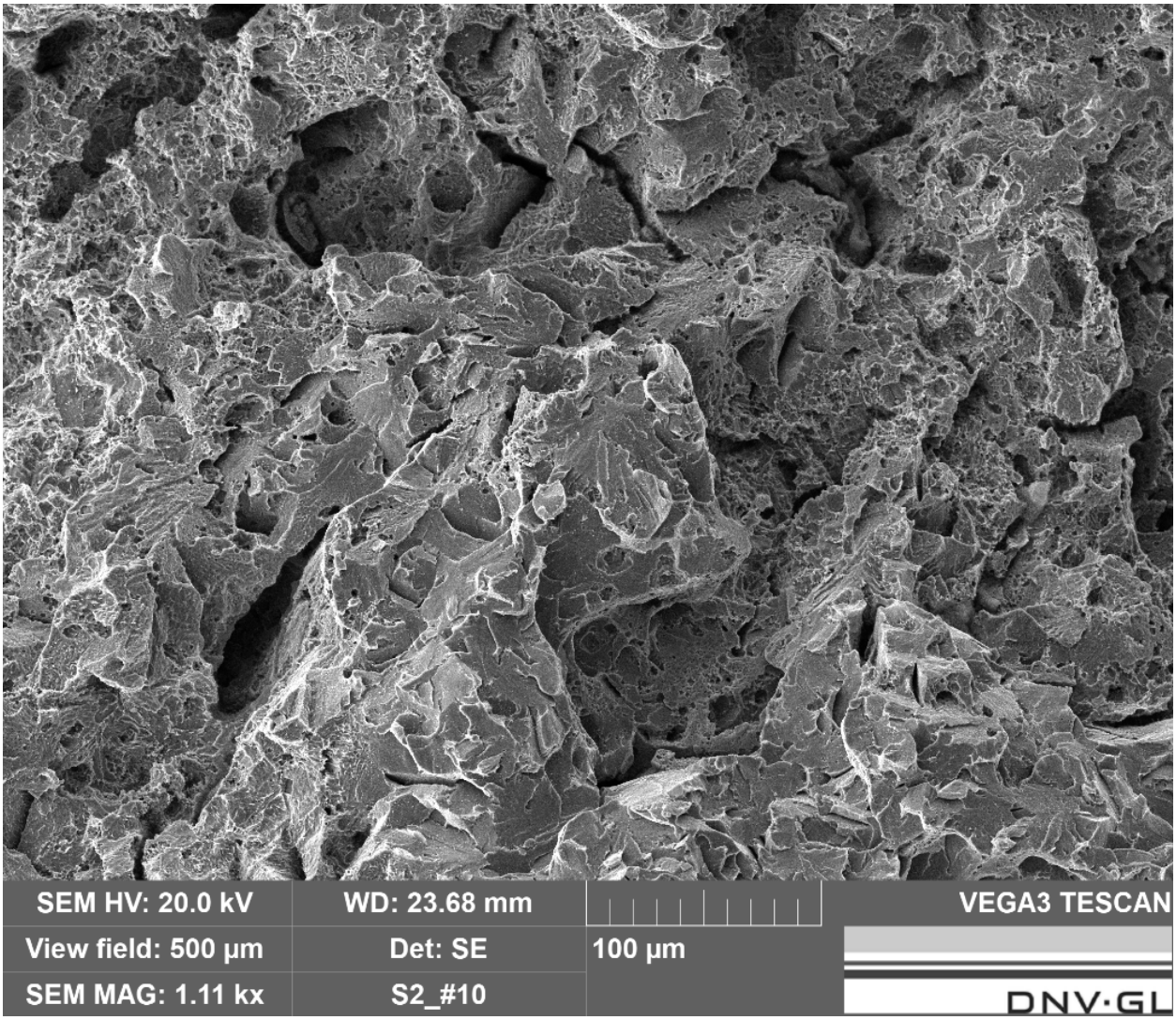

Figure 37. Sample S2 – Facets Associated with Brittle Fracture

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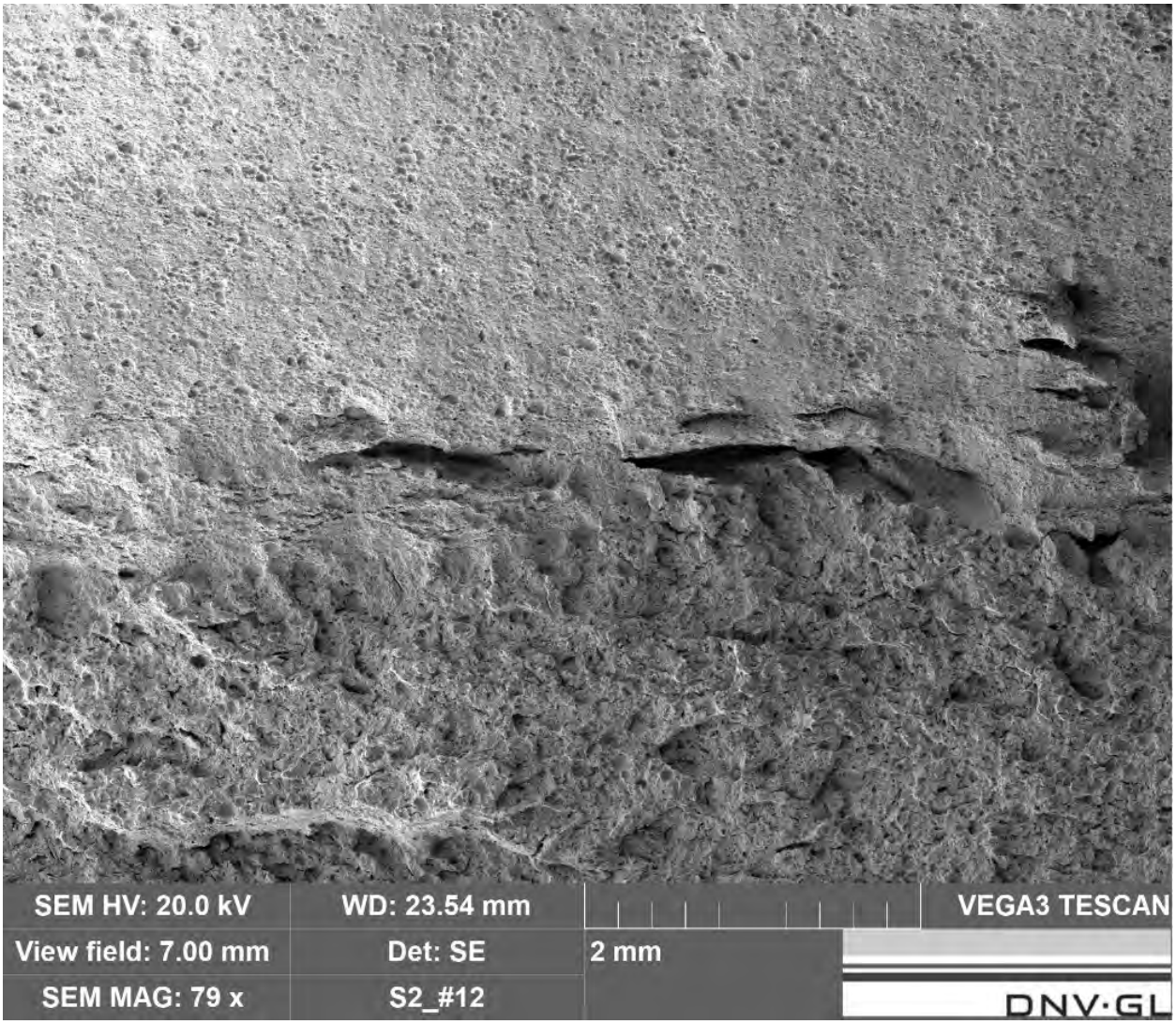

Figure 38. Sample S2 – Tears Mid-Wall (Smooth Region)

5.5 Hardness Testing

Vickers hardness testing was conducted on all six metallographic cross sections. No areas of unusually high hardness were identified. Hardness testing of the failed girth weld exhibit variability that is likely associated with cold work sustained during the failure. The hardness testing of the intact weld are the best representation of the base hardness of the welds preceding the failure. The results indicate a lower hardness of the weld metal compared to the pipe metal, which indicating that the weld metal is softer than the parent metal. Typically, the parent metal

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is harder than the weld metal. The axial tensile tests on the intact girth weld show similar failure to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. Hardness levels at varying points on sample M2 from the failed girth weld are shown in Figure 39.

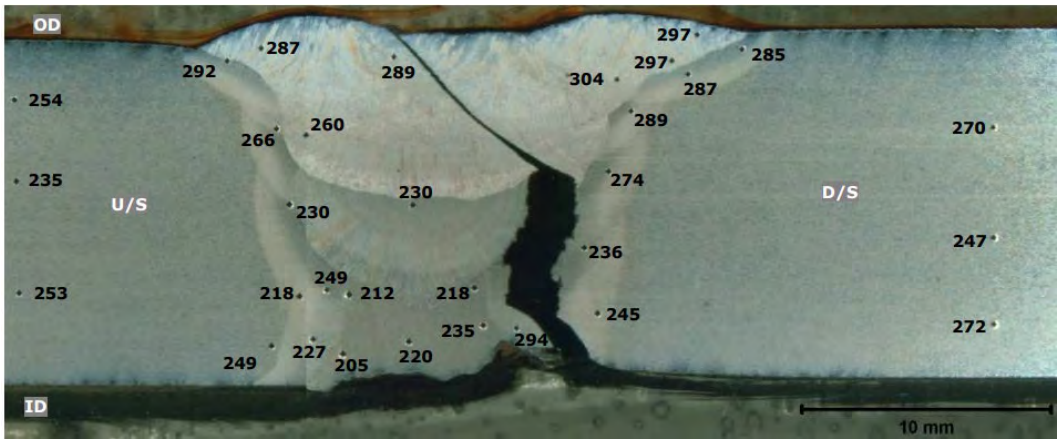

Figure 39: Light Photomicrograph of M2 Axial Cross-Section Showing Hardness Levels in HV

5.6 Mechanical Testing

A summary of mechanical testing results for the Delhi 24-inch pipeline samples is provided below. Additional detail is included in Appendix C.

5.6.1 Tensile Testing

Tensile testing of duplicate circumferential base metal specimens indicates the average yield strength (YS) and ultimate tensile strength (UTS) meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. Both specimens failed in the girth weld, similar to the in-service pipeline failure. The average axial YS and UTS value across the weld meets the tensile requirements for API 5L X80M PSL 2 line pipe at the time of construction.

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5.6.2 Charpy V-Notch Testing

The results of CVN testing of the base metal samples indicate impact values all exceeding the specified values for the specified minimum value for API 5L X80M PSL 2 line pipe at the time of construction. Test results of the girth weld samples taken from PS C indicate acceptable values, with the 85% Fracture Appearance Transition Temperature (FATT) 59.9ºF.

5.6.3 Chemical Analyses

The results of the chemical analysis indicate that the steels meet the compositional requirements of API 5L Grade X80M PSL 2 line pipe. The carbon equivalent (CE) values were calculated for the base metal samples PS A and PS C and are 0.17 and 0.16 respectively. These values compare favorably to the maximum allowable 0.25 according to API 5L specification at the time of construction.

6.0 CONCLUSIONS

The combined results of this investigation indicate that the root cause of the 24-inch Delhi pipeline failure was overload at a field girth weld due to axial stresses sufficient to cause an overload condition. Movement is considered to be a possible contributing factor. Based on the results of this investigation, we provide the following conclusions:

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.

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4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

7.0 APPENDICES

Appendix A – Denbury Yazoo County Pipe Sample Collection Protocol

Appendix B - Denbury Yazoo County Metallurgical Sampling & Testing Protocol

Appendix C - DNV-GL Metallurgical Analysis Report

Appendix D - Responses to Questions Provided by PHMSA 4/7/2021

Appendix E - Chain of Custody Documentation

Appendix F - Welding Procedure Development and Qualification for X80 Line Pipe

Appendix G - Welding Procedure Specification WPS 14 6/18/2008

Appendix H - Stress Analysis Report Denbury Delta Pipeline Repair 7/28/2021

Appendix A

Denbury Yazoo County Pipe Sample Collection Protocol

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Pipe Sample Collection Protocol

Denbury Yazoo County Pipeline

1. Each pipe sample location will be identified and documented according to Mears procedures.

2. The as-found condition of the site will be documented and photographed, and the areas previously identified will be excavated to uncover the pipeline.

3. Any welded sleeves or temporary repair clamps covering the area of interest are to be left in place for removal after delivery of the sample to the laboratory.

4. If any bolted connections are disconnected or removed, fasteners and gaskets will be marked for identification purposes, photographed and retained for further analysis (if applicable).

5. If the pipeline is encased at the area of interest:

    a. The exterior of the casing will be visually inspected, condition documented, and a section of the casing will be selected and marked for identification purposes.
    b. The identified casing section will then be removed in a manner that preserves the condition of the pipeline and casing in the area of interest to provide access for inspection of the pipeline in the area of interest.
    c. The interior surface of the casing will be visually inspected, documented and photographed.
    d. If applicable, samples of the casing or materials inside the casing will be selected and collected for detailed analysis.

6. The as-found condition of the carrier pipe will be documented and photographed. Labeling will include the 12:00 position of the pipe and direction of flow, prior to coating removal and pipe inspection.

7. Prior to disturbing or removing the pipe coating, samples of any liquids or solids deposits located between the carrier pipe and coating or adhered to the pipe surface located in the area of interest will be collected in duplicate. Liquid samples will be retrieved using a syringe. Solids samples will be collected using a wooden spatula/tongue depressor. All samples will be placed in sealed enclosures (test tubes or sample bags). Samples will then be labeled and photographed. Duplicate samples will be transferred to designated representatives of IPL or shall be retained for future transfer.

8. If no liquids are present, pH paper may be used to evaluate any moisture present on the pipe section.

9. The pipeline in the area of interest will then be evaluated to determine if pipe samples are required for further detailed analysis.

10. If temporary repairs are required at the area of interest in order to allow future removal of a pipe sample, the repair will be installed preserving the condition of the area of interest and will be left in place for removal after delivery to the laboratory.

11. Sample(s) to be removed for detailed analysis and testing from the pipe section cut out of the pipeline will be identified:

    a. The sample(s) will be marked for identification, including the 12:00 position of the pipe and direction of flow.
    b. The identified sample(s) will be photographed prior to removal from the pipeline.
    c. Coating removal and cuts will be made at least 12" from the identified defect/damage location, with care taken not to disturb the area of interest.
    d. If welded sleeves or temporary repair clamps cover the area of interest, cuts will be performed at least six inches from the edges of the sleeve or clamp.

12. After removal, the pipe sample(s) will be photographed prior to packaging for shipment:

    a. The pipe sample(s) will be wrapped in hydrophobic material like polyethylene to prevent contamination.
    b. The pipe sample(s) will then be crated for shipment, along with any other portable evidence identified for further testing.
    c. The pipe sample(s) will be immobilized within the container.

13. Transport documentation and chain of custody will then be initiated.

14. The pipe sample will then be shipped to DNV GL, Columbus, OH or Plain City, OH receiving yard.

Appendix B

Denbury Yazoo County Metallurgical Sampling & Testing Protocol

METALLURGICAL FAILURE INVESTIGATION PROTOCOL

Denbury Delhi 24 inch Transmission Pipeline

1. INTRODUCTION

The purpose of the failure analysis is to assign one or more probable causes to the failure. This failure analysis protocol specifically addresses the failure analysis of line pipe.

The protocol was written in accordance with the March 21, 2019 Metallurgical Laboratory Failure Examination Protocol by PHMSA.

2. VISUAL AND NONDESTRUCTIVE EXAMINATION

2.1 Open the crate to visually inspect the failed pipe sections. The crates should contain the failed pipe section, including one intact girth weld.

2.2 Photographically document each pipe section in the “as-received” condition before initiating the metallurgical evaluation.

2.3 Remove the protective wrapping from the failed pipe sections and perform visual examination of the external and internal pipe surfaces in the “as received” condition. Measure the length of the failed pipe sections and document the position and orientation of anomalies that may be present in the failed pipe sections. This step shall include:

- Fracture area and surface
- Seams
- Girth welds
- Coating condition
- Anomalies
- Manufacturing flaws and defects
- Presence of External or internal corrosion

2.4 Collect coating samples, solid and liquid samples (if present). All samples will be collected with companion samples or retained. If a sample is determined to be of insufficient volume for a companion sample to be collected, the sample will be retained for evaluation at a later date. Solid deposits and liquid samples, if present, from the internal and external pipe surfaces will be submitted for energy dispersive spectroscopy (EDS) elemental analysis, X-ray diffraction (XRD) and microbial tests. If not enough liquid is present for collection, consider using pH paper to characterize

pH. Use a soft clean/uncontaminated knife or spatula to collect samples and re-inspect the pipe section after collecting samples. Knives/Tools should be cleaned with alcohol wipes before each use. The films or deposits may be from the steel surface, coating surface, interior of a corrosion pit, or the backside of the coating. The color and type of sample should be recorded. Carefully transfer the sample to the test kit vial for testing and carefully follow the instruction given in the kit manual.

2.5 Carefully remove and retain samples of the coating around the suspected area of damage using a knife or similar instrument. Knives/Tools should be cleaned with alcohol wipes before each use. Avoid touching the soil, pipe surface deposits or product, or film with hands or tools other than those to be used in sample collection and/or provided with the test kits. Any liquid under the coating should be sampled if sufficient quantities are available. If insufficient quantities are found, the pH shall be tested with litmus paper.

2.6 After the coating sample is collected, visually inspect the internal and external surfaces of the failed section. Identify areas that may contain other types of anomalies such as cracking, stress corrosion cracking, or any other condition that could affect the long-term integrity of the pipeline. Clean and examine the external pipe surfaces adjacent to the failure using nondestructive testing techniques, such as magnetic particle inspection (MPI) such as wet fluorescent magnetic particle (WFMT). The surfaces of the pipe surrounding the corrosion or cracks must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products and coating remnants.

2.7 The physical location of all samples that are removed from the pipe section for examination and metallurgical analysis will be documented such that all relevant features are visible (graphically and/or photographically). A pipe section schematic detailing the location and orientation of any samples will be prepared.

2.8 Determine the appropriate failure analysis processes to complete based on the initial observations and testing.

3. PHYSICAL MEASUREMENTS

3.1 Measure the diameter and wall thickness at the 12, 3, 6 and 9 o’clock orientations on undisturbed areas of the pipe.

3.2 Measure and record the length of each sample.

3.3 Examine the details of the failed area. Measure and record any additional defects identified.

3.4 Measure the diameter and wall thickness at selected locations of anomalies.

3.5 Verify roundness and geometry of pipe at the extremities and near the failed surface.

3.6 Measure the wall thickness around the failure and any damaged areas. Provide a schematic detailing the extent of the damage on the pipe surface and the pipe wall thickness on those areas. Supplement with photographic records. Supplement these measurements with laser scanning.

3.7 Determine and mark the locations of the long seam weld at each end of the sample.

3.8 Measure and record the size and location of anomalies and confirm the dimensions of the failed pipe section. Measure crack depths (if present) using direct exploration (grinding), shear wave ultrasonic testing, or other suitable method.

3.9 Measure the shortest axial distance from the failure to the nearest long seam weld (if applicable). Measure the shortest longitudinal distance from the failure to the nearest girth weld (if applicable).

4. CORROSION EXAMINATION

4.1 Examine the pipe external surface near the failure location to determine if anomalies exist.

4.2 Examine the pipe internal surface at the failure location to determine if anomalies exist.

4.3 If not already performed as described in Section 2, collect surface deposits and residues associated with the external pipe surface at the failure area and adjacent areas and analyze using MIC IV kits (or equivalent) and energy dispersive spectrometry (EDS) and microbial analysis. Knives/Tools should be cleaned with alcohol wipes before each use.

4.4 Photographically document the pipe internal surface conditions and any anomalies present.

4.5 Evaluate and document processes that potentially contributed to the failure to support selection of samples within the failed pipe section.

4.6 If internal anomalies are found, proceed with collection of surface deposits and residues associated with the failure area and analyze using MIC IV and MIC V kits (or equivalent) and energy dispersive spectrometry (EDS) and microbial analysis.

4.7 Determine specific locations of the failed pipe section for further investigation.

4.8 Cut and clean the selected locations for selection of initial metallographic sections, taking additional solids and liquid samples as necessary.

4.9 Perform hardness measurements in areas near the anomalies and also remote from the failure site.

4.10 Take initial metallographic sections at appropriate locations within the failure area.

4.11 Anomaly depths may be determined using pit depth gauge, ultrasonic thickness probe, profile gauges, 3D laser scanning, etc.

5. FRACTOGRAPHIC EXAMINATION

5.1 Visually examine the fracture surface in detail to identify specific characteristics, the nature of the original defect, and the failure initiation point (s). If it becomes necessary, a metallographic section will be made through the sample to open the failure for further examination.

5.2 Clean samples in an appropriate manner to remove loose rust, scale, etc. as necessary.

5.3 Remove selected fractographic samples as necessary for detailed microscopic examination using a scanning electron microscope equipped with EDS. Examine and document the fracture surface morphology.

5.4 Thoroughly document the location of the samples taken from the pipe section at or near the failure.

6. METALLOGRAPHIC EXAMINATION

6.1 Identify metallographic sample origin (sample identification, location, orientation, etc.), perform metallographic evaluation, and take representative photomicrographs.

6.2 Perform micro-hardness profiles at appropriate locations.

6.3 Document microstructural appearance of samples.

6.4 Document the extent of the wall loss, if any, of the cross section.

6.5 Based on the results of the visual, non-destructive, and metallographic examinations, the presence of corrosion will be documented, and the type and characteristics of any corrosion present should be evaluated.

NOTE:

- This protocol is subject to change.
- Additional tests may be added and/or changes made as necessary to accomplish the purpose of this failure analysis and complete this process.

Appendix C

DNV GL Metallurgical Analysis Report

DNV·GL

Draft Report

Metallurgical Analysis of 24-Inch Diameter Delhi Pipeline Failure (02/22/20)

Mears Group, Inc.
Plain City, Ohio

Report No.: O-AP-FINV / GTQU (10206282)
June 4, 2020



Project Name:	Metallurgical Analysis of 24-Inch Diameter Delhi Pipeline Failure (2/22/20)
Customer:	Mears Group, Inc.
Contact Person:	Aida Garrity
Date of Issue:	June 4, 2020
Project No.:	10206282
Organization Unit:	Incident Investigation
Report No.:	O-AP-FINV / GTQU

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Tel: (614) 761-1214
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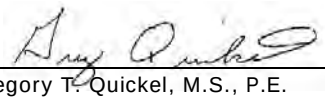
Task and Objective:

Please see Executive Summary.

Prepared by



Gregory T. Quickel, M.S., P.E.
Principal Engineer

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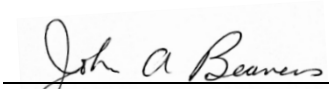

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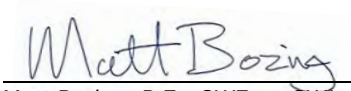

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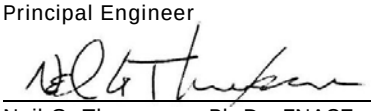

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Senior Vice President

Approved by

David M. Norfleet, Ph.D., P.E.
Head of Section –
Incident Investigation

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Executive Summary

Mears Groups, Inc. (Mears) retained DNV GL USA, Inc. (*DNV·GL*) to perform a metallurgical analysis on a portion of the Delhi 24-inch diameter carbon dioxide (CO_2, dry) transmission pipeline, that failed at a girth weld while in service, resulting in full separation. The failure occurred on February 22, 2020 in Satartia, Mississippi at Stationing 348+26, 6.59 miles from the nearest upstream (U/S) pump station.

The segment of the pipeline that failed is comprised of 24-inch diameter by 0.540-inch wall, API 5L Grade X80M PSL 2 line pipe steel that contains a high frequency electric resistance welded (HF ERW) seam. The maximum allowable operating pressure (MAOP) is 2,160-psig, which corresponds to 59.6% of the specified minimum yield strength (SMYS). The pressure at the Tinsley Meter Station (Stationing 0+00) at the time of the failure was 1,336-psig (36.9% of SMYS). The pipeline normally operates between 1,200 and 1,450-psig (33.1 and 40.0% of SMYS, respectively).

The pipeline was installed in 2009 and is externally coated with a factory applied fusion bonded epoxy (FBE) and abrasion resistant overlay (ARO) coating. A liquid epoxy coating was applied to the pipeline at the girth welds in the field. Following construction, a hydrostatic pressure test was performed on January 14, 2009 to a minimum pressure at the dead weight gage of 2,908 psig (80.3% of SMYS). The pipeline has an impressed current cathodic protection (CP) system that was commissioned in 2009, directly following pipeline installation.

Three pipe sections (Pipe Sections [PSs] A, B, and C) were delivered to DNV GL for analysis. Pipe Section A was 5.99 feet long and contained the downstream (D/S) portion of the failed girth weld. Pipe Section B was 6.08 feet long and contained U/S portion of the failed girth weld. Pipe Section C was 8.00 feet long and contained an adjacent U/S intact girth weld. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor to the failure was that the pipe steel was stronger than the girth weld.

The scope of the work consisted of:

- Visual inspection and photography
- Magnetic particle inspection
- Fractography
- Scanning electron microscopy
- Metallography
- Energy dispersive spectroscopy

- Hardness testing
- Mechanical testing
- Chemical analysis

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses includes stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joint's D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.
- The tensile and toughness properties of the joint's U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The chemical compositions of the joint's U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

- The microstructures of the joint's U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.
- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% fracture appearance transition temperature (FATT) is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

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1.0 BACKGROUND

Mears Groups, Inc. (Mears) retained DNV GL USA, Inc. (*DNV·GL*) to perform a metallurgical analysis on a portion of the Delhi 24-inch diameter carbon dioxide (CO_2, dry) transmission pipeline, that failed at a girth weld while in service, resulting in full separation. The failure occurred on February 22, 2020 in Satartia, Mississippi at Stationing 348+26, 6.59 miles from the nearest upstream (U/S) pump station.

The segment of the pipeline that failed is comprised of 24-inch diameter by 0.540-inch wall, API 5L Grade X80M PSL 2 line pipe steel that contains a high frequency electric resistance welded (HF ERW) seam. The maximum allowable operating pressure (MAOP) is 2,160-psig, which corresponds to 59.6% of the specified minimum yield strength (SMYS). The pressure at the Tinsley Meter Station (Stationing 0+00) at the time of the failure was 1,336-psig (36.9% of SMYS). The pipeline normally operates between 1,200 and 1,450-psig (33.1 and 40.0% of SMYS, respectively).

The pipeline was installed in 2009 and is externally coated with a factory applied fusion bonded epoxy (FBE) and abrasion resistant overlay (ARO) coating. A liquid epoxy coating was applied to the pipeline at the girth welds in the field. Following construction, a hydrostatic pressure test was performed on January 14, 2009 to a minimum pressure at the dead weight gage of 2,908 psig (80.3% of SMYS). The pipeline has an impressed current cathodic protection (CP) system that was commissioned in 2009, directly following pipeline installation.

Three pipe sections (Pipe Sections [PSs] A, B, and C) were delivered to DNV GL for analysis. Pipe Section A was 5.99 feet long and contained the downstream (D/S) portion of the failed girth weld. Pipe Section B was 6.08 feet long and contained U/S portion of the failed girth weld. Pipe Section C was 8.00 feet long and contained an adjacent U/S intact girth weld. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

2.0 TECHNICAL APPROACH

The procedures used in the analysis were in accordance with industry-accepted standards. Five of the general standards governing terminology, specific metallographic procedures, mechanical testing, and chemical analysis used are as follows:

- ASTM E7, “Standard Terminology Relating to Metallography.”
- ASTM E3, “Standard Methods of Preparation of Metallographic Specimens.”
- ASTM E8, “Test Methods for Tension Testing of Metallic Materials.”

- ASTM E23, “Standard Test Methods for Notched Bar Impact Testing of Metallic Materials.”
- ASTM A751, “Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products.”

The following steps were performed for the analysis. The pipe sections were removed from the wooden shipping crates and visually inspected and photographed. Wall thicknesses, outside diameters (ODs), and circumferences were measured at the field cut ends of the pipe sections. The external and internal surfaces of the pipe sections at the failed girth weld were cleaned with a Scotch-Brite™ pad, followed by photography of the surfaces. The fracture surfaces were then cleaned with a soft bristle brush, followed by photography at one hour o’clock increments. The external surface of PS C was grit blasted at the intact girth weld, followed by magnetic particle inspection (MPI) of the grit blasted surface. Samples were removed from PS A and C for mechanical testing and steel chemical analysis.

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and intact girth weld (one total) for metallographic analysis. The cross-sections were mounted, polished, and etched. Light photomicrographs were taken to document the morphology of any flaws and the microstructures of the pipe steel and welds. Hardness testing was performed on the six mounted cross-sections to document the hardness values at and away from the girth welds. Fracture surface samples (four total) were removed from PS A, cleaned in ENPREP® 214, examined optically at low magnification with a stereomicroscope, and imaged at high magnification in a scanning electron microscope (SEM) to document the fracture morphologies.

Magnetic particle inspection was performed on the internal surfaces of the intact and failed girth welds. Chemical analyses were performed on the steel samples removed from the joints U/S and D/S of the failed girth weld to determine the compositions. Tensile (duplicates) testing was performed on transverse and axial specimens removed from the joints U/S and D/S of the failed girth weld, and on axial (cross-girth weld) specimens removed from the intact girth weld, to document the tensile properties. Charpy V-notch (CVN, triplicates) testing was performed on transverse specimens removed from the joints U/S and D/S of the failed girth weld to document the base metal toughness. Charpy V-notch (CVN) impact testing (full curve, 10 specimens per curve) was performed on axial (cross-girth weld, heat affected zone [HAZ] notch) specimens removed from the intact girth weld and an upper shelf impact energy and 85% fracture appearance transition temperature (FATT) was determined.

Figure 1 is a schematic of PSs A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mount M1, M2, M3, M4, M5, and MU1),

fractography (Sample S1, S2, S3, and S4), mechanical testing, and chemical analysis were removed.

3.0 RESULTS AND DISCUSSION

3.1 Optical Examination

Figure 2 is a photograph of the wooden shipping crate that contained PS A as received at DNV GL. The crate is approximately 10 feet long and was in good condition. Figure 3 is a photograph of PS A after removal from the wooden crate. The figure shows that the ends of the pipe were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the U/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 4 are photographs of PS A after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 5.99 feet long, contains a longitudinal seam weld at the 12:26 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and portions of a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The figure shows a large portion of the coating is not present. The coating is not present between approximately 0 and 5.70 feet D/S of the girth weld, from the 8:00 to 4:00 orientations. Field personnel indicated that following failure the product flow was toward PS A, which may have contributed to the lack of coating. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 5 is a photograph of the wooden shipping crate that contained PS B as received at DNV GL. The crate also is approximately 10 feet long and was in good condition. Figure 6 is a photograph of PS B after removal from the wooden crate. The figure shows that the ends of this pipe also were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the D/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 7 is a photograph of PS B after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 6.08 feet long, contains a longitudinal seam weld at the 10:37 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. Some of the field applied coating was not present adjacent to the girth weld, for the entire circumference. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 8 is a photograph of the wooden shipping crate that contained PS C. The crate also is approximately 10 feet long and was in good condition. Figure 9 is a photograph of PS C after removal from the wooden crate. The figure shows that the ends of the pipe also were wrapped in clear plastic that was secured with duct tape. Figure 10 is a photograph of PS C

after removal of the clear plastic. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 8.00 feet long and contains longitudinal seam welds at the 1:24 orientation (U/S joint) and at the 10:37 orientation (D/S joint). An intact girth weld, that is the girth weld just U/S of the failed girth weld, is indicated in the figure. A field applied liquid epoxy coating (light blue appearance) is located at the girth weld and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The field and factory applied coatings were intact. Additionally, the figure shows some residual soil is present on the pipe section. There was no evidence of notable internal or external corrosion of the three pipe sections.

Figure 11 through Figure 14 are photographs of the external surface of PSs A and B adjacent to the fracture surfaces/failed girth weld. The figures are sequential photographs taken around the circumference of the girth weld and show the morphology of the weld pattern and where coating is present. The lack of coating adjacent to the girth weld on the PS B side (U/S of the failed girth weld) suggests that large strains were present prior to/during the failure. The figures shows that the fracture path traversed (crossed over) the weld at various locations. The external appearance of the weld ripple pattern is indicative of low hydrogen electrodes deposited in the vertical-down direction, with a triple pass wide weave cap pass. Even though downhill welding progression with low-hydrogen electrodes is not common in the pipeline industry, electrode manufactures do provide low-hydrogen electrodes specifically designed to weld down, which are classified as EXX45 type electrodes. The morphology of the weld ripple pattern also indicates that the top button (start of welding) is located near the marked 12:00 orientation; see Figure 14.

Figure 15 and Figure 16 contain photographs of the internal pipe surface adjacent to the fracture surface of PS B. Each photograph shows approximately 3 o'clock hours of the internal surface at the girth weld adjacent to the fracture surface. The figures show that the root pass is located on the PS A side of the failure opening between approximately the 6 and 9 o'clock orientations and a majority of the root pass is located on the PS B side of the failure opening elsewhere. The top button is indicated in Figure 16, near the marked 12:00 orientation.

Circumferences and ODs were measured at the four field cut ends of the pipe sections. Table 1 summarizes the results of the measurements. The ODs calculated from the circumference measurement were between 24.1 and 24.2 inches at the field cut ends. The diameters meet API 5L tolerance requirements for 24-inch diameter pipe. The ODs were measured with a tape measure from the 3 to 9 o'clock and 12 to 6 o'clock orientations to check for ovality. The ODs at the ends of PSs B and C, and both orientations, were 24.0 inches, indicating no measurable ovality. The ODs at the end of PSs A, and both orientations, were 24.1 inches, indicating no measurable ovality.

Wall thicknesses were measured at the 12, 3, 6, and 9 o'clock orientations at the four field cut ends. The external coating was ground prior to the measurements. The wall thickness values were between 0.530 and 0.540 inches, as shown in Table 2, and meet API 5L tolerance requirements for pipe with a nominal wall thickness (NWT) of 0.540 inches.

3.2 Magnetic Particle Inspection

The intact girth weld on PS C was grit blasted and MPI was performed. Figure 17 and Figure 18 contain photographs of the external surface at the girth weld following MPI. No crack-like indications were identified. A metallographic cross-section (Mount MU1) was removed from the 12:24 orientation. The weld ripple pattern of the weld is consistent with PS A and PS B and with the use of a low hydrogen electrode and a vertical-down progression. The top button (Figure 18) is just above (counter-clockwise of) the 12:00 orientation.

Note that MPI of the internal surface of the intact weld also was performed following mechanical testing, as was MPI of the internal surface of at the failed GW, following metallography. No crack-like indications were identified.

3.3 Fractography

3.3.1 Optical

Figure 19 is a photograph of the fracture surface and internal surface of PS A following cleaning with a soft bristle brush. Each o'clock hour is indicated and located at the twelve grey magnets. Figure 20 through Figure 31 are sequential photographs of the PS A side of the fracture surface of the failed girth weld, in 1 hour o'clock increments, starting at the 12:00 orientation. The fracture surface mainly consists of fairly smooth surfaces (*smooth regions*) at a shear (~45°) angle with respect to the free surfaces, and rougher surfaces (*rough* surfaces) that are perpendicular to the free surfaces. Some examples of the smooth surfaces are in Figure 21 through Figure 23, between the 1:00 and 3:45 orientations. The fracture surface between the 3:45 and 4:15 orientations contains smooth and rough regions. Some other examples of the rough regions are in Figure 29 through Figure 31, between the 9:15 and 12:00 orientations, where the rough regions are mainly ID surface breaking, with some midwall portions. The differences in these appearances is related to the fracture mode (ductile vs brittle), as described in Section 3.3.2, and both regions formed as a result of overload. There was no evidence of gross pre-existing flaws on the fracture surface that would have been rejected if detected by radiographic inspection. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified.

3.3.2 Optical and Scanning Electron Microscopy

Four fracture surface samples (Samples S1, S2, S3, and S4) were removed from the PS A side of the failed girth weld, adjacent to the metallographic cross-sections. The results of examinations of Samples S2 and S3 are below.

Figure 32 is a light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. Sample S2 was removed near the 4:00 orientation. The figure shows smooth regions (black dashed double arrows) adjacent to the OD and ID surfaces, and a rougher region (white double arrow) midwall. There is no evidence of any pre-existing (present prior to the failure) flaws on the facture surface. Figure 33 is an SEM image of Sample S2 adjacent to the ID surface. The figure shows a smooth region (adjacent to the ID surface) and a rough region of the fracture surface. Figure 34 is an SEM image of Sample S2 at the interface of a smooth and rough region. The black box in the figure is just below the interface and the figure shows dimples in the smooth region. Dimples indicate ductile (overload) fracture, which occurred during the failure. Figure 35 is a high magnification SEM image of Sample S2 in the smooth region. The figure clearly shows the dimples. Figure 36 and Figure 37 are SEM images of Sample S2 in a rough region. The fracture surface contains cleavage facets, which indicates brittle (overload) fracture, which occurred during the failure.

Figure 38 is an SEM image of Sample S2, midwall at a second interface of the smooth and rough regions. The figure shows what appear to be some tears in the smooth region, above the rough region. Figure 39 and Figure 40 are SEM images in the smooth region. The figures shows dimples, consistent with ductile (overload) fracture.

Figure 41 and Figure 42 are SEM images of Sample S2 in a smooth region adjacent to the OD surface. The figures show dimples, which is very clear in the high magnification SEM image. Again, the dimples indicate ductile (overload) fracture and are consistent with ductile fracture in the smooth region.

Figure 43 is a light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. Sample S3 was removed near the 8:30 orientation. Figure 44 is an SEM image of Sample S3. The fracture surface is macroscopically smooth and at a shear angle to the free surfaces, and consists of mainly, if not entirely, smooth regions. Figure 45 is an SEM image of Sample S3 midwall. The figure shows small and larger dimples. Figure 46 is a high magnification SEM image of Sample S3 in the smooth region. The figure clearly shows the dimples.

Examination of Samples S1 and S4 showed similar fractographic features that formed as a result of overload failure. There was no evidence of obvious pre-existing flaws or fatigue growth on the fracture surfaces examined.

3.4 Metallography

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and the intact girth weld (one total) for metallographic analysis. Figure 47 is a photograph of the mounts that were removed from across the failed girth weld. The figure shows that Mounts M1 and M3 contain fracture paths at a shear angle, which is indicative of ductile overload failure. Mounts M2 and M4 (and a small portion of M5) contain regions where the fracture path is perpendicular to the free surface and regions of shear failure. The perpendicular portions are where the fracture surfaces are rough and the shear angle portions are where the fracture surfaces are smooth.

Figure 48 is a light photomicrograph of the axial metallographic cross-section (Mount M1), which was removed from the failed GW at the 1:35 o'clock orientation; refer to Figure 1 and Figure 11 for the location. The sequence of the welding is typical of a pipeline girth weld consisting of a root pass, a hot pass, several fill passes (depending on o'clock orientation), and cap passes. There is no evidence of excessive porosity or slag inclusions in the weld. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.023 inches (4.3% of NWT); note the misalignment is difficult to measure on the fracture cross-section and is an approximation.

Figure 49 is light photomicrograph of Mount M1 adjacent to the OD surface. The figure shows the fracture path is located in the HAZ, near the toe of the weld at the OD surface. Figure 50 is a light photomicrograph of Mount M1 adjacent to the fracture surface, near the OD surface. The figure shows inclusions aligned at an oblique angle with the fracture surface. The orientation of the inclusions is a result of cold work from the failure. Figure 51 is a high magnification light photomicrograph of Mount M1 adjacent to the fracture surface. The figure shows some grain elongation adjacent to the fracture surface and inclusions. The presence of the grain elongation from cold work and orientation of the inclusions is consistent with ductile overload. Figure 52 is a high magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface. The figure clearly shows the change in the grain orientation and thus more grain elongation adjacent to the fracture surface.

Figure 53 and Figure 54 are light photomicrographs showing the microstructures of the U/S and D/S Joints, respectively. The microstructures of the joints consist mainly of ferrite (white areas), which is consistent with modern X80 line pipe.

Figure 55 is a light photomicrograph of the axial metallographic cross-section (Mount M2), which was removed from the failed GW at the 3:55 o'clock orientation; refer to Figure 1 and Figure 12 for the location. The morphology of the weld similar to Mount M1. The high-low weld misalignment at this location is approximately 0.037 inches (6.9% of the NWT). The figure clearly illustrates the smooth and rough regions examined near SEM Sample S2, such

that the smooth regions are surface breaking and the rough region is midwall. The fracture path at this location is in both the weld metal and HAZ, such that smooth region near the OD surface is in the weld metal, and the rough region midwall and smooth region near the ID surface are in the HAZ. Fractography in the SEM demonstrated that the smooth region contains dimples and the rough region contains cleavage facets.

Figure 56 is a light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows that the fracture surface is relatively smooth. Figure 57 is a high magnification light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows grain elongation adjacent to the fracture surface. The presence of the grain elongation from cold work is consistent with ductile overload. Figure 58 is a light photomicrograph of Mount M2 midwall, in a rough region. The fracture surface is clearly rougher here than the previous figure, and the fracture path is mainly located in the HAZ, if not entirely. Figure 59 is a light photomicrograph of Mount M2 adjacent to the fracture, midwall. The figure shows some fissures. Figure 60 is a high magnification light photomicrograph of Mount M2 at fissures. The fissures are located where cleavage facets (brittle fracture) were present on the fracture surface. These fissures are commonly seen in girth weld overload failures, adjacent to fractures surfaces, or pipe (body or seam weld) failures that involve axially running fracture.

Figure 61 is a light photomicrograph of the axial metallographic cross-section (Mount M3), which was removed from the failed GW at the 8:35 o'clock orientation; refer to Figure 1 and Figure 13 for the location. The morphology of the weld is similar to Mounts M1 and M2. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.014 inches (2.6% of the NWT). The figure clearly illustrates the smooth region examined near SEM Sample S3.

Figure 62 is light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface. The figure shows grain elongation adjacent to the fracture surface that is consistent with ductile overload.

Figure 63 is a light photomicrograph of the axial metallographic cross-section (Mount M4), which was removed from the failed GW at the 10:24 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is minimal. The figure shows both a smooth shear angle region and a rough region oriented perpendicular to the free surfaces. The fracture path at this location is mainly in the HAZ.

Figure 64 is light photomicrograph of Mount M4 adjacent to the OD surface. The figure clearly shows the fracture path is located in the HAZ. Figure 65 is a high magnification light photomicrograph of Mount M4 adjacent to the OD surface. The figure shows grain

elongation, and an inclusion orientated parallel to the fracture surface, both observations consistent with ductile overload. Figure 66 is a light photomicrograph of Mount M4 midwall, mainly in a rough region. The figure shows some fissures. Figure 67 is a high magnification light photomicrograph of Mount M4 at some fissures. The fissure have the same morphology as shown in Mount M2. Figure 68 is a high magnification light photomicrograph of Mount M4 near the ID surface. The figure shows grain elongation adjacent to the fracture surface.

Figure 69 is a light photomicrograph of the axial metallographic cross-section (Mount M5), which was removed from the failed GW at the 11:37 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.025 inches (4.6% of the NWT). The figure shows a smooth shear angle region for a majority of the fracture surface, and a rough region oriented perpendicular to the free surfaces midwall. The fracture path at this location is located in both the weld metal and base metal.

Figure 70 is a light photomicrograph of the axial metallographic cross-section (Mount MU1), which was removed from the intact GW at the 12:24 o'clock orientation; refer to Figure 1 and Figure 17 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.011 inches (2.0% of the NWT). Figure 71 is a light photomicrograph of Mount MU1 adjacent to the ID surface. The figure shows a shallow (0.01 inches [1.9% of NWT] deep) flaw between the weld metal and HAZ. The location of the flaw is consistent with incomplete fusion (IF). Figure 72 is a high magnification light photomicrograph of Mount MU1 at the tip of the shallow IP flaw. The figure shows there is no evidence of crack extension at the flaw.

3.5 Hardness Testing

Vickers hardness testing was performed on all six mounts in the base metal, HAZ, and weld metal. A 1 kg load was used on Mounts M1, M4, and MU1 and approximately 1500 indents with approximately 0.5 mm spacing were performed. Figure 73, Figure 76, and Figure 78 are hardness map overlays showing the locations of the indents and color coded maps indicating the hardness values. The hardness values for the two mounts from the failed girth weld are between 208 and 317 HV, and the values for the mount from the intact girth weld are between 167 and 268 HV. The average hardness for Mount M1, M4, and MU1 are 266, 253, and 228 HV, respectively. There was a larger variation in the hardness values, and less of a consistent pattern of hardness values, for the mounts from the failed GW compared to the intact girth weld. Overall for the mounts from the failed girth weld, the weld metal in the root pass was the softest, the weld metal in the cap pass was higher than the fill passes, and the base metal was somewhere in between. The highest values for the

mounts from the failed girth weld was adjacent to the shear fracture surface, between midwall and the OD surface.

The hardness of the intact girth weld (Figure 78) is a better representation of the hardness of all the welds prior to the failure. For the intact girth weld, the values appeared to follow a more consistent pattern. Figure 78 clearly shows that the root pass of the weld metal is the softest and the surrounding base metal (adjacent to the HAZ) is harder than the weld metal. Hardness typically correlates with ultimate tensile strength (UTS) fairly well, thus the data indicates that the weld metal is weaker than the surrounding pipe material. The higher hardnesses measured in the failed welds, and the large variation and lack of a consistent pattern, is a byproduct of the cold work the material experienced during the failure.

A 10 kg load was used on Mounts M2, M3, and M5 (all from the failed girth weld) and indents were performed at approximately 20 to 30 locations. Figure 74, Figure 75, and Figure 77 are light photomicrographs of the mounts showing the indents and hardness values. The hardness values are between 205 and 304HV. The lowest values are at the ID weld metal (root pass, similar to the hardness maps), and the highest values are in the weld metal cap pass. The base metal is generally harder than the root and fill passes, and similar to or sometimes less than the cap pass.

Overall no areas of unusually high hardness area were found. The hardness results show that the softest region is located in the weld metal root pass, suggesting a lower grade electrode was used for the root pass compared to the other passes.

3.6 Mechanical Testing

3.6.1 Tensile Testing

The results of tensile testing of duplicate circumferential base metal specimens removed from PS A (Joint D/S of failed GW) are shown in Table 3. The average yield strength (YS) and ultimate tensile strength (UTS) of the circumferential specimens were 93.5 ksi and 112.4 ksi, respectively. The results of tensile testing of axial base metal specimens also are shown in the table and YS values for the axial specimens are quite a bit higher than those of the circumferential specimens (by 8 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The results of tensile testing of duplicate circumferential base metal specimens removed from PS C (Joint U/S of failed GW) are shown in Table 4. The average YS and UTS of the circumferential specimens were 91.0 ksi and 104.8 ksi, respectively, which is slightly less than the values for PS A. The results of tensile testing of axial base metal specimens also

are shown in the table and the YS values for the axial specimens also are higher than those of the circumferential specimens (by 6.7 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The average UTS of duplicate axial specimens removed across the intact girth weld was 103.3 ksi. Both cross-girth weld specimens failed in the girth weld, similar to the actual failure. YS values across the girth weld are not reliable and not specified in API 1104. The average UTS value across the weld meets the tensile requirements API 5L X80M PSL 2 line pipe at the time of construction. Note that the value of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld.

3.6.2 CVN Testing of Base Metal Specimens

The results of CVN testing of triplicate transverse base metal specimens removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are shown in Table 5. The specimens were tested at 32°F. The impact values are relatively high, i.e. full-size values all above 93 ft·lbs for PS A and above 148 ft·lbs for PS C. The shear % values are all 100% (indicating fully ductile behavior). The impact values all exceed the specified minimum value of 30 ft·lbs (at 32°F) for API 5L X80 PSL 2 line pipe, and the average of shear % values are greater than 85 %.

3.6.3 CVN Testing of Girth Weld Specimens

Table 6 shows the results of CVN testing for axial specimens removed from the intact girth weld (notch in the HAZ from PS C), while Figure 79 and Figure 80 show the Charpy percent shear and impact energy curves. An analysis of the data for the girth weld specimens indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs, as shown in Table 7. Both values are good for line pipe steel.

3.7 Chemical Analysis

The results of the chemical analyses conducted on steel samples removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are summarized in Table 8. The results of the chemical analyses indicate that the steels meet the chemical composition requirements for API 5L Grade X80M PSL 2 line pipe steel at the time of construction. Carbon equivalent (CE) values were calculated for the base metal samples. The calculated CE_{Pcm} values for the PSs A and C are 0.17 and 0.16, respectively, compared to a maximum allowed CE_{Pcm} of 0.25 per the API 5L spec at the time of construction. These values for the joints are relatively low and indicate a very good resistance to HACC in the HAZ.

4.0 CONCLUSIONS

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses include stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.
- The tensile and toughness properties of the joints U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The chemical compositions of the joints U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The microstructures of the joints U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.

- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

Table 1. Results of circumference and diameter measurements performed at the field cut ends of Pipe Sections (PS) A, B, and C.

Pipe Section	Pipe Section End	Circumference (feet)	Diameter (inches)		
			From Circumference Measurement	3 to 9 o'clock	6 to 12 o'clock
A	D/S	6.31	24.1	24.1	24.1
B	U/S	6.31	24.1	24.0	24.0
C	D/S	6.32	24.2	24.0	24.0
C	U/S	6.31	24.1	24.0	24.0

Table 2. Results of wall thickness measurements performed at the field cut ends of PS A, B, and C.

O'clock Orientation	Wall Thickness (inches)			
	PS A, D/S End	PS B, U/S End	PS C, D/S End	PS C, U/S End
12	0.539	0.536	0.537	0.531
3	0.533	0.538	0.536	0.530
6	0.536	0.535	0.534	0.530
9	0.533	0.540	0.537	0.530
Average	0.535	0.537	0.536	0.530

Table 3. Results of tensile tests performed on circumferential specimens from PS A (Joint D/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel, and axial base metal specimens from Pipe Section A.

	Circumferential	API 5L X80M Line Pipe Steel [2]	Axial
Yield Strength, ksi [1]	93.5	80.5 – 102.3	101.5
Tensile Strength, ksi [1]	112.4	90.6 – 119.7	109.7
Elongation in 2 inches, % [1]	29.5	20.7 (min)	31.1
Reduction of Area, % [1]	61.6	–	67.1

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 4. Results of tensile tests performed on circumferential specimens from PS C (Joint U/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel and axial base metal specimens and axial/cross-girth weld specimens from Pipe Section C.

	Circumferential	API 5L X80M Line Pipe Steel [2]	Axial	Cross Girth Weld
Yield Strength, ksi [1]	91.0	80.5 – 102.3	97.7	–
Tensile Strength, ksi [1]	104.8	90.6 – 119.7	106.0	103.3
Elongation in 2 inches, % [1]	29.0	20.7 (min)	31.8	–
Reduction of Area, % [1]	62.1	–	70.9	–

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 5. Results of Charpy V-notch impact tests for circumferential base metal specimens removed from the PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW). Specimens were tested at 32F.

Sample ID	Sub Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
Pipe Section A				
PSA1	93	93	100	56
PSA2	109	109	100	71
PSA3	105	105	100	68
Avg.	102	102	100	65
Pipe Section C				
PSC1	164	164	100	71
PSC2	148	148	100	81
PSC3	155	155	100	73
Avg.	156	156	100	75
API 5L [1]	-	30	$\geq$ 85	-

1 – API 5L 44th Edition, October 1, 2007.

Table 6. Results of Charpy V-notch impact tests performed on axial/cross-girth weld (heat affected zone [HAZ] notch) specimens removed from PS C.

Sample ID	Temperature, °F	Sub Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
1	-184	4	4	5	0
2	-112	7	7	16	6
3	-76	32	32	44	22
4	-40	59	59	51	41
5	32	69	69	69	48
6	73	116	116	97	81
7	104	117	117	87	65
8	140	122	122	100	86
9	176	95	95	92	64
10	194	118	118	100	87

Table 7. Results of analyses of Charpy V-notch impact energy and percent shear plots for axial/cross-girth weld (HAZ notch) specimens removed from PS C (Joint U/S of failed GW).

	Girth Weld
Upper Shelf Impact Energy (Full Size), Ft-lbs	114
85% FATT, °F	59.9

Table 8. Results of chemical analyses of base metal samples removed from PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW), compared with composition requirements for API 5L X80M PSL 2 line pipe steel. The highlighted CE values are the ones that are applicable based on carbon wt%.

Element	Composition (Wt. %)		
	PS A (Joint D/S of failed GW)	PS C (Joint U/S of failed GW)	API 5L X80M [1] Req.
C (Carbon)	0.059	0.053	0.12 (max)
Mn (Manganese)	1.62	1.65	1.85 (max)
P (Phosphorus)	0.012	0.009	0.025 (max)
S (Sulfur)	0.003	0.005	0.015 (max)
Si (Silicon)	0.202	0.219	0.45 (max)
Cu (Copper)	0.016	0.023	≤ 0.50
Sn (Tin)	0.006	0.002	–
Ni (Nickel)	0.006	0.009	≤ 1.00
Cr (Chromium)	0.047	0.038	≤ 0.50
Mo (Molybdenum)	0.260	0.249	≤ 0.50
Al (Aluminum)	0.042	0.039	–
V (Vanadium)	0.006	0.007	–
Nb (Niobium)	0.082	0.081	–
Zr (Zirconium)	0.002	0.002	–
Ti (Titanium)	0.020	0.019	–
B (Boron)	0.0003	0.0003	–
Ca (Calcium)	0.0034	0.0025	–
Co (Cobalt)	0.002	0.004	–
Fe (Iron)	Balance	Balance	Balance
Nb + V + Ti	0.108	0.107	≤ 0.15
CE_{IIW} [2]	0.39	0.39	0.43 (max)
CE_{Pcm} [3]	0.17	0.16	0.25 (max)

1 – API 5L 44th Edition, October 1, 2007.

2 – $CE_{IIW} = C + Mn/6 + (Cu + Ni)/15 + (Cr + Mo + V)/5$

3 – $CE_{Pcm} = C + Si/30 + Mn/20 + Cu/20 + Ni/60 + Cr/20 + Mo/15 + V/10 + 5B$.

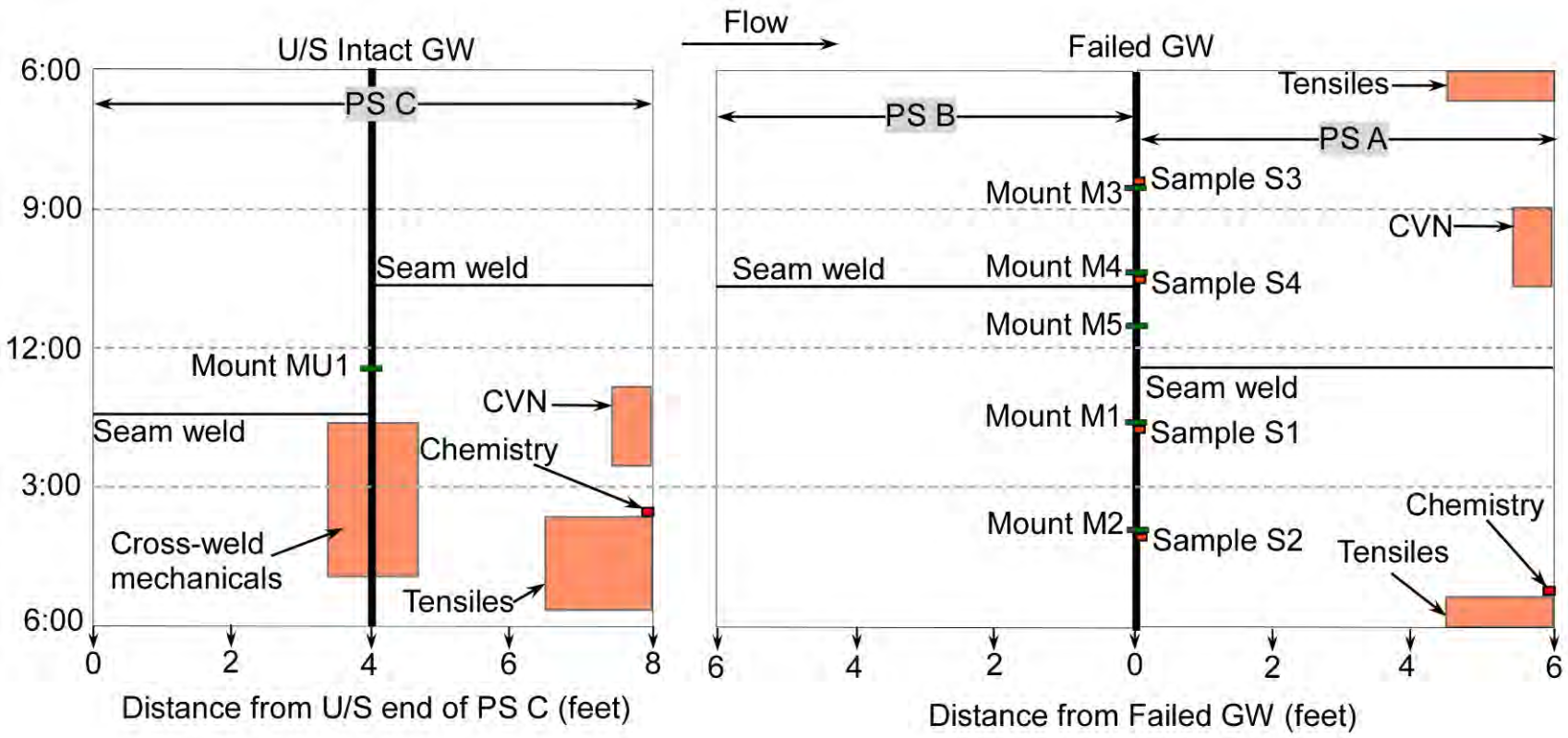

Figure 1. Schematic of Pipe Sections (PSs) A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mounts M1, M2, M3, M4, M5, and MU1), fractography (Sample S1, S2, S3, and S4), mechanical testing (CVN, cross-weld mechanicals, and tensiles), and chemical analyses (chemistry) were removed.



Figure 2. Photograph of the wooden crate that contained PS A, as received at DNV GL.

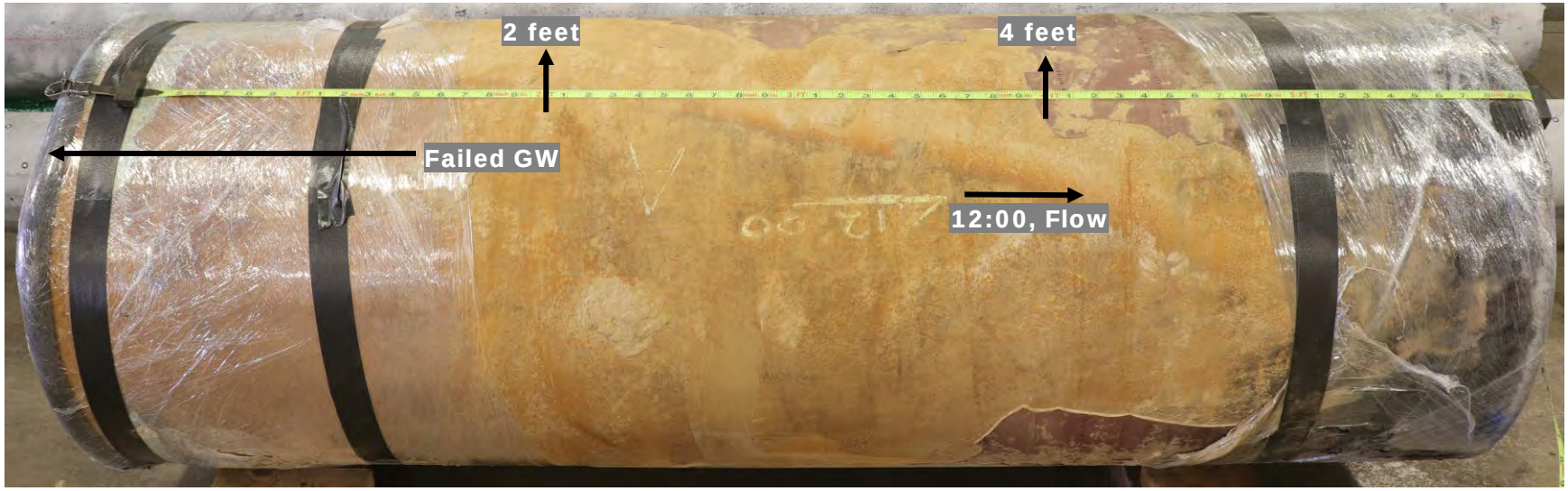

Figure 3. Photograph of PS A after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS A.

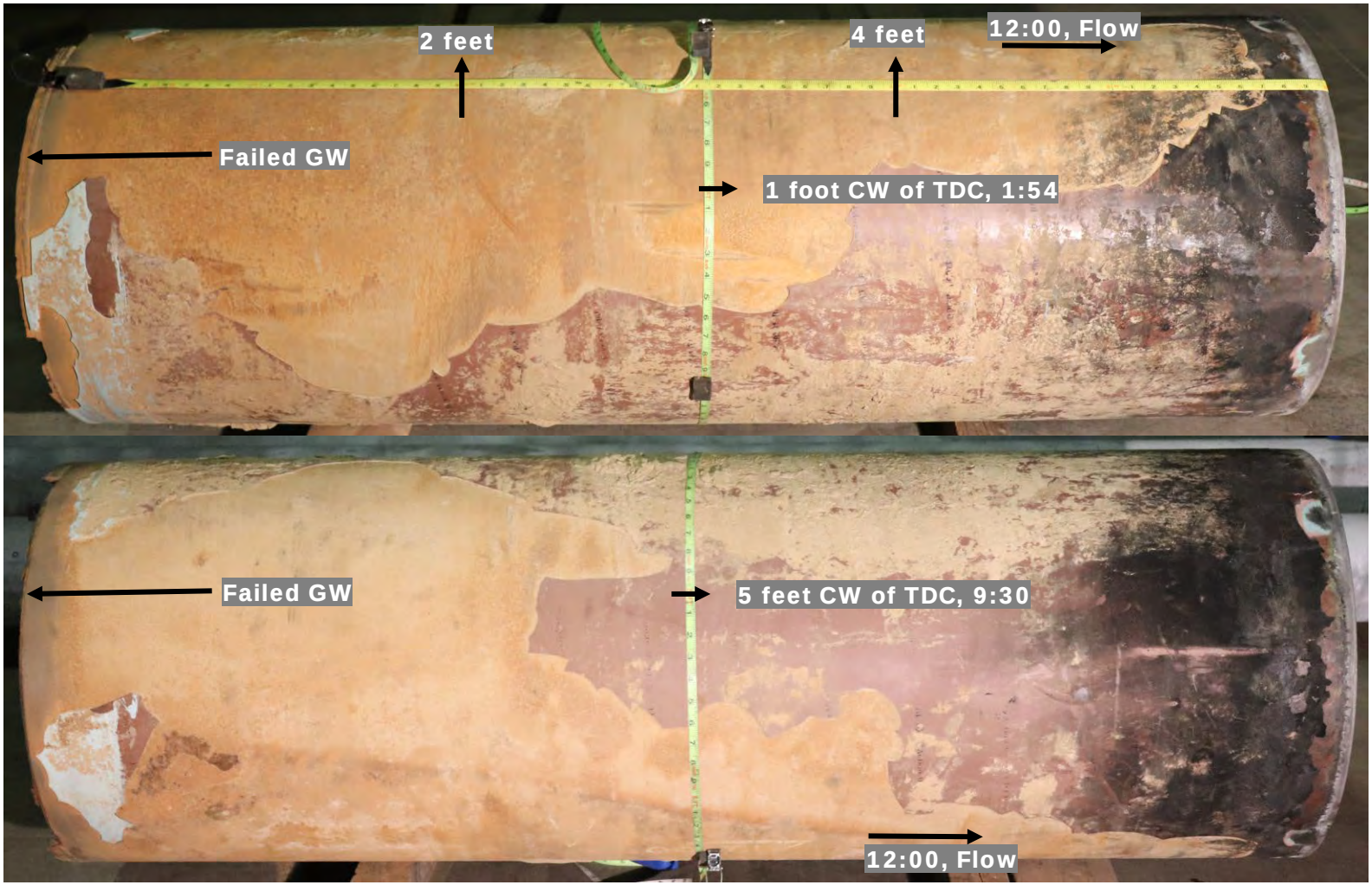

Figure 4. Photographs of PS A after removal of the protective wrappings. The horizontal tape measure indicates the distance from the U/S end of PS A, and circumferential tape measure indicates the distance clockwise (CW) of top-dead-center (TDC) looking downstream (D/S).



Figure 5. Photograph of the wooden crate that contained PS B, as received at DNV GL.

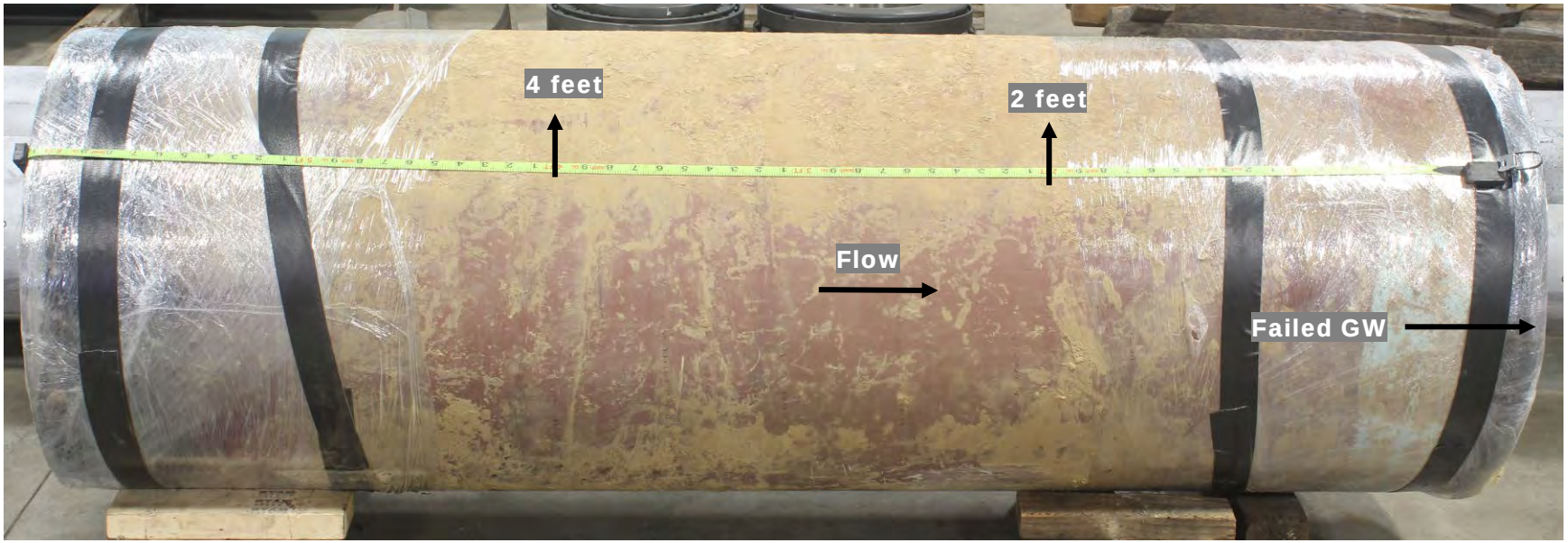

Figure 6. Photograph of PS B after removal from the wooden crate. The tape measure indicates the distance from the D/S end of PS B.



Figure 7. Photograph of PS B after removal of the protective wrappings. The tape measure indicates the distance from the D/S end of PS B.



Figure 8. Photograph of the wooden crate that contained PS C, as received at DNV GL.

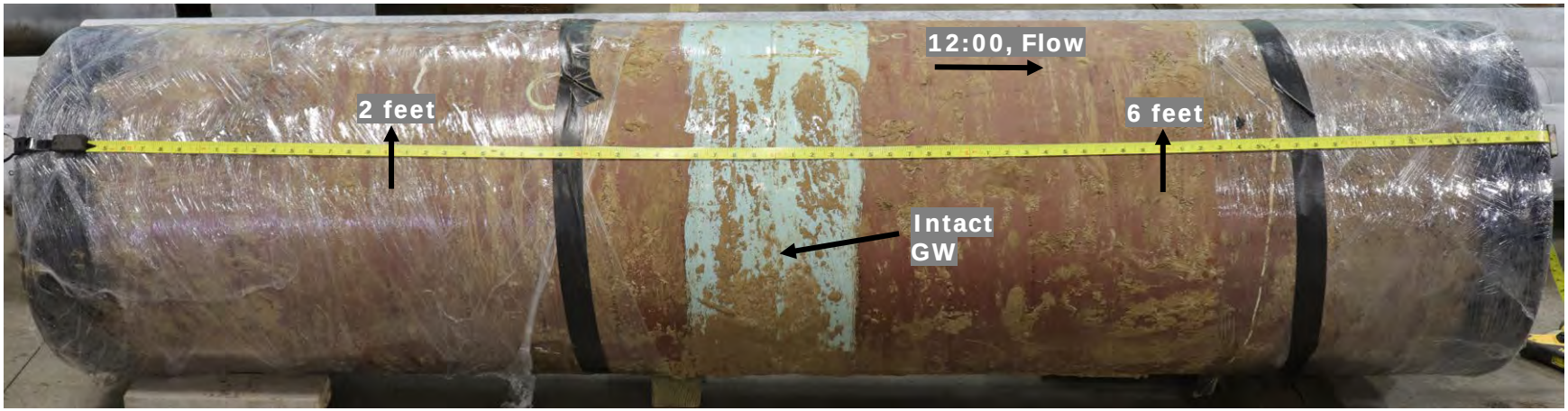

Figure 9. Photograph of PS C after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS C.

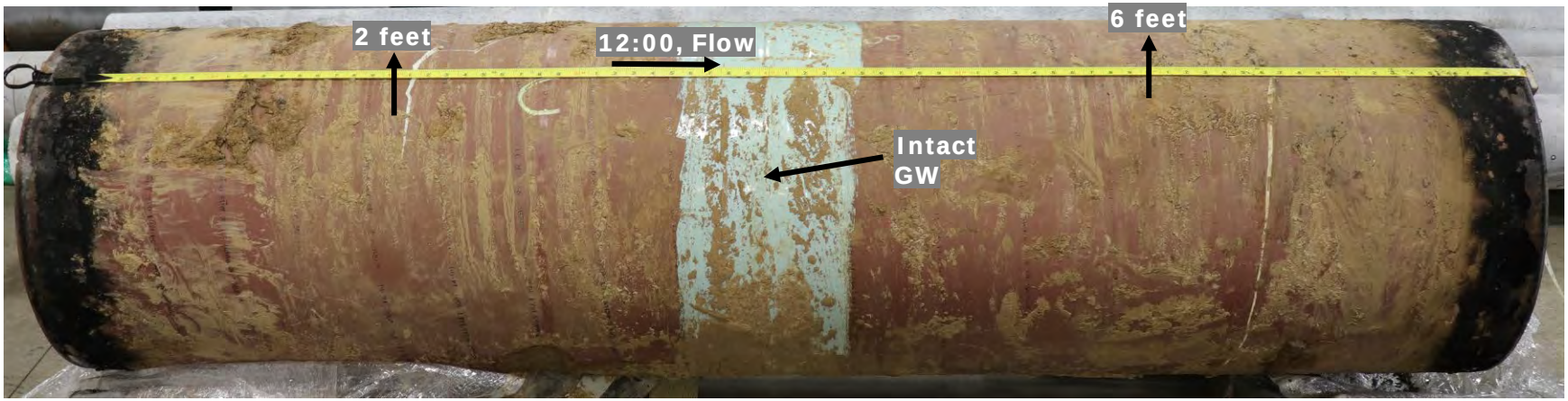

Figure 10. Photograph of PS C after removal of the protective wrappings. The tape measure indicates the distance from the U/S end of PS C.

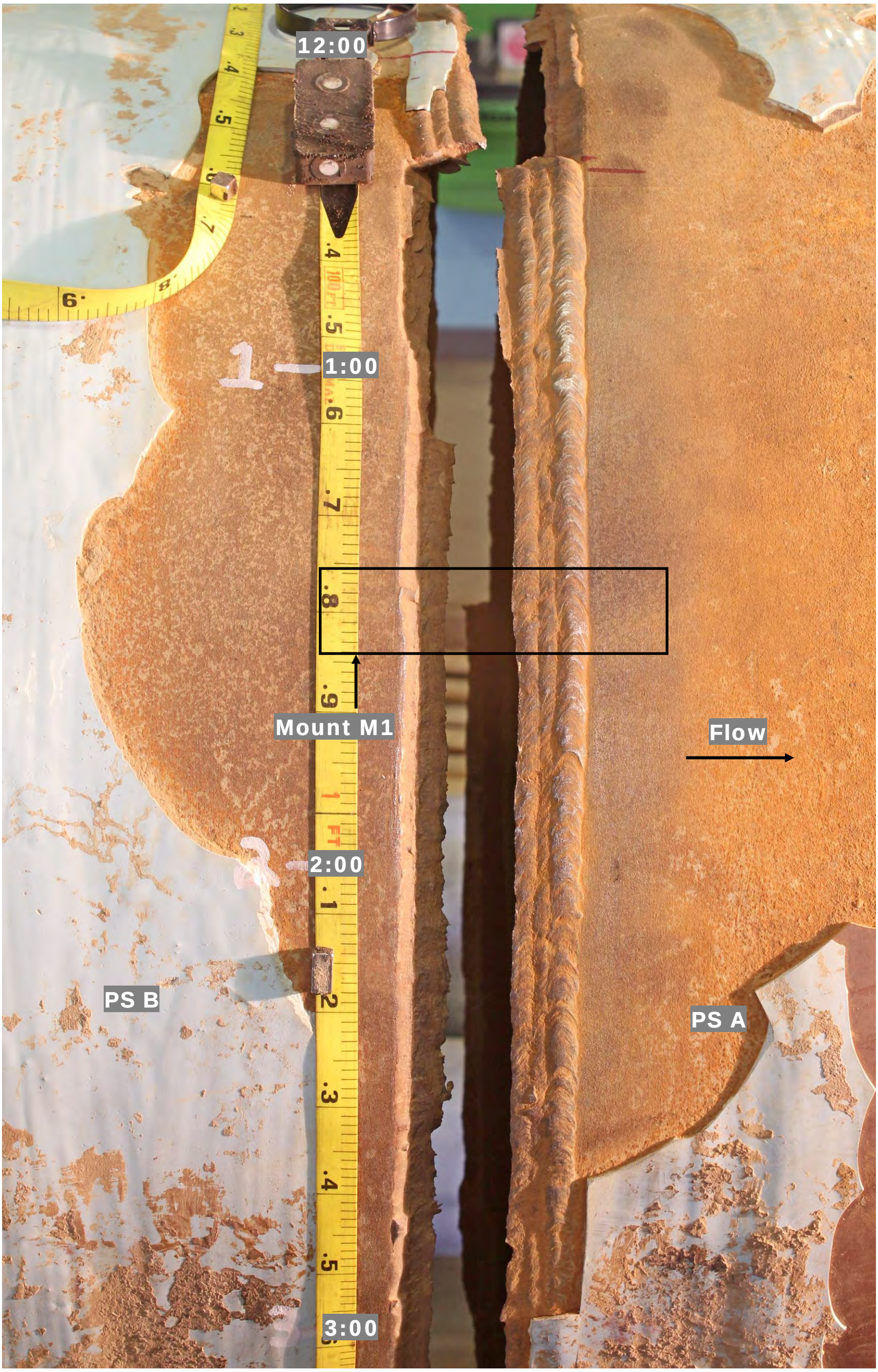

Figure 11. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 12 and 3 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

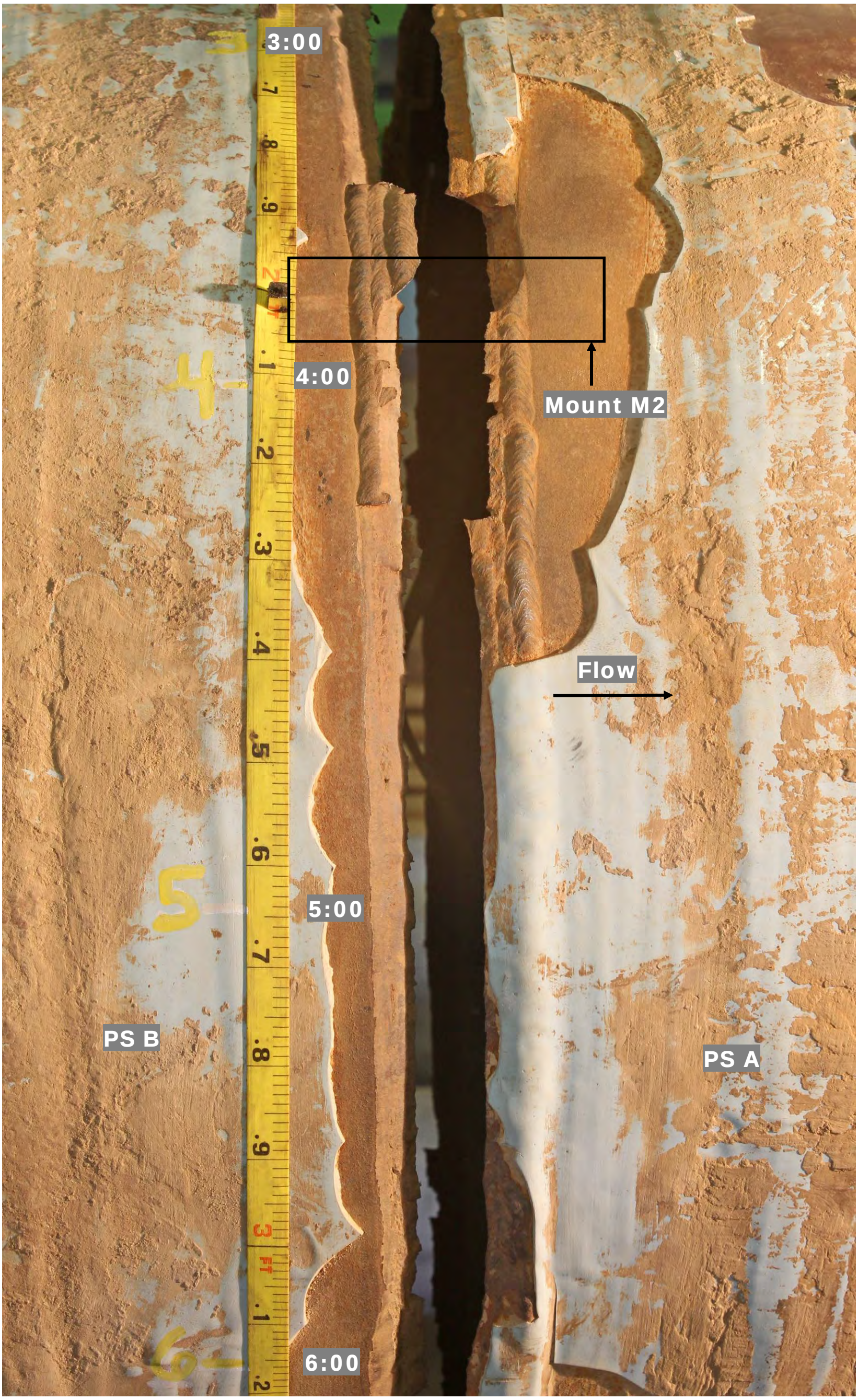

Figure 12. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 3 and 6 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

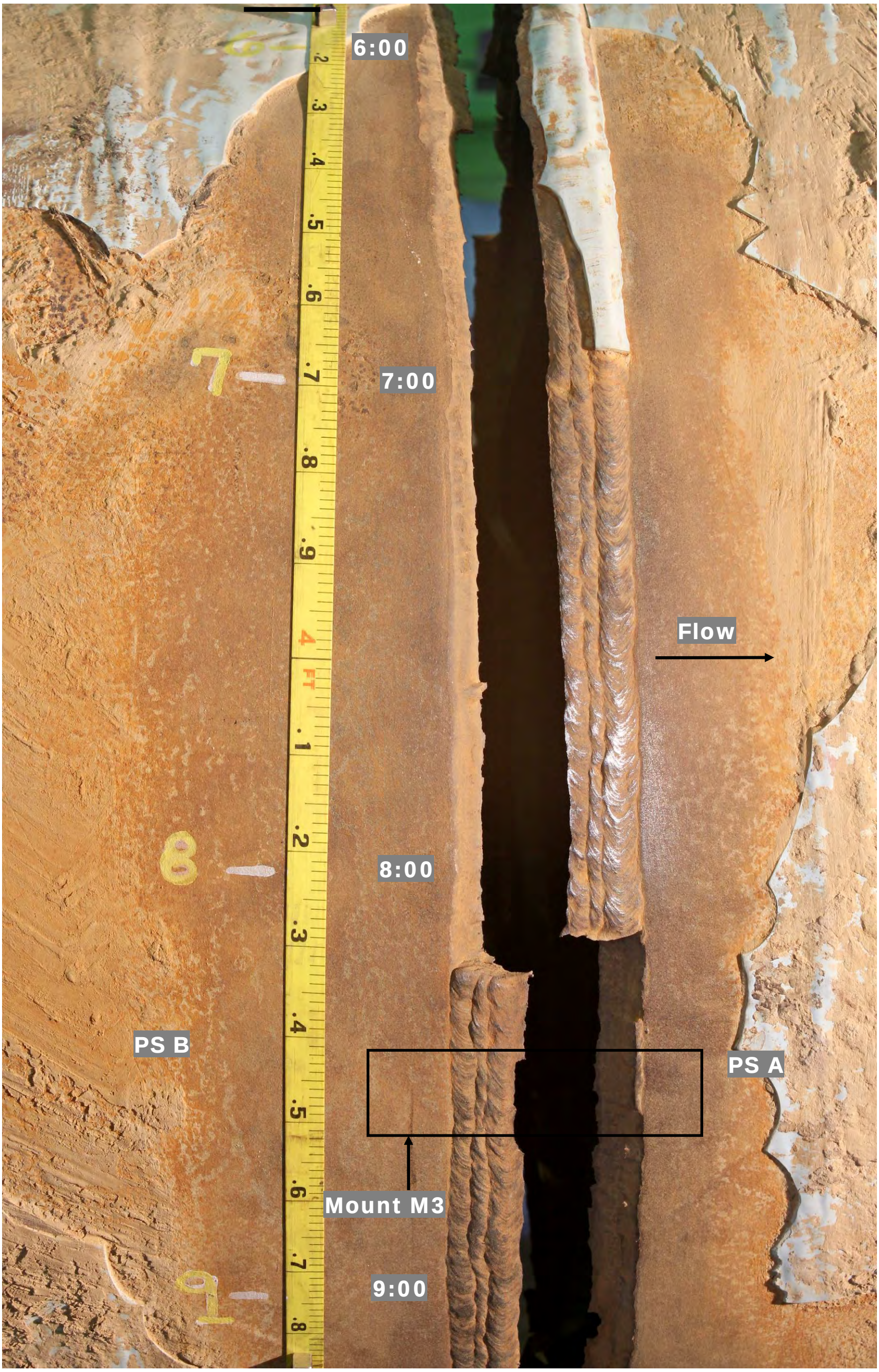

Figure 13. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 6 and 9 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

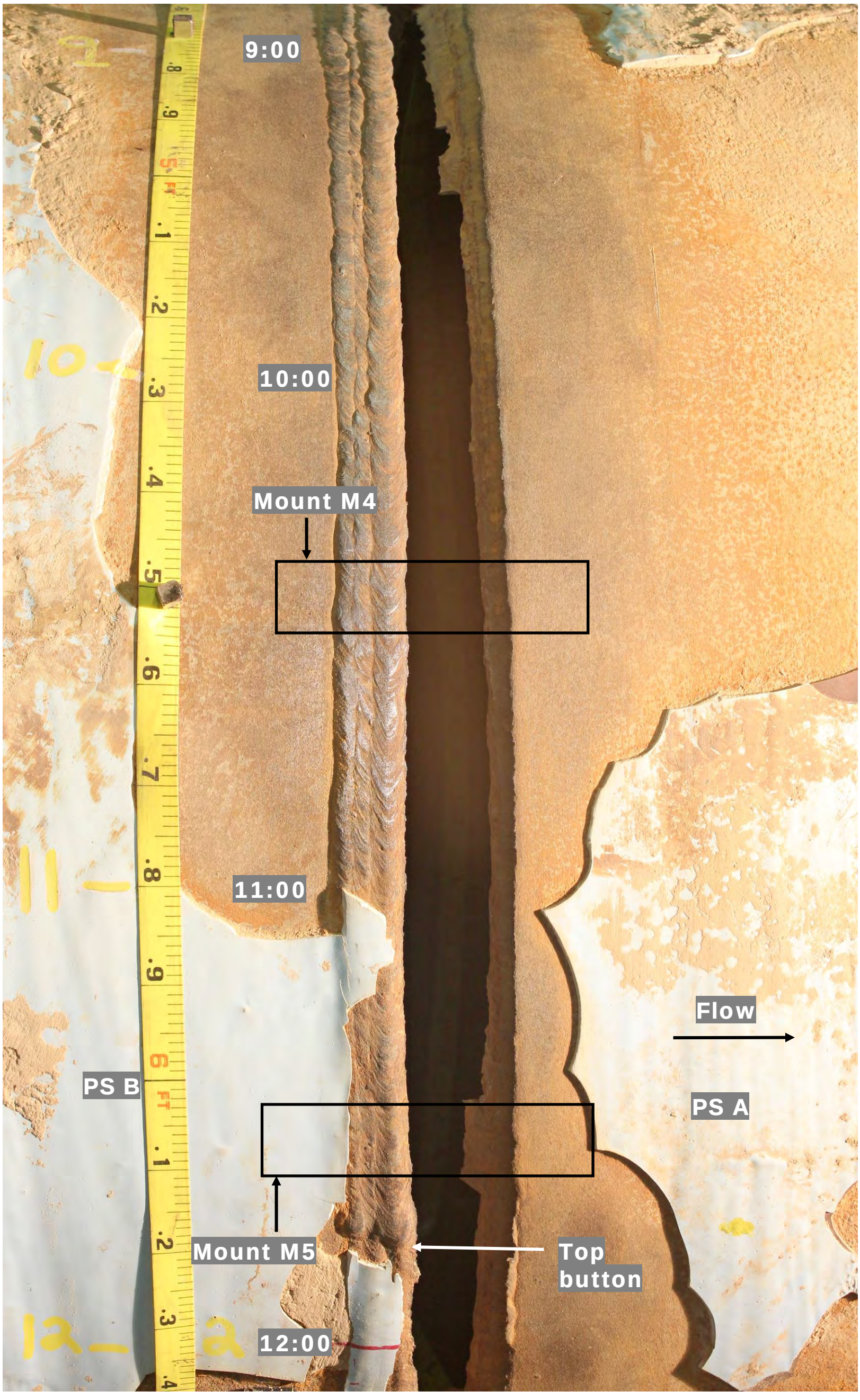

Figure 14. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 9 and 12 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

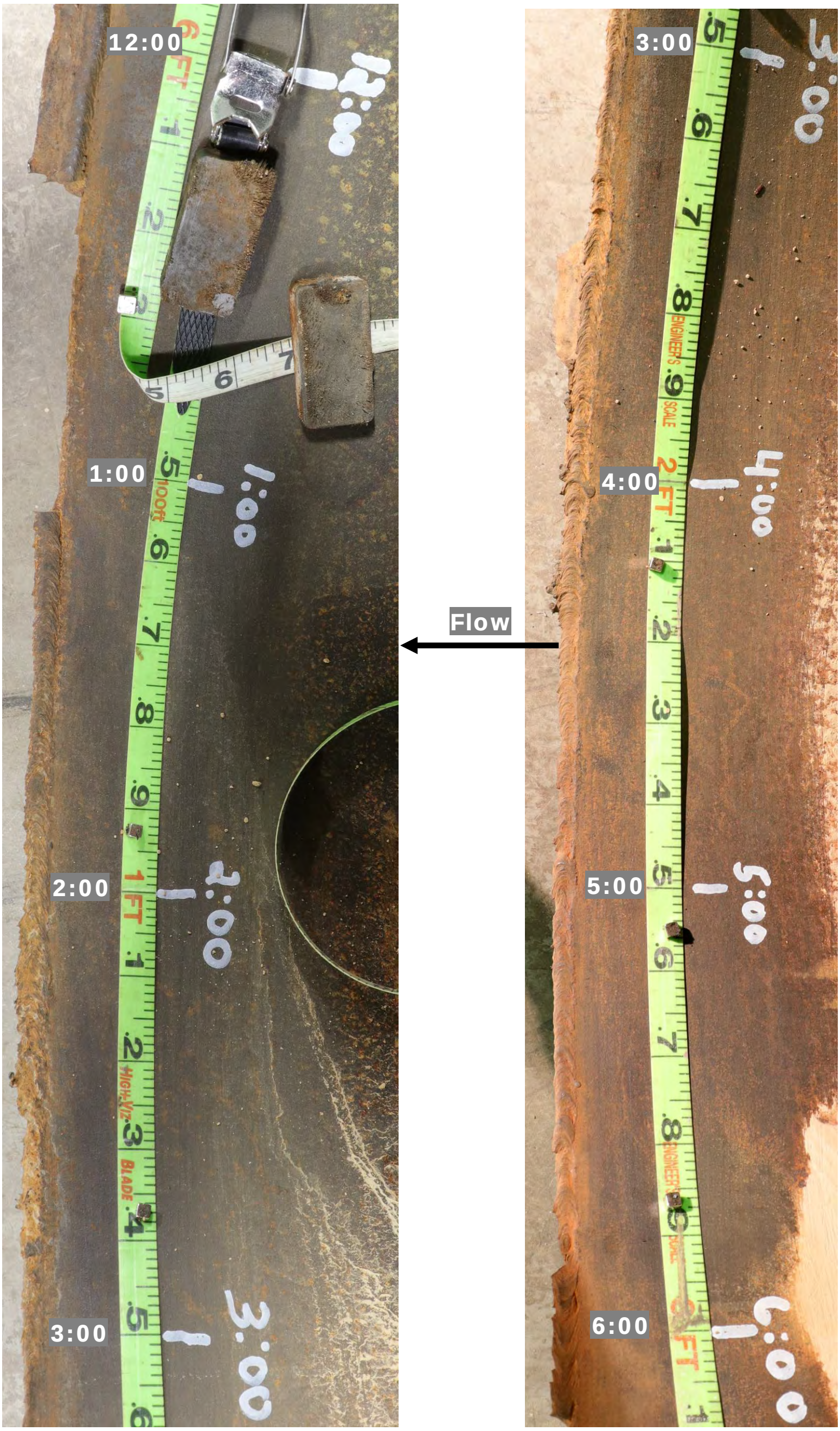

Figure 15. Photograph of the internal pipe surface adjacent to the fracture surface of PS B, between the 12 and 6 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

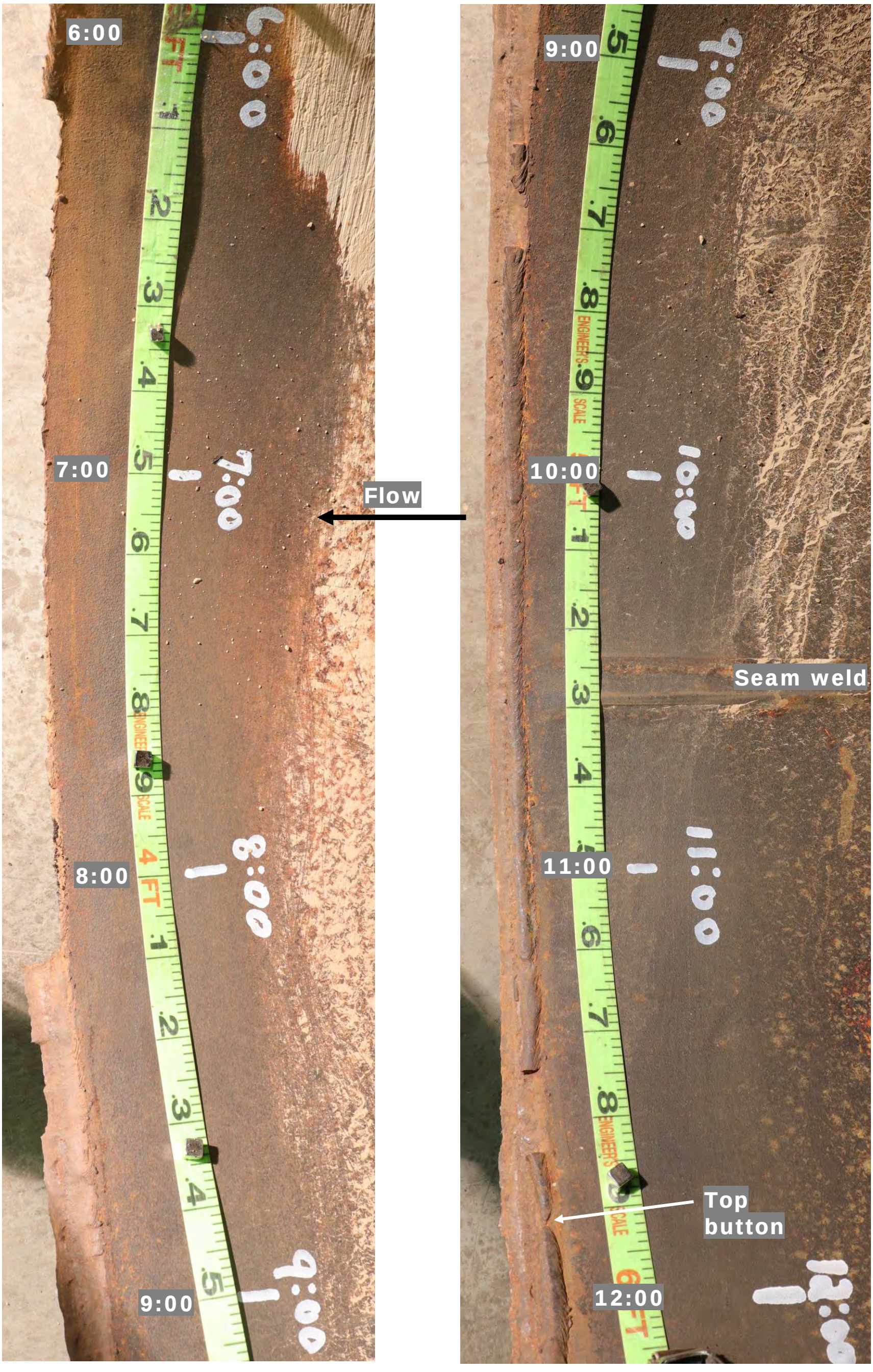

Figure 16. Photographs of the internal pipe surface adjacent to the fracture surface of PS B, between the 6 and 12 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

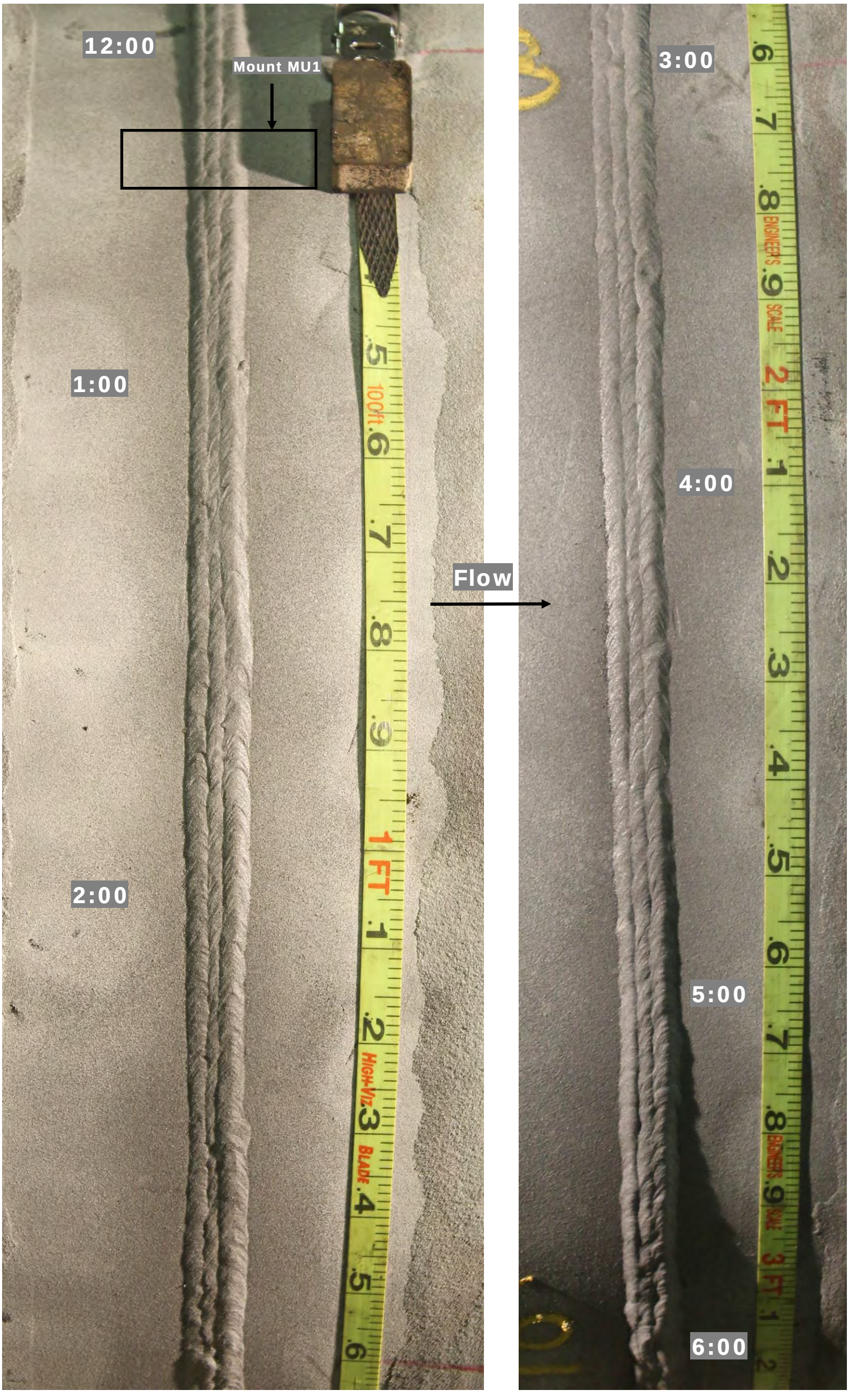

Figure 17. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 12:00 and 6:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

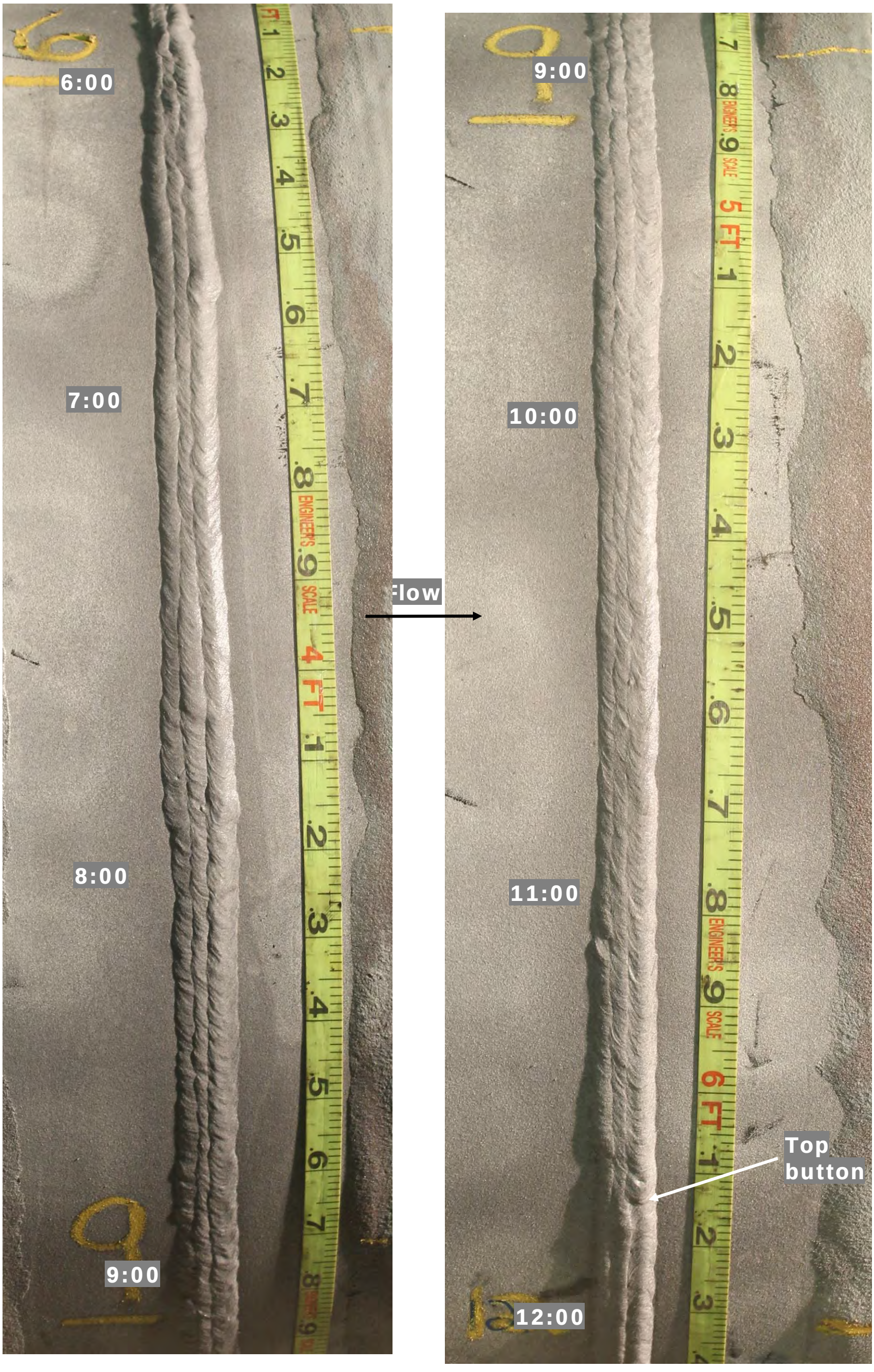

Figure 18. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 6:00 and 12:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).



Figure 19. Photograph of the fracture surface and internal pipe surface of PS A. Flow direction is into the photograph. Labels on magnets indicate o'clock orientations.



Figure 20. Photograph of the fracture surface of PS A between the 12 and 1 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 21. Photograph of the fracture surface of PS A between the 1 and 2 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

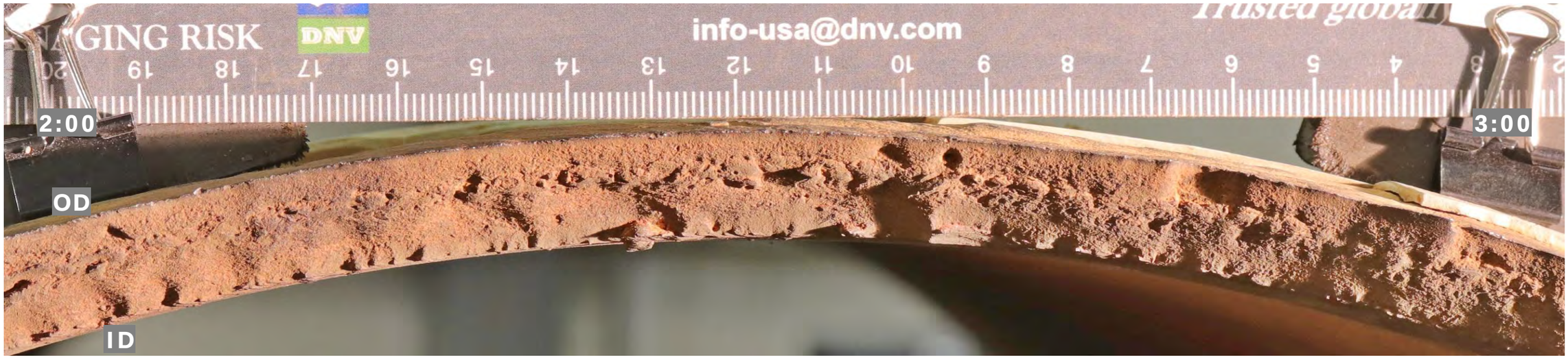

Figure 22. Photograph of the fracture surface of PS A between the 2 and 3 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 23. Photograph of the fracture surface of PS A between the 3 and 4 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

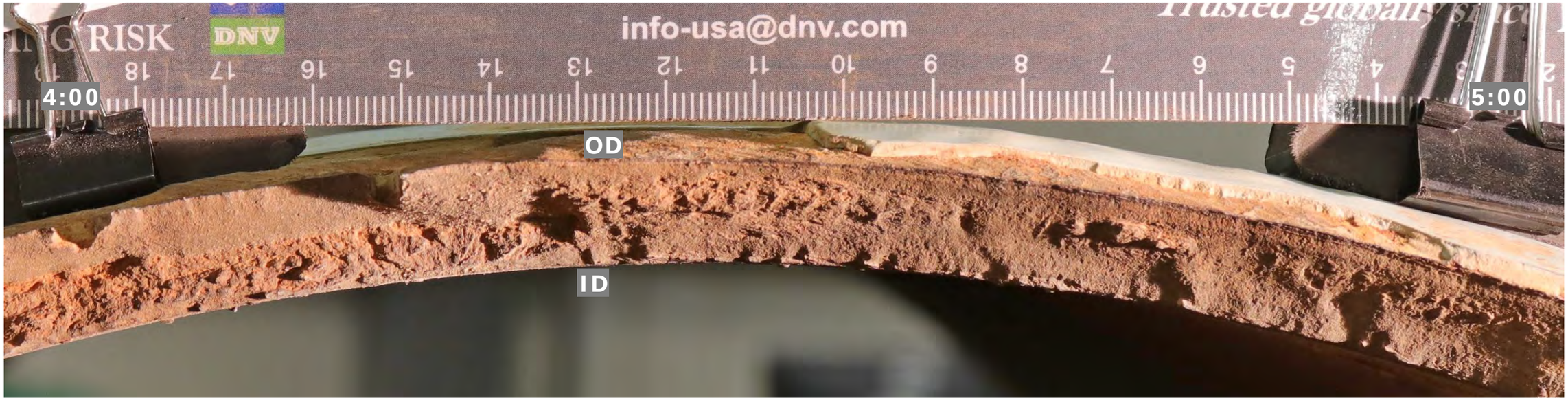

Figure 24. Photograph of the fracture surface of PS A between the 4 and 5 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 25. Photograph of the fracture surface of PS A between the 5 and 6 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 26. Photograph of the fracture surface of PS A between the 6 and 7 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 27. Photograph of the fracture surface of PS A between the 7 and 8 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 28. Photograph of the fracture surface of PS A between the 8 and 9 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 29. Photograph of the fracture surface of PS A between the 9 and 10 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 30. Photograph of the fracture surface of PS A between the 10 and 11 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

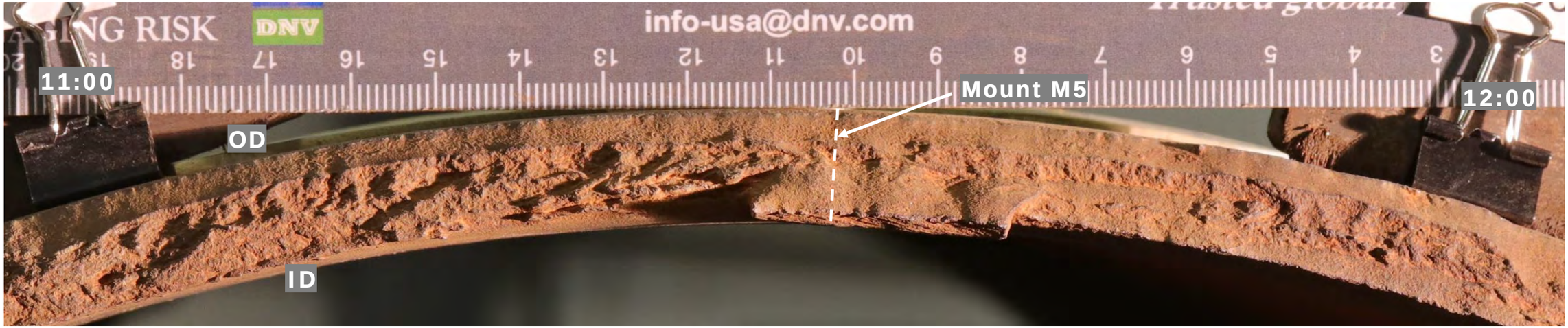

Figure 31. Photograph of the fracture surface of PS A between the 11 and 12 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

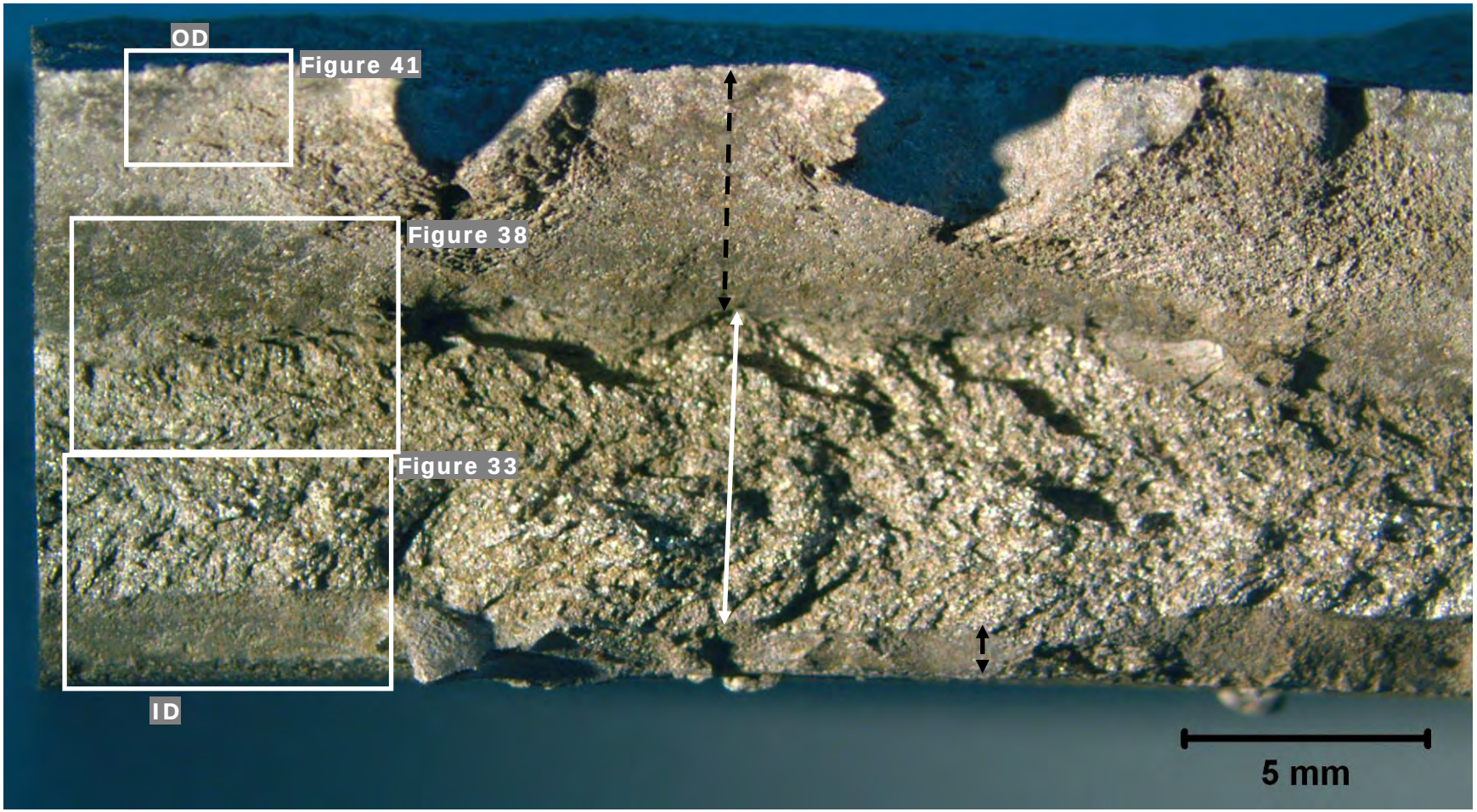

Figure 32. Light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. The sample was removed near the 4:00 orientation from PSA; area indicated in Figure 23. The black, dashed double arrows indicate smooth regions and the white double arrow indicates a rough region.

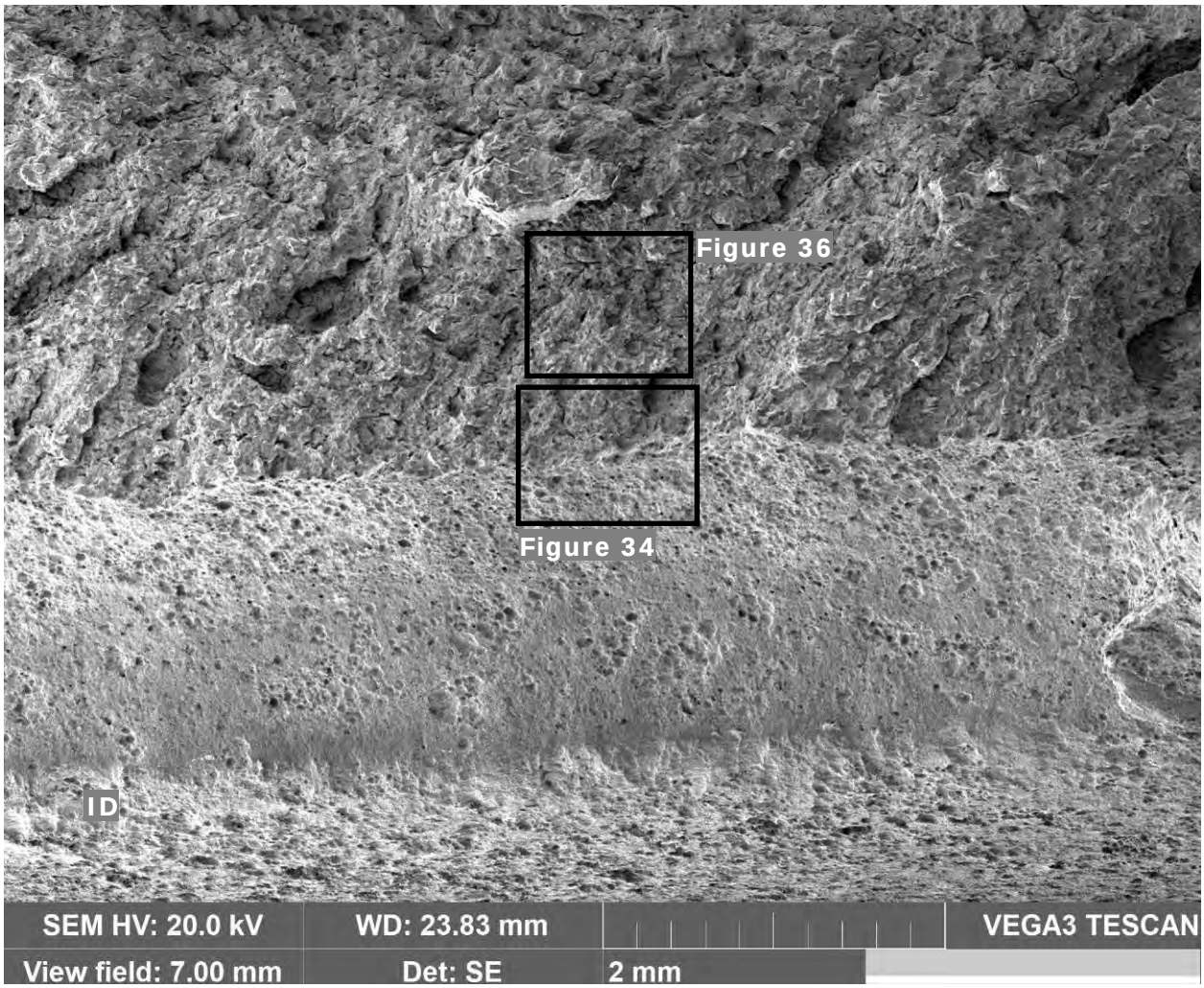

Figure 33. SEM image of Sample S2 adjacent to the ID surface; area indicated in Figure 32.

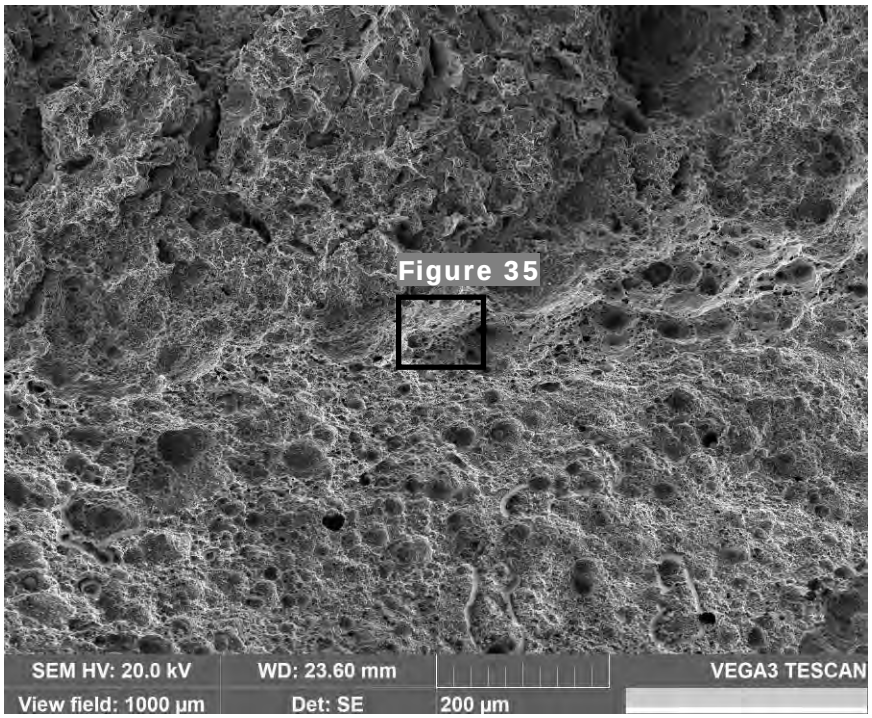

Figure 34. SEM image of Sample S2 at the interface of a macroscopically smooth and rough region; area indicated in Figure 33.

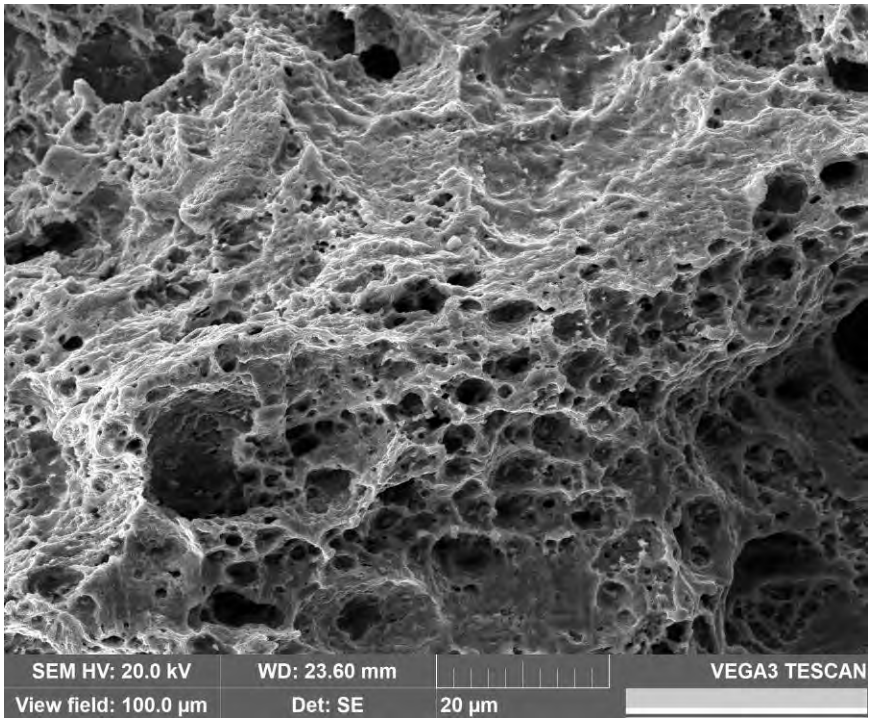

Figure 35. High magnification SEM image of Sample S2 in the macroscopically smooth region; area indicated in Figure 34.

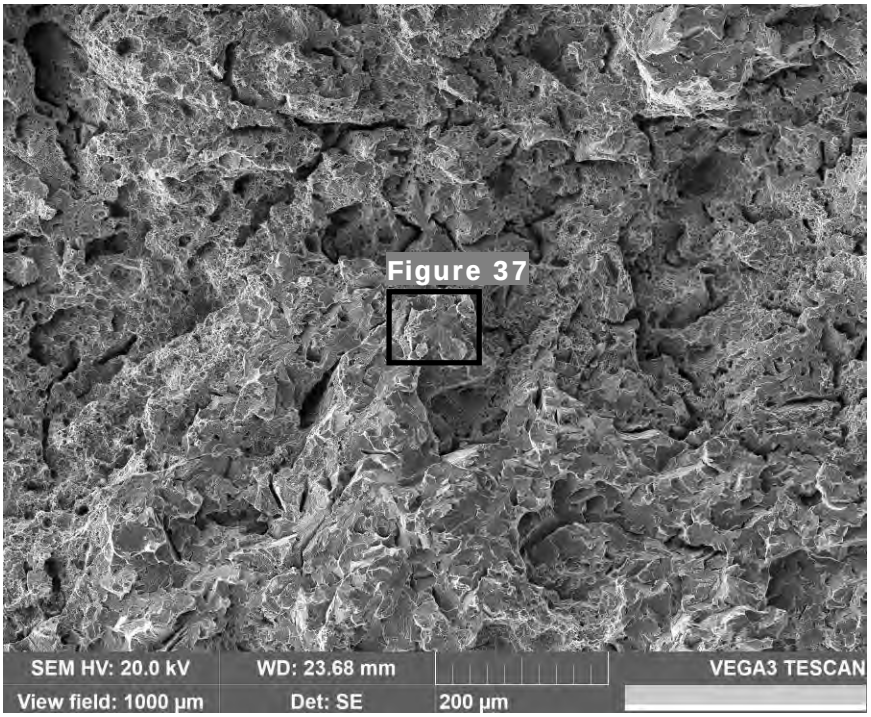

Figure 36. SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 33.

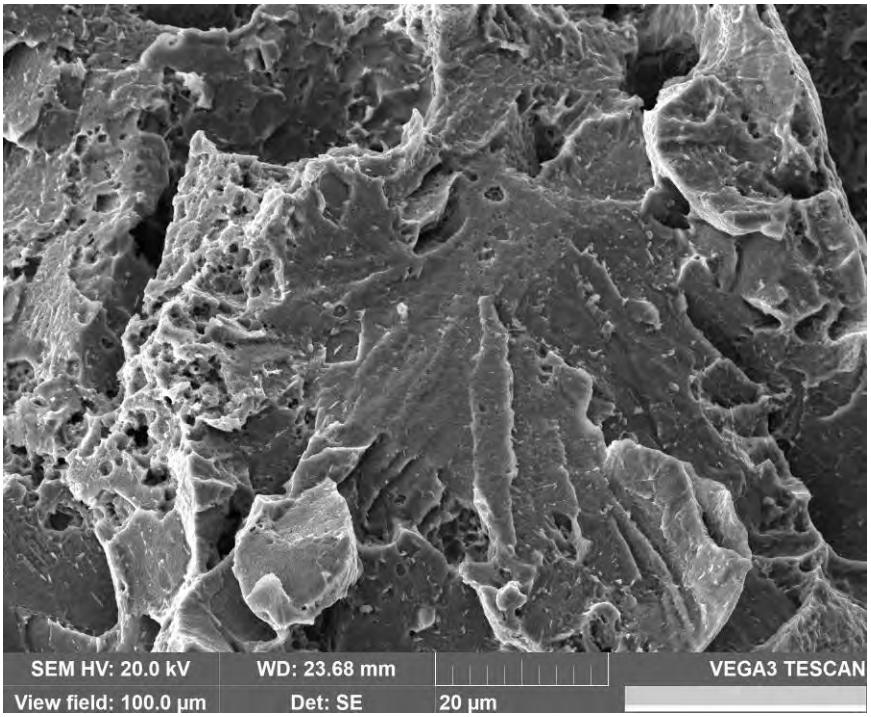

Figure 37. High magnification SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 36.

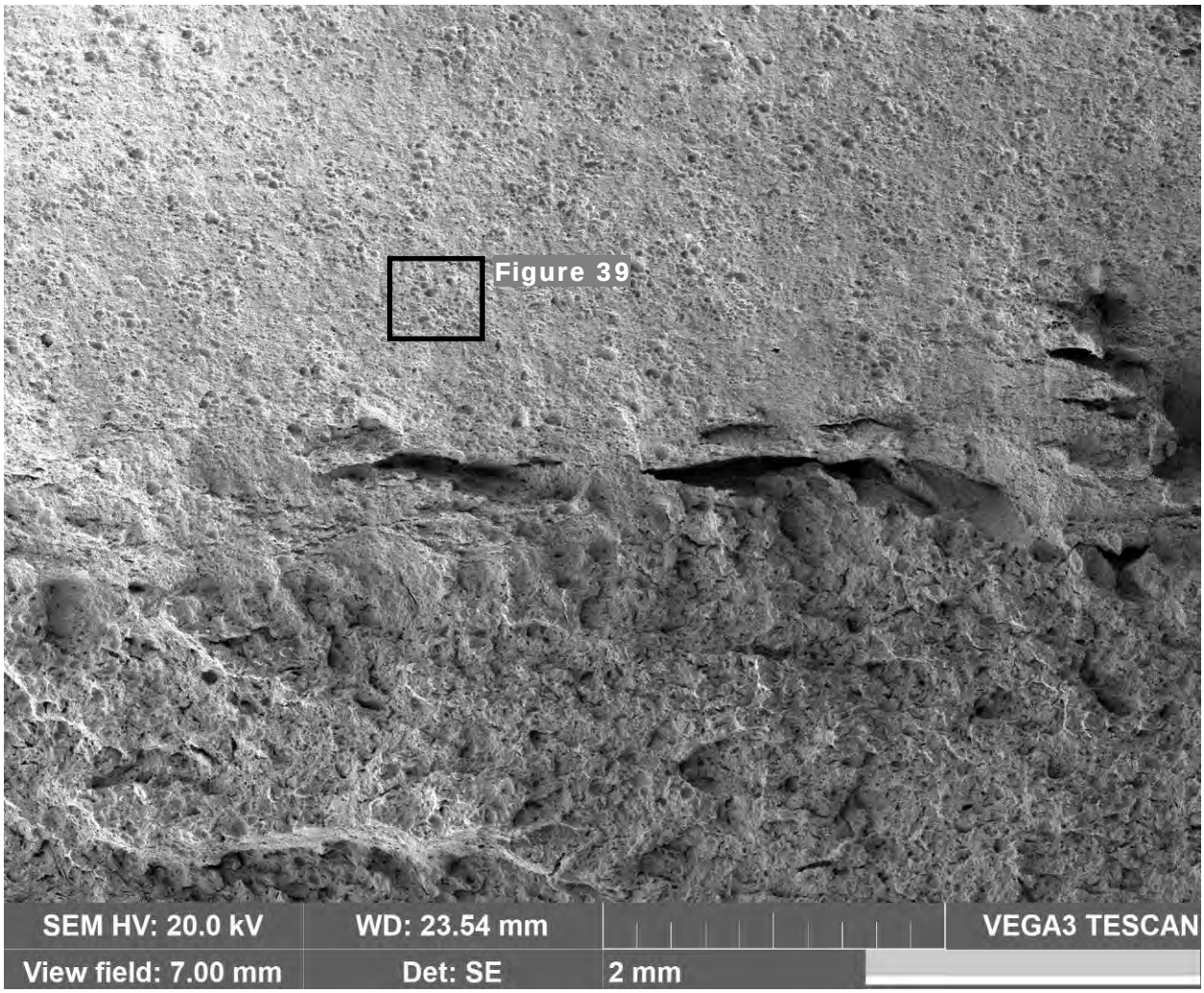

Figure 38. SEM image of Sample S2 midwall, showing macroscopically rough and smooth regions; area indicated in Figure 32.

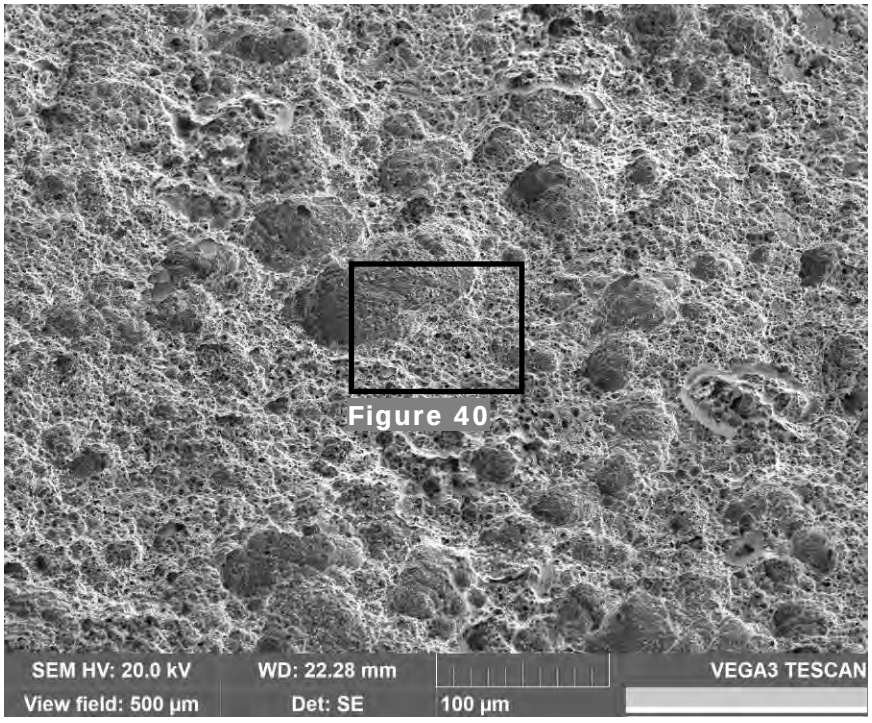

Figure 39. SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 38.

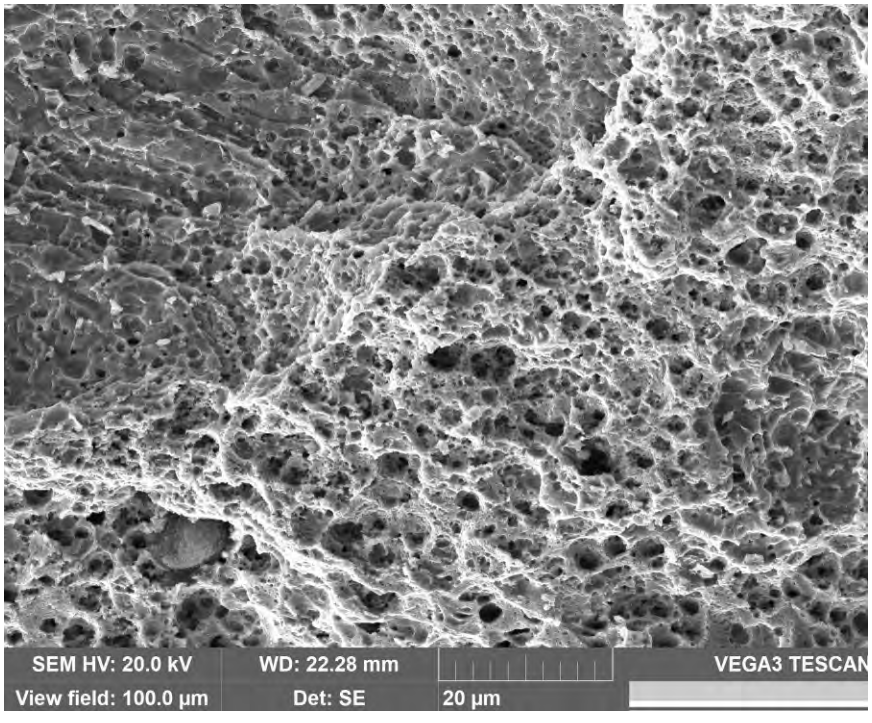

Figure 40. High magnification SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 39.

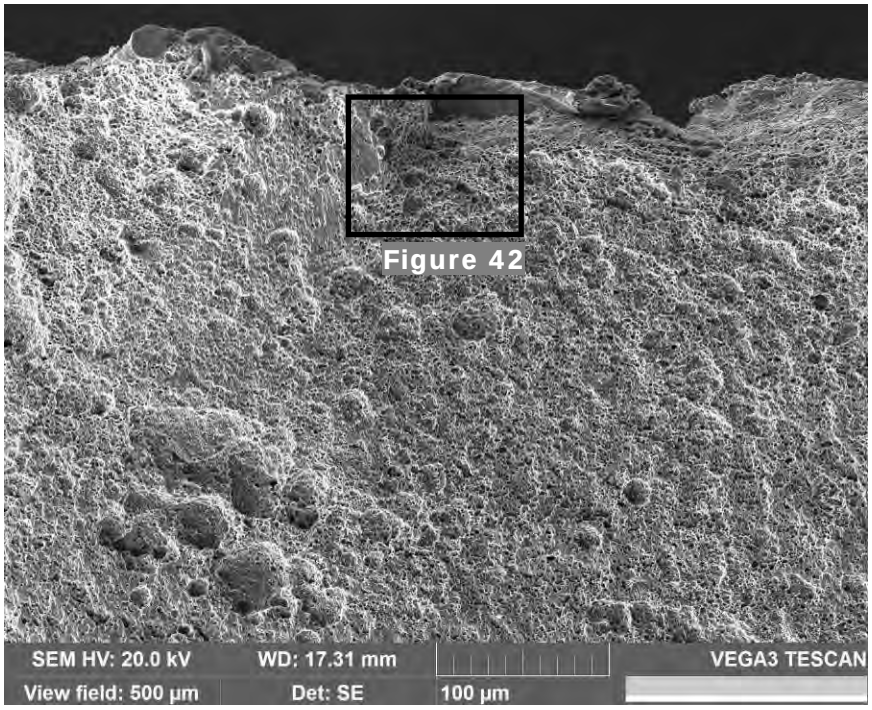

Figure 41. SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 32.

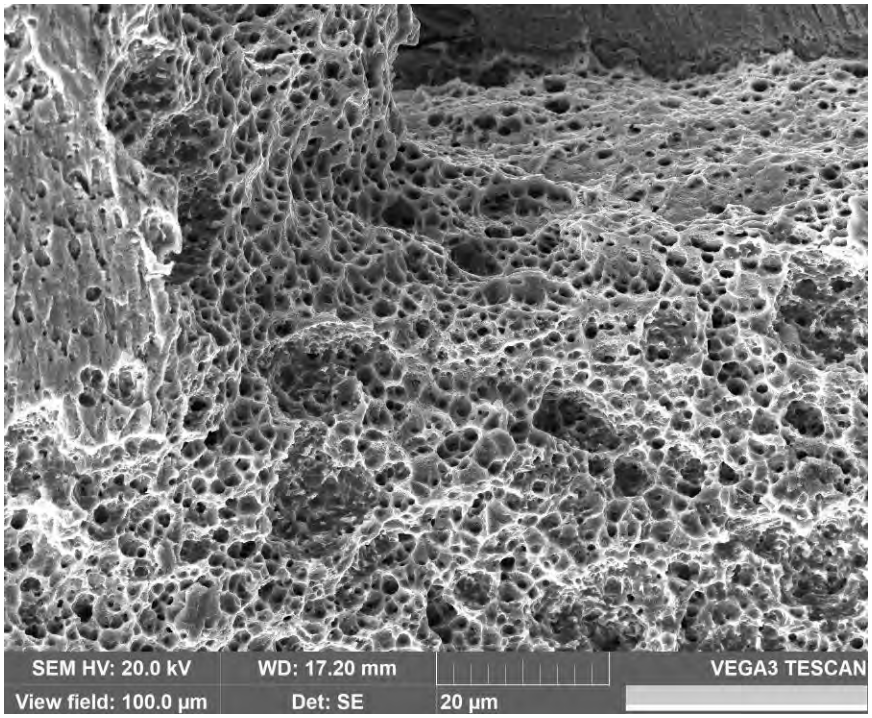

Figure 42. High magnification SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 41.

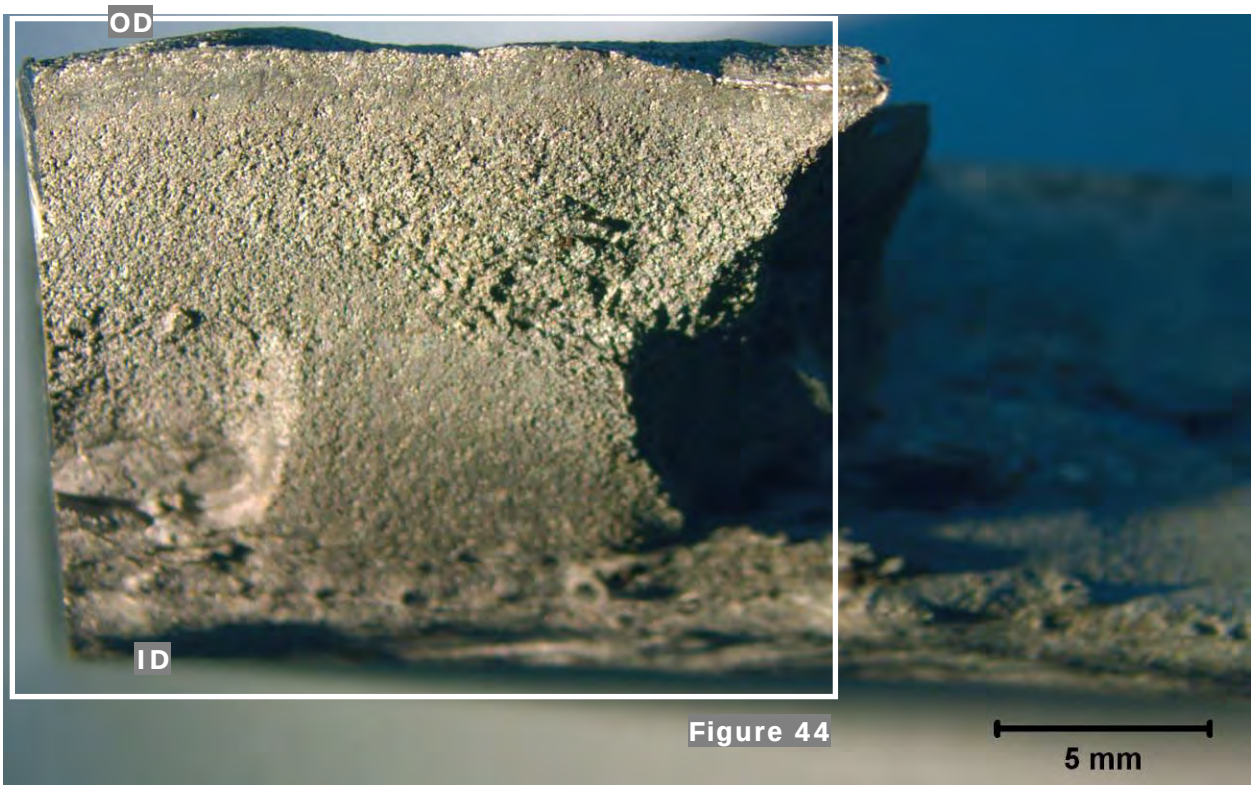

Figure 43. Light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. The sample was removed near the 8:00 orientation; area indicated in Figure 28.

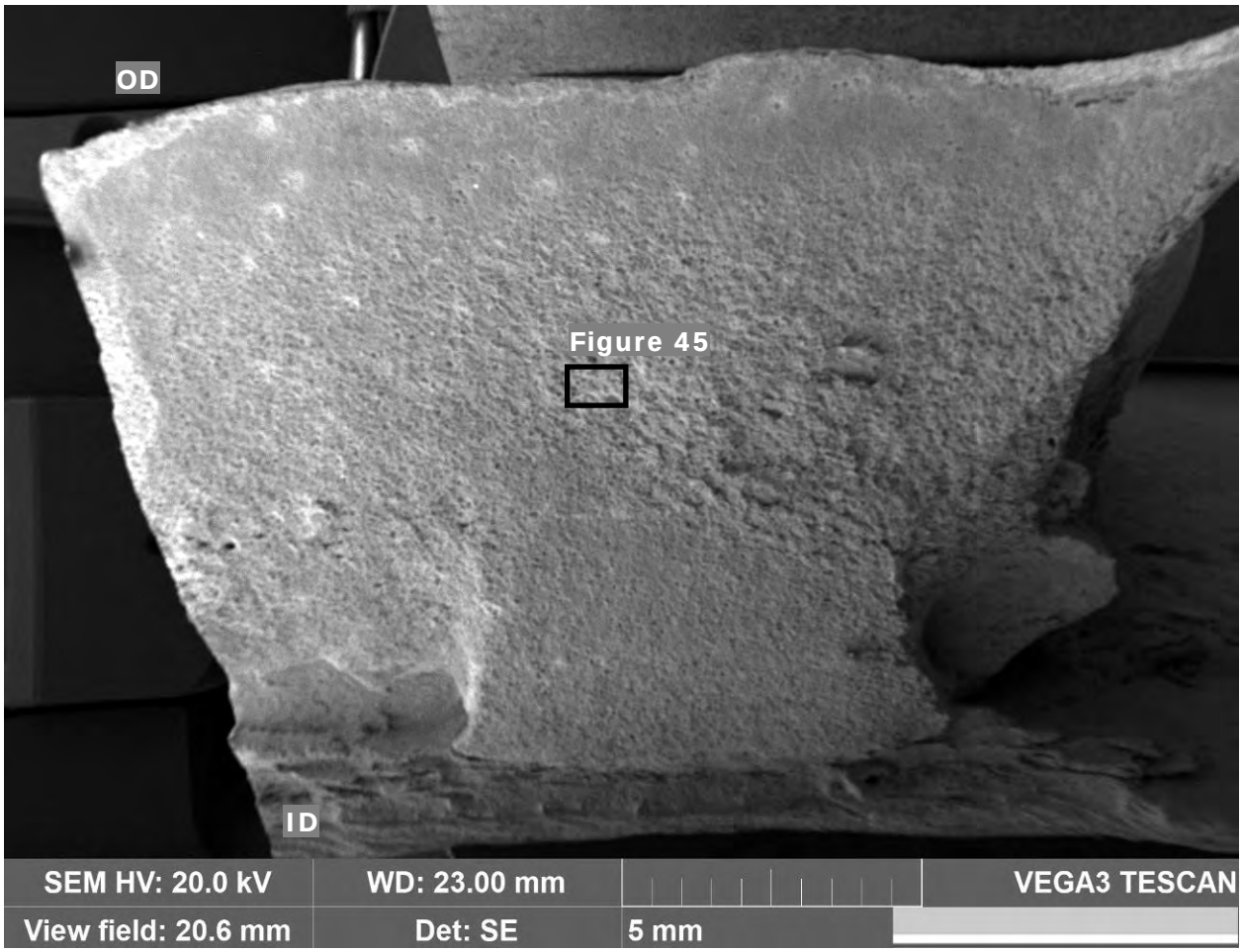

Figure 44. SEM image of Sample S3; area indicated in Figure 43.

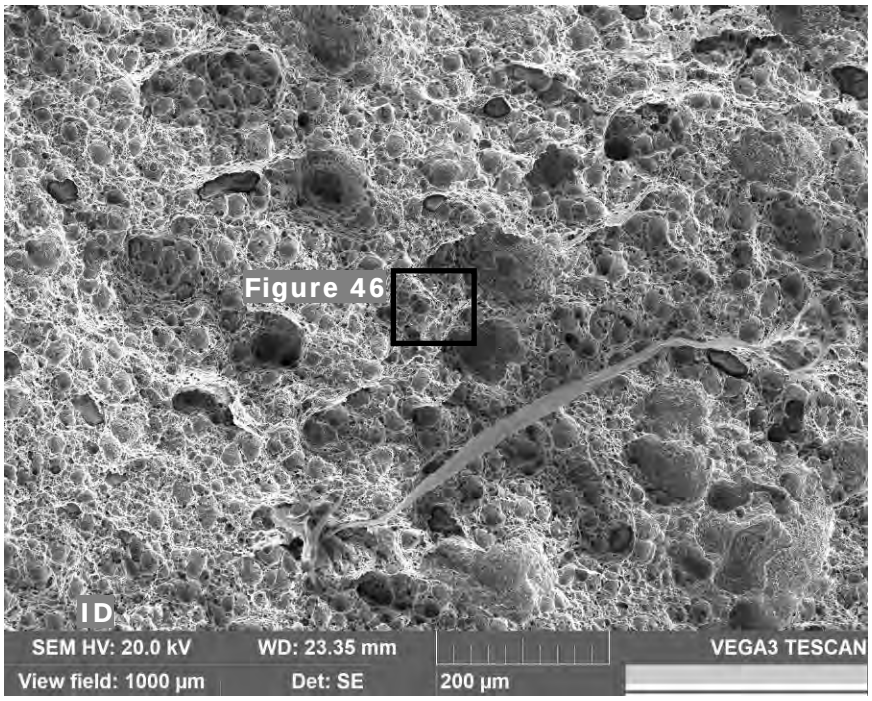

Figure 45. SEM image of Sample S3 midwall; area indicated in Figure 44.

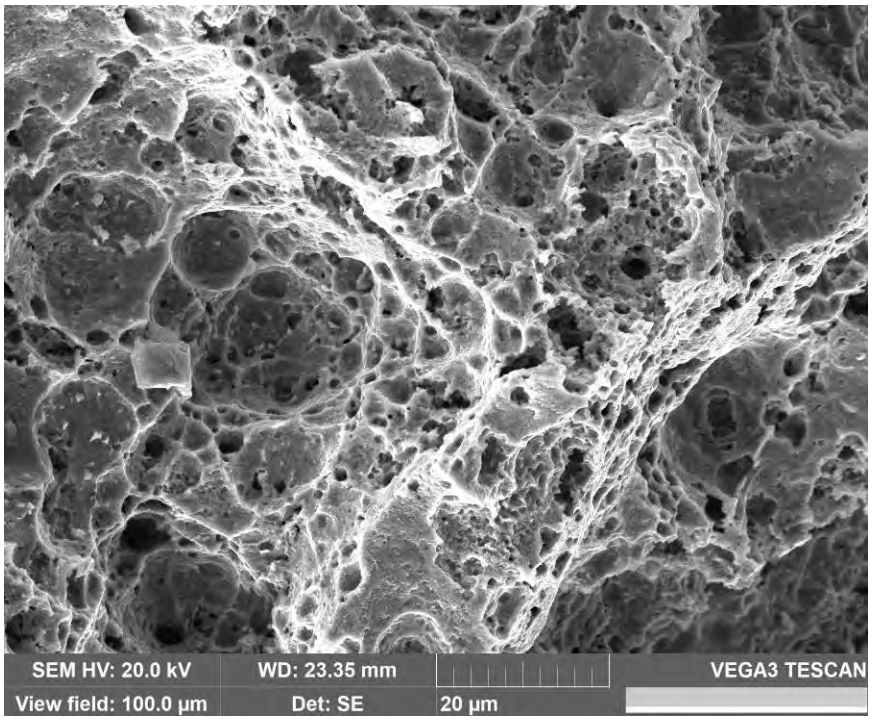

Figure 46. High magnification SEM image of Sample S3 midwall; area indicated in Figure 45.

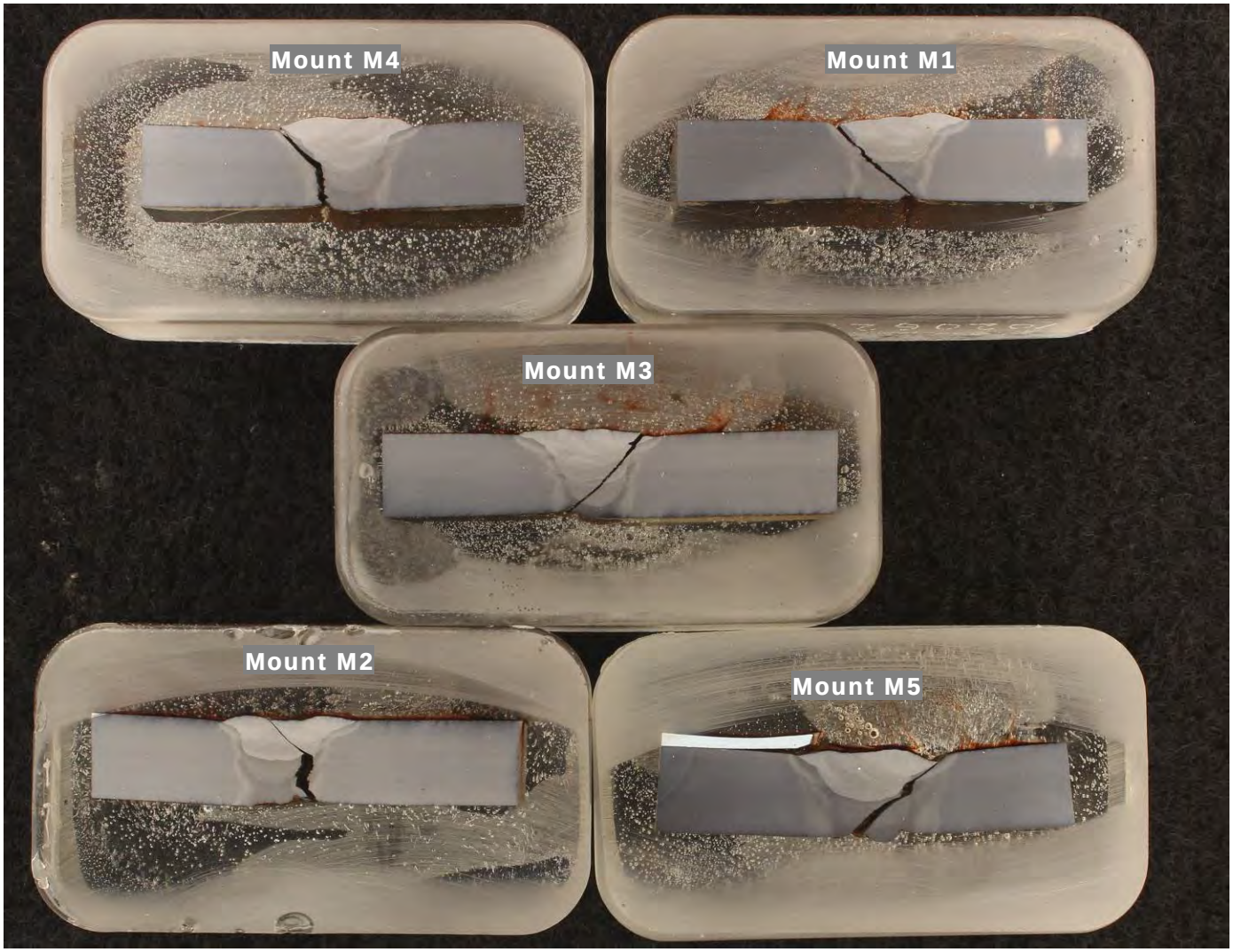

Figure 47. Photograph of the mounts (M1, M2, M3, M4, and M5) that were removed across the failure opening (2% Nital Etchant).

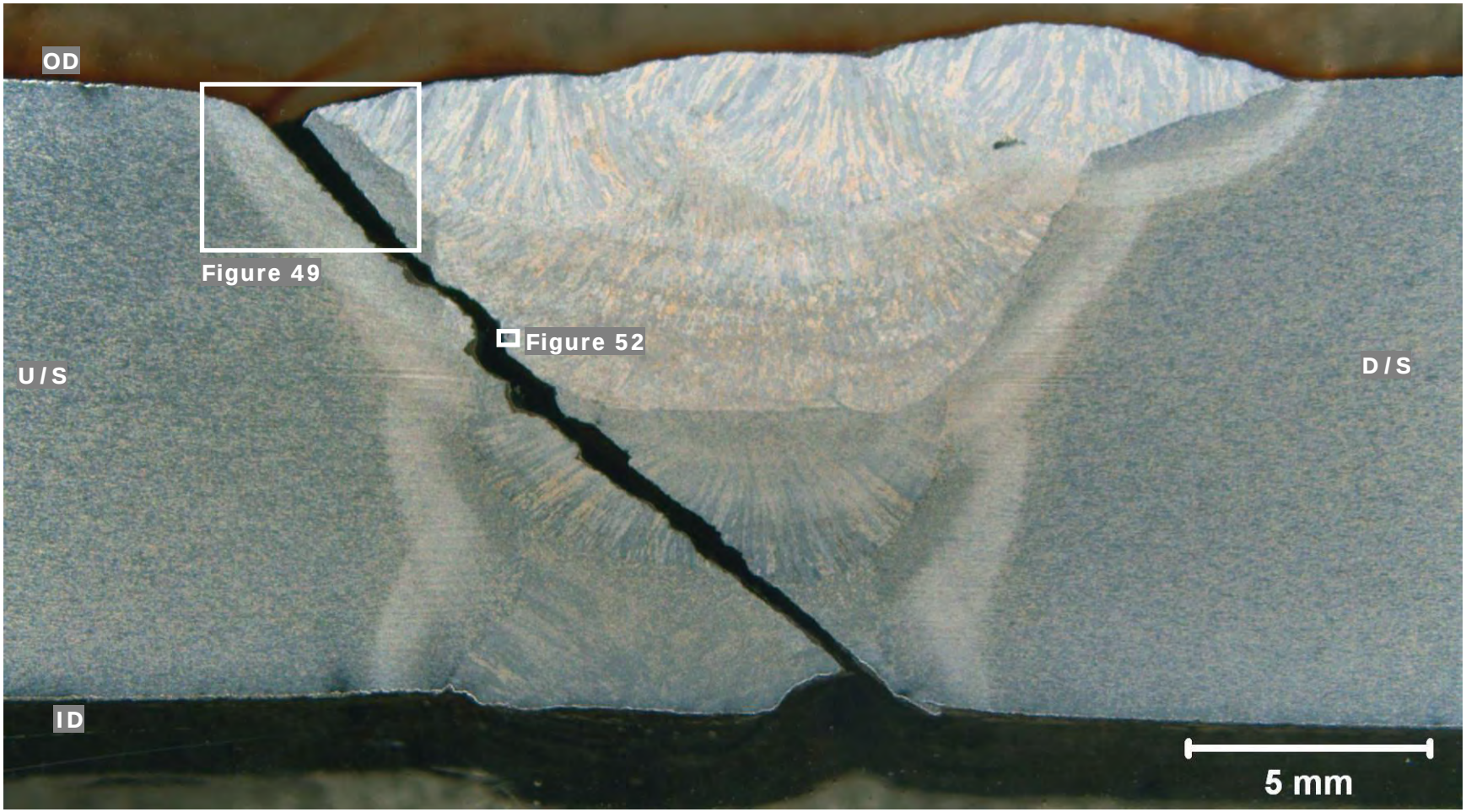

Figure 48. Light photomicrograph of Mount M1 (axial cross-section), which was removed from the failed GW at the 1:35 orientation; refer to Figure 1, Figure 11, and Figure 21 for location (2% Nital Etchant).

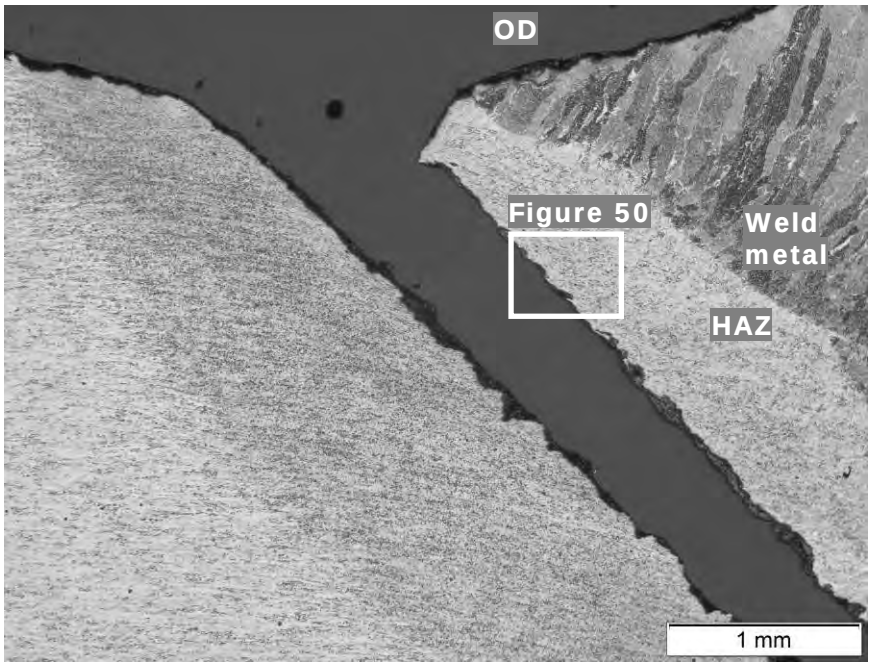

Figure 49. Light photomicrograph of Mount M1 adjacent to the OD surface (2% Nital Etchant); area indicated in Figure 48.

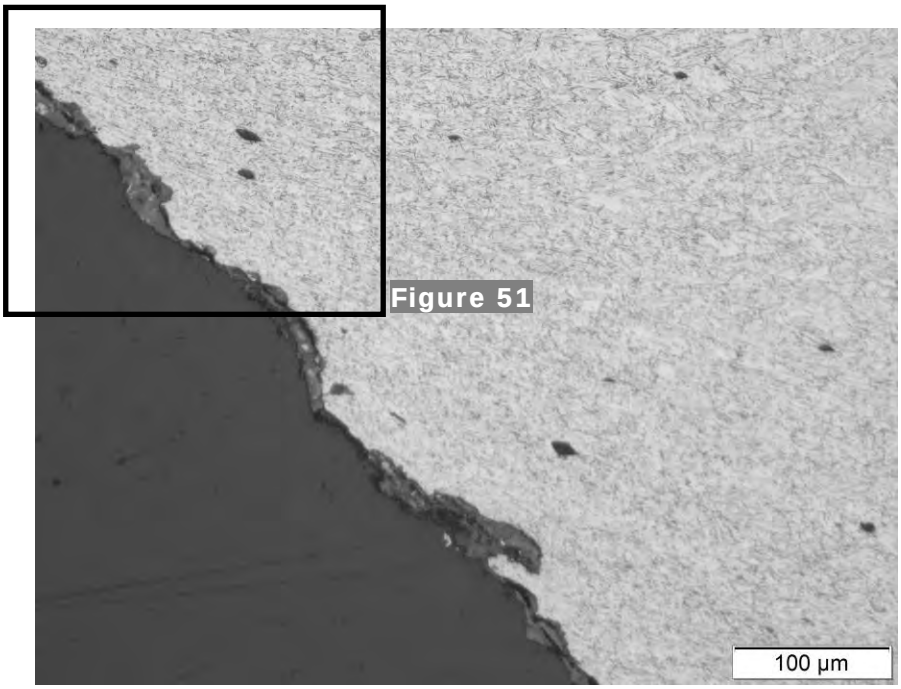

Figure 50. Light photomicrograph of Mount M1 showing inclusions in HAZ adjacent to the fracture surface; area indicated in Figure 49.

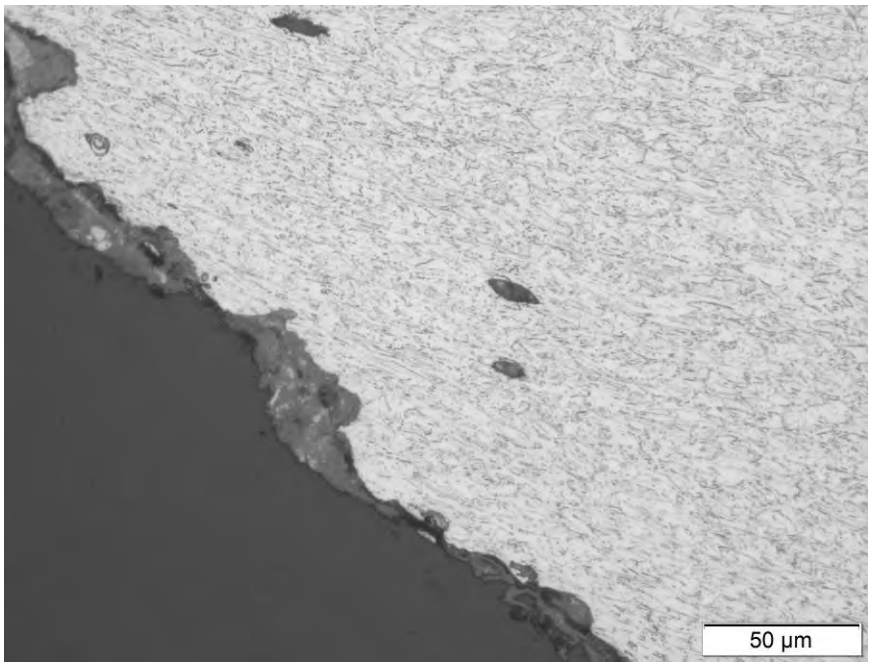

Figure 51. High magnification light photomicrograph of Mount M1 showing grain elongation adjacent to the fracture surface; area indicated in Figure 50.

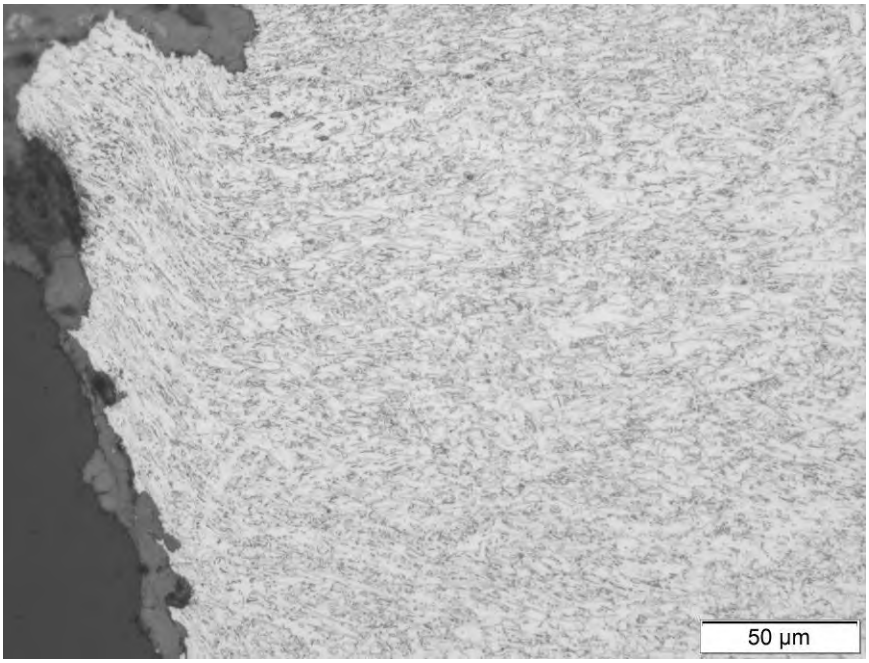

Figure 52. High magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 48.

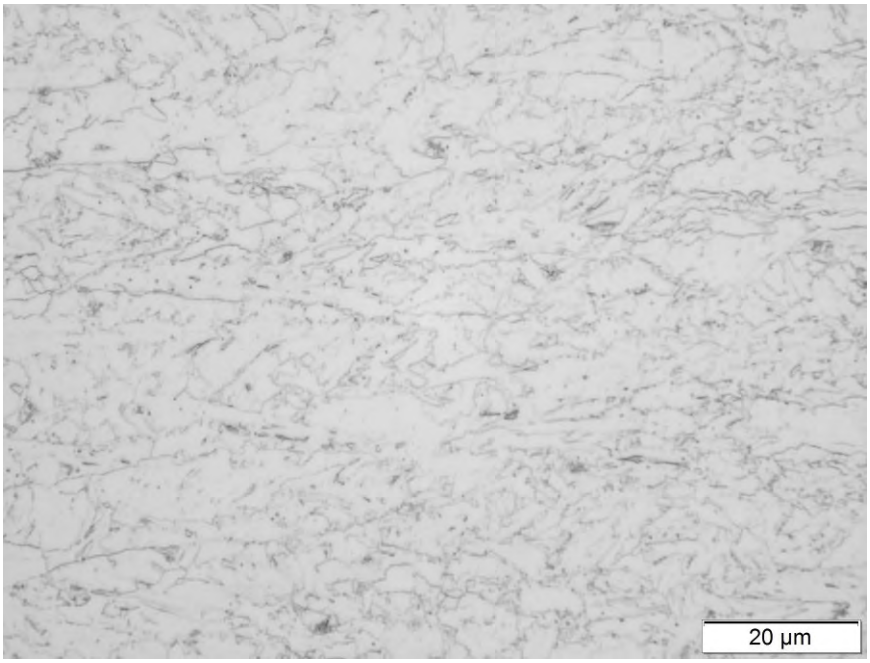

Figure 53. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the U/S Joint (PS B, 2% Nital Etchant).

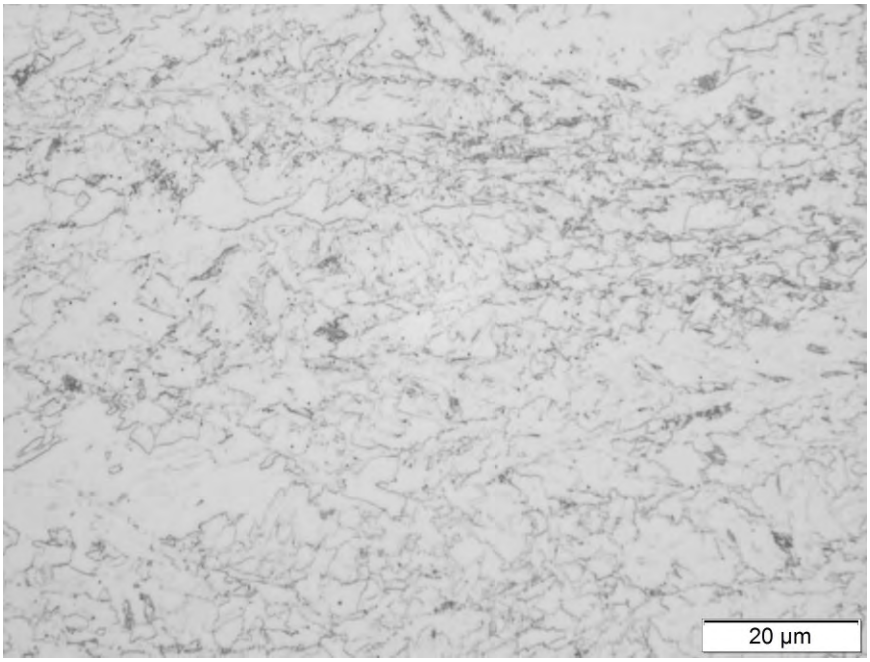

Figure 54. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the D/S Joint (PS A, 2% Nital Etchant).

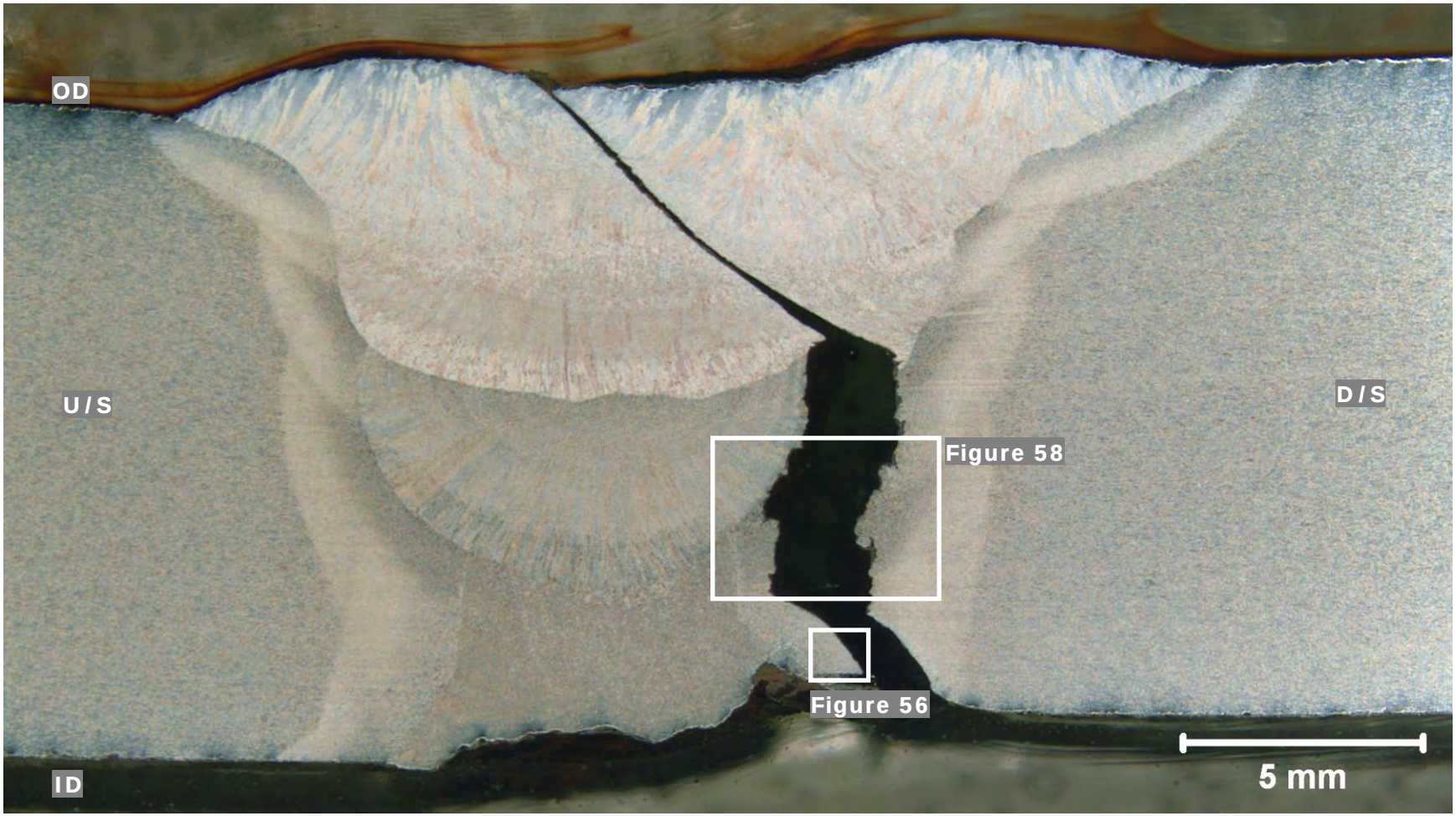

Figure 55. Light photomicrograph of Mount M2 (axial cross-section), which was removed from the GW at the 3:55 orientation; refer to Figure 1, Figure 12, and Figure 23 for location (2% Nital Etchant).

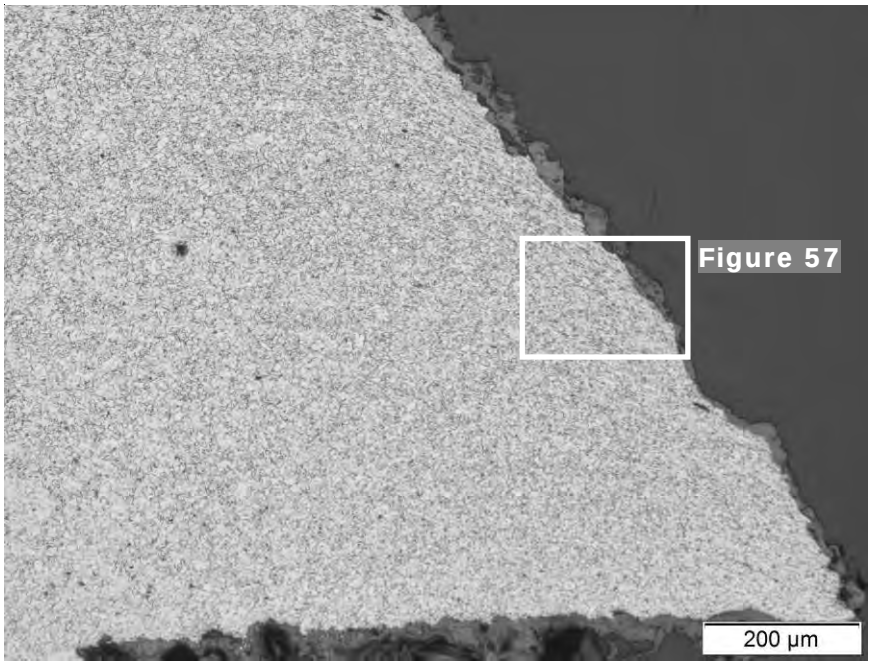

Figure 56. Light photomicrograph of Mount M2 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 55.

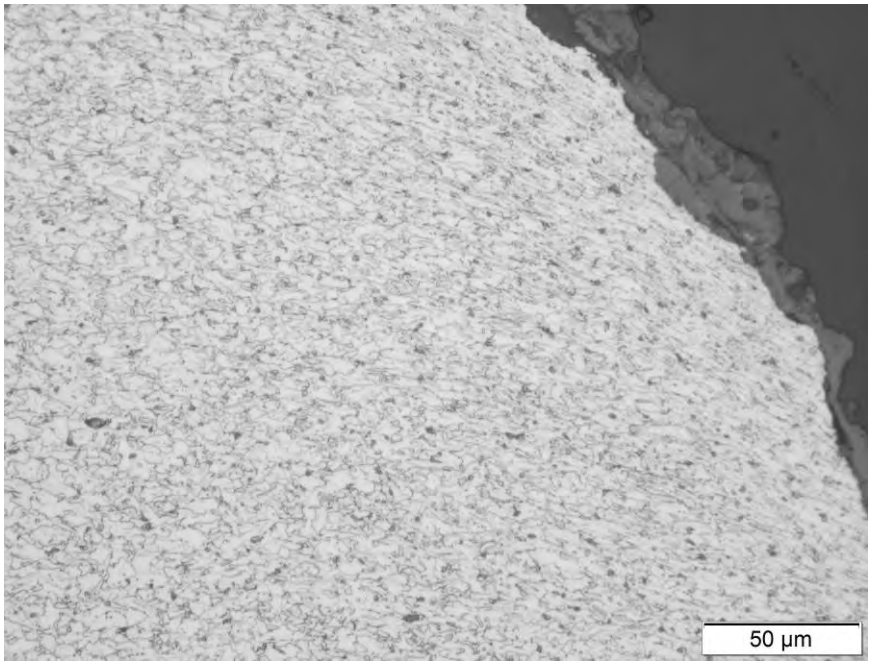

Figure 57. High magnification light photomicrograph of Mount M2 near the ID surface, adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 56.

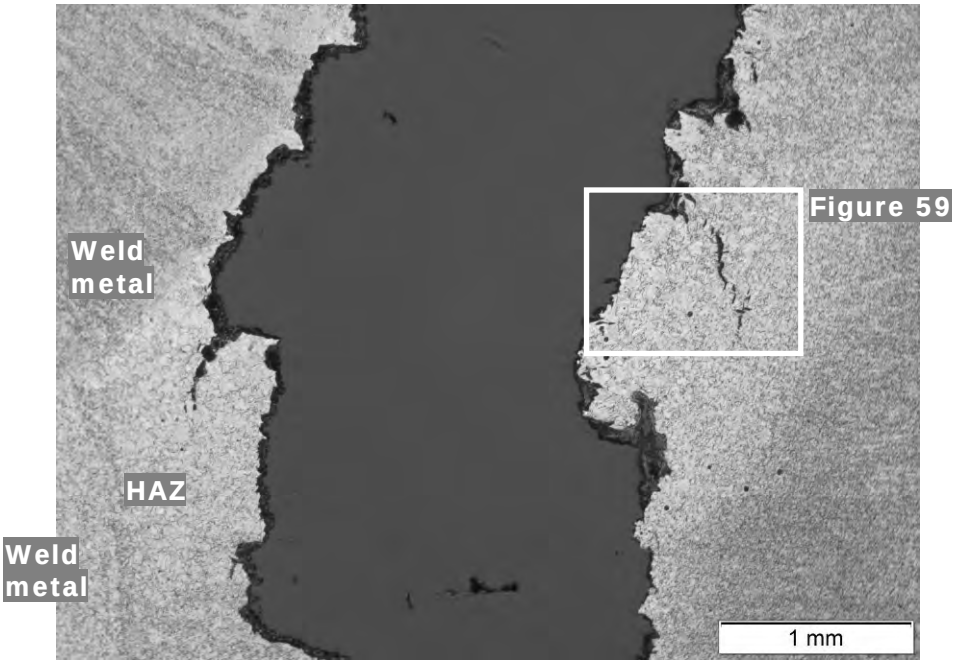

Figure 58. Light photomicrograph of Mount M2 midwall (2% Nital Etchant); area indicated in Figure 55.

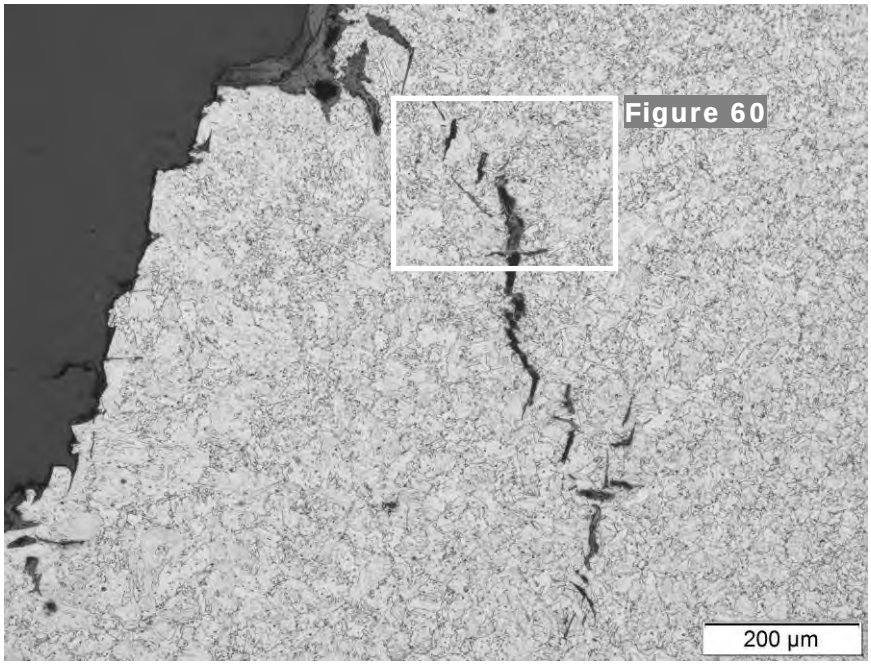

Figure 59. Light photomicrograph of Mount M2 adjacent to the fracture surface showing fissures (2% Nital Etchant); area indicated in Figure 58.

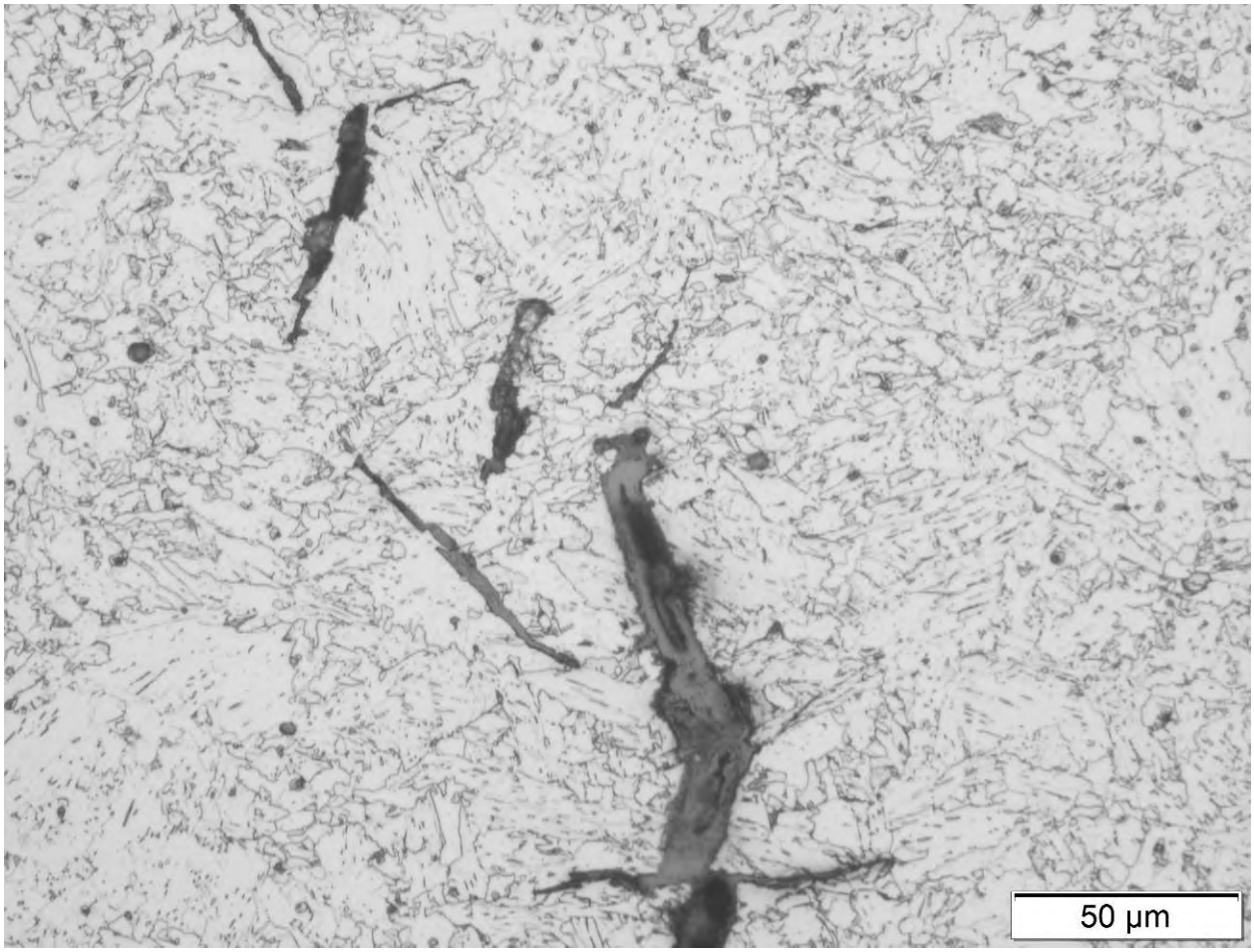

Figure 60. High magnification light photomicrograph of Mount M2 at fissures (2% Nital Etchant); area indicated in Figure 59.

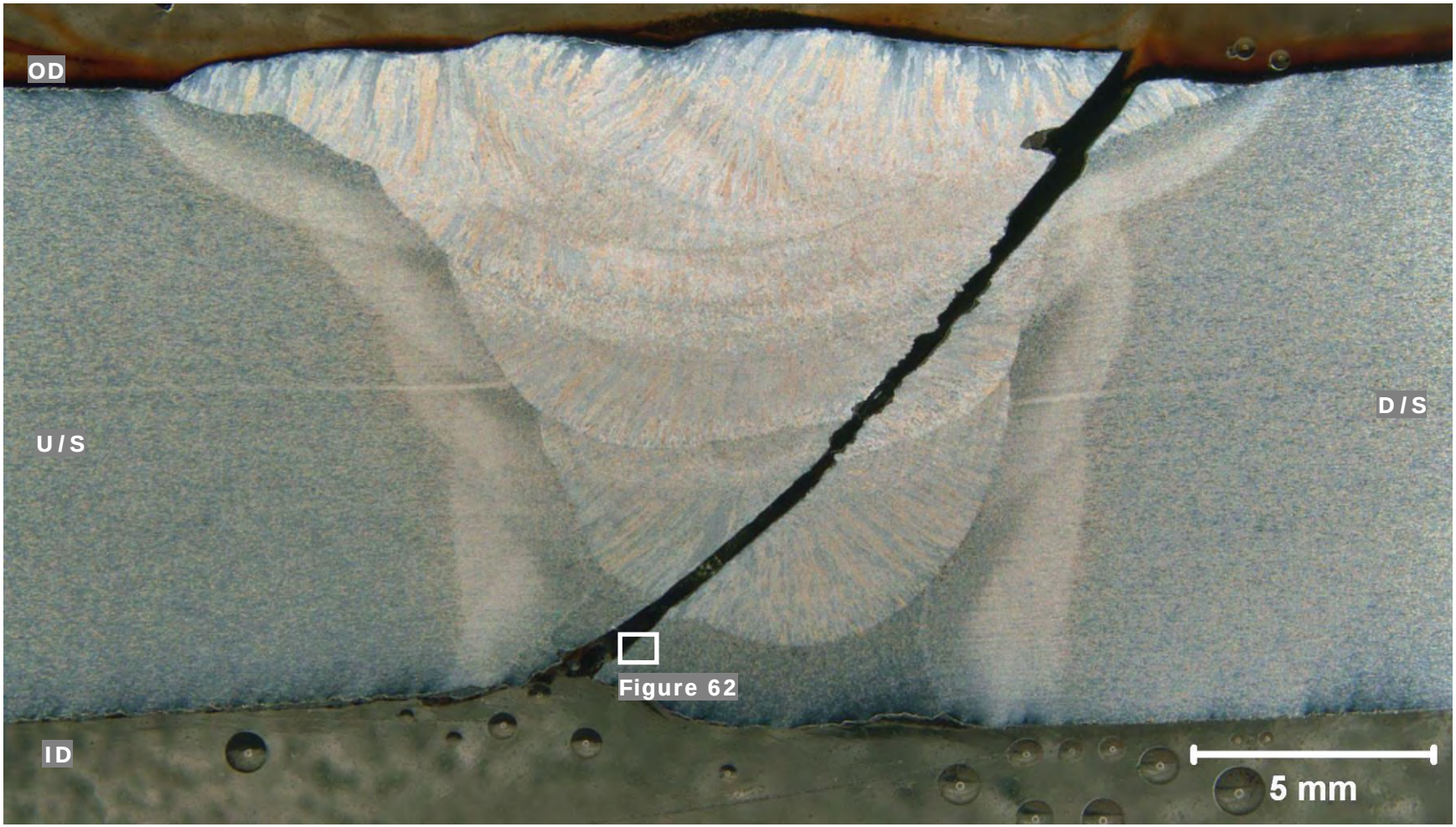

Figure 61. Light photomicrograph of Mount M3 (axial cross-section), which was removed from the GW at the 8:35 orientation; refer to Figure 1, Figure 13, and Figure 28 for location (2% Nital Etchant).

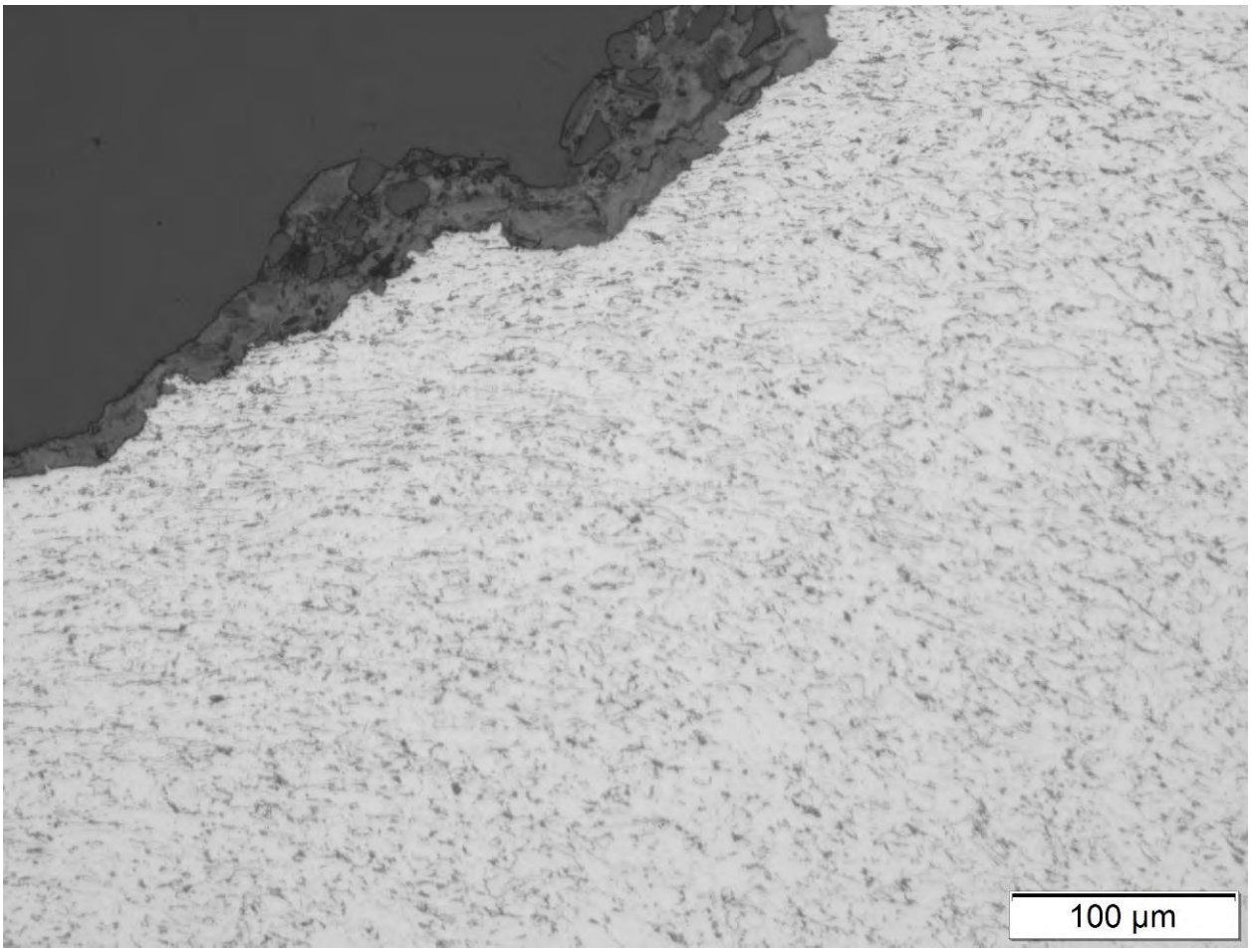

Figure 62. Light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 61.

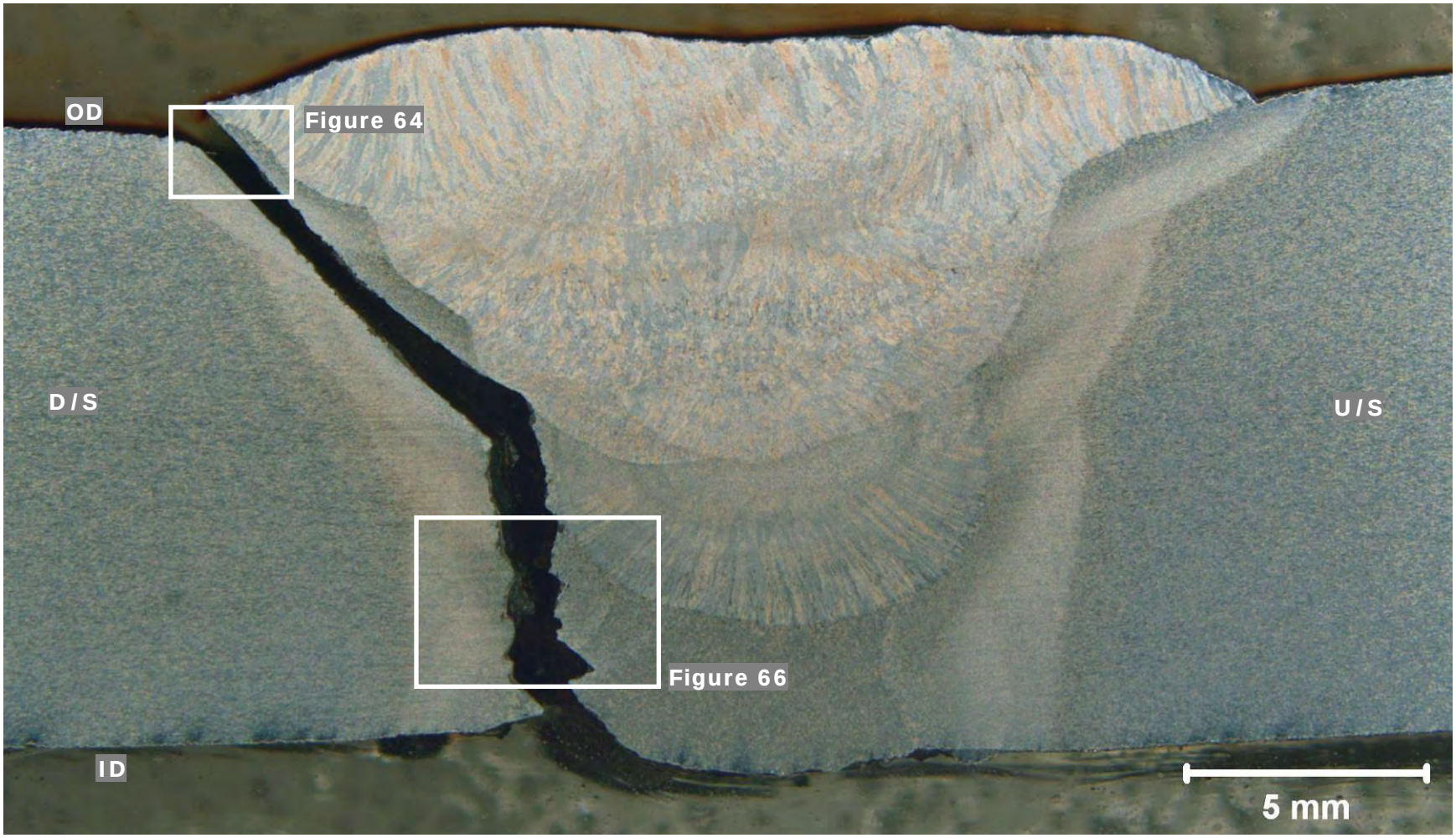

Figure 63. Light photomicrograph of Mount M4 (axial cross-section), which was removed from the GW at the 10:24 orientation; refer to Figure 1, Figure 14, and Figure 30 for location (2% Nital Etchant).

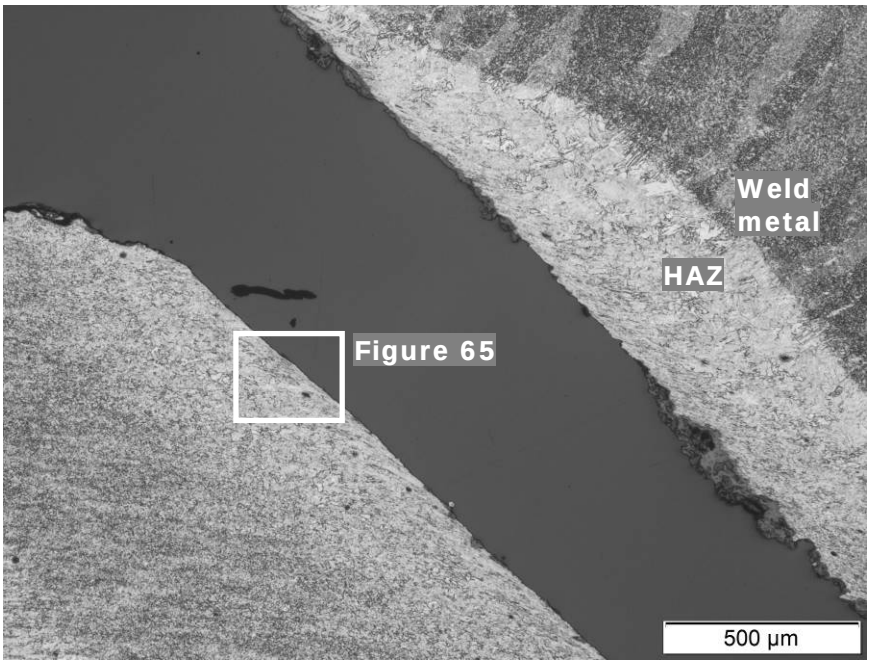

Figure 64. Light photomicrograph of Mount M4 near the OD surface (2% Nital Etchant); area indicated in Figure 63.

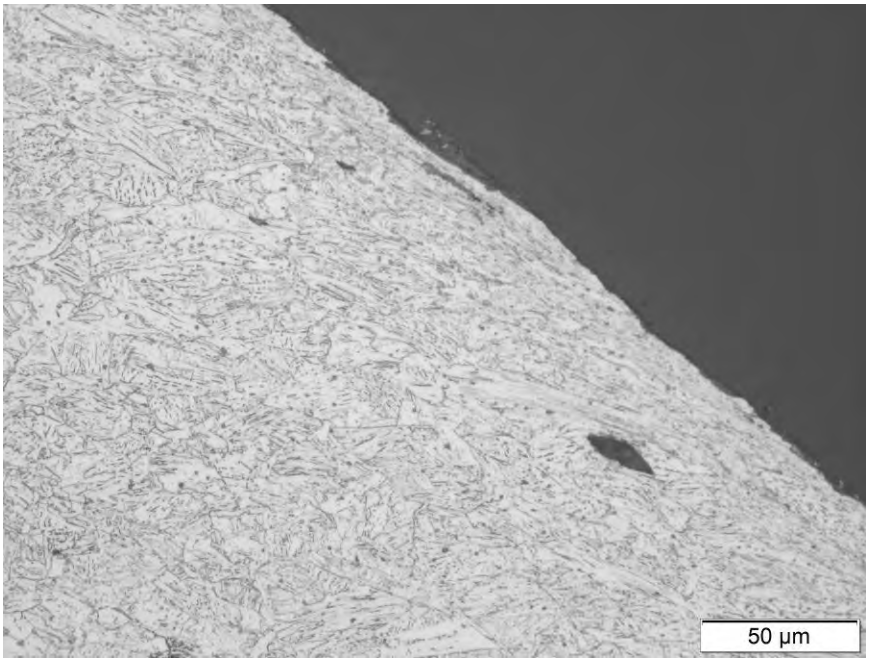

Figure 65. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 64.

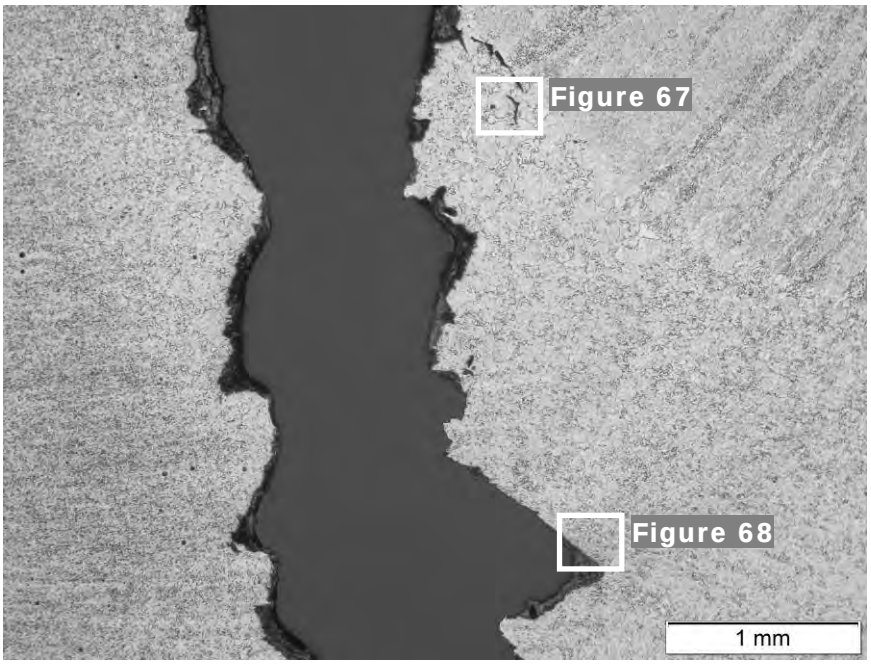

Figure 66. Light photomicrograph of Mount M4 near the ID surface (2% Nital Etchant); area indicated in Figure 63.

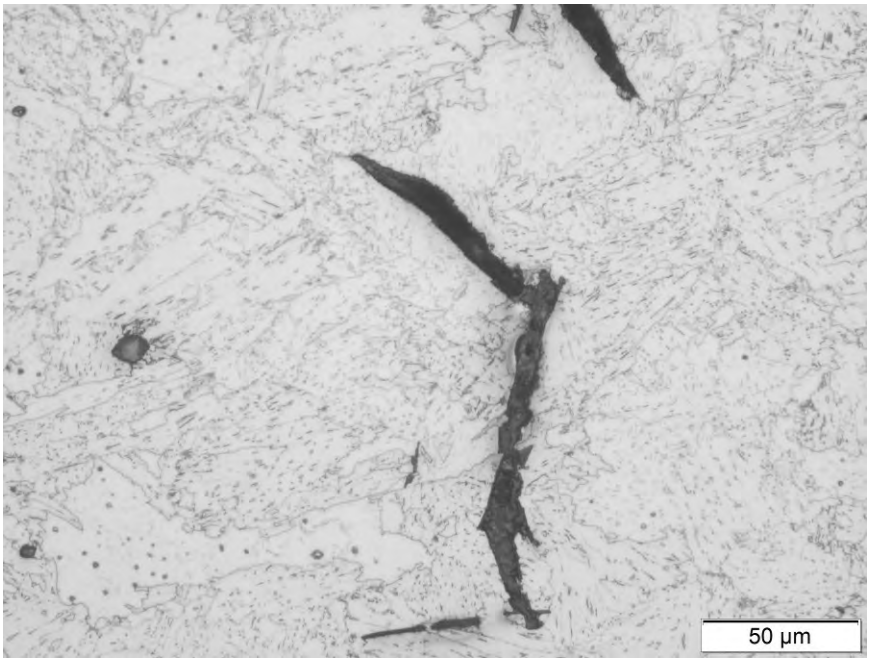

Figure 67. High magnification light photomicrograph of Mount M4 showing fissures (2% Nital Etchant); area indicated in Figure 66.

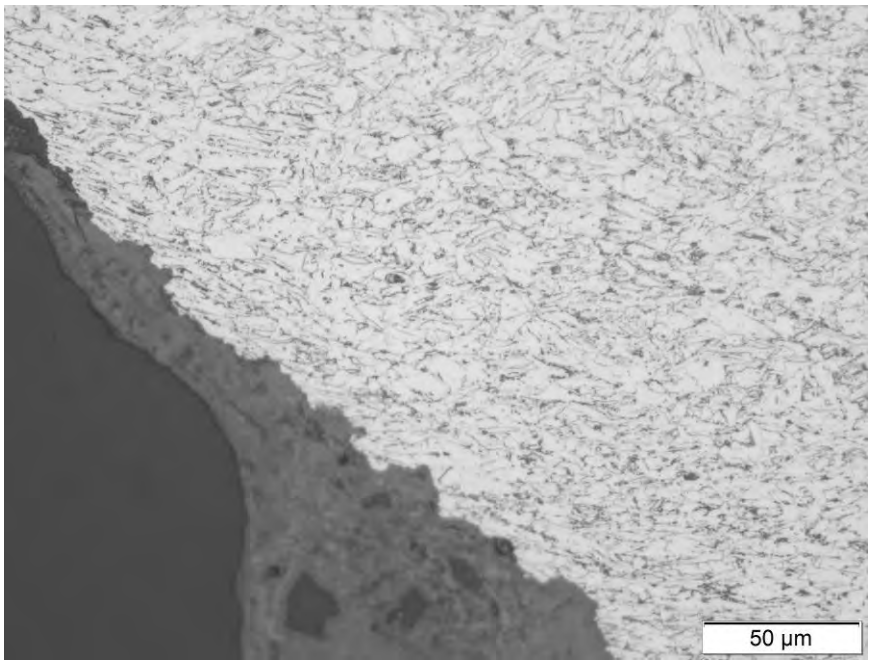

Figure 68. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 66.



Figure 69. Light photomicrograph of Mount M5 (axial cross-section), which was removed from the GW at the 11:37 orientation; refer to Figure 1, Figure 14, and Figure 31 for location (2% Nital Etchant).

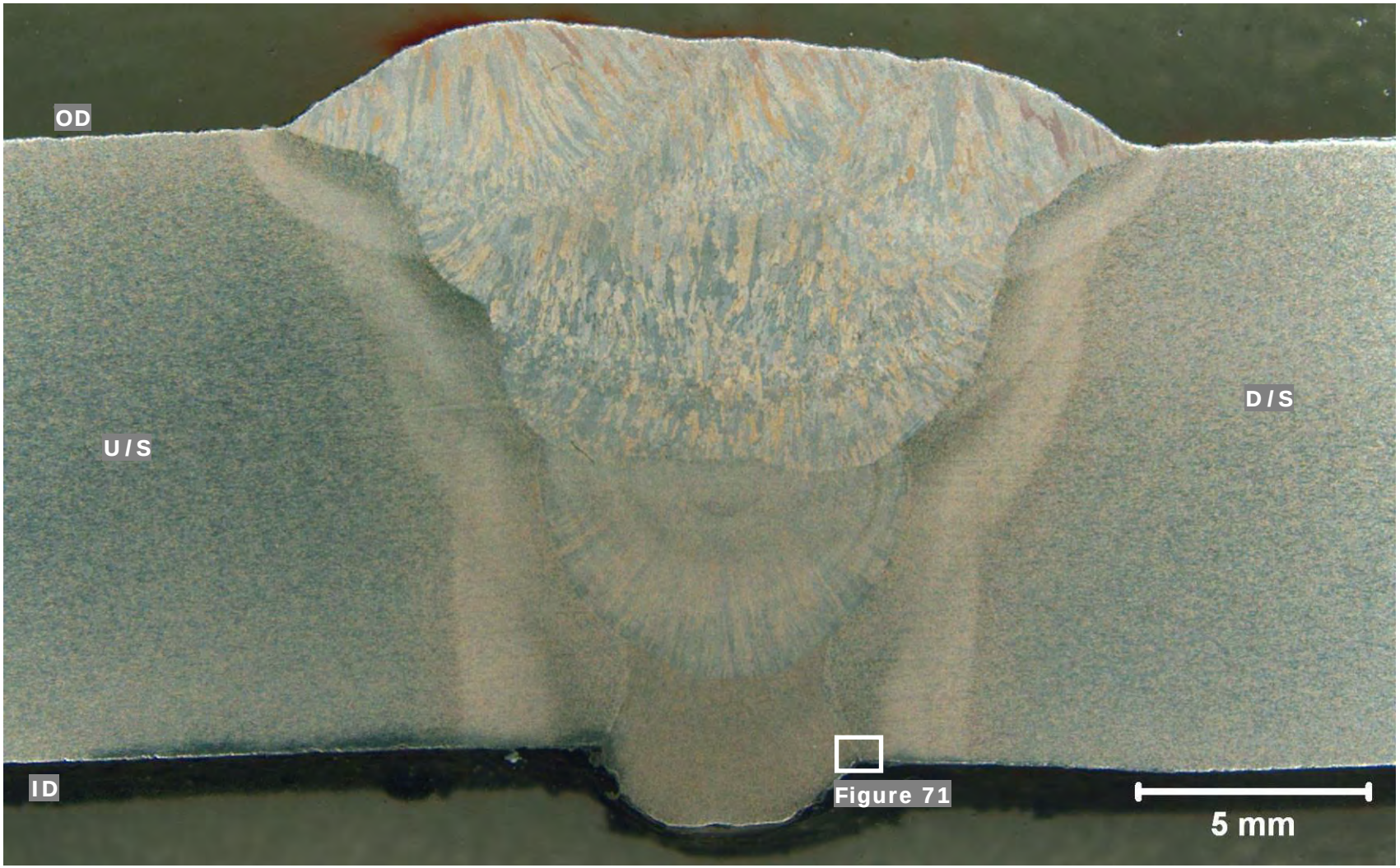

Figure 70. Light photomicrograph of Mount MU1 (axial cross-section), which was removed from the intact GW at the 12:27 orientation; refer to Figure 1 and Figure 17 for location (2% Nital Etchant).

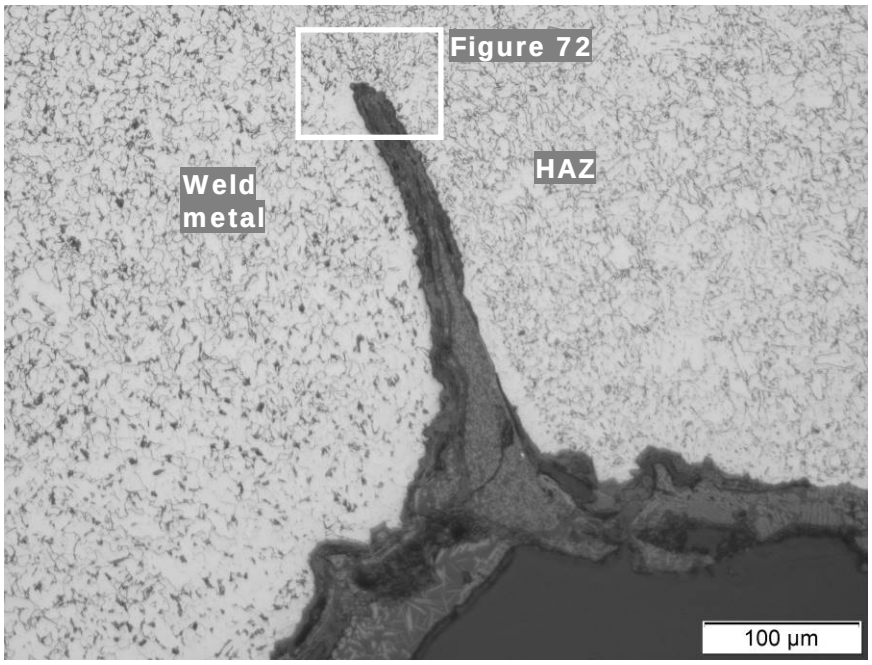

Figure 71. Light photomicrograph of Mount MU1 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 70.

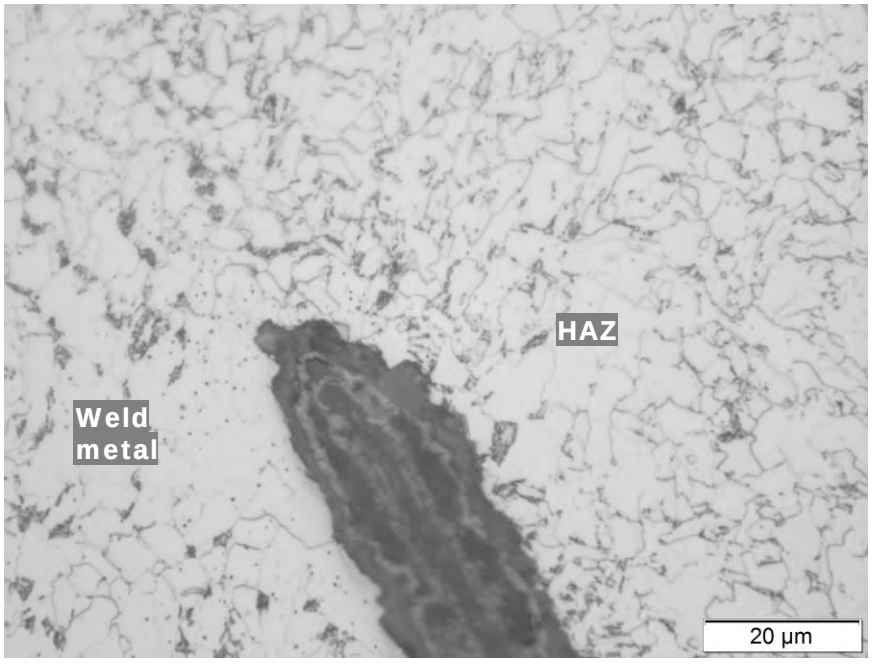

Figure 72. High magnification light photomicrograph of Mount MU1 at the tip of a shallow incomplete fusion (IF) flaw (2% Nital Etchant); area indicated in Figure 71.

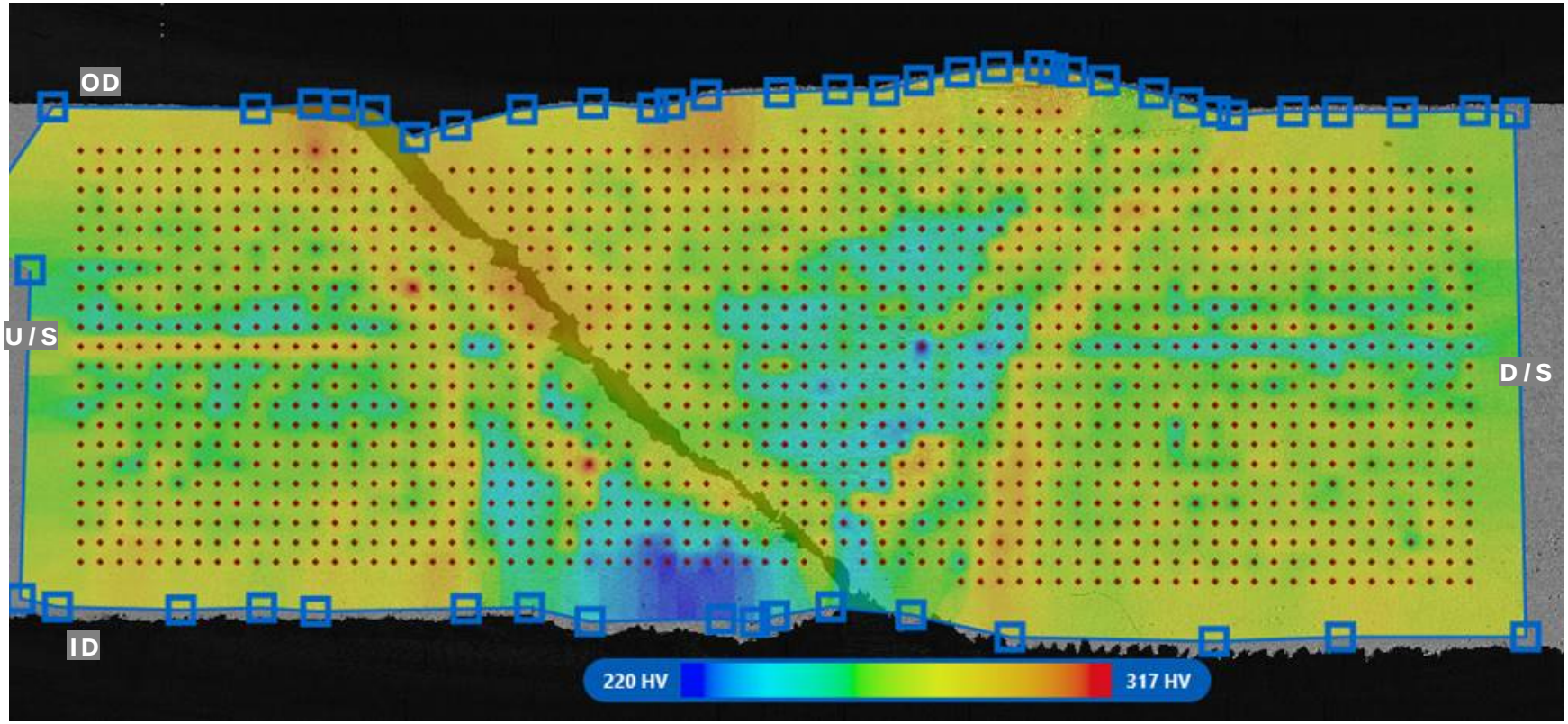

Figure 73. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M1.

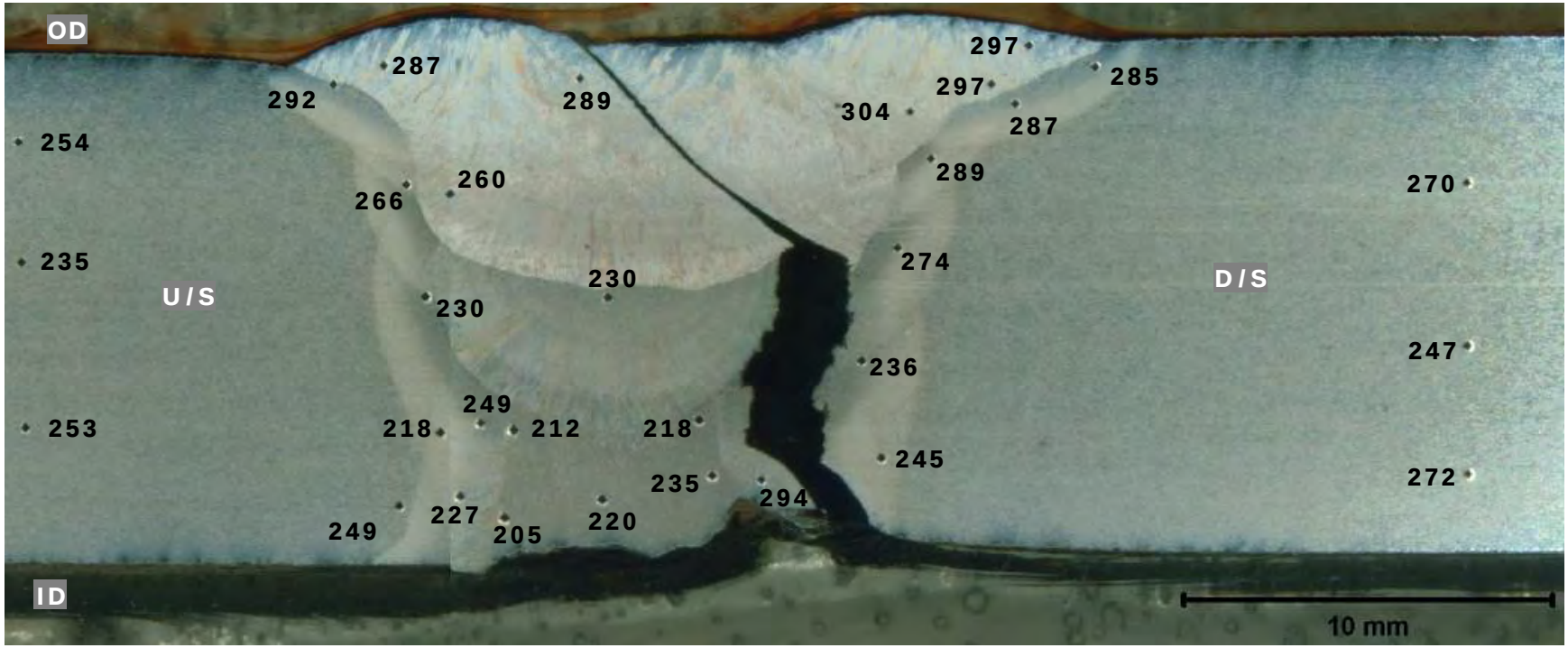

Figure 74. Light photomicrograph montage of Mount M2 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

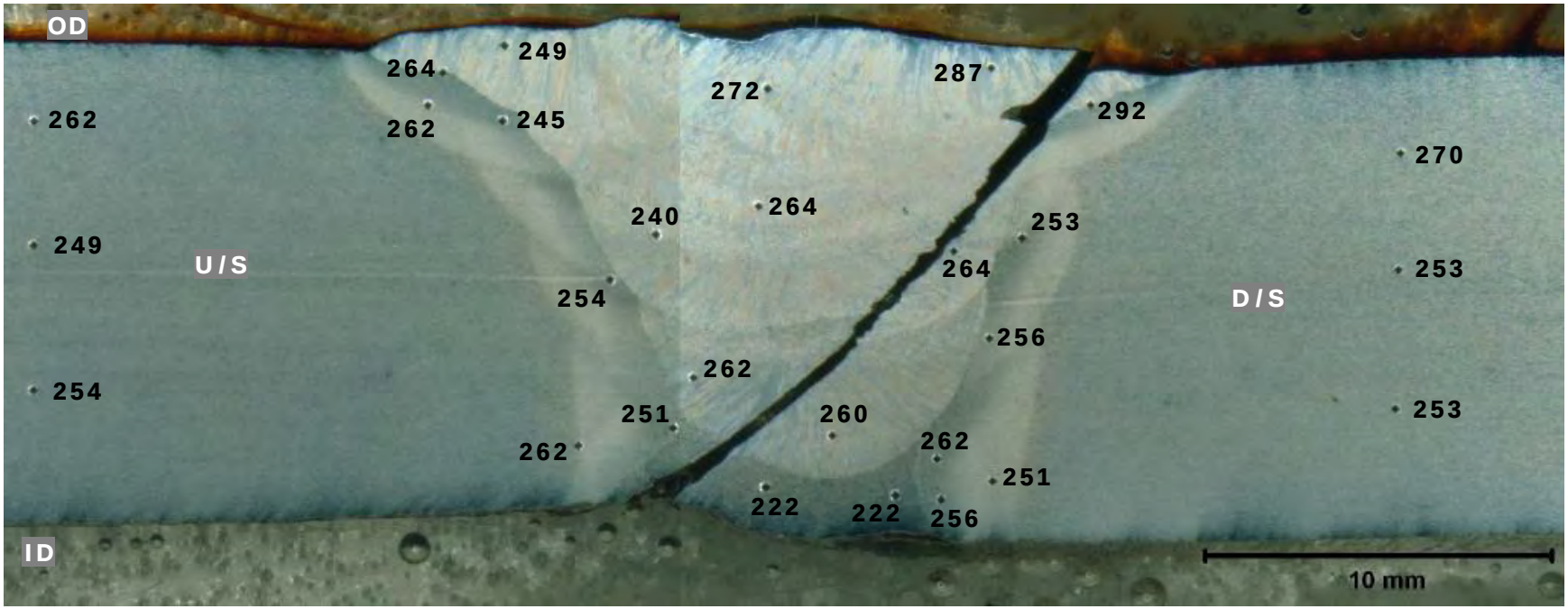

Figure 75. Light photomicrograph montage of Mount M3 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

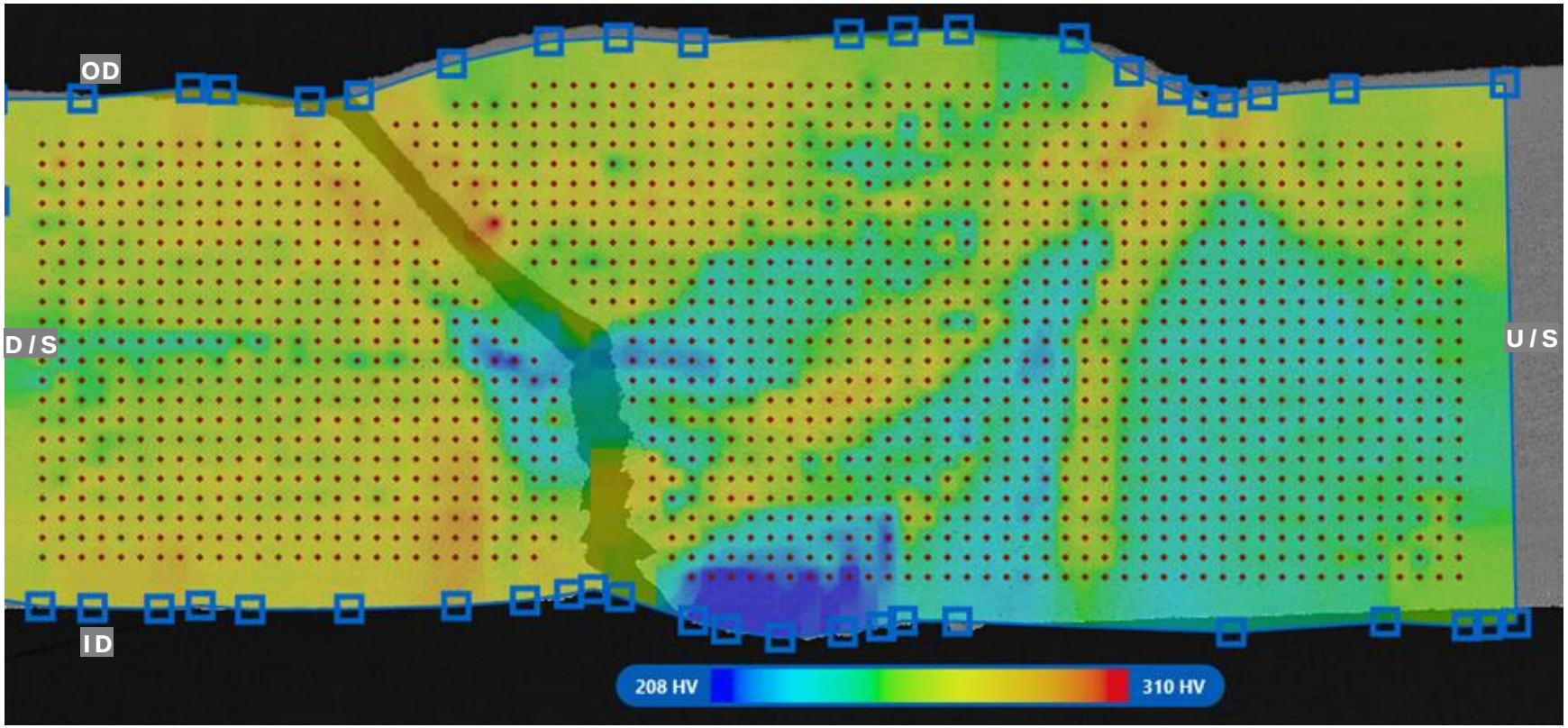

Figure 76. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M4.

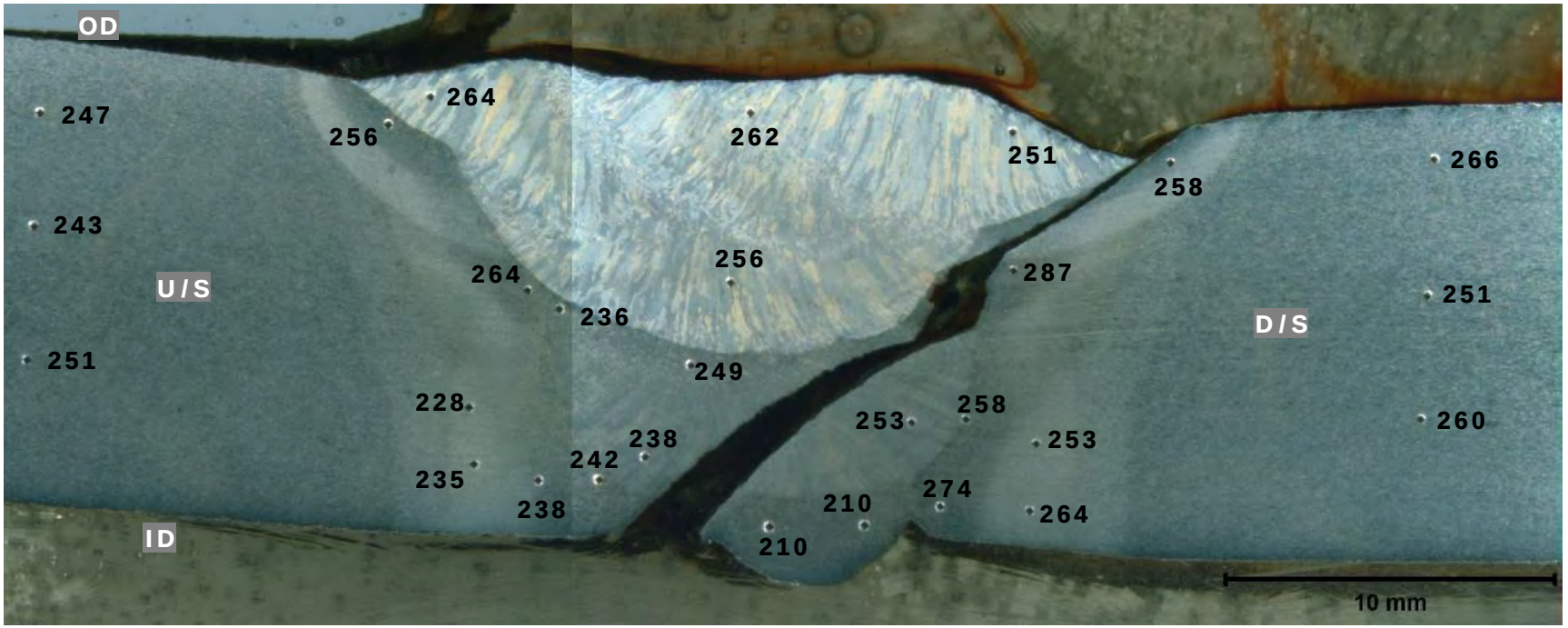

Figure 77. Light photomicrograph montage of Mount M5 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

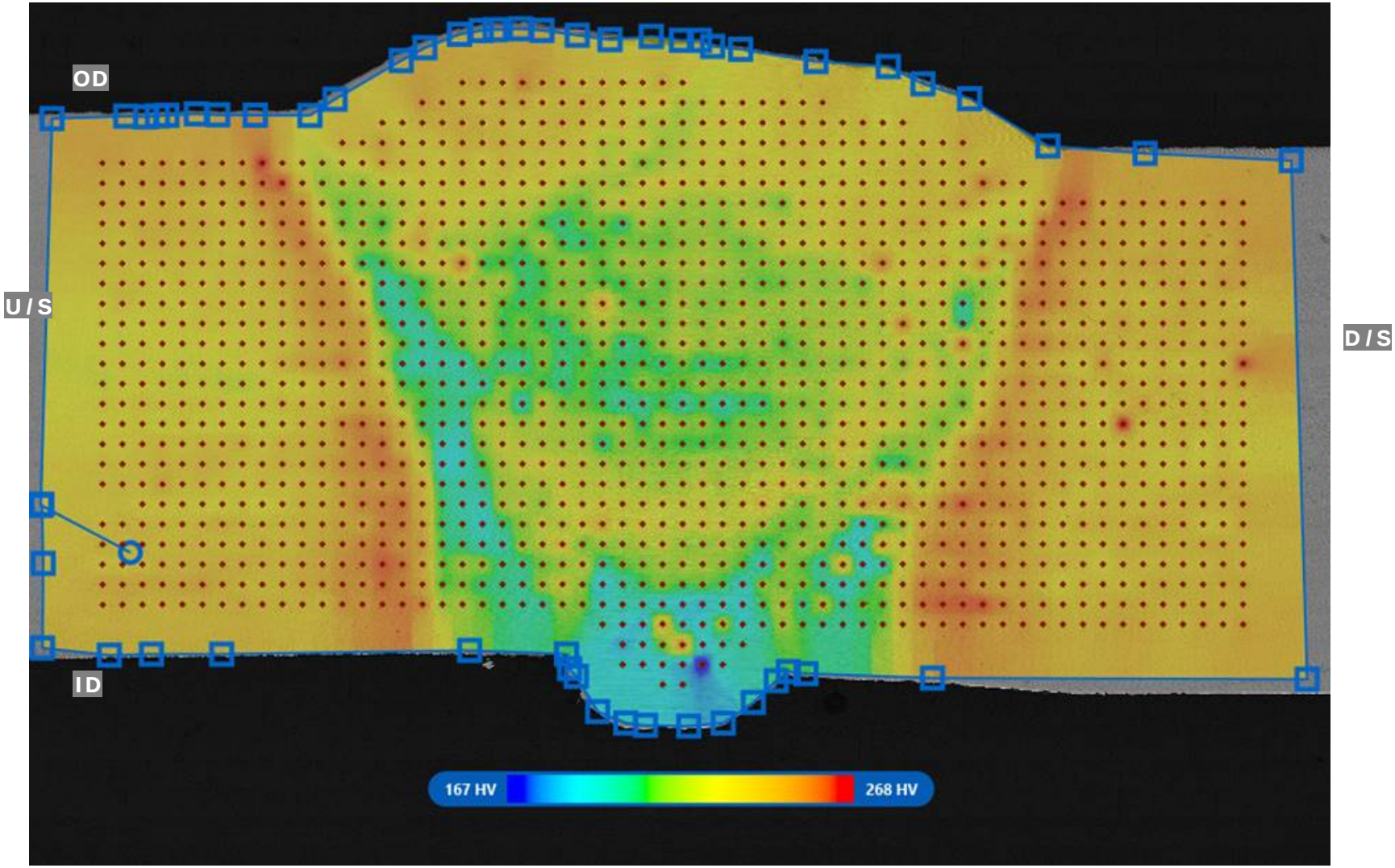

Figure 78. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount MU1.

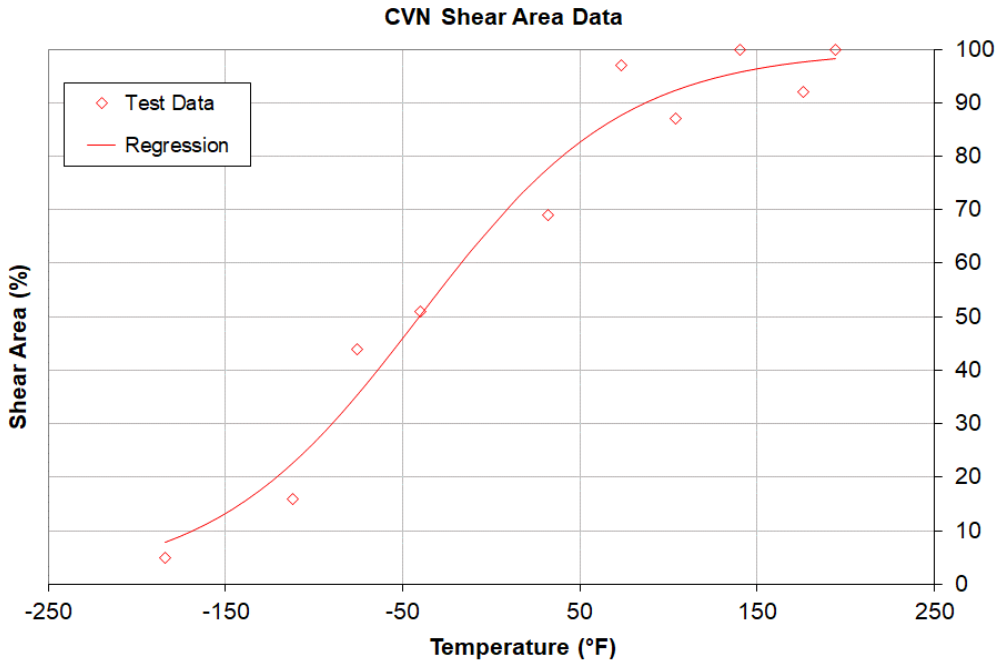

Figure 79. Percent shear from Charpy V-notch tests as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

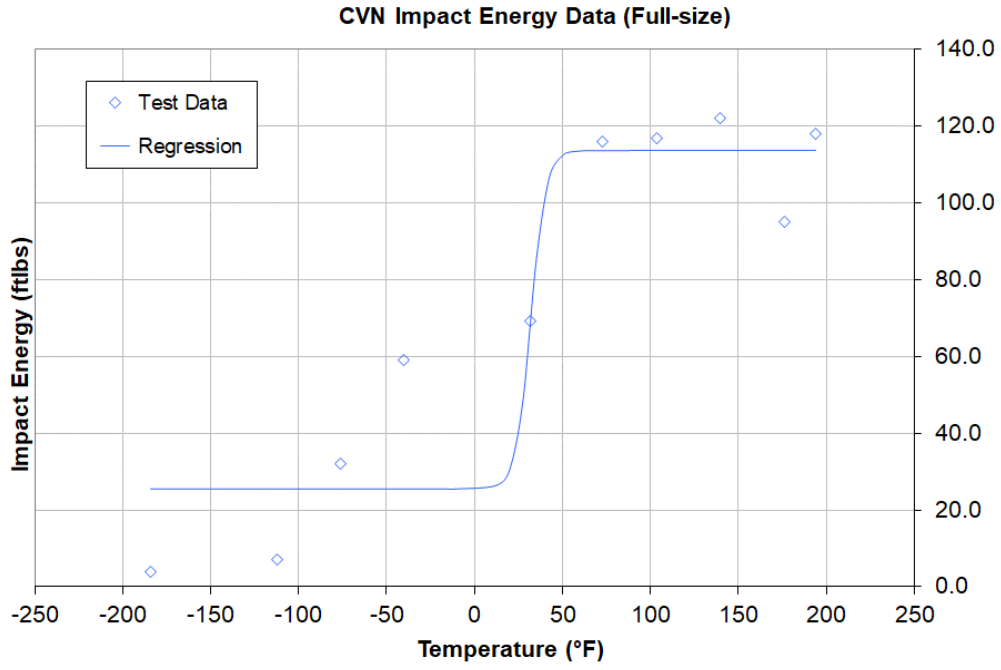

Figure 80. Charpy V-notch impact energy as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

ABOUT DNV GL

Driven by our purpose of safeguarding life, property, and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our professionals are dedicated to helping our customers make the world safer, smarter, and greener.

Appendix D

Responses to Questions Provided by PHMSA 4/7/2021

Questions and responses related to the Denbury Yazoo County RCA Final Report dated 8/7/2020:

1. **The metallurgy report does not reference chain-of-custody. Were chain-of-custody procedures used**

   Chain of custody procedures were used for collection and transport of the failed pipe section and samples. Copies of the chain-of-custody documentation have been provided to PHMSA and have been added to the appendices of this report.

2. **Copy and discussion of welding procedure used needed**

   A summary of the review of Denbury's welding procedure for the Delhi 24-inch Transmission Line utilized for original construction is provided below:

   Material: In this case the pipe material was high strength API 5L-X80-PSL2, 24-inch diameter, and 0.54-inch wall thickness.
   It is a requirement of the welding procedure that it produce a completed girth weld with similar strength properties of the pipe's base metal. This helps to ensure that the strains caused by loads imposed on the completed pipeline structure, do not concentrate in the vicinity of the weld. Another important aspect of the welding procedure is that it mitigates the risk of hydrogen embrittlement, which could lead to hydrogen cracking at the weld.

   There are 3 requirements for hydrogen cracking:
   a) Hydrogen in the weld,
   b) A crack susceptible microstructure, and
   c) Tensile stresses acting on the weld

   Weld Material: The Welding Procedure Specification WPS 14 indicates the use of the following electrodes:
   a) Root Bead: E6010
   b) Hot: E9010-G
   c) 1st Fill: E10045 P2 H4R
   d) Fill (s): E10045 P2 H4R
   e) Cap (s): E10045 P2 H4R

   Post Weld Heat Treatment: Not recommended

   Comments:

   1) Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. In the Denbury procedure electrode AWS E6010 and E9010-G were used for the root and hot pass in conjunction with low-hydrogen electrodes for the fill and cap passes. The Welding Procedure indicated that this is permissible because the heat from the fill and cap passes allows the hydrogen from the first 2 passes to diffuse out of the weld.

2) Electrode E10045 P2 H4R was used as a strength level low hydrogen downhill electrode. Only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were selected for this case. “H” stands for hydrogen, the “4” stands for a maximum of 4ml of hydrogen per 100 grams of deposited weld metal, and “R” means the consumable is resistant to absorbing moisture from atmospheric conditions. During the qualification procedure, this electrode was found to be the most suitable electrode for this project. After the destructive testing, it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line material which has a yield strength approaching 100 ksi.
3) Samples obtained during the failure analysis were evaluated using standard microscopy techniques including stereographic evaluations, microscopic evaluation, and scanning electron microscopy. Five axial and cross-sections were removed from the failed girth weld and one from an intact weld for metallographic analysis.

Actual findings during the failure analysis process:

a) There was no evidence of pre-existing manufacturing or welding flaws,
b) No indications of excessive porosity and/or inclusions,
c) Slight misalignment of high-low weld in the failed girth weld between 2.6% and 6.9% of the NWT,
d) Grain elongations due to the cold work that took place during the rupture process which is consistent with ductile overloading (see fig. 21 of the Mears report),
e) The sample obtained from the intact GW presented a similar morphology to the previous mounts. The high-low weld misalignment at this location was 4.6% of the NWT. The metallography of the section does not indicate a presence of a martensitic phase.
f) Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal, which indicates that the weld metal is softer than the parent metal, however tests results were consistent with specifications for pipe of this vintage and yield strength in both the base metal and weld metal. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual failed pipe sample, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).
g) The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing.

Based upon review of the welding procedure, we conclude that:

1) The Welding Procedure Specification WPS 14 was appropriate to be use as a welding process for the material involved in this project.

2) The testing performed on the samples obtained during the failure investigation indicate that the welds showed that the microstructure and the mechanical properties of the base material and girth weld were in accordance with industry accepted standards.

3. **Report states on page iv: "The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified." "no significant" how was this determined?**

   The failure surfaces were inspected visually and optically for indications of surface oxides associated with development and deepening of cracks over an extended period. The lack of oxides precludes the possibility of pre-existing cracks and supports the determination that the failure occurred due to a sudden axial stress. In addition, the visual and optical inspections did not identify any marks or indications on the surface of the fracture that indicated an initiation point of the failure.

4. **The section on page 7 describes figures 53 and 54 and describes the area as "mainly ferrite". Specifically characterize the complete microstructure of the pipe and the weld metal.**

   Figures 53 and 54 of the DNV Metallurgical Analysis Report (Section 3.4) characterize the microstructure of the upstream and downstream pipe. Analysis of these photomicrographs indicate a significantly larger amount of ferrite than pearlite, which is consistent with the expected microstructure for pipe with the specified minimum yield strength and vintage of the Delhi 24-inch pipeline. Compared with photomicrographs of metal samples provided through industry literature, the microstructure of the 24-inch pipeline has a low carbon content, consistent with other X-80 pipelines. The microstructure of the failed girth shows similar characteristics (see Figure 62 of the DNV Metallurgical Analysis Report.

5. **Provide the hardness montage for MU1**.

   The hardness montage for mount MU1 is provided in Figure 78 of the DNV Metallurgical Analysis Report (Appendix C).

6. **Section 3.5 on hardness testing indicates various areas related to the weld area, include a discussion of the welding procedure utilized to produce the weld.**

   Discussion of the welding procedure is provided in the response to question #2 above.

7. **Typically, there is narrowing of a tensile specimen due to the area reduction during tensile overload. In this case was there a measurable necking down of the wall thickness adjacent to the fracture surface**

Evaluation of the metallurgical samples indicated slight reduction in wall thickness in each sample, ranging from 1.44% to 6.46%. Photos and measurements are provided in in figures 1 through 5 below:

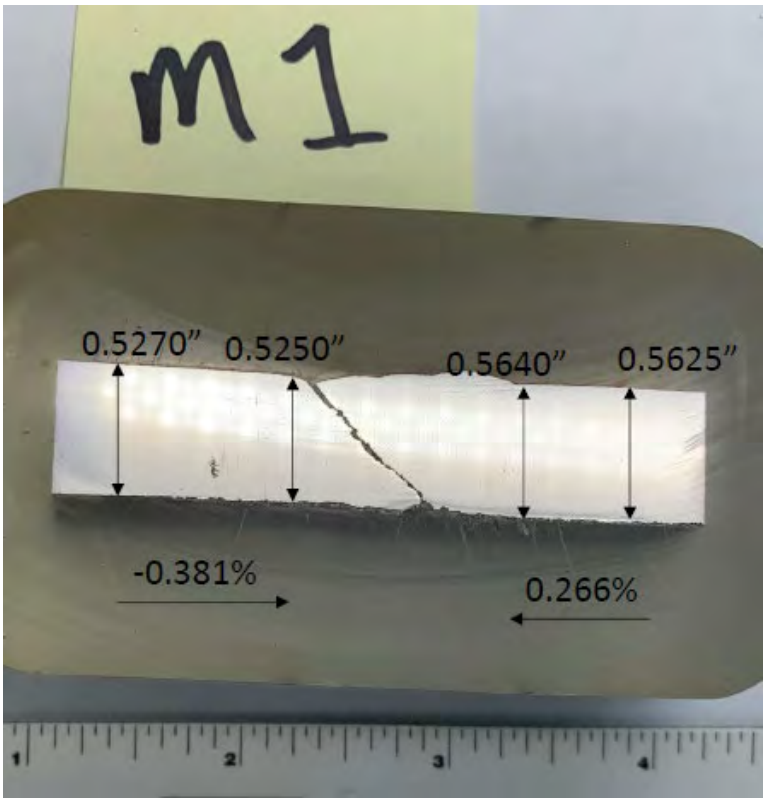

Figure 1: Cross-Sectional Measurements, Mount M1

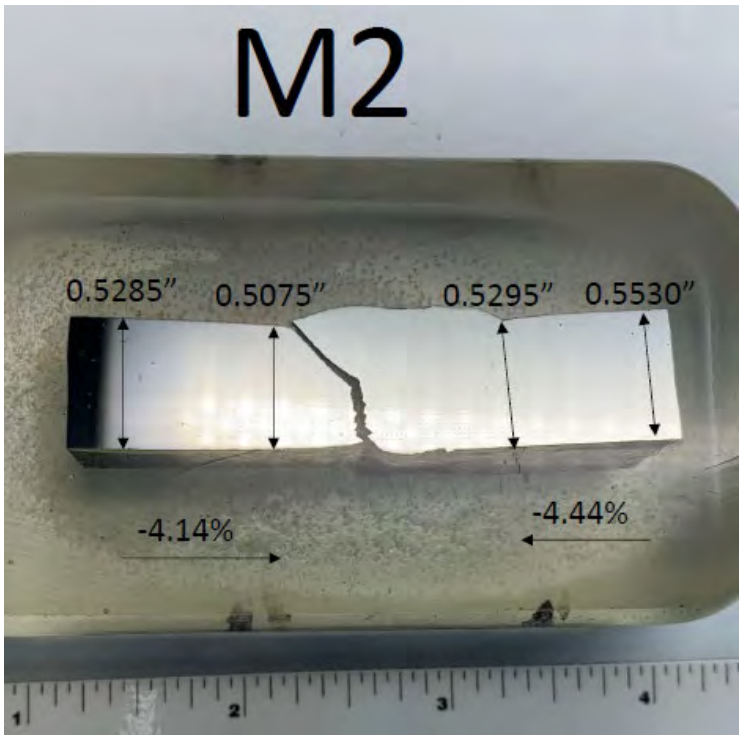

Figure 2: Cross-Sectional Measurements, Mount M2

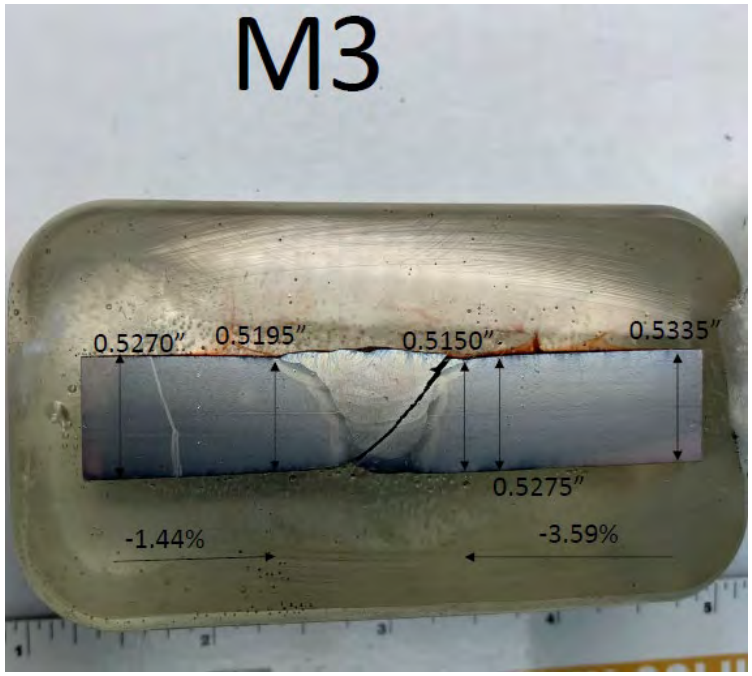

Figure 3: Cross-Sectional Measurements, Mount M3

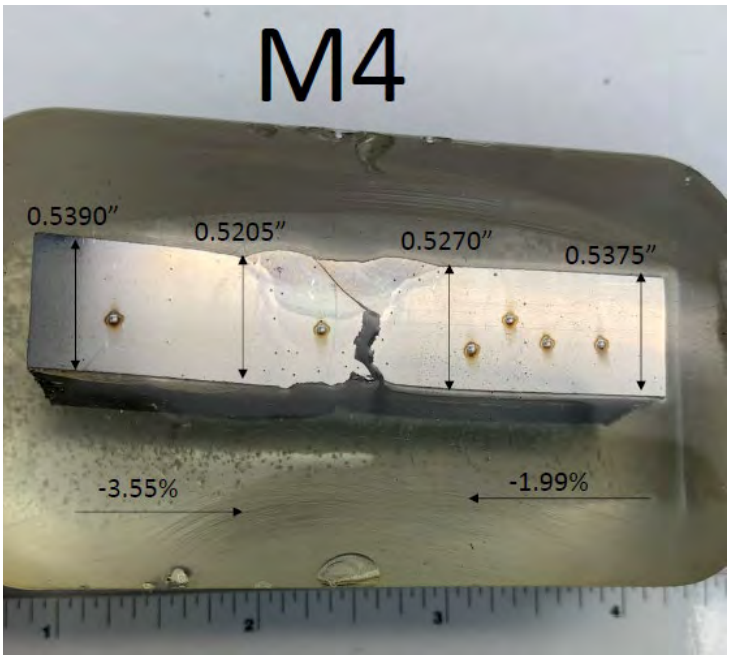

Figure 4: Cross-Sectional Measurements, Mount M4

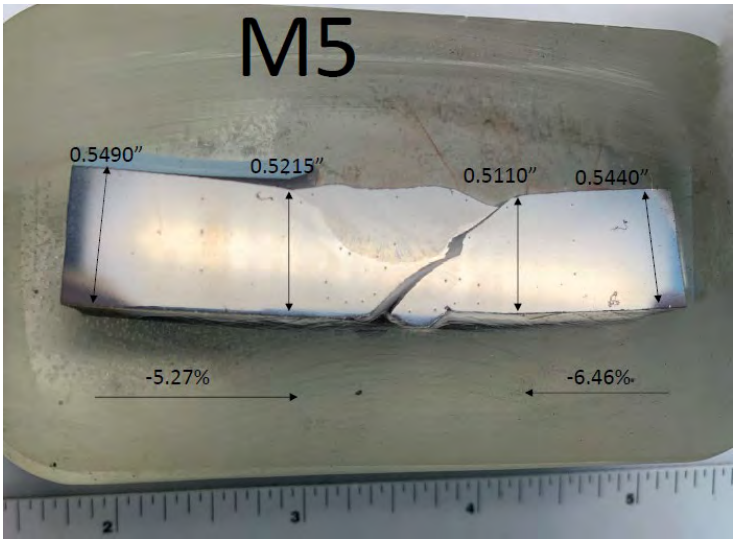

Figure 5: Cross-Sectional Measurements, Mount M5

These results are consistent with the characteristics of API X80M PSL 2 Line pipe.

8. Intact girth weld was tensile tested – compare and contrast fracture appearance of tested intact weld to failed girth weld

The average UTS of the axial specimens taken from the intact girth weld was 103.3 ksi, and both samples failed in the girth weld (DNV Metallurgical Analysis Report, section 3.6). While visual examination of the tensile sample fractures will confirm the location of each fracture, a comparison of the samples would only provide confirmation of the location of each fracture and not provide additional insight as to the reason for the failure, as the applied stresses would not be similar. The Pipeline Stress Analysis Report

provided by Mott MacDonald provides information related to the stress analysis associated with this failure.

9. Was leak before fracture mode of failure considered

Occurrence of a leak prior to the failure was considered, however the available information supports a rupture of the pipeline, including the following:

1) There was no indication of a pre-existing defect that would have contributed to a leak and a specific failure initiation site was not apparent.
2) Based upon a witnessed examination of the pipe, there was no evidence of internal or external corrosion that may have contributed to the failure mode.
3) No indication of a leak prior to the failure was identified in operating pressure trends.

10. Failure mode and influence of CO2 on ductile/brittle transition considering leak before rupture

Based upon the metallurgical examination, there is no evidence a leak occurred prior to the failure, therefore brittle failure mode is not feasible.

11. Chemistry of weld needed as this was a girth weld failure

Chemical analysis of the GW was not performed during the investigation. The mechanical testing results were within the accepted criteria during the preparation of the Welding Procedure Specification WPS 14. No additional testing of the chemistry of the girth weld was considered necessary based upon the results of the testing conducted.

12. Report states failure caused by large axial stress but fails to quantify strain

The Pipeline Stress Analysis Report provided by Mott MacDonald identified a stress ratio approximately 43% greater than allowable stresses per ASME B31.4 (2016).

13. Strain analysis would be an input for a geohazard management plan

The Pipeline Stress Analysis Report provided by Mott MacDonald provides information related to the strain analysis associated with this failure.

14. Brittle (cleavage facets) mode of failure noted, but no chevrons – significance

V-shaped chevron markings are characteristic of brittle fracture. These markings may indicate the origin of the fracture, however in this case no chevrons were identified.

15. Explanation of ductile/brittle appearance of the failed girth weld

As described in section 5.3 of the Mears report, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough). The appearance of these surfaces further support the mode of failure as described in the executive summary of the DNV Metallurgical Analysis Report "The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor was that the pipe steel was stronger than the girth weld."

16. Correlation of hardness areas and welding procedure

Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal. Which indicates that the weld metal is softer than the parent metal, which was in accordance with the results of the welding qualification. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual fracture to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).

17. How does the welding procedure tensile tests compare to the intact weld tensile tests

The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing (see section 5.6.2 of the Mears RCA Final Report).

The results of the Procedure Qualification Record (PQR 14a) indicated cross weld UTS of 115.6 ksi to 117.3 ksi. Per the Welding Procedure Development and Qualification for X80 Line Pipe, dated 8/13/2008, section 3.1, "After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line pipe material, which has a yield strength approaching 100 ksi." Therefore test results from the mechanical testing of the intact girth weld are consistent with the pipeline's specifications.

Appendix E

Chain of Custody Documentation

mears
A QUANTA SERVICES COMPANY

STEP 2 – CHAIN OF CUSTODY

1. ORIGINATING LOCATION – Denbury Delhi 24 inch Transmission	
Contact Person: Seth Bayham	*Phone Number: (225) 202-1402*
Title: Corrosion Foreman	*Date: 3/10/2020*
Contact Address: 31589 Netterville Rd, Denham Springs, LA 70726	
Material Location, City, State: 688 MS 433, Sartitia, MS	
Signature: Seth Bayham	*Date:* 3/10/2020

2. AUTHORIZATION FOR RELEASE	
Authorized by: Seth Bayham	*Phone Number:* (225) 202-1402
Title: Corrosion Foreman	*Date:* 3-10-20
Department:	
Authorization provided (check one): _____ *by Telephone* ✓ *in Person* _____ *in Writing*	

SHIPPING INSTRUCTIONS

Samples should be shipped to DNV GL 9037 Heritage Drive, Plain City, OH 43064. Please contact Greg Quickel. Phone: (614) 378-4083.

3. ITEMS TRANSFERED	
Reference Number: Delhi 24-3 *Sample Identifier: Sample A* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6' long pipe sample (D/S failure section)*
Reference Number: Delhi 24-4 *Sample Identifier: Sample B* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6 ' long pipe sample (U/S failure section)*
Reference Number: Delhi 24-5 *Sample Identifier: Sample C* *Date Collected: 3/09/2020*	*Description: 24" diameter by 8' long pipe sample (U/S pipe section containing exemplar weld)*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

☒ Received from Denbury Resources Date: 3/10/hr 1:30P Received by P. Jo. Reid
Reason for transfer

From: Company: Denbury Resources Signature
To: Company: Reid's Dozer service Signature P-JOE REID

Until the time you transferred custody of sample
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
NO

If YES, please explain:

Signature

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

□ Received from Reid's Dozer Service Date: 3/12 /hr 8:10 Received by Greg Quickle

Reason for transfer Testing at DNVGL

From: Company: Reid's Dozer Sevice Signature P-JOE REID
To: Company: DNV GL Signature Greg Quickel

Until the time you transferred custody of sample A, B, C
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
✓ NO

If YES, please explain:

Signature P-JOE REID

DNV GL USA, Inc.
Materials & Corrosion Technology Center
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Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnvgl.com

DNV·GL

CHAIN OF CUSTODY FORM

Project No.: 10206282 Sample: 24" Ø Denbury

1. ORIGINATING LOCATION	
Contact Person: Greg Quickel	*Phone No.:* 614 378 4083
Title: Principal Eng	*Date:* 9/30/2020
Contact Address: See above	
Material Location, City, State:	
Signature: [signature]	*Date:* 9/30/2020

Description of Evidence	Date Evidence Placed into Controlled Custody:
24" Ø Denbury Failure	
Four pipe sections	
One box of samples (met/FS.)	Date Evidence Released from Controlled Custody: 9/30/2020
Two bags of soil from pipe	
Five steel coupons for mech testing	
Two bags of mech specimens	
	Release of Evidence Authorized by: [signature]
Received by:	

	Date	Time
Signature: [signature] Reason: TRANSFER	9/30/20	
Signature: _____ Reason: _____		
Signature: _____ Reason: _____		

Appendix F

Welding Procedure Development and Qualification for X80 Line Pipe

8/13/2008

FINAL REPORT

PROJECT CONSULTING SERVICES, INC.

WELDING PROCEDURE DEVELOPMENT AND QUALIFICATION FOR X80 LINE PIPE

PROJECT NO. 82681591
AUGUST 13, 2008

DET NORSKE VERITAS

FINAL REPORT

Date of Issue:
August 13, 2008

Project No.:
82681591

CC TECHNOLOGIES, INC.
Integrity & Materials

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Welding Technology

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Approved By:
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Senior Vice President
Integrity & Materials

Client:
Project Consulting Services, Inc.

Summary:

CC Technologies, Inc. (CCT) was retained by Project Consulting Services, Inc. to develop and qualify welding procedures for 24 inch by 0.54 inch grade X80 line pipe. Several different production, repair, and in-service procedures were developed. These procedures were run at a Progressive Pipeline Inc. facility in Meridian, Missipppi under the supervision of a representative from CCT. The welds were sent to an independent laboratory for destructive testing. CCT then created welding procedure specifications and procedure qualification records for welds that passed all testing.

Project No:	Subject Group:	Date :	Number of Pages:
82681591	Welding Technology	August 13, 2008	6

Report Title:

Welding Procedure Development and Qualification for X80 Line Pipe

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FINAL REPORT

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Appendix B. Letter Report Pertaining to the Use of Cellulosic-Coated Electrodes for X80 Pipelines

FINAL REPORT

1. PROJECT SCOPE

CC Technologies, Inc. (CCT) was contracted by Project Consulting Services Inc. (PCS) to create and qualify welding procedure specifications (WPS) and procedure qualification records (PQR) for the construction of two 24-inch diameter x 0.54 inch wall thickness, API 5L-X80-PSL2 pipelines as per the requirements of the 19th and 20th editions of API 1104. A variety of procedure qualifications were performed so as to give PCS's client, Denbury Resources Inc. (DRI), options when selecting welding processes and consumables for construction. CCT was also asked to use their welding experience and expertise to identify the most appropriate welding procedures for the construction, maintenance, and repair of these pipelines. Procedure qualifications were performed using welding consumables and process that were suggested by PCS/DRI and using welding consumables and process that were determined by CCT to be acceptable alternatives to those suggested by PSC/DRI.

2. WORK PERFORMED

CCT attended a project kick off meeting in Birmingham, Alabama on April 2, 2008 at the PCS office. The goal of this meeting was to discuss what consumables to use for the construction of two new X80 pipelines that will operate in carbon dioxide service. When welding higher strength line pipe material such as X80, several concerns need to be addressed including weld strength level and the risk of weld metal hydrogen cracking.

In most welding applications, including pipeline girth welding, it is desirable for the weld to overmatch the strength of the base material. This ensures that the strains caused by loads imposed on the completed structure do not concentrate in the vicinity of the weld. Welds are more likely to contain discontinuities than base materials, so it is desirable to avoid the concentration of strains in the vicinity of welds. A letter report pertaining to the use of welding consumables and process that were suggested by DRI for construction of these pipelines, from the prospective of weld strength level, is shown in Appendix A.

There are three requirements for hydrogen cracking; hydrogen in the weld, a crack-susceptible weld microstructure, and tensile stresses acting on the weld. Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. Traditionally, heat-affected zone (HAZ) microstructures have been considered to be the most susceptible to hydrogen cracking. With the introduction of higher strength line pipe steels with good weldability, and the higher strength welding consumables required to weld them, weld metal microstructures are now as susceptible (if not more so) than HAZ microstructures. A letter report pertaining to the use of cellulosic-coated electrodes for construction of these pipelines, from the prospective of hydrogen cracking risk, is shown in Appendix B.

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CCT was asked to provide alternatives to traditional cellulosic-coated electrodes in the form of low-hydrogen consumables and processes. CCT provided several low-hydrogen alternatives to be qualified along with cellulosic-coated electrode procedures requested by DRI. These procedures were qualified, documented, and the completed WPS's and PQR's delivered to PCS.

The procedure qualifications were performed at a Progressive Pipeline Inc. facility in Meridian, Mississippi. A CCT employee was onsite during procedure qualification to provide support and record relevant welding parameters. The first round of welding procedure qualifications took place April 14 through 18, 2008. WPS 4 through WPS 11 (Table 1) were conducted during this first round of welding. A typical setup for these procedures is shown in Figure 1. A 2 foot long length of pipe was welded onto a longer piece of pipe using an external lineup clamp. The preheat was applied using propane with rosebud torches. These welds were inspected by radiography before being sent for destructive testing to prevent incurring the cost of performing destructive testing on welds that may contain unacceptable discontinuities. A second round of procedures was performed at the same location May 12 through 17, 2008. The procedures performed in May were WPS 14 through WPS 20 (Table 1) and included two in-service repair procedures for the installation of a tight fitting Type B repair sleeve, as shown in Figure 3.

3. RESULTS

3.1 Pipeline Girth Welding

A total of 12 procedures were qualified, a complete list of the procedures can be found in Table 1. The low-hydrogen procedures are WPS 7 through WPS 11 and WPS 17 through WPS 20. All of the other procedures involve the use of cellulosic-coated electrodes exclusively. Except for the in-service procedures (WPS 19 and 20), all of the procedures use cellulosic-coated electrodes for the root pass and the hot pass. For pipeline girth welding on thicker-wall X80 line pipe material, it is typically acceptable to use cellulosic-coated electrodes for the root and hot pass in conjunction with low-hydrogen consumables for the fill and cap passes. This is permissible because the heat from the fill and cap passes allows the hydrogen from the first two passes to diffuse out of the weld.

Three different types of low hydrogen consumables were used; low hydrogen down-hill stick electrodes (AWS EXX45-type), traditional up-hill low-hydrogen stick electrodes (AWS EXX18-type) and gas-shielded flux-cored arc welding wire (AWS E101T1-type). These consumables were used with the manual shielded metal arc welding (SMAW) process and the semi-automatic flux-core arc welding (FCAW) processes, respectively. Traditional vertical up low-hydrogen electrodes (E10018-G H4R) were used for a single repair procedure, WPS 11. Two different strength levels of the low hydrogen down-hill electrode (E9045 P2 H4R and E10045 P2 H4R) were used during the first set of welding trials. These strength levels represent the minimum ultimate tensile strength of the consumable. After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line

pipe material, which has a yield strength approaching 100 ksi. During the second round of procedure qualifications the E10045 P2 H4R electrodes were the only low hydrogen down-hill electrodes used.

3.2 In-Service Welding

When qualifying welding procedures to be used on pipelines that are in-service, it is good practice to simulate in-service operating conditions. This is important because of the effect that the flowing contents in the pipeline has on the weld cooling rate. The flowing contents act as a heat sink when welding onto the carrier pipe, which causes the weld to solidify and cool extremely quickly. This in turn can promote the formation of crack-susceptible weld microstructures and cause large amounts of hydrogen to become trapped in the weld, if good low hydrogen welding techniques are not used. It is therefore critical to use welding processes and consumables that produce welds with a low amount of diffusible hydrogen.

For this reason, only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were used. Notice the "H4R" designation at the end of the consumable specification in column 5 of Table 1. The "H" stands for hydrogen, the "4" stands for a maximum of 4 ml of hydrogen per 100 grams of deposited weld metal, and the "R" means the consumable is resistant to absorbing moisture from atmospheric conditions.

The setup used for the in-service welding procedure qualification can be seen in Figure 4. To create this testing rig, a section of pipe is enclosed by welding end caps to the open ends. A nozzle for an ordinary garden hose is installed on both ends of the vessel. This allows water from the faucet to flow through the pipe section while welding is performed. A valve was installed on the top of the pipe close to the end where the water exits to allow for air to be vented, ensuring the pipe is completely full of water. That end of the pipe was slightly elevated, which ensures that no air bubbles become trapped along the top of the pipe. Water flow was maintained during welding and continued until the welds cooled to room temperature.

3.3 Documentation

WPS and PQR combinations for each of the procedures that passed destructive testing were provided to PCS.

FINAL REPORT

Table 1. Qualified Welding Procedures Specifications.

Procedure	Type	Root Pass Consumable Specification	Hot Pass Consumable Specification	Fill and Cap Pass Consumable Specification
WPS 4	Production	E6010	E9010-G	E9010-G
WPS 7	Production	E6010	E9010-G	E9045 P2 H4R
WPS 8	Repair	E6010	E9010-G	E9045 P2 H4R
WPS 9	Production	E6010	E9010-G	E10045 P2 H4R
WPS 10	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 11	Repair	E6010	E9010-G	E10018-G H4R
WPS 14	Production	E6010	E9010-G	E10045 P2 H4R
WPS 15	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 16	Repair	E6010	E9010-G	E9010-G
WPS 17	Production	E6010	E9010-G	E101T1-GM-H8
*WPS 19	Sleeve	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
*WPS 20	Sleeve	E101T1-GM-H4R	E101T1-GM-H4R	E101T1-GM-H4R

*In-service weld.

FINAL REPORT

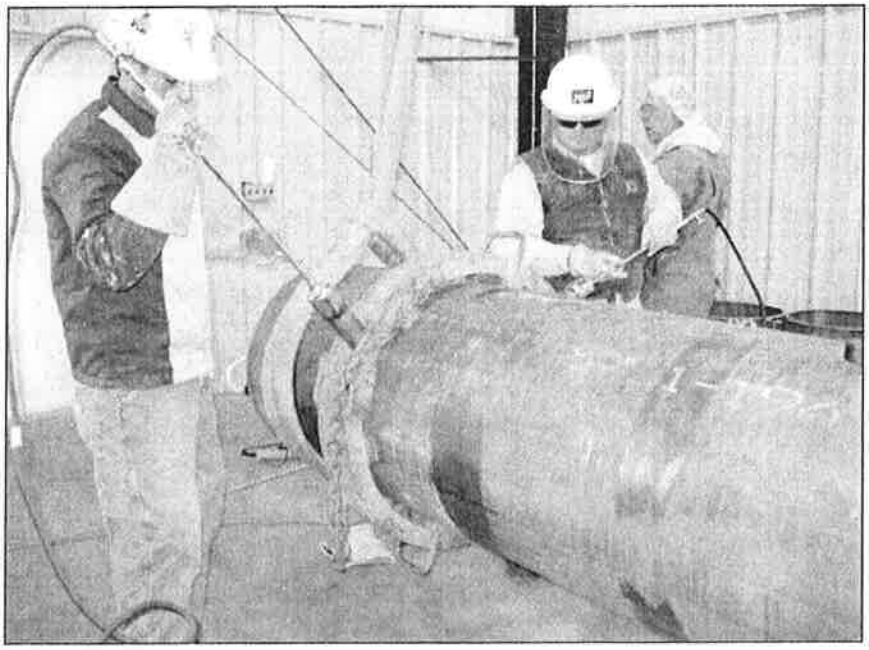


Figure 1. Typical setup for girth weld procedure qualification.



Figure 2. Typical completed girth weld coupon after cutting.

FINAL REPORT



Figure 3. In-service tight-fitting repair sleeve.

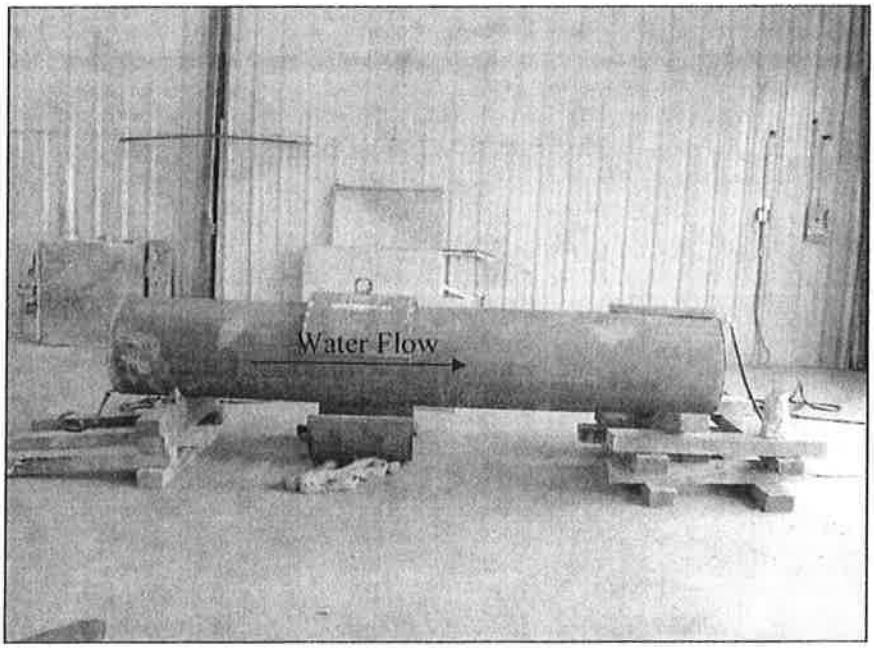
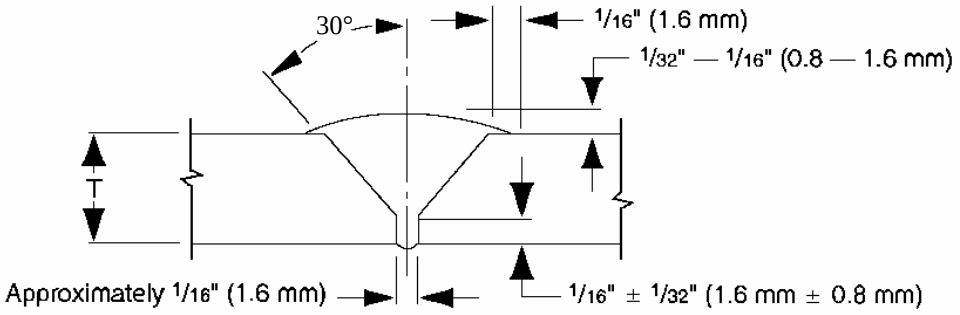
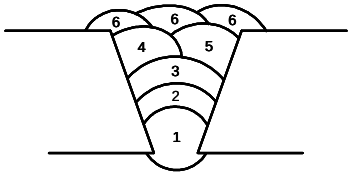


Figure 4. Setup for in-service welding procedure qualification.

Appendix G

Welding Procedure Specification WPS 14

6/18/2008

Scope of Procedure	This welding procedure specification details the procedure to be followed for the production of field butt welds in line pipe as required by the 19th and 20th editions of API 1104, Welding of Pipelines and Related Facilities			
Applicable Codes and Specifications	■ 19th & 20th Editions of API 1104 ☐ DOT 49 CFR Part 195 ☐ DOT 49 CFR Part 192	☐ ASME B 31.3 ☐ ASME B 31.4 ☐ ASME BPVC Section IX	☐ ASME B 31.8	
Supporting PQR	PQR: PQR-14a		Date Qualified: 5/14/08	
	Witnessed By: Brad Etheridge		Location: Meridian, Mississippi	
Materials	Grades Qualified	X80	PQR Material	API 5L – X80 - PSL2
	Qualified Diameter Range	All	Diameter of PQR	24 inches
	Qualified Wall Thickness Range	from 0.188" through 0.750"	Wall Thickness of PQR	0.54 inches
API 1104 Material Groupings Qualified	Diameter (inch)	☐ OD < 2.75 ☐ 2.75 < OD ≤ 12.750 ■ OD ≥ 12.750		
	Wall Thickness (inch)	☐ WT < 0.188 ■ 0.188 ≤ WT ≤ 0.750 ☐ WT > 0.750		
	SMYS (psi)	☐ ≤ 42,000 ☐ 42,000 < SMYS < 65,000 ■ ≥ 65,000		
Joint Design				
Position of Pipe Axis	■ Horizontal (1G or 5G) ☐ Vertical (2G) ☐ Inclined (6G)	■ Fixed ☐ Rolled	Generic Bead Sequence 	
Minimum Number of Welders	☐ One ■ Two ☐ Other			
Line Up Clamp	Type: External or Internal	A minimum of 50% the root bead must be completed before removal of the clamp.		
Preheating	Gas torch, electric induction coils, or any other company approved method. Verify temperature using company approved method	Preheat Temp. Min.	200℉	
		Interpass Temp. Max.	N/A	
		Interpass Temp. Min.	200℉	

Time Between Passes	Root and Hot	5 minutes	Hot and First Fill		24 hours
Cleaning	The use of both hand and power tools is acceptable. The base material should be free of scale or anything else that may impede welding before the start of any welding. Each pass should be thoroughly cleaned and free from slag and spatter before the next pass is made.				
Defect Removal	The only area that may be repaired is the weld cap. Other repairs are to be addressed by qualified repair welding procedures. Defects in the cap should be removed by grinding and welding shall follow the guidelines set forth in this procedure.				
Post Weld Heat Treatment	☐ Yes ■ No				

Welding Pass	Root Bead	Hot	1st Fill	Fill(s)	Cap(s)
Welding Process	SMAW	SMAW	SMAW	SMAW	SMAW
Manual or Automatic	Manual	Manual	Manual	Manual	Manual
Direction of Welding	Vert. Down	Vert. Down	Vert. Down	Vert. Down	Vert. Down
Shielding Gas	N/A	N/A	N/A	N/A	N/A
Flow Rate	N/A	N/A	N/A	N/A	N/A
Wire Feed Speed	N/A	N/A	N/A	N/A	N/A
Deposition Type	Stringer	Stringer/Weave	Weave	Weave	Weave
Technique	Backhand	Backhand	Backhand	Backhand	Backhand
Filler Manufacturer	Lincoln	Lincoln	Lincoln	Lincoln	Lincoln
Filler Trade Name	Fleetweld 5P+	Shield-Arc 90	LH-D100	LH-D100	LH-D100
AWS Group	1	2	3	3	3
AWS Specification	A5.1	A5.5	A5.5	A5.5	A5.5
AWS Classification	E6010	E9010-G	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
Polarity	DCEP	DCEP	DCEP	DCEP	DCEP
Electrode Diameter(s)	1/8"* or 5/32"	5/32"	5/32"	5/32"	5/32"
Arc Voltage (V)	20 - 32	20 - 30	18 - 26	18 - 26	18 - 26
Current Range (Amp)	100 – 150* 110 - 170	110 - 170	150 - 230	150 - 230	150 - 230
Travel Speed Range (inch/min)	5 – 15	5 – 15	5 – 20	5 – 20	5 – 20

Minimum number of Passes	Wall Thickness Range (in)	Number of passes	Minimum does not include stripper passes or split caps.
	≤ 0.188	3	
	> 0.188 to 0.25	4	
	> 0.25 to 0.50	5	
	> 0.50 to 0.750	7	

Notes	Weave the hot pass as necessary to prevent wagon tracks. Stripper passes are optional. Either a two or three bead cap is acceptable.		
Submittal	Author: Brad Etheridge	Title: Welding Engineer	
	Company: CC Technologies Inc. A DNV Company		Date: 5/30/08

Owner Approvals	Title	Name	Signature	Date

Company Name: Progressive Pipeline	Date: 5/14/08	Notes: Welding machine used was a Lincoln Red-D-ARC, D300K 3+3 Diesel	
Project Number:	Location: Meridian, MS @ Progressive Pipeline facility		
PQR #: 14a	Inside/Outside: Inside, with open bay doors		
WPS #: 14	Temperature: 78 inside shop		
Coupon #:	Recorded by: Brad Etheridge		

#	Material	OD	WT	Length	Joint ID #	Heat #	Test Position	Horizontal	Time between root and hot			2:55
1	API 5L - X80 - PSL2	24	0.54	2 feet	L	8791-1940-06	Preheat Temp	200	Time between hot and first			
2	API 5L - X80 - PSL2	24	0.54	N/A	R	8791-1943-06	Clamp Type	EXT	Start	9:41 AM	Stop	11:00 PM

Filler Metal #	Manufacturer	Trade name	Classification	Specification	Diameter	Batch/Lot #	Welder Information	
1	Lincoln	Fleetweld 5P+	E6010		5/32	11558962	Side A Welder	Randall Nunez
2	Lincoln	Shield-Arc 90	E9010	G	5/32	11558966	Welder Stamp	
3	Lincoln	LH-D100	E10045	P2 H4R	5/32	Lot Q2 863C	Side B Welder	Ken Abernathy
4							Welder Stamp	

Notes: External linup clamp used to tack 2 foot coupon onto long joint. The short side of the coupon is "R" and the long side is "L". Pass 2 and 3 were split passes; they were placed side by si

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Root A	1	SMAW	VD	116	22	6	33	10.91		13.7			S			
Root A	1	SMAW	VD	118	23	2.25	14	9.64		16.5			S			
Root A	1	SMAW	VD	107	24	8	45	10.67		14.1			S			
Root B	1	SMAW	VD	128	23	9	54	10.00		17.3			S			
Root B	1	SMAW	VD	137	24	2.5	16	9.38		21.0			S			
Hot A	2	SMAW	VD	141	29	8	32	15.00		16.0			S/W			
Hot B	2	SMAW	VD	138	30	6	36	10.00		24.3			S/W			
Hot B	2	SMAW	VD	136	30	6	36	10.00		24.1			S/W			
Fill 1-1 A	3	SMAW	VD	194	22	7	50	8.40		30.4			S/W			
Fill 1-2 A	3	SMAW	VD	218	21	8.5	46	11.09		24.8			S/W			
Fill 1 A	3	SMAW	VD	208	24	13	51	15.29		19.2			S/W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Fill 1-1 B	3	SMAW	VD	198	20	6.5	48	8.13		28.4			S/W			
Fill 1-3 B	3	SMAW	VD	216	20	8.5	48	10.63		24.4			S/W			
Fill 2-1 A	3	SMAW	VD	199	22	8.5	48	10.63		24.1			S/W			
Fill 2-3 A	3	SMAW	VD	215	20	8	43	11.16		23.1			S/W			
Fill 2-1 B	3	SMAW	VD	205	21	8.75	55	9.55		26.4			S/W			
Fill 2-2 B	3	SMAW	VD	199	20	12	55	13.09		17.8			S/W			
Fill 3-1 A	3	SMAW	VD	197	22	8.5	51	10.00		25.4			S/W			
Fill 3-3 A	3	SMAW	VD	176	21	8	35	13.71		16.1			S/W			
Fill 3-1 B	3	SMAW	VD	196	20	7.5	49	9.18		25.6			S/W			
Fill 3 B	3	SMAW	VD	201	20	8.75	49	10.71		21.9			S/W			
Fill 4-1 A	3	SMAW	VD	195	20	8	46	10.43		22.4			S/W			
Fill 4-3 A	3	SMAW	VD	215	20	9	36	15.00		17.2			S/W			
Fill 4-1 B	3	SMAW	VD	184	21	8.5	45	11.33		20.4			S/W			
Fill 5-1 A	3	SMAW	VD	195	21	8	42	11.43		21.4			S/W			
Fill 5 A	3	SMAW	VD	212	20	9	34	15.88		16.0			S/W			
Fill 5-1 B	3	SMAW	VD	205	20	13.5	53	15.28		16.1			S/W			
Fill 5 B	3	SMAW	VD	198	20	9.5	49	11.63		20.4			S/W			
Cap 1 A	3	SMAW	VD	205	20	7	42	10.00		24.6			W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Cap 1 A	3	SMAW	VD	208	20	9.5	58	9.83		24.8			W			
Cap 1 B	3	SMAW	VD	198	20	9	37	14.59		16.3			W			
Cap 1 B	3	SMAW	VD	214	20	8	33	14.55		17.6			W			
Cap 2 A	3	SMAW	VD	201	20	7.5	44	10.23		23.6			W			
Cap 2 B	3	SMAW	VD	207	20	10	46	13.04		19.0			W			
Cap 2 B	3	SMAW	VD	212	20	7	27	15.56		15.9			W			

Bodycote

Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No O802887 : Issue 1
Ord No 82681591

Date Tested 06/02/08
Date Reported 06/02/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Cross Weld Tensile - API 1104

	Dimensions [in]	Area [in^2]	UTL [lbs]	UTS [psi]	Fracture Location	Fracture Type
001:Cross Weld	0.9770x 0.5440	0.5315	61872.0	116400	Base	Ductile
002:Cross Weld	0.9720x 0.5400	0.5249	61559.0	117300	Base	Ductile
003:Cross Weld	0.9810x 0.5330	0.5229	60659.0	116000	Base	Ductile
004:Cross Weld	1.0170x 0.5400	0.5492	63462.0	115600	Base	Ductile

Item 01: Quad 1
Item 02: Quad 2
Item 03: Quad 3
Item 04: Quad 4

Charpy Test - ASTM E 23

	Position	Dimensions [mm]	Denomination	Test Temp [°F]	Energy Absorbed [ft.lbf]	Average [ft.lbf]	Comments
005:Weld Centre Line	N/A	10x10x2V	N/A	32.0	79, 69, 70	72.7	See Below
006:Weld Centre Line	N/A	10x10x2V	N/A	-50.0	45, 39, 29	37.7	See Below
007:Weld Centre Line	N/A	10x10x2V	N/A	-80.0	15, 31, 14	20.0	See Below

Item 05: Percent Shear: 85, 80, 75 / Mils Lat Exp: 58, 53, 46
Item 06: Percent Shear: 25, 35, 10 / Mils Lat Exp: 33, 25, 21
Item 07: Percent Shear: 10, 20, 10 / Mils Lat Exp: 12, 24, 14

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [°]	Former Dia	Result	Comments
008:Face Bend	Quad 1	.500	180	3.5"	Acceptable	Nil

This certificate should not be reproduced other than in full, without the written approval of Bodycote Testing Group, Inc.
These results pertain only to the item(s) tested as sampled by the client unless otherwise indicated.

Bodycote

Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

CC Technologies, Inc.
24" OD x 1/2" Wall girth welded pipe sample
WPS 14

REF No O802887 : Issue 1

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [°]	Former Dia	Result	Comments
009:Face Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
010:Face Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
011:Face Bend	Quad 4	.500	180	3.5"	Acceptable	Nil
012:Root Bend	Quad 1	.500	180	3.5"	Acceptable	Nil
013:Root Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
014:Root Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
015:Root Bend	Quad 4	.500	180	3.5"	Acceptable	Nil

Nick Break Test - API 1104

	Result	Comments
016:Weld	Unacceptable	Quad 1
017:Weld	Acceptable	Quad 2
018:Weld	Acceptable	Quad 3
019:Weld	Unacceptable	Quad 4

Approved By **Jim Blevins**

Jim Blevins
For and on authority of
Bodycote Testing Group

The failed two nick break tests were replaced by four acceptable retests of adjacent specimens. This is common practice in welding procedure qualification testing. The retest results can be found on the next page.

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These results pertain only to the item(s) tested as sampled by the client unless otherwise indicated.

Page 2 of 2

Bodycote MATERIALS TESTING
METAL TECHNOLOGY
Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

Test Certificate

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No O803170 : Issue 1
Ord No 82681591

Date Tested 06/09/08
Date Reported 06/09/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Nick Break Test - API 1104		
	Result	Comments
001:Weld	Acceptable	Quad 1
002:Weld	Acceptable	Quad 1
003:Weld	Acceptable	Quad 4
004:Weld	Acceptable	Quad 4

Certificate Comments

This is an electronic copy. See original certificate for photographs and figures where referenced.

Approved By Jim Blevins

Kevin J. Elliott
For and on authority of
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Appendix H

Stress Analysis Report

Denbury Delta Pipeline Repair

7/28/2020

Denbury

MOTT MACDONALD

Document No. 20200724_MM_507102444_Pipeline Stress Analysis Report_EN_0015

PIPELINE STRESS ANALYSIS REPORT
DENBURY GULF COAST PIPELINES, LLC

DELHI PIPELINE REPAIR PROJECT

SATARTIA, MISSISSIPPI

Issue and Revision Record					
Rev	**Date**	**Originator**	**Checker**	**Approver**	**Description**
A	06/12/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Draft
B	07/27/20	D. Dowling, PE	R. Sprague	R. Spence, PE	For Review
C	07/28/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Final

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1 EXECUTIVE SUMMARY

Mott MacDonald (MM) has performed a stress analysis on the piping associated with the Delhi Pipeline incident/release on February 22, 2020. The piping was modeled using dimensions from Denbury supplied as-built records and Mott MacDonald survey data using AutoPIPE CONNECT Advanced Edition 12.02.00.14. The model was analyzed utilizing a combination of stress engineering methodologies and computational stress analysis.

Mott MacDonald performed a site-specific soil movement analysis that was used to establish soil loading on the pipeline for the stress analysis Utilizing guidance presented in the American Lifelines Alliance (guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors.

The mitigation procedure involved the identification and evaluation of critical areas against code allowable stress combinations. The results were compared using the stress ratio experienced by the component. A stress ratio greater than 1.0 represents components exhibiting stresses greater than the allowable stresses per ASME B31.4 (2016).

The following stress conditions were evaluated in the stress analysis:

- Load Cases
- Code Combinations
- Non-Code Combinations
- Thermal Analysis
- Soil Spring Analysis
- Soil Settlement Analysis
- Thermal Displacement

The geotechnical properties simulated within the models were reflective of the soil spring results presented in Section 7.2. Based on the models developed for this analysis, it is apparent that the soil movement present at the incident location was capable of exerting forces on the pipeline that exceed allowable limits. Mott MacDonald has reviewed the stress results with Denbury and developed solutions for the repair of the pipeline.

2 PROJECT DESCRIPTION

On February 22, 2020 the 24" CO2 Delhi Pipeline ruptured near a crossing of Mississippi Highway 433 approximately 1 (one) mile southeast of Satartia, MS. To help evaluate the cause of the release, Denbury contracted Mott MacDonald to gather information to support a thorough investigation. Mott MacDonald collected drone photogrammetry, terrestrial LIDAR and contracted PSI to perform a geotechnical investigation. Using this information Mott MacDonald performed a nodal evaluation using Bentley AutoPIPE CONNECT Advanced Edition Version 12.02.00.14 to determine stresses from external loading near the release of the Delhi Pipeline.

3 SCOPE

The stress model reflects the design of the project drawings and as-built information. The models were further analyzed using the various code and non-code guidelines listed in this section. These load combination guidelines can be generally categorized as follows:

- Hoop
- Sustained
- Occasional
- Expansion
- Combined Stress
- Unrestrained
- Support Loads

3.1 LOAD COMBINATIONS

Mott MacDonald analyzed the following code combinations as required by ASME B31.4. The loads are listed in Table 1 and 2 shown below. For allowable stress limits definition, see Appendix A.

Table 1 – Code Combinations

Case No.	Load Case Combinations	Category	Load Description
1	Max P	Hoop	Hoop Stress; ASME B31.4 Para. 402.3.5
2	GR + Max P	Sustained	Stress due to Sustained Loads; ASME B31.4 Para 402.6
3	Amb to T1	Expansion	Thermal stress range from restraint temp to the maximum temperature; ASME B31.4, Para. 402.5
7	Max Range	Expansion	Thermal stress range from the minimum temp to the maximum temperature (refer to all combinations); ASME B31.4, Para. 402.5
8	SUS + U1	Sustained	Stress due to Sustained Load and Soil Settlement; Sustained ASME B31.4, Para. 402.6

4 DESIGN INPUTS AND RESOURCES

The following resources and reports were utilized to provide design information and engineering inputs to various portions of the stress calculations and analysis:

Codes, Standards and Regulations - Applicable Federal, Provincial and Territorial Regulations, Codes and Bylaws – Latest Edition

1. ASME B31.4, Pipeline Transportation Systems for Liquids and Slurries
2. Federal Energy Regulatory Commission (FERC), Onshore Pipeline Regulations

External References

1. 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline
2. American Lifelines Alliance, Guidelines for the Design of Buried Steel Pipe, 2001
3. Peng, L.-C., & Peng, T.-L. (2009). Pipe Stress Engineering. New York, NY: The American Society of Mechanical Engineers.

The Project Data Sheet (Table 3) and additional variables (Table 4) defined below contain the design information and engineering inputs that were used for the stress calculations and analysis:

Table 3 – Project Data Sheet Variables

General Project Information			
Project Name:	Delhi Pipeline Repair Project	**Project No:**	507102444
Description:	Pipeline Repair Project		
Pipeline Data			
General Location	Satartia, MS		
MOP [psig]	2160		
Maximum Operating Temperature [˚F]	Maximum: +120˚F		
Pipe Data	API 5L 24" – 0.469" W.T., X80		
	API 5L 24" – 0.540" W.T., X80		
Pipeline Data			
Minimum Operational Design Temperature [˚F]	Above grade:	32˚F	
	Below grade:	70˚F	
Design Temperature [˚F]	Minimum:	-20˚F	
	Maximum:	120˚F	
Pipe Installation Temperature [˚F]*	60˚F		

* Based on average low temperature for this region during the month of construction.

5 ANALYSIS ASSUMPTION SUMMARY

The facility stress analysis was carried out using the following assumptions.

- Minimum Installation temperature of 60˚F.
- All welds connecting assembly piping are defect free
- Pipe is homogeneous and does not contain defects.
- Strains due to welding were ignored for this analysis.
- Bolt up strains are negligible.
- Small bore attachments do not govern the design.
- Dynamic Fluid loads were ignored for this analysis.
- Pressure and viscous drag effects were ignored for this analysis.
- All dynamic loads applied internally/externally were minimal.
- All material properties were assumed to be linear and elastic.
- Soil is represented by discrete linear elastic perfectly plastic springs.
- Welded branch connections consist of an ASME B31.4 listed fitting and is constructed with adequate strength.

6 PROJECT ANALYSIS

6.1 SOILS

Soil data used for the analysis was taken from soil bore samples provided by Intertek-PSI USA. For each USCS soil type, average values were developed for the peak and remolded undrained shear strengths and typical values were used for the soil densities. This data was applied to all below grade piping by centering the soil blocks at each of the shear vane locations. American Lifelines Alliance (ALA) soil spring calculations were generated manually using the ALA formulas at a depth appropriate for the location and spacing appropriate for the pipe size. The soil spring summary is included in Table 4.

Table 4 – Soil Spring Summary			
Stiff Clay – Under Road (SCUR)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**1000**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	5780.82	13873.96	2.4
Longitudinal	14566.52	4369.96	0.3
Trans. Vertical Up	4166.67	20000	4.8
Trans. Vertical Dn	2643.55	12689.02	4.8
Soft Clay – Embankment (SOE)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**250**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	920.34	3313.22	3.60
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	833.33	4000	4.80
Trans. Vertical Dn	871.78	4184.57	4.80
Soft Clay – Landside Edge (LSE)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**200**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)

Trans. Horizontal	657.98	2470.98	3.76
Longitudinal	3171.19	1268.48	0.40
Trans. Vertical Up	416.67	2000.00	4.8
Trans. Vertical Dn	639.78	3070.94	4.8
Stiff Clay – Outside Landslide (OLS)			
Total Unit Weight below pipe (lb/ft³)		**100**	
Dry Unit Weight above pipe (lb/ft³)		**97**	
Effective Unit Weight above pipe (lb/ft³)		**100**	
Soil Cohesion (psf)		**250**	
Friction Angle (deg)		**0**	
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	1072.47	3088.72	2.88
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	520.83	2500.00	4.80
Trans. Vertical Dn	746.79	3584.57	4.80

6.2 ENVIRONMENTAL LOADING

During the initial site visit, Mott MacDonald noticed evidence of soil movement along the ROW. The soil failure planes in the ROW extended approximately 900 ft at varying angles from 45˚ to 90˚. Figure 1 and Figure 2 below show 3D photogrammetry scans taken of the ROW and displays the long linear failures.



FIGURE 1: SOIL MOVEMENT PLAN VIEW



FIGURE 2: SOIL MOVEMENT ROW VIEW

The depth of the soil failures varied throughout the ROW, but as shown in Figure 3, the high level of detail captured with the 3D photogrammetry allowed for accurate measurements.

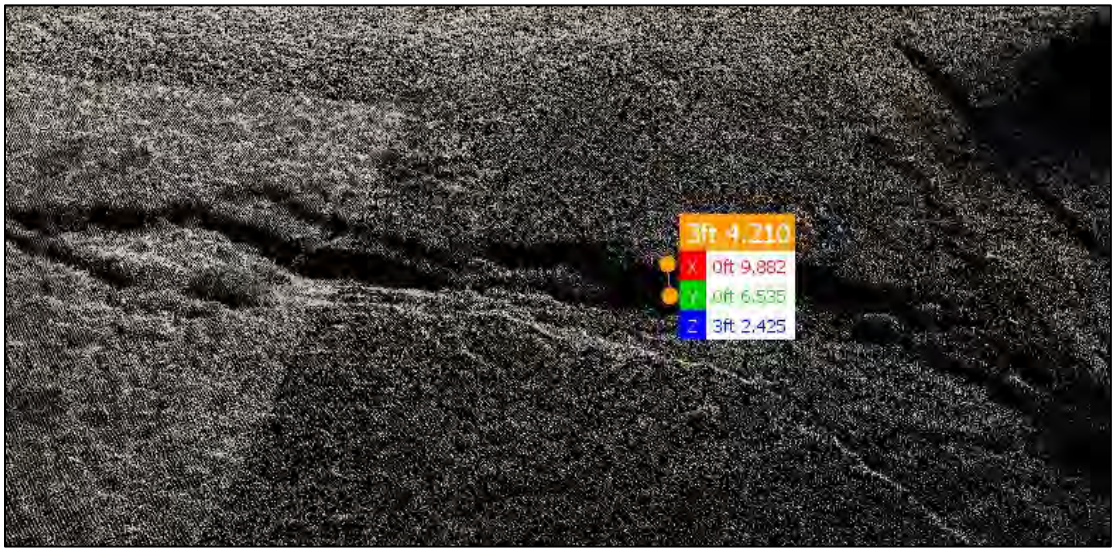

FIGURE 3: SOIL FAILURE DEPTH

To model the external force due to soil movement appropriately, Mott MacDonald's geotechnical team performed a soil movement analysis. Based upon information of the soil properties, pipeline burial depth and relative slope movement a calculation of the maximum earth pressure which could be applied to the pipe was developed. This value represents the maximum force per unit length which the soil could apply to the pipeline.

Note that this calculation method is applicable to small strain (pipe-soil localized strain) situations. Utilizing guidance presented in the American Lifelines Alliance

(guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors. This calculation resulted in a value of **2,800lb/ft** (force per foot length of pipe) being the maximum force the moving soil could apply to the pipeline at small strain. For this calculation, the following assumptions were made:

- Ground surface to spring line = 5ft
- Soil cohesion = 200 psf
- Soil angle of internal friction = zero
- Applied distributed load value = the maximum force per unit length of pipe that the soil could transmit to the pipe. This force may not have fully mobilized if pipe failed before sufficient earth strain occurred to reach this maximum force.
- Calculations follow American lifeline alliance, guideline for the design of buried steel pipe 2001 (B-2).

Utilizing the as-built data in conjunction with the photogrammetry, the Mott MacDonald team was able to provide varying environmental loading conditions for the pipeline. Table 6 below presents the soil classification (from geotechnical investigations performed by PSI), applied environmental loads and general soil description.

Table 6 – Environmental Loading

Station	Soil Classification	Applied Distributed Loads	General Description
361+00 -> 349+80	[A] Stiff Clay		Stronger soils restraining movements at boundary
349+80 -> 348+50	[B] Stiff Clay		Stronger soils with deep burial from highway embankment causing strong pipe restraint
348+50 -> 347+00	[C] Soft Clay		Softer soils down from highway embankment.
347+00 -> 346+50	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
346+50 -> 340+00	[E] Soft Clay [Horiz. Strength = 0]	2,800 lb/ft	Moving landslide body middle

340+00 -> 339+00	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
339+00 -> 338+50	[C] Soft Clay		Softer materials outside landslide body
339+00 -> 325+00	[A] Stiff Clay		Stronger soils restraining movements at boundary

The distributed loads were applied in the model based on understanding of the topography in the area as shown in the Figure 4 below.

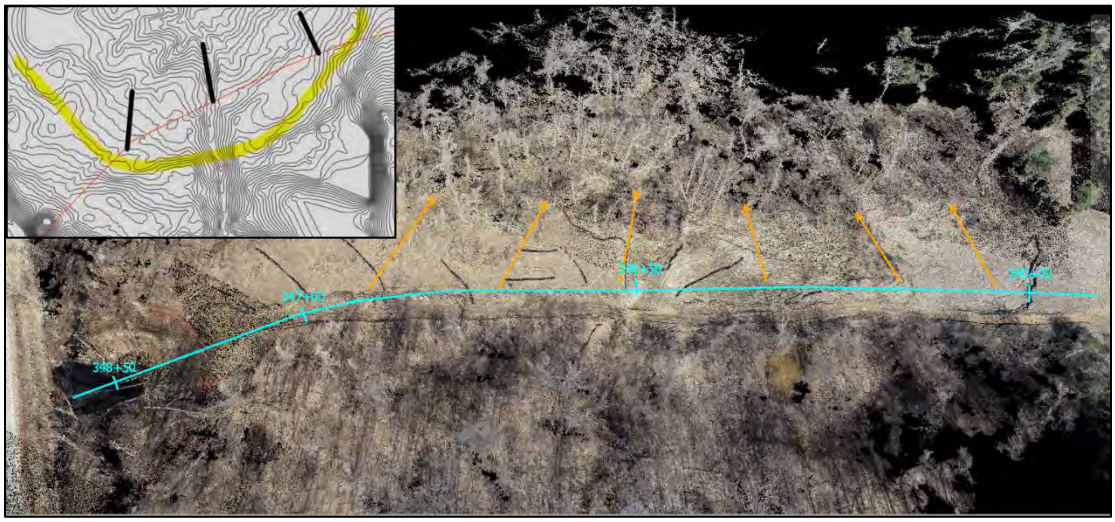

FIGURE 4: SOIL MOVEMENT DIRECTION

The external loads due to soil movement were applied per the list below.

- 347+00 -> 346+50 Azimuth 005 (5° east of north)
- 346+50 -> 340+00 Azimuth 350 (10° west of north)
- 340+00 -> 339+00 Azimuth 335 (25° west of north)

7 ANALYSIS RESULTS

7.1 PIPELINE ANALYSIS

The pipeline was modeled as per the above listed design information. Though not all of the model is shown the below Figure 5, Figure 6 and Figure 7 display the area of concern.

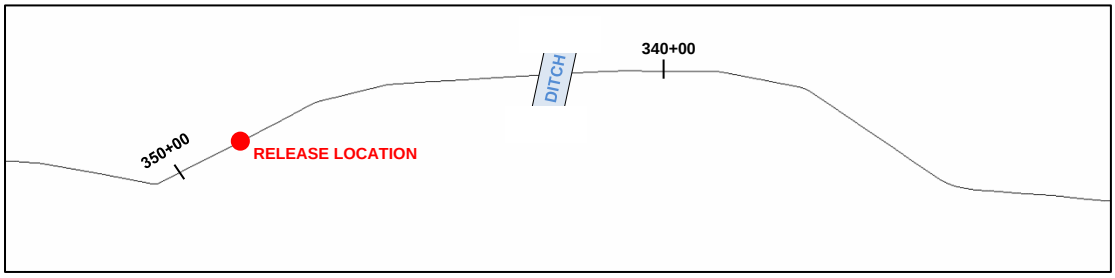

FIGURE 5: AUTOPIPE MODEL

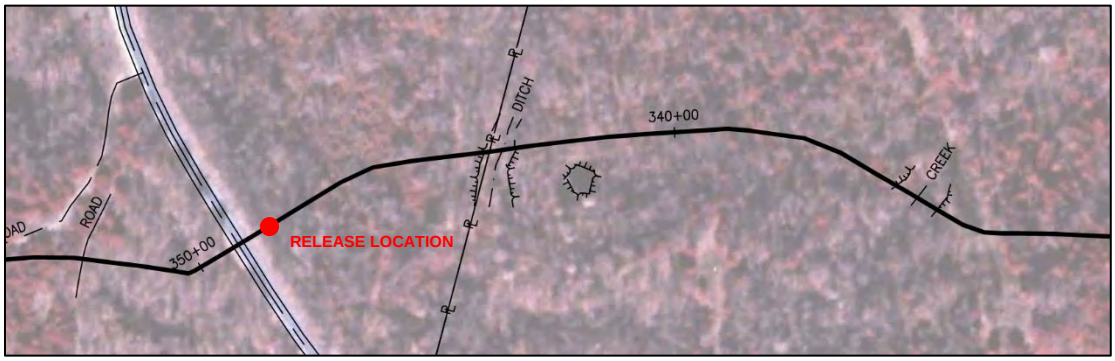

FIGURE 6: AS-BUILT ALIGNMENT SHEET

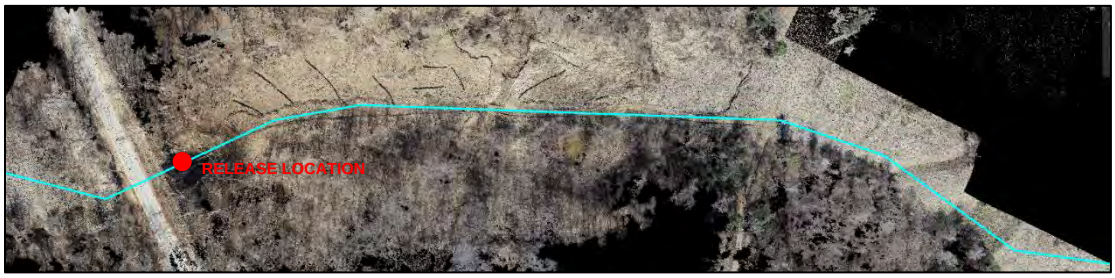

FIGURE 7: MODEL OVERVIEW

The road crossing utilized thicker pipe and was modeled as per the as-built alignment sheet, as shown in Figure 8.1.3.

- 24”–0.540 in – API 5LX–X80 – Cyan
- 24”–0.469 in – API 5LX–X80 – Red

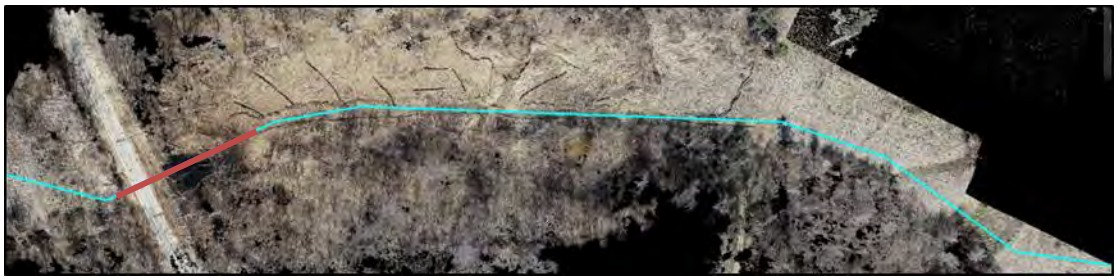

FIGURE 8: PIPE IDENTIFIER

Below shows the soil modeling based on the guidelines set forth in Section 7.1. The colors shown below denote the division in the soil as defined in Table 6.



FIGURE 9: SOIL IDENTIFIERS

The piping model was analyzed at low temperature limits defined by the project data sheet. At this location, the entire design was modelled at installation temperature, 60ºF. The effects of thermal expansion due to temperature within the pipeline as well as environmental changes are negligible.

The most significant stress values came from the external loading from soil movement. To establish a baseline, the stress team determined the maximum horizontal distributed load the pipe could withstand without rupture. Once the geotechnical team determined the estimated distributed loads, these numbers were compared. The comparison showed that the geotechnically determined loads exceeded the allowable horizontal distributed loads by more than 300 lbs/ft (2,800 lbs/ft vs. 2,475 lbs/ft).

As shown in Figure 10 below, the pipeline release location experienced excessive stress. The focal point of the stress at this location shows a maximum stress ratio of 1.43.

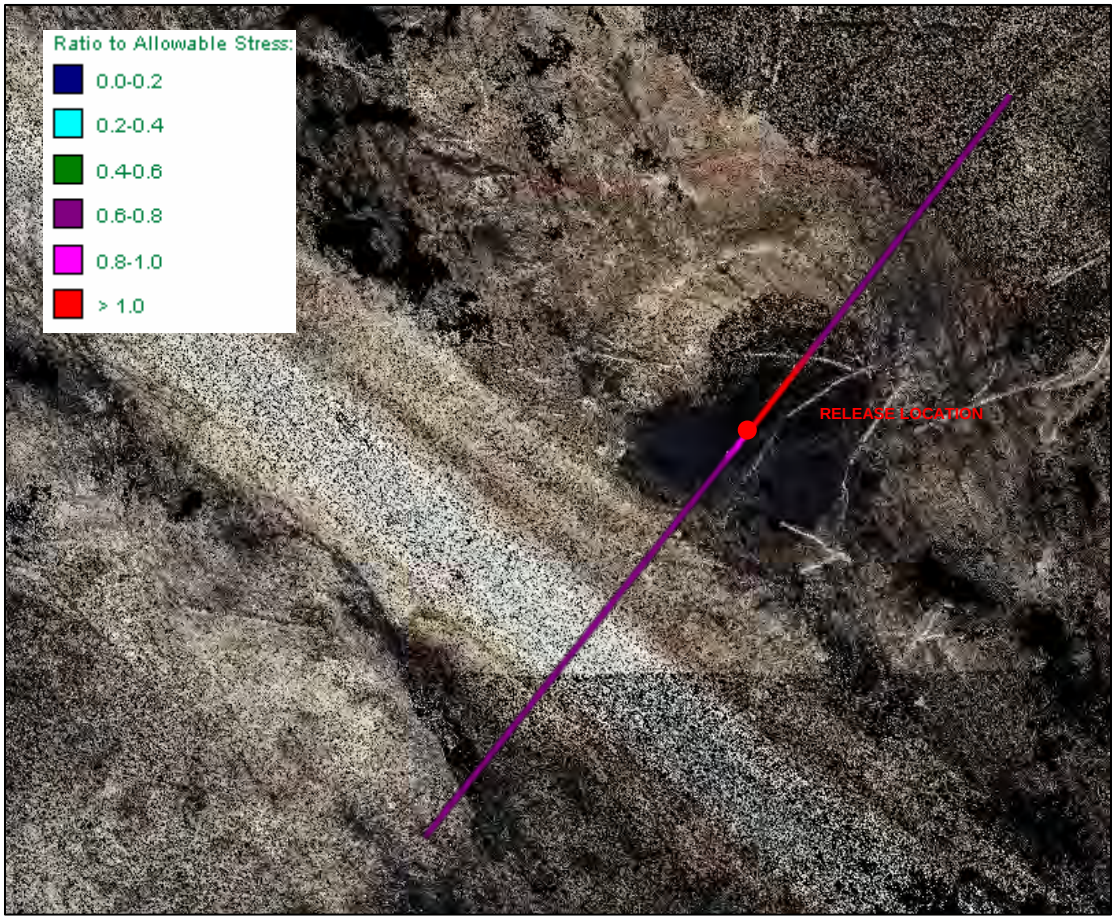

FIGURE 10: FAILURE LOCATION

At the release location, the pipe was calculated to have experienced load given in Table 7 below.

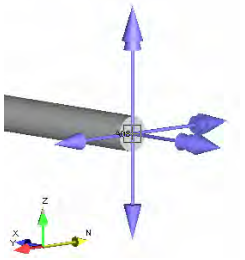

Table 7: Loads Experienced at Pipeline Release Location		
X-Direction	Y-Direction	Z-Direction
-848,020 lbf	7,229 lbf	-46483 lbf
-54,921 ft-lb	-706,996 ft-lb	36,274 ft-lb

Figure 11 below shows an exaggerated deflection curve of the pipeline.

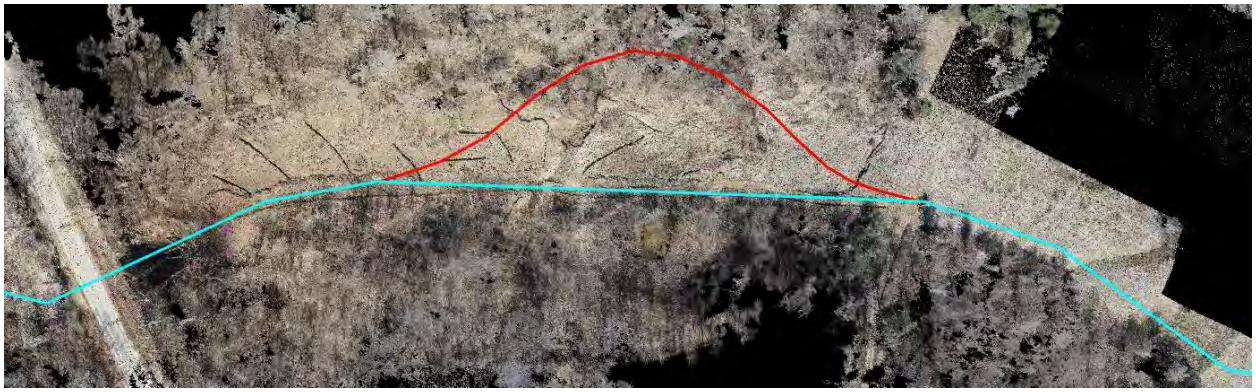

FIGURE 11: DEFLECTION CURVE

Mott MacDonald examined results as full design group to analyze the failure types and deflection curves. It was established that forces applied to the pipeline from the soil movement were significant enough to exceed the allowable stress limit of the Delhi Pipeline and likely was a contributing factor to the rupture.

8 CONCLUSION

Mott MacDonald performed a nodal analysis to analyze the Denbury Delhi Pipeline for stress concerns surrounding the rupture area. Key information (i.e. soil bores, topography, LIDAR scans) was gathered, interpreted and used in the evaluation.

The initial task performed by the stress team was to determine the maximum distributed load due to soil movement the pipeline could withstand under the given environmental conditions without exceeding the allowable stress. The results of this study found that at 2475 lb/ft certain areas began to exceed the allowable stress.

Utilizing the geotechnical investigation results and drone topography, the geotechnical team performed a soil movement analysis. The analysis concluded that the soil movement could project a load of 2800 lb/ft on the pipeline.

Under the provided 2800 lb/ft condition, the stress analysis showed the area of rupture on the Delhi Pipeline could have experienced stress ratios up to 1.43 or 43% greater than the allowable stresses under ASME B31.4 code.

The results of the analysis concluded that the soil movement found on the Delhi Pipeline Right-of-Way could induce axial stresses sufficient to cause an overload condition in the pipeline near the incident location.

9 RECOMMENDATION

Based on the results of the evaluation, Mott MacDonald recommends to stress relieve the pipeline by exposing approximately 135 feet of pipe near the opposing soil failure plane(at 339+00) then cut and replace a length of pipe.

The length of stress relieving area was determined by evaluating the over stressed model from the previous analysis. Using the deflection curve and stress ratio visuals in conjunction, the stress team identified a length of pipeline that exhibited a peak in stress values near the soil failure plane or at approximately 339+00.

On the upstream side of 339+00, the stress values decrease from 1.51 to 1.2 where they remained as it progressed upstream. These values are acceptable given these forces were due to axial stress and therefore were relieved when the pipeline failed.

The stress on the downstream side of 339+00 was caused by the restrained/unrestrained boundary condition created by the soil movement. This bending stress is the target of the relief exercise. The area shown in Figure 12 below, show a sharp rise in stress from a ratio of 0.70 to 1.51 in less than 50 ft. This boundary condition at the soil failure plane did not relieve after the pipeline failure and will have to be repaired.

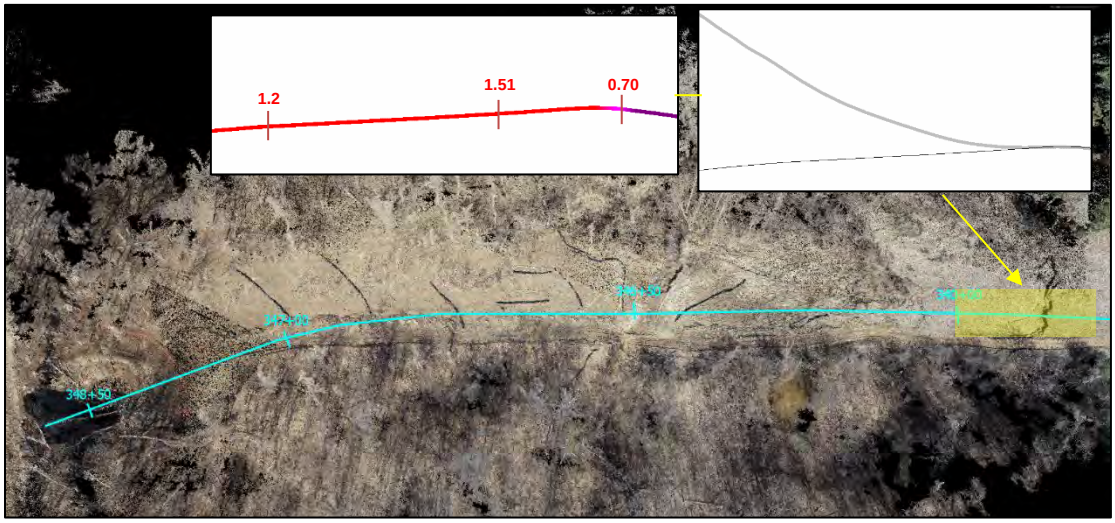

FIGURE 12: RECOMMENDED

Exposing at least 135 ft and removing and replacing as least a 10 ft section of pipe as recommended in the repair alleviates the overstressed boundary condition left by the soil movement and allows for safe transition between the two soil conditions. This recommendation is with the understanding that the remainder of the area of concern will be hydrotested as per ASME B31.4 to ensure the integrity of the pipe that experienced high tensile loads.

APPENDIX A: SUPPORTING INFORMATION

TEMPERATURE FOR SATARTIA, MS

History

September Data	Choose another month: September Submit		
Averages			
Average High Temperature	31 °C	Average Morning Relative Humidity	94%
Average Low Temperature	18 °C	Average Afternoon Relative Humidity	55%
Average Mean Temp	24 °C	Typical Sky Cover	CLR
Average Dew Point	19 °C	Average Precipitation (US Only)	91 mm
Average Windspeed	13 km/h	Average Snowfall (US Only)	0.00 cm
Average Wind Direction	SE		
Daily Counts			
Days With Precipitation	8	Days With Snow	0
Days With Thunderstorms	5	Days With Lows Below Freezing	0
Days With Fog	20	Days above 90° F (32.2° C)	12
Records			
Record High	40 °C	Record 24-hour Snowfall	0.00 cm
Record Low	2 °C	Record Monthly Rainfall	244 mm
Record Wind Speed	83 km/h	Record 24-hour Rainfall	117 mm
Record Monthly Snowfall	0.00 cm	Record Minimum Monthly Precipitation	15 mm

http://myforecast.co/bin/climate.m?city=21275&zip_code=39162&metric=true

ALLOWABLE STRESS LIMITS

HOOP STRESS

Hoop Stress (ASME B31.4 - 2016)

The hoop stress (Shoop) is calculated per A402.3.5

$$S_h = (P_i - P_e) \cdot \frac{D}{2t} \leq F_1 ST \quad (1)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D}{2000t}\right] \leq F_1 ST \quad (2)$$

$$S_h = (P_i - P_e) \cdot \frac{D-t}{2t} \leq F_1 ST \quad (3)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D-t}{2000t}\right] \leq F_1 ST \quad (4)$$

Where,

D is the nominal outside diameter of pipe, in. (mm)

F1 is the hoop stress design factor from Table A402.3.5-1

Pe is the external pressure, psi (kPa)

Pi is the internal pressure, psi (kPa)

S is the yield strength, psi (MPa)

Sh is the hoop stress, psi (MPa)

T is the temperature derating factor, found in the Results Model Options dialog

t is the nominal wall thickness, in. (mm)

Notes:
1. Equation 1 should be used if D/t is greater than or equal to 30. Equation 3 should be used if D/t is less than 30.
2. Equations 2 and 4 are the SI equivalents of equations 1 and 3, respectively.
3. In AutoPIPE, pressure data is gage pressure. In other words, $P_{AutoPIPE} = P_i - P_e$

SUSTAINED LOADS

Restrained

Calculations for restrained piping take into account flexibility and stress intensification factors of piping components. Longitudinal stress in restrained piping is calculated as:

$$S_L = S_E + \nu S_H \pm \frac{M}{Z} + \frac{F_a}{A}$$

Where sE is the restrained **thermal expansion stress**, sH is the **hoop stress** and A is the cross sectional area of steel.

When the "Use rest. long. code eq" option is not taken into account, AutoPIPE considers the actual restraint condition from supports and soil stiffness for longitudinal stress calculation.

$$S_L = MAX(\sigma_a + \sigma_b;\ \sigma_a - \sigma_b)$$

Where

$$\sigma_a = \frac{P_i D}{4t} - \frac{F_a}{A}$$

$$\sigma_b = \frac{\sqrt{M_i^2 + M_o^2}}{Z}$$

AutoPIPE reports sL and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength. If more than one operating load condition exists there may be more than one P value. Results are output for the operating load condition which produces the smallest margin (i.e., smallest value of 0.90· Sy, sL) at each point.

Note: AutoPIPE does not use the exact code equation for the longitudinal pressure stress. The code requires the use of vSH, whereas AutoPIPE uses PD/4t, which is approximately equal to 0.5SH.

THERMAL EXPANSION

Thermal Expansion Stress Range (ASME B31.4 - 2016)

Unrestrained

The stress due to defined thermal expansion ranges (sE) is calculated per the equation listed in para. 419.6.4(c) of the code, and as shown in Equation I.5-5:

$$S_E = \sqrt{S_b^2 + 4 \cdot S_t^2} \quad \text{(I.5 5)}$$

where:

$$S_b = \frac{\sqrt{(i \cdot M_{it})^2 + (i_o \cdot M_{ot})^2}}{Z_{cor}} \quad \text{(I.5 6)}$$

and:

$$S_t = \frac{M_{tt}}{2 \cdot Z_{cor}} \quad \text{(I.5 7)}$$

AutoPIPE reports sE, and the allowable stress (SA).

Restrained

The thermal expansion stress in restrained pipe is calculated as shown in Equation I.5-8:

$$S_E = E\alpha(T_1 - T_2) \quad \text{(I.5 8)}$$

Where E is the cold modulus of elasticity, a is coefficient of thermal expansion, in./in./F (mm/mm/C), T1 is the temperature of the pipe at installation or completion of final tie-in, F(C), and T2 is the operating temperature, F(C).

AutoPIPE reports sE and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength of the pipe material, in psi (MPa).

Appendix E CTEH Air Monitoring Summary Report

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DENBURY RESOURCES

AIR MONITORING REPORT

Satartia, Mississippi

Carbon Dioxide Pipeline Release

February 22-23, 2020

Project #112628

Report Submitted on June 05, 2020

1.0 INTRODUCTION

On February 22, 2020, CTEH®, LLC (CTEH) responded to a request from Denbury Resources (Denbury) to provide toxicology and air monitoring support following a carbon dioxide (CO_2) pipeline release near the town of Satartia, Mississippi. The village of Satartia was evacuated at approximately 2100 Central Standard Time (CST)[1] by local emergency management personnel and first responders. At 2230 on February 22, a CTEH consultant arrived onsite with air monitoring instrumentation and began monitoring areas in and around the village of Satartia for the presence of CO_2. As the potential for residual hydrogen sulfide (H_2S) resided in the line and complaints of an odor were received, monitoring was also conducted for the presence of H_2S. Additional CTEH personnel arrived and conducted air monitoring throughout the community. Once CO_2 levels returned to near ambient within the community, CTEH personnel conducted clearance monitoring within eighteen homes and three churches and their associated buildings. Denbury demobilized CTEH once ambient CO_2 concentrations within those structures were sustained below 5,000 parts per million (ppm) and residents had returned to their homes. This report summarizes data collected from February 22 through February 23.

2.0 METHODS

2.1 Handheld Real-Time Air Monitoring

Prior to CTEH's arrival, an air Sampling and Analysis Plan (SAP, Attachment A) was developed for worker monitoring, community monitoring, and site characterization. Based on site characteristics and associated scope of work, no worker monitoring or site characterization readings were recorded. In accordance with the SAP, CO_2, H_2S, and oxygen (O_2) concentrations were monitored using handheld real-time instrumentation throughout the community as well as within homes of residents who requested monitoring prior to re-occupancy. Monitoring was performed using RAE Systems by Honeywell MultiRAE Pro instruments. All instrumentation was calibrated prior to use.

Community monitoring was delineated into two subcategories: community real-time monitoring and indoor assessment real-time monitoring. Community real-time monitoring consisted of roaming handheld monitoring performed outdoors and downhill from the incident site, including checkpoints and church parking lots. Indoor assessments consisted of real-time monitoring within residences and church buildings potentially affected by the incident at the request of community members. If the initial indoor assessment resulted in CO_2 levels above the CTEH project-specific action level, another indoor assessment was performed after allowing the building to air out. For example, if real-time monitoring during the initial indoor assessment detected CO_2 levels above the CTEH project-specific action level, the windows and doors were opened and the occupant was advised not to re-enter until CO_2 concentrations returned to ambient levels, as determined by another indoor assessment. The ambient levels CO_2 in the non-industrial

[1] All other times referenced in the report will be CST unless otherwise delineated.

indoor environments may have a variety of sources, including human metabolism, and CO_2 levels can vary based on the number of people present, how long the area has been occupied, and the amount of outdoor fresh air entering the area.

2.2 Protective Action Criteria and CTEH Project-Specific Action Levels

The U.S. Department of Energy's Subcommittee on Consequence Assessment and Protective Actions (SCAPA) has established Protective Action Criteria (PACs) for over 3,300 chemicals for planning and response to uncontrolled releases of hazardous chemicals (DOE/SCAPA 2018). These criteria, combined with estimates of actual exposure, provide information necessary to evaluate chemical release events for the purpose of taking appropriate protective actions. During an emergency response, these criteria may be used to evaluate the severity of the event and to inform decisions regarding what protective actions may be taken. The PAC values for the chemicals of concern for this response are provided in Attachment B. The PAC-1, -2, and -3 for CO_2 are 30000, 40000, and 50000 ppm, respectively. For comparison, the American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit values (TLVs) are also included in Attachment B. Although the TLVs are intended for occupational daily work shift exposures over an entire working lifetime, the literature regarding reviewed human studies involving CO_2 within the TLV documentation were referred to and will be discussed in Section 4.0. The current ACGIH TLV-Time Weighted Average (TLV-TWA) for CO_2 (5,000 ppm) is based on the lack of inhalation toxicity data in humans at this level and the ACGIH TLV-Short Term Exposure Limit (STEL) for CO_2 is 30,000 ppm. The TLV documentation cites data indicating elevated concentrations (above 50,000 ppm) of CO_2 can produce '*mild narcotic effects, stimulation of the respiratory center, and asphyxiation*', depending on exposure duration and conditions (ACGIH 2001). CTEH project-specific action levels for both monitoring plans were set at 5,000 ppm (sustained for 15 minutes) for CO_2 based on the ACGIH TLV-TWA (well below PAC-1 and ACGIH TLV-STEL), and the action level for H_2S was set at 1 ppm, which was also based on the ACGIH TLV-TWA.

In accordance with the SAP, CTEH project-specific action levels were used to provide information for assessing need to take corrective action to limit the potential of exposure. These values do not replace community exposure standards or guidelines but are intended to be a concentration limit that triggers a course of action to better address public safety.

3.0 RESULTS

Handheld real-time air monitoring results are summarized by subcategory in Tables 1 and 2: community real-time air monitoring and indoor assessment real-time air monitoring. Maps of the site location, community real-time monitoring locations, and indoor assessment real-time air monitoring locations are provided in Attachment C.

Table 1 Community Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	108	108	100 – 26,000 ppm
H_2S	MultiRAE Pro	85	0	< 0.1 ppm
O_2	MultiRAE Pro	84	84	20.9 - 21.1 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

Table 2 Indoor Assessment Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	30	30	200 – 28,000 ppm
H_2S	MultiRAE Pro	18	0	< 0.1 ppm
O_2	MultiRAE Pro	8	8	20.9 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

4.0 DISCUSSION

CTEH performed real-time air monitoring using handheld real-time instrumentation. Results of handheld real-time air monitoring are discussed below.

No H_2S detections were observed during handheld real-time air monitoring in the community or indoor assessment real-time monitoring. O_2 concentrations were not observed below 20.9%. Outdoor CO_2 concentrations ranged from 100 through 26,000 ppm in the community. Five detections of CO_2 exceeded 5,000 ppm. Residents of the community were already evacuated when these detections were observed.

After outdoor community CO_2 levels were sustained continually measured below 5,000 ppm, initial indoor assessment real-time monitoring was performed inside residences and church buildings potentially impacted by the incident, at owners'/occupants' request. During initial indoor assessment real-time monitoring, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows and not to occupy those structures prior to re-assessment.

Indoor assessment real-time monitoring was performed for six structures to further assess homes and church buildings in which CO_2 concentrations above 5,000 ppm were observed during initial indoor assessment real-time monitoring. No readings of CO_2 greater than 3,500 ppm were recorded following any of these re-assessments.

While CTEH personnel were onsite, values of CO_2 were recorded up to 28,000 ppm. A notice issued by the Satartia Fire Department advising residents and members of the general public to evacuate the area was active during the period in which elevated CO_2 concentrations were observed. The ACGIH TLV documentation reports several effects resulting from inhalation of elevated CO_2 concentrations, including mild narcotic effects (30,000 ppm) and unconsciousness (> 50,000 ppm). Additional reports of human exposure to CO_2 indicate 20,000 ppm for several hours may cause transient effects, such as headaches, and exposure to up to 5,500 ppm for six hours may cause *no noticeable symptoms* (ACGIH 2001). To the best of CTEH's knowledge, including several interactions with community members during this response, there were no reports of hospitalization due to loss of consciousness within the community.

In conclusion, during the time period CTEH was present, the CO_2 concentrations observed were below the ACGIH TWA-STEL and PAC values and thus were not detected at levels that would be expected to cause anything other than transient effects, if any, or pose a chronic health risk to members of the community.

5.0 REFERENCES

ACGIH (2001) Carbon dioxide: TLV® Chemical Substances 7th Edition Documentation. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

ACGIH (2019) Guide to Occupational Exposure Values. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

DOE/SCAPA (2018) Protective Action Criteria (PAC): Chemicals with AEGLs, ERPGs, & TEELS: Rev. 29A. Washington, DC: U. S. Department of Energy. Available at:https://www.energy.gov/ehss/protective-action-criteria-pac-aegls-erpgs-teels-rev-29-chemicals-concern-may-2016.

Attachment A

Sampling and Analysis Plan

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Carbon Dioxide Pipeline Release

Satartia, MS

Air Sampling and Analysis Plan (SAP)

Version 1.0

Prepared on Behalf of:

Denbury Resources

Prepared By:

CTEH, LLC

5120 Northshore Drive

Little Rock, AR 72118

501-801-8500

February 22, 2020

	Name/Organization	Signature	Date Signed
Prepared by:	Pamella Tijerina, Ph.D.	PBT	02-22-2020
Reviewed by:	Eric Allaby		02-22-2020
Approved by:			
Approved by:			

Air Monitoring Strategy

CTEH® is focusing on the chemicals below chosen below because they are among the most important and readily monitored hazards of a carbon dioxide (CO_2) release. It is notable, however, that some chemicals may also be included within the SAP on the basis that some uncertainty exists during incidents and monitoring for these chemicals is necessary to ensure that a hazard does not exist. Monitoring for some chemicals or indicators of the presence of CO_2 may be conducted less frequently or even discontinued as product-specific information becomes available or as initial air monitoring results indicate that these chemicals and indicators do not pose a health concern.

The strategy is to utilize three broadly defined monitoring plans: **1)** Work Area Monitoring; **2)** Community Monitoring; and **3)** Site Assessment. Work Area monitoring will generally take place in those areas where workers are actively performing/supporting remediation operations. The readings will generally be taken at a height consistent with that of the workers breathing zone and in close proximity to workers without interfering or obstructing their remediation tasks. Community Monitoring may take place in those residential and/or commercial locations immediately surrounding the incident site, not necessarily currently occupied by members of the community. Unlike Work Area and Community monitoring, Site Assessment does not necessarily represent ambient air monitoring near breathing zone level. Site Assessment may involve a variety of different monitoring tasks intended to provide information that may help to delineate the nature and extent of the release (e.g. fence line monitoring, worst case determination, container head space, ground level, etc.).

Free-roaming handheld real-time air monitoring may be conducted in a variety of areas based on levels of activity, proximity to the release, and site conditions. Fixed-location handheld real-time locations may be established in the Community in order to provide concentration averages that may be observed and analyzed over time in distinct geographic locations in the community. AreaRAEs may be utilized to monitor the scene from remote location, if necessary.

CTEH® has the capabilities on site to collect ambient air samples, if necessary. These sampling methodologies may be utilized if the results from real-time air monitoring efforts indicate the potential for exposure above acceptable occupational or community exposure levels. CTEH® will discuss these methodologies with Denbury staff prior to implementation.

CTEH Site-Specific Action Levels

CTEH® site-specific action levels may be employed in all air monitoring plans to provide information for corrective action to limit potential exposures. These values do not replace occupational or community exposure standards or guidelines, but are intended to represent a concentration limit that triggers a course of action to better address worker and public safety. Action level exceedances will be communicated to Site Management and the CTEH Project Technical Director by the CTEH Project Manager (PM). Work practice may be assessed and then altered if necessary. Site-Specific Action Levels are not utilized for Site Assessment monitoring.

Plan 1: Work Area Monitoring

Objective: Report air levels before they reach those requiring respiratory protection

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 ppm 15 min.	Egress & Notify PM	OSHA PEL & ACGIH TLV	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
	30,000 ppm* 1 min.	Egress & Notify PM	ACGIH STEL				
O_2	< 20.3 %	Egress and Notify PM	ACGIH STEL for CO_2	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	1 ppm	Egress and Notify PM	ACGIH TLV-TWA; Precautionary Monitoring to Rule Out	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note small margin between STEL and NIOSH IDLH (40,000 ppm)

Plan 2: Community Assessment

Objective: Report air levels before they reach those causing nuisance or health issues

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 PPM* 15 min.	Notify PM	Warning prior to reaching PAC-1	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
O_2	< 20.3 %	Notify PM	Precautionary	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	Detection	Notify PM	Precautionary	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note: PAC-1 is 30,000 ppm, PAC-2 is 40,000 ppm, PAC-3 is 50,000 ppm

Plan 3: Site Assessment							
Objective: Characterize nature and extent of release							
Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	NA	Report reading to PM	NA	MultiRAE PID	0.1 ppm	Measuring range: 1 – 5,000 ppm	NA

All Plans (1-3): Flammability								
Analyte	Action Level	Corrected Value/ Instrument Reading	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
LEL				CO_2 is non-flammable; Notify PM & PTD if LEL detected.				

General Information on Procedures (Assessment Techniques) Used

Procedure	Description
Real-Time Handheld Survey	CTEH staff members may utilize handheld instruments (e.g. MultiRAE Plus; ppbRAE, Gastec colorimetric detector tubes, etc.) to measure airborne chemical concentrations. CTEH will use these handheld instruments primarily to monitor the ambient air quality at breathing zone level. Additionally, measurements may be made at grade level, as well as in elevated workspaces, as indicated by chemical properties or site conditions. CTEH may also use these techniques to verify detections observed by the AreaRAE network.
Radio-Telemetering Network	CTEH may deploy a radio-telemetering network of AreaRAEs in locations where monitoring from a remote location would be beneficial. These instruments will relay readings back to a centralization location that is monitored by CTEH.
Fixed Real-Time Monitoring locations	Multiple Community locations may be identified and monitored at the same location approximately once per hour using handheld instruments. This allows the use of statistical analysis more effectively than with a random approach.

Quality Assurance/Quality Control Procedures

Method	Procedure
Real-Time	Real-time instruments may be calibrated in excess of the manufacturer's recommendations.

Method	Procedure
	At a minimum whenever indicated by site conditions or instrument readings. Co-located sampling for analytical analysis may be conducted, if necessary, to assess accuracy and precision in the field. Lot numbers and expiration dates may be recorded with use of Gastec colorimetric tubes.
Reporting	Daily data summaries may be provided for informational purposes using data that have not undergone complete QA/QC. Comprehensive reports of real-time and/or analytical data may be generated following QA/QC and may be delivered 60 days following receipt of validated results, if applicable.

Glossary

Term	Definition
Sustained	Instrument reading above the action level continuously for the listed time period.
Breathing zone	The area within an approximate 10-inch radius of an individual's nose and mouth.
Ambient Air	That portion of the atmosphere (indoor or outdoor) to which workers and the general public have access.

Attachment B

SCAPA PACs and ACGIH TLVs

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No.	Chemical Name	CASRN	PACs based on AEGLs, ERPGs, or TEELs			Units
			PAC-1	PAC-2	PAC-3	
570	Carbon dioxide	124-38-9	30,000	40,000	50,000	ppm
1426	Hydrogen sulfide	7783-06-4	0.51	27	50	ppm

Chemical Name	CASRN	ACGIH TLVs		Units
		TWA	STEL	
Carbon dioxide	124-38-9	5,000	30,000	ppm
Hydrogen sulfide	7783-06-4	1.0	5.0	ppm

Attachment C

Site Maps

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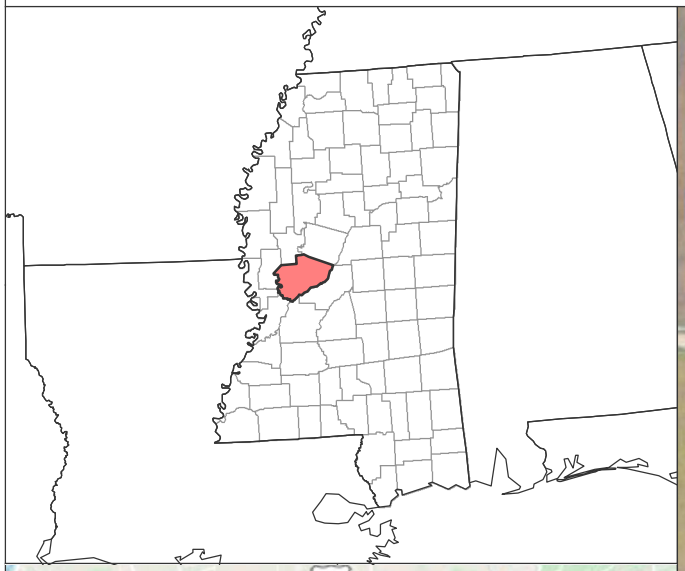
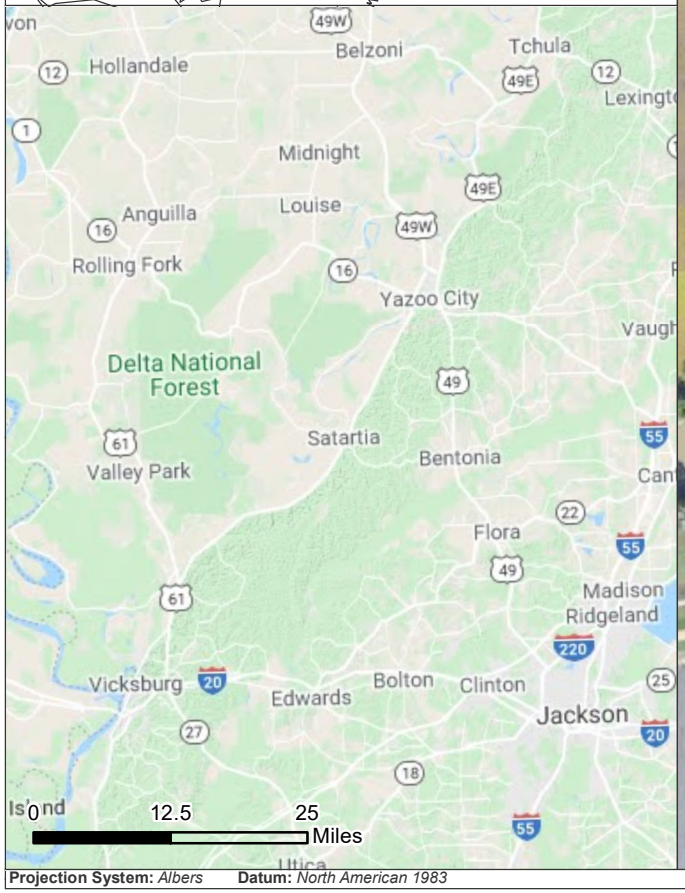
Site Location

CO_2 Pipeline Release

Project: 112628
Client: Denbury
City: Satartia, MS
County: Yazoo







Projection System: *Albers* **Datum:** *North American 1983*

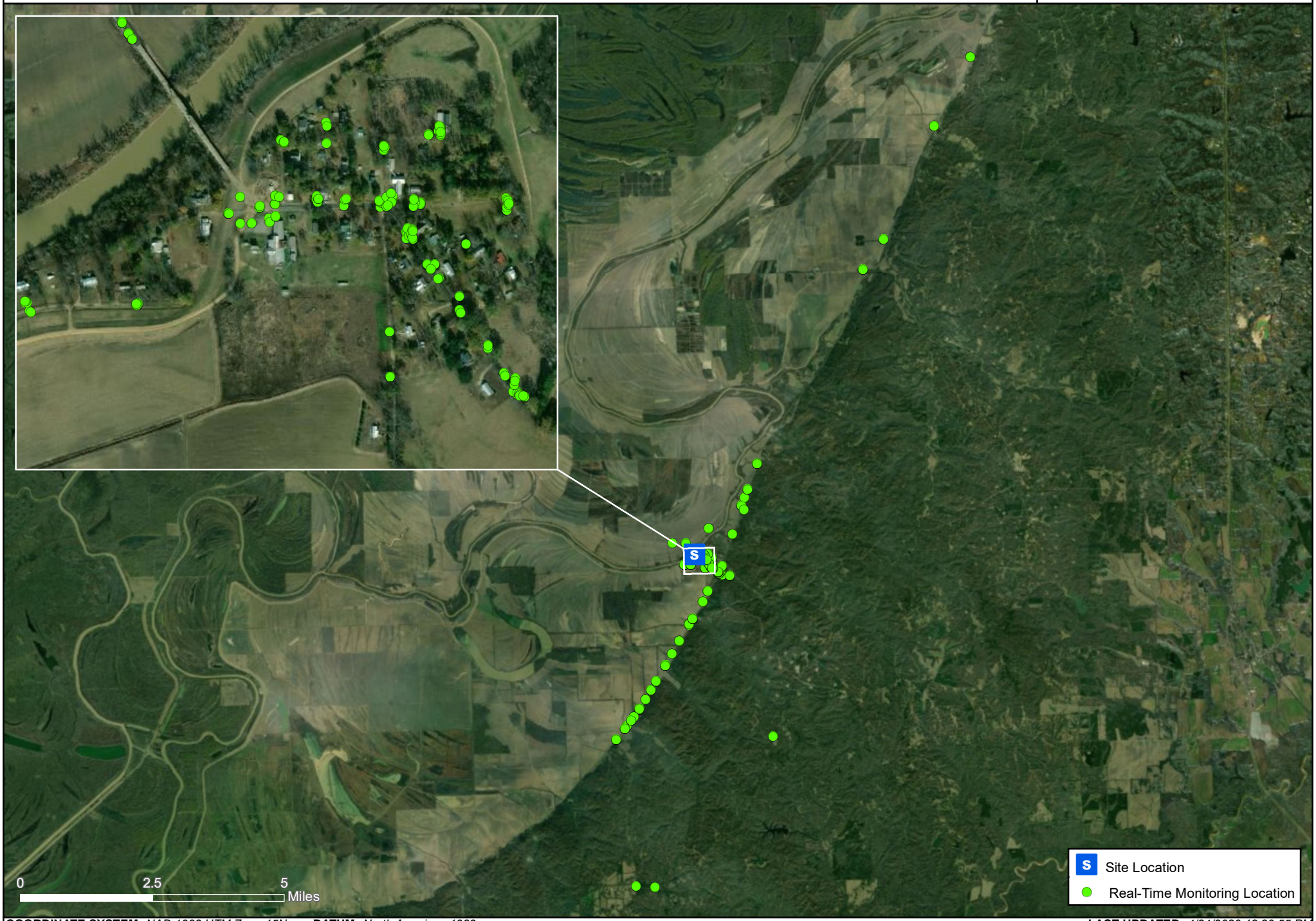
Document Name: 112628_site_location

Last Updated: *3/19/2020 1:44:18 PM*

Community Real-Time Air Monitoring Locations

CO_2 Pipeline Release | Satartia, MS | 2/22/2020 2230 - 2/23/2020 1134 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo



COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:20:55 PM*

Indoor Assessment Real-Time Monitoring Locations

CO_2 Pipeline Release l Satartia, MS | 2/23/2020 0636 - 2/23/2020 1805 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo



COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:10:31 PM*

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B.3 Miscellaneous Air Quality Attachments

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THE CARL MOYER PROGRAM GUIDELINES

2017 Revisions

VOLUME I: PROGRAM OVERVIEW, PROGRAM ADMINISTRATION AND PROJECT CRITERIA









Approved by the Board: APRIL 27, 2017

California Environmental Protection Agency

Air Resources Board



In Memory of Dr. Carl Moyer

(1937 - 1997)

This program is named in honor of the late Dr. Carl Moyer, whose extraordinary dedication, hard work, vision and leadership made this program possible. He created and masterminded this program, in a noble effort to unite business and government in the name of public interest to improve California's air quality.

This update was a collaborative effort and has benefited from the valuable contributions of the participating air quality management districts and air pollution control districts, and all other stakeholders. The Air Resources Board appreciates the considerable efforts of air district staff both in the development of these guidelines as well as the day-to-day implementation of the Carl Moyer Memorial Air Quality Standards Attainment Program.

Disclaimer

Publication does not signify that the content reflects the views and policies of the California Air Resources Board, nor does the mention of trade names or commercial products constitute endorsement or recommendation for their use.

EXECUTIVE SUMMARY

Since 1998, the Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program or Program) has cost-effectively reduced smog-forming and toxic emissions. Approximately $1 billion has been allocated to date and the Program continues to provide over $60 million in grant funding each year to clean up older polluting engines throughout California. The regulatory, technological and incentives landscape has changed significantly since the creation of the Moyer Program and to address evolving needs, the Legislature has periodically modified the Program to better serve California. Most recently, Senate Bill (SB) 513 (Beall, 2015) has provided new opportunities for the Program to contribute significant emission reductions alongside implemented regulations, advance zero and near-zero technologies, and combine program funds with those of other incentive programs.

This report addresses the implementation of SB 513 by the Air Resources Board (ARB or Board) and California's air pollution control and air quality management districts (air districts) through new guidelines to serve California's air quality goals. SB 513 requires the Board to adopt updated guidelines by July 1, 2017.

California's strategic plans for air quality and mobility, including the State Implementation Plan (SIP) and the Sustainable Freight Action Plan, point to the need for combustion engines to transition to zero and near-zero emission alternatives. This move is critical to California's clean air mission, to the attainment of health-based air quality standards, and to meeting future transportation goals without harm to public health and the environment. Public incentive funds are an increasingly important part of this transition. Incentives both encourage customers to purchase cleaner technologies and stimulate the marketplace to manufacture cleaner technologies.

Collaboration is paramount to the Moyer Program's ongoing success. The changes made through SB 513 were supported and informed by a coalition that included air districts, environmental organizations, industry stakeholders, equipment dealers, and consumers. Many different alternatives and approaches were considered. The result was a working group consensus on new program objectives and improvements essential to continuing program value. In turn, ARB staff developed and conducted public workshops on a proposal to implement those program improvements. Three key changes to the program are described below.

Cost-effectiveness. SB 513 specified that the Board consider the cost of technology and the cost of regulations in establishing a new limit. Staff proposes a tiered cost-effectiveness approach that will allow the Program to more effectively incentivize deployment of cleaner technologies. This two-step approach would support both conventional diesel clean-up projects and emerging technologies at appropriate funding levels. First, staff proposes to increase the general cost-effectiveness limit from the current $18,260 up to $30,000 per weighted ton of emission reductions. This reflects the cost-effectiveness of more recent regulations and will enable more meaningful grants for cleaner engines at the required standard. For advanced technology projects that are zero-emission, or alternatively meet the cleanest certified optional standard applicable

by source category, staff proposes that air districts be given the option to apply a cost-effectiveness limit of up to $100,000 per weighted ton, limited to the increment of emissions reductions beyond those achieved at the required standard. This higher limit would provide additional incentive to turn engines and fleets over to the cleanest certified technologies now emerging in the marketplace.

Infrastructure. SB 513 provides broader opportunity for air districts to support infrastructure projects. The staff proposes to provide air districts with the ability to fund infrastructure projects where the greatest penetration of commercially available advanced technology vehicles and equipment exists. These categories include commercial battery charging and alternative fueling stations for on-road and off-road vehicles and equipment, and continued support for marine shore power electrification and stationary agricultural projects. To provide project selection transparency for publicly accessible projects staff proposes requiring a competitive bid process when the project includes public access. Air districts would retain the flexibility to select projects that meet their local needs and priorities. Per SB 513, infrastructure projects would not be required to meet a cost-effectiveness limit.

Project Co-Funding. As envisioned in SB 513, leveraging of funds allows air districts to work with grant applicants to co-fund projects with other incentive programs up to the cost of the project, without penalizing project cost-effectiveness. Project cost sharing supports the deployment of the cleanest technologies statewide by providing opportunities to co-fund private, local, State and federal funding to cover technology costs. Staff proposes the following safeguards consistent with SB 513: the requirements of all contributing programs must be met, incentives must not exceed the total project costs, there can be no double counting of emission reductions for SIP credit, and the applicant should provide a 15 percent cost share for private sector projects.

Even as the 2017 Guidelines would implement the program improvements directed by SB 513, they retain the Moyer Program's longstanding core objectives. The proposed Guidelines are intended to:

- Ensure continued program accountability and good stewardship of public funds;
- Ensure Moyer projects provide emission reductions that the U.S. Environmental Protection Agency (EPA) will find creditable in the SIP;
- Emphasize reduction in communities with higher pollutant exposure, including communities of minority and low-income populations;
- Provide sufficient incentive to encourage California businesses to participate in and benefit from the program, getting surplus emission reductions within cost-effectiveness limits.

This report describes Moyer Program context and background, and explains how a renewed Moyer Program can support the changing landscape of clean air technology in

and beyond California. Staff's proposed changes will ensure that Moyer can assist the technology shifts that bring California closer to the clean air future called for in our State's strategies.

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THE CARL MOYER PROGRAM GUIDELINES

PROGRAM OVERVIEW, PROGRAM ADMINISTRATION AND PROJECT CRITERIA

VOLUME I

(The Carl Moyer 2017 Guidelines are comprised of two Volumes. Volume I includes the program overview, program administration, source category chapters and appendices. Volume II includes the On-Road and Off-Road Voucher Incentive Programs, and the Agricultural Assistance Program.)

THE CARL MOYER PROGRAM GUIDELINES

PART 1 of 3

PROGRAM OVERVIEW, PROGRAM ADMINISTRATION AND PROJECT CRITERIA

CHAPTER 1: PROGRAM OVERVIEW

The Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program or program) is a grant program that funds the incremental cost of cleaner-than-required engines, equipment, and other sources of air pollution. Since 1998, the Moyer Program has been successful in reducing smog-forming and toxic emissions cost-effectively. Although air pollution regulations have significantly reduced emissions and improved air quality across the State, many areas of California continue to experience unhealthy air. The Moyer Program complements California's regulatory program by providing incentives to obtain early or extra emission reductions, especially from emission sources in minority and low-income communities and areas disproportionately impacted by air pollution. Incentives encourage customers to purchase cleaner technologies, and stimulate the marketplace to manufacture cleaner technologies. Although the Moyer Program has grown in scope, it retains its primary objective of obtaining cost-effective and surplus emission reductions to be credited toward California's legally-enforceable obligations in the State Implementation Plan (SIP) – California's road map for attaining health-based national ambient air quality standards.

The 2017 Moyer Program Guidelines (Guidelines) update the program to meet new opportunities provided by Senate Bill 513 (SB 513, Beall, 2015). These changes – cost-effectiveness limits that recognize technology and regulatory costs, the ability to leverage Moyer dollars with project co-funding, added eligibility for infrastructure projects – enable the Moyer Program to fully support emission reductions within the changing landscape of clean air technology.

This program update arrives in time to support the multiple strategic planning efforts that are relying on emission reductions from incentive programs. California's strategic plans for air quality and mobility, including both the Proposed 2016 State Strategy for the SIP and the Sustainable Freight Action Plan, point to the need for combustion engines to transition to zero and near-zero emission alternatives. This move is critical to the State's clean air mission, to the attainment of air quality standards, and to meeting future transportation goals without harm to public health and the environment. The Moyer Program is particularly important among mobile source strategies identified for the SIP, contributing reductions needed toward ozone attainment milestones in the South Coast Air Basin in 2023 and 2031.

The Guideline updates were developed in close and continuing consultation with air quality management districts and air pollution control districts (air districts), who ultimately implement Moyer Program projects. This includes the formation of several teams with specific responsibilities in re-crafting the guidelines, and input from larger group and rural sections meetings. A total of five public workshops were held to collect input from the public, including initial workshops in the San Joaquin Valley and South Coast air basins.

A. Background

The Moyer Program has been a successful and popular air pollution reduction program. Since 1998, Moyer Program grants have enabled the owners of diesel engines to go beyond regulatory requirements by retrofitting, repowering, or replacing their engines to gain early or extra emission reductions. Over the past 18 years more than $900 million in program grants have cleaned up over 50,000 engines, reducing oxides of nitrogen (NOx) and reactive organic gases (ROG) by 178,000 tons and toxic diesel particulate matter (PM) by 6,500 tons. Moyer incentive funds have not only removed old, dirty equipment that would have otherwise remained in operation for years to come, but have benefited the economy by increasing consumer demand for newer and cleaner technologies.

The Moyer Program has been successfully implemented through the cooperative efforts of the Air Resources Board (ARB) and California's air pollution control and air quality management districts (air districts). The Health and Safety Code (H&SC) directs ARB to oversee the program by managing and distributing funds; developing and revising guidelines, protocols, and criteria for covered vehicle projects; and determining methodologies to evaluate project cost-effectiveness. Air districts follow the Board-approved Guidelines to select, fund, and monitor specific clean air projects in their areas, providing grants to public and private entities for the incremental cost of cleaner-than-required engines and/or equipment.

Air districts enjoy considerable flexibility in implementing the Moyer Program. Each air district may focus its funds on specific source categories, to tailor projects to meet local air quality objectives while still ensuring the proper and responsible use of State funds.

Emission reductions funded through the Moyer Program must be permanent, surplus, quantifiable, and enforceable in order to meet the underlying statutory provisions and be SIP-creditable. To ensure that projects are surplus to regulations, funded projects must not be required by any federal, State or local rule or regulation. In most cases project life – the period in which surplus emission reductions are delivered – must be at least three years, so that the program does not fund actions that would otherwise be taken to comply with regulatory deadlines, as well as to help ensure cost-effectiveness. A maximum project life is also established to ensure that the emission reductions remain real for a specified period.

The Guidelines require that emission control technologies be certified or verified by ARB or by U.S. EPA when ARB does not have an applicable certification or verification program. Robust administrative requirements also help ensure emission reductions are enforceable and are achieved for the life of a project. Grantees sign contracts or agreements enforceable for the life of a project. Their replaced engines must be scrapped. Incentive program review by ARB and fiscal audits by Department of Finance help ensure Moyer funds are serving the purpose of achieving expected emission reductions.

1. **Project Types**. The Moyer Program funds clean air projects involving a wide variety of vehicles and equipment. Typical project types include:

   (A) **Replacement.** An older vehicle or piece of equipment that includes an engine with remaining useful life is replaced with a newer, cleaner vehicle or piece of equipment. On-road trucks and buses may be replaced through a fleet modernization contract or through a voucher incentive program (VIP). Off-road equipment also may be replaced under contract or through off-road VIP. In all cases, the older vehicles and equipment are scrapped.

   (B) **Repower.** A newer, cleaner engine is installed in place of a higher-polluting engine in an existing vehicle or piece of equipment.

   (C) **Retrofit**. An emission control system is added to an in-use engine, vehicle or piece of equipment.

   (D) **Vehicle Retirement (car scrap).** Light duty scrap programs pay the owners of older, more polluting vehicles that still have remaining useful life to voluntarily retire those vehicles earlier than they would have otherwise.

   (E) **Infrastructure.** Moyer funds provide for the installation of fueling or energy infrastructure to fuel or power covered sources. Though infrastructure does not directly deliver emission reductions, it enables the advanced clean vehicles and equipment that do.

More details on eligible project types can be found in the source category chapters of the Guidelines. Other projects may be eligible; interested applicants should reference the details in each section and consult with their local air district for additional solicitation material, program brochures, and to discuss potential Moyer Program projects.

2. **Funding Sources**. The Moyer Program has been funded through a variety of mechanisms since its inception in 1998. In the program's first four years, the California Legislature funded the Moyer Program through annual budget appropriations. Voter approval of *Proposition 40: The California Clean Water, Clean Air, Safe Neighborhood Parks, and Coastal Protection Act of 2002* provided program funding for the fifth and sixth years.

   Bills enacted in 2004 (SB 1107 and Assembly Bill (AB) 923) provided for continuous funding of the Moyer Program thereafter. The program is currently authorized at $69 million per year from these sources:

   (A) **Smog Abatement Fee.** SB 1107 adjusted the smog abatement fee collected for new vehicles registered by the Department of Motor Vehicles (DMV) from $6 to $12, while extending the new vehicle Smog Check exemption period. This additional fee is directed to fund the Moyer Program (H&SC § 44091.1). SB 1107 funds do not have a sunset date.

(B) **Tire Fee.** AB 923 adjusted the tire fee that is assessed on purchasers of new tires from $1 per tire to $1.75 per tire (Public Resources Code section 42885). This legislation was due to sunset in 2015; AB 8 extended that date through 2023.

ARB receives from DMV the funds from the additional $6 portion of smog abatement fees, and from the Board of Equalization the funds from the additional $0.75 portion of tire fees. ARB distributes these funds, currently about $65 million per year to air districts following a statutory formula (H&SC § 44299.2).

In addition, AB 923 gave air district governing boards the authority to increase the vehicle registration surcharge by $2 to pay for specific clean air incentive programs, including projects eligible for grants under the Moyer Program. AB 923 $2 DMV funds have become the primary source of the 15 percent Moyer match required of air districts receiving more than the minimum allocation. Nineteen air districts have adopted the $2 Motor Vehicle Registration fee, providing these air districts about $50 million per year for incentive projects. The $2 DMV surcharge fees are sent directly by DMV to the air districts.

B. Program Legislative History

The Moyer Program was created in 1998 when $25 million was included in the fiscal year 1998-1999 State budget to fund a lower-emission heavy-duty engine incentive program. ARB adopted the first set of Moyer Program Guidelines in early 1999, and legislation (AB 1571) enacted in 1999 formally established the statutory framework for the program (H&SC § 44275 et seq.). The program initially focused on reducing NOx emissions from heavy-duty diesel engines in order to implement a strategy in the 1994 California SIP for ozone that called for the early introduction of cleaner engines. The scope of the program has expanded over the years with statutory changes adding both new covered pollutants and new source categories.

Legislation enacted in 2001 (AB 1390) required air districts with a population of over 1 million to expend 50 percent of Moyer Program funds for projects that operate or are based in environmental justice areas (H&SC § 43023.5).

Legislation enacted in 2004 (AB 923 and Senate Bill (SB) 1107) provided increased and continued funding through 2015 while significantly expanding the Moyer Program. AB 923 expanded the Moyer Program to include light-duty vehicle projects and agricultural sources of air pollution as defined in Health and Safety Code section 39011.5(a). AB 923 also expanded the Moyer Program from a NOx focused incentive program to include projects that also reduce reactive organic gases and fine particulate matter (PM_{10}). This change allowed the Moyer Program to more comprehensively address California's air pollution challenges, including the air toxic risk associated with emissions from diesel engines. Additional legislation enacted in 2004 (AB 1394) directed ARB to include in the Moyer Program heavy-duty fleet modernization projects that reduce NOx and/or PM_{10} emissions through the replacement of old trucks.

Legislation enacted in 2005 (SB 467) required ARB to revise the Moyer Program Guidelines to include projects in which an applicant turns in off-road equipment powered by internal combustion engines and replaces that equipment with new zero-emission technologies.

Legislation enacted in 2006 (SB 225) provided additional resources for program administration to address the expansion of the program. This legislation increased allowable expenditures for air districts' program administration from 2 percent of program funds for outreach to 5 percent for air districts with one million or more inhabitants and to 10 percent for those with less than one million inhabitants. ARB was provided 4 percent of program funds for outreach, oversight, and administration. These additional resources enabled ARB and the air districts to improve program accessibility, efficiency and accountability.

Legislation enacted in 2009 (SBx2 3) allows a maximum project life of 10 years for off-road farm equipment projects. This legislation also allows for funding of these off-road farm equipment projects up to the compliance date as determined by statute, regulation or rule.

Legislation enacted in 2010 (AB 1507) required ARB to revise the Guidelines by July 1, 2011, to allow for the combination of Moyer Program funds with funds designed to reduce greenhouse gas emissions from federal programs or the Alternative and Renewable Fuel and Vehicle Technology Program without including them in the cost-effectiveness calculation for the Moyer Program funds.

Legislation enacted in 2013 (AB 8) extended funding of AB 923 tire fees ($1.75 per tire) through year 2023, effectively reauthorizing the Moyer Program and associated local funds through that year. AB 8 also directed ARB to convene a working group and work with local air districts to evaluate the Moyer Program and provide recommendations for program changes. The efforts of this working group led to SB 513.

Signed by the Governor in 2015, SB 513 provided new flexibilities that allow the Moyer Program to continue to make a viable contribution to emission reductions in California into the future. SB 513 was implemented in two phases; the early revisions became effective January 1, 2016, following a public meeting and 45-day public comment period, under authority delegated to the Executive Officer. Remaining updates are scheduled for consideration by the Board in April 2017. The most noteworthy changes enabled by SB 513 included:

1. Updating cost-effectiveness criteria, authorizing the Board, in collaboration with the air districts, to establish and revise cost-effectiveness limits to account for the costs of technology and regulation;

2. Allowing for a separate school bus cost-effectiveness limit to allow the Program to fund at the levels equivalent to the Lower-Emission School Bus Program. This change has already been implemented through the amendment of the 2011 Guidelines that became effective January 1, 2016.

3. Expanded opportunities for infrastructure projects; and

4. Allowing project co-funding without penalizing cost-effectiveness.

C. Summary of Changes for the 2017 Guidelines

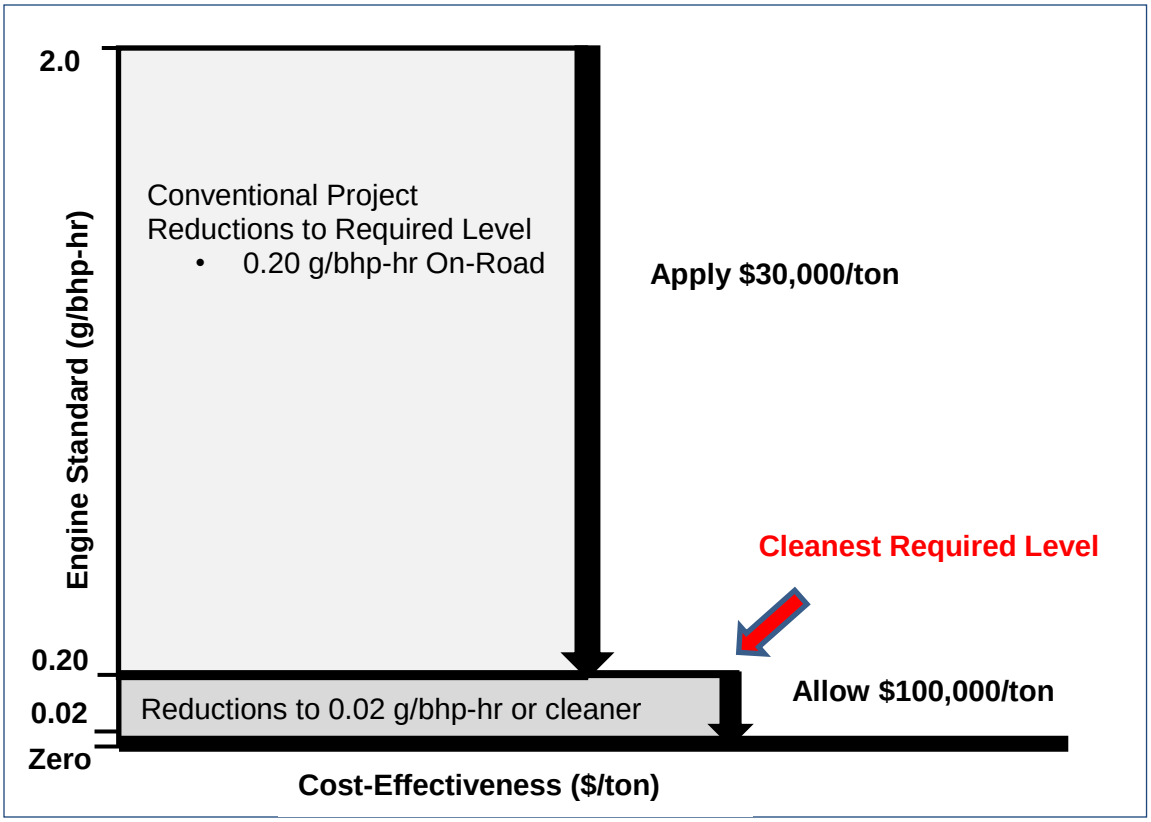
The 2017 Guidelines are proposed as an update to the Moyer Program to reflect the opportunity and flexibility provided by SB 513. The key program changes to be implemented through these Guidelines include the following. (Additional detail is included in the Staff Report issued to accompany Board consideration of these Guidelines.)

1. **Establish New Cost-Effectiveness Limits.** SB 513 specified that the Board, in collaboration with the air districts, should consider the cost of technology and the cost of regulations in establishing cost-effectiveness values. The proposed Guidelines include a tiered cost-effectiveness approach that will allow the program to meet dual needs – supporting both conventional projects and emerging technologies. The general cost-effectiveness limit would be increased from the current $18,260 up to $30,000 per weighted ton of emission reductions (particulate matter (PM) reductions would still be weighted by a factor of 20 due to diesel PM toxicity). The increase in the base limit reflects more recent regulatory costs and will enable more meaningful grants for cleaner engines at the required standard.

   For advanced technology engines that are zero-emission or, alternatively, meet the cleanest optional standard level certified, the proposal allows air districts to choose to apply a cost-effectiveness limit of up to $100,000 per weighted ton. This higher limit would provide additional incentive to turn engines and fleets over to the cleanest certified technologies now emerging in the marketplace.

   Figure 1 below illustrates how the dual cost-effectiveness limits would be implemented under the proposed change for an on-road engine meeting the 0.02 g/bhp-hr Optional Low NOx standard.

Figure 1: Illustration of Dual Cost-Effectiveness Limit for On-Road Projects



2. **School Buses**: Note that a separate cost-effectiveness limit of $276,230 per weighted ton will continue to apply to school bus projects, to enable consistency with the funding levels used in California's Lower-Emission School Bus program as directed by SB 513. This program change has already been made, through a revision to the Moyer Program 2011 Guidelines effective January 1, 2016.

3. **Expansion of Infrastructure Program**. SB513 provided new opportunities to fund installation of fueling or energy infrastructure for zero and near zero alternative vehicles and equipment and other projects that enable clean air technologies. Under SB 513, infrastructure projects are not subject to the cost-effectiveness limit. Infrastructure categories included in the chapter are commercial battery charging and alternative fueling stations for on-road and off-road vehicles and equipment, and continued support for marine shore power electrification and stationary agricultural electrification projects. Proposed funding limits for infrastructure projects are as follows:

   (A) Up to 50 percent of eligible costs for all projects;

   (B) Up to an additional 10 percent (total of 60 percent) for publicly accessible stations;

(C) Up to an additional 15 percent (total of 65 percent) for projects including on-site solar or wind power generation;

(D) Up to 100 percent for electric charging stations and alternative fueling stations for school buses. This is consistent with recent Board direction to consider opportunities for funding to assist public school buses.

To provide project selection transparency for public accessible projects staff proposes requiring a competitive bid process when the project includes access to the public. The proposal also provides flexibility for air districts to select projects that meet their local needs and priorities.

4. **Opportunity to Co-Fund Moyer Projects with Other Public Funds.** Proposed Guideline changes would provide now opportunities for Moyer Program funds to co-fund projects with other incentive programs without a cost-effectiveness penalty, as provided for in SB 513. Co-funding would allow projects to be approved with support from multiple program grants up to the total eligible cost of the project. Moyer Program and AB 923 funds would continue to be subject to cost-effectiveness limits (except in the case of infrastructure), regardless of whether such thresholds apply in other contributing programs. There is no limit on the number of co-funding sources that can be used to fund a project, as long as the total project costs are not exceeded and a 15 percent applicant cost share requirement is met for private sector projects. Provisions in the General Criteria and Program Administration Chapters would safeguard against double counting of emission reductions, and the Moyer Program will account for all emission reductions for SIP purposes. Projects would still be required to meet the individual requirements of each funding source.

5. **Changes to Program Administration**. Program administration affects air district implementation of all Moyer projects, and ARB staff has worked with air districts to streamline and reorganize the administrative requirements that ensure program accountability. A major reporting update made in SB 513 was changing the two year expenditure deadline for grant funds to a four year liquidation deadline. Guideline changes to reflect this provide additional time to complete more complex projects, while contract execution will serve as an interim milestone for progress tracking. Another key change to the chapter is the phase-in of accounting principles, as recommended by California Department of Finance, to improve fiscal transparency and lower the cost of program audits. The updated Guidelines also provide air districts procedures for redirection of unallocated grant funds to districts with ready projects.

6. **Changes to the On-Road Sections**. This version of the Guidelines would merge previous 2011 Guideline chapters 4, 5 and 6 into one comprehensive chapter for heavy-duty trucks and buses. The On-Road Voucher Incentive Program (VIP) program would remain separate in Part II of the Guidelines. A significant change in the on-road section is the addition of funding caps for new technologies such as Optional NOx and zero emission engines. Staff also

modified VIP funding caps for conventional project types. The fleet size limit of ten or less vehicles was removed; however, fleets larger than ten would have to use cleaner engine technology.

7. **Changes to the Off-Road Sections**. The proposed 2017 Guidelines would combine previous chapters 7, 8, 9 and 10 into one off-road equipment chapter, while Off-Road VIP remains separate. Staff proposes to extend the eligibility for large fleets (more than 5,000 horsepower) to one additional opportunity after January 1, 2017. This will provide large fleets a path to add Tier 4 final equipment while retaining broader opportunity for medium fleets within this time frame. Program changes also allow equipment with Tier 3 engines and portable equipment to be eligible for equipment replacement.

8. **Changes to the Locomotive Section**. Program guidelines would be updated for locomotive projects to require all new equipment be Tier 4 or cleaner. Staff also proposes to allow the reuse and/or the recycling of the baseline chassis while still requiring the baseline engine to be destroyed. Idle limiting devices and retrofit projects would no longer be eligible for funding.

9. **Changes to the Marine Section**. For marine projects, proposed changes would include allowing the cleanest technologies to be eligible for the highest maximum percentage of eligible cost, and allowing compliant Tier 2 engines to be repowered. Vessels that are compliant with the Commercial Harbor Craft replacement schedule would become eligible for the same funding amounts as unregulated vessels. Provisions would also be added for hybrid system vessel retrofits.

10. **Emissions Estimates and Deterioration**. Staff proposes that project evaluation consider the emissions that occur due to deterioration of vehicles and equipment emission controls over time. Deterioration rates used in ARB emissions inventories are available for on-road trucks and off-road equipment. Including these factors in Moyer Program emissions and cost-effectiveness calculations for both old and new equipment will better reflect real-world engine emissions over project lives, and align Moyer calculation methods with those used in ARB planning inventories and SIP air quality modeling.

11. **Other Changes**.

    (A) New purchase projects that expand fleets would no longer be eligible projects, due to SIP creditability concerns.

    (B) The baseline vehicle for Light Duty Vehicle projects must have an engine model year of 2003 or older.

    (C) Only minor changes are proposed for the Agricultural Assistance Program (Part III).

(D) Appendices have been re-worked. Calculations in Appendix C are updated to improve the flow of calculations; formulas have been added to account for engine deterioration and calculate the new dual cost-effectiveness limits. Emission factors have been updated in Appendix D and now include deterioration. The appendices for acronyms, definitions and references have been updated. Previous appendices E and G have been removed, with cost-effectiveness information moved to Appendix C and capital recovery tables moved to Appendix D.

CHAPTER 2: GENERAL CRITERIA

The criteria listed below apply to all Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) projects. In addition to the criteria below, Moyer Program projects must also meet the additional project criteria found in the applicable source category chapter and the Program Administration Chapter. In cases where there is a conflict between the Guidelines and statute, the Moyer Program statutory provisions take precedence over the Guidelines. In cases where the source category requirements conflict with either the criteria listed below or Program Administration requirements, the source category requirements take precedence.

A. Covered emission reductions obtained through Moyer Program projects must not be required by any federal, State or local rule or regulation, memorandum of agreement, memorandum of understanding, settlement agreement, mitigation requirement, or other legal mandate.

B. If a Moyer Program project contract has not been fully executed prior to the approval date of an air quality management district or air pollution control district (air district) governing board or Air Resources Board (ARB) rule or regulation (or the promulgation date of a federal regulation) the air district must consider the rule or regulation when evaluating a project's eligibility. If a Moyer Program project contract has been fully executed prior to that date, the air district does not need to consider the rule in evaluating whether the project's emission reductions are surplus.

C. An air district must consider all applicable rules or regulations when determining eligibility for a project. If an existing contract is amended to increase the total Moyer Program funding of the project, then the air district must reevaluate eligibility and consider all applicable rules or regulations. If the total dollars do not increase, then the air district does not need to reevaluate eligibility.

D. A grant applicant subject to an in-use regulation may be eligible to receive funding through the Moyer Program if the applicant has met all compliance requirements of applicable regulations. Documentation of regulatory compliance must be provided by applicants to air districts prior to funding.

E. Participating air districts retain the authority to impose additional more stringent requirements in order to address local concerns.

F. No project funded by the Moyer Program may be used for credit under any federal or State emission averaging, banking or trading program throughout the contract term. No covered emission reductions generated by the Moyer Program may be used as marketable emission reduction credits, or to offset any emission reduction obligation of any person or entity throughout the contract term (Health and Safety Code (H&SC) § 44281(b)).

G. The new engine, vehicle, or equipment must remain in service for the entire contract term, which must extend to the end of the project life. Throughout the contract term, the emission reductions funded by the Moyer Program must not be used to generate credits or compliance extensions and must be excluded when determining regulatory compliance (H&SC § 44281(b)).

H. The State Board and the air districts shall take all appropriate and necessary actions to ensure that all covered emission reductions achieved from a Moyer Program project are creditable in the State Implementation Plans (SIP) and are enforceable, surplus, quantifiable and permanent (H&SC § 44286(g)).

I. When Moyer funds are used for co-funded projects, the Moyer Program will account for all covered emission reductions for SIP purposes (H&SC § 44287.2(a)(4)).

J. ARB will provide protocols for calculating surplus covered emission reductions over the life of representative project types (H&SC § 44283(c)).

K. Engines operating under flexibility provided by an enforcement discretion advisory, mail-out or other advisory issued by ARB, an air district, or the United States Environmental Protection Agency (U.S. EPA) are not eligible for funding.

L. Projects funded by the Moyer Program must be included when determining the size of the fleet for regulatory compliance.

M. Projects selected for funding must meet cost-effectiveness limits per weighted ton of oxides of nitrogen (NOx), reactive organic gases, and particulate matter reduced, as calculated in accordance with Appendix C, except in the case of infrastructure projects.

N. Moyer funds, all local air district AB 923 funds, and match funds must be included in the project cost-effectiveness calculation and are subject to cost-effectiveness limits (H&SC § 44283(d)). Funds from sources other than those listed here are not required to be included in the project cost-effectiveness calculation (H&SC § 44287.2(a)).

O. Applicants must report to air districts all private or public financial incentives applied for or used to co-fund Moyer projects (H&SC § 44283(g)). The air district must ensure that the sum of the other incentive funds and the Moyer funds does not exceed the total project cost (H&SC § 44287.2(b)). Appendix C contains an example of the calculation methodology.

P. Projects co-funded with Moyer and other public funds must meet all requirements of the contributing programs. Grantees from non-public entities must provide at least 15 percent of the Moyer eligible cost from non-public sources.

Q. Moyer Program grants can be no greater than a project's incremental cost. Incremental cost is defined in Appendix B, and some source category chapters provide additional guidance.

R. Moyer Program funds cannot be used to pay for energy or fuel costs. However, local funds under an air district's budget authority or fiduciary control (i.e., match or other local funds) may be used to fund energy or fuel costs other than standard gasoline or diesel fuel, when those costs are integral to a project receiving grant funding under the Moyer Program (H&SC § 44283(f)).

S. Projects must have at least 75 percent of their total activity for the project life in California, unless otherwise stated in the source category chapters. Activity outside of California is excluded from the covered emission reductions used to determine grant funding and SIP emissions benefits.

T. Project engines and retrofits must use only the fuel allowed by the engine certification or retrofit device verification during the project life. Fuel additives are prohibited unless specifically allowed in the engine certification or retrofit device verification.

U. Emission reduction technologies must be certified or verified by ARB. If an ARB certification or verification process does not exist or if engines or retrofits are preempted from ARB certification/verification, then an engine or retrofit must be certified/verified to Federal standards as applicable. For the purposes of the Moyer Program, a technology granted a conditional certification/verification by ARB is considered certified/verified. An ARB certification process may not exist for some zero-emission technologies. See the relevant source category chapter for specific requirements for zero-emission technologies.

V. In circumstances where an eligible vehicle or piece of equipment has more than one engine, the air district may choose to base the cost-effectiveness calculation on overall vehicle/equipment emission reductions rather than on a per engine basis. The project must meet the current project cost-effectiveness limit.

W. Prior to destruction, an engine that is required to be dismantled may be used as a test engine for purposes of retrofit or fuel verification. This can occur as long as the engine complies with the requirements of the guidelines, and the old engine must be destroyed before a payment to the grantee is issued for the new engine.

X. Funding is not available for projects where a spark-ignition engine (i.e., natural gas, gasoline, etc.) is replaced with a diesel engine.

Y. For repower and replacement projects the replacement engine must achieve an annual NOx emissions benefit of at least 15 percent to receive any funding for NOx reductions.

Z. For a repower project, the installation of the engine must be completed in a manner that does not void the engine warranty provided by the manufacturer or any remaining warranty provided by the equipment/vehicle manufacturer.

AA. No public monies are allowed for the support of any sectarian or denominational school, or any school not under the exclusive control of the officers of the public schools. (Cal. Const. Art. 16 § 5 and Art. 9 § 8).

BB. The revised cost-effectiveness limit and capital recovery factors may be used by air districts once the Board adopts the updated Moyer Program Guidelines, but must be used by July 1 following its adoption. ARB will update the cost-effectiveness limit and capital recovery factors annually through a Mail-Out.

CC. ARB may approve, on a case-by-case basis, projects that vary from the requirements of these Guidelines or that do not meet all eligibility criteria in the Guidelines. Projects with case-by-case approvals must provide permanent, surplus, quantifiable, enforceable, cost-effective emission reduction benefits in California for the full contract term. Additional information regarding approval of case-by-case projects is found in the Program Administration chapter.

CHAPTER 3: PROGRAM ADMINISTRATION

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CHAPTER 3: PROGRAM ADMINISTRATION

This chapter describes the administrative requirements that the Air Resources Board (ARB), air quality management districts or air pollution control districts (air districts), and interested parties must follow to ensure that Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) projects achieve State Implementation Plan (SIP)-creditable emission reductions.

A. Background

An air district may choose to require more stringent administrative procedures in implementing its local program. Some source category chapters of the Moyer Program Guidelines (Guidelines) give additional administrative requirements. In a case where the source category requirements conflict with requirements specified in this chapter, the source category requirements take precedence.

These Guidelines must be used for all projects funded with fiscal year 2017-18 (Moyer Program Year 20) and subsequent years' funds. The 2017 Guidelines may be utilized for previous year funds after the Board approval date, and applied to projects for which contracts are fully executed after the Board approval date. When an air district begins applying the 2017 Guidelines to projects, it must continue to apply only the 2017 Guidelines to all subsequently funded projects. ARB will follow these 2017 Guidelines for administration of the Moyer Program following Board approval.

For projects funded using fiscal year 2016-17 (Year 19) and previously awarded funds, an air district may use either the 2011 Guidelines or these 2017 Guidelines, with any applicable program advisories and mail-outs. An air district may not apply elements of both Guidelines to a project.

B. Grant Fund Allocation and Solicitation

1. **Grant Funds Notification**. During each fiscal year, ARB will send a solicitation letter to each air district's Air Pollution Control Officer (APCO) with notification that Moyer Program funds for that year are available. Enclosures with the letter will include the application for funds, a tentative allocation of regular program funds (not including State Reserve funds) for all air districts showing a breakdown of project and administrative funds, and any associated match funds requirement.

2. **Tentative and Final Funds Allocation**. After a review of projected revenues for the current fiscal year, a tentative funds allocation for all air districts will be determined by ARB under the requirements of Health and Safety Code (H&SC) section 44299.2(a); it may include funds returned or reverted to ARB under section 44287(j). Following receipt and review of air district applications, ARB will determine a final funds allocation that (a) considers any update in projected revenues and (b) redistributes any funds declined by air districts to other air districts that have requested additional funds. This redistribution will also follow

the allocation requirements of Health and Safety Code section 44299.2(a). The typical timeline for the initial allocation, air district application, final allocation, disbursement and subsequent expenditure of a fiscal year's grant funds is provided in Table 3-1.

Table 3-1
Moyer Program Regular Funds Timeline

Date	Action
By end of January	ARB sends application packet to air districts
By end of March	Air districts apply to ARB for funds
By end of April	ARB notifies air districts of final awards
By end of May	Air districts return signed grant agreements
June 30 of Following Year	Target date for contracts to be executed
June 30 of Second Year	Deadline for air districts to receive fund disbursements.
June 30 of Fourth Year	Deadline for air districts to liquidate funds

3. **State Reserve Funds**. ARB may direct up to ten percent of Moyer Program funds available each fiscal year to eligible projects selected in accordance with Health and Safety Code section 44286(d). ARB shall annually post on its website a solicitation packet for State Reserve projects. The solicitation packet will include the application requirements and due date, project eligibility criteria, and project selection criteria.

C. Air District Applications for Grant Funds

1. **Air District Options**. An air district may consider the following options upon receiving the solicitation:

   (A) Accept the tentative allocation in full without change, and commit to the associated match funds amount;

   (B) Accept the tentative allocation but request additional funds, and commit to the associated match funds amount;

   (C) Accept the minimum allocation of $200,000, with no match requirement;

   (D) Accept the minimum allocation and authorize the funds be designated to the Rural Assistance Program, for the current year and up to four additional years unless rescinded in a future year;

   (E) Accept the tentative allocation and authorize the funds be designated to a lead air district for Moyer Program funding in the region, for the current year and up to four additional years unless rescinded in a future year;

   (F) Decline an allocation. In this case the air district's share of funds will be redistributed with the final funds allocation.

2. **Application and Resolution**. Within 60 calendar days of the date of the solicitation letter, an air district accepting or designating funds will provide ARB a completed application indicating the option chosen above and signed by the APCO. The application will include a board resolution or minute order that supports the option chosen, and will indicate the district is maintaining a Moyer Program Policies and Procedures manual that meet the requirements of this section. For air districts accepting funds the resolution or minute order will commit the district to participate in the Moyer Program, comply with Program requirements, and commit to providing matching funds if requesting funds above the minimum allocation. If the air district board is unable to consider the Moyer Program application within the 60 days following the solicitation letter, the application will indicate when a resolution or minute order will be considered by the board.

3. **Match Funds**. An air district requesting the tentative allocation or a greater amount must make a match funds commitment equal to 15 percent of State funds requested. The district will indicate on its application the source of match funds. An air district may account for up to 15 percent of its match requirement with in-kind contributions. Sources and requirements for match funds are described in Section I of this chapter.

4. **Policies and Procedures**. To remain eligible for continued funding, an air district will maintain a Moyer Program Policies and Procedures Manual. The manual will focus on the district's local implementation of the Moyer Program Guidelines, including roles and responsibilities within the district and local application of Moyer Program policies. Air district staff will review the manual at least once a year and make it available when requested by ARB staff or a member of the public. The manual will include at least the following elements:

    (A) Roles and responsibilities within the air district for program implementation, including staff or positions responsible for: responding to ARB funding solicitations; evaluation, selection and inspection of projects; and obtaining governing board approval for program participation and projects to be funded;

    (B) Identification of the project source categories supported by the air district Moyer Program, and the schedule for solicitation and review of applications to be submitted under these source categories;

    (C) Procedures for project selection, including cost-effectiveness or other criteria applied to rank projects, or whether projects are selected in order of application receipt (first-come, first-serve); and any procedures that vary by source category;

    (D) Procedures for notifying successful applicants of their grant awards, and for notifying applicants who have not been awarded grants;

(E) Where applicable, project selection procedures that ensure priority for funding projects that will reduce air pollution in communities with the most significant exposure to air pollution (H&SC § 43023.5);

(F) Where applicable, the procedures for selecting projects to be funded with Moyer Program match funds;

(G) The method for calculating interest earned on Moyer Program funds held by the air district;

(H) Procedures for grantees to submit program invoices and receive payment, including itemization required to limit reimbursement to eligible costs, conditions for progress or partial payment, and practices for withheld payments pending grantee reporting;

(I) Methods the air district will use to verify the destruction of engines and equipment when required, consistent with minimum standards specified in these Guidelines by source category;

(J) Methods the air district will use to store and retrieve digital photographs documenting project inspections along with associated project-specific information;

(K) Procedures, schedules and required content for grantee reports;

(L) The types of acceptable documentation for establishing historical annual usage, and procedures for considering and granting usage waiver requests, including supporting information to be provided by the grantee;

(M) Procedures for working with nonperforming grantees to gain full compliance with contracts and program requirements;

(N) Any air district program requirements that are more stringent than those specified in Moyer Program Guidelines and Mail-Outs;

(O) Any ARB approvals of air district program elements that vary from those required by Moyer Program Guidelines and Mail-Outs, e.g., methods of ensuring engine or equipment destruction that vary from those specified in the source category chapters.

D. Grant Application Review and Grant Award

1. **Review Period**. ARB will review an application immediately upon receipt and, when necessary, provide the air district with a written explanation of what is missing from the application within ten working days of its receipt. ARB will approve completed applications that fulfill all criteria no later than 60 working days after receipt, including time for ARB review and comment on air district Policies and Procedures if desired (H&SC § 44287(m)).

2. **Conditional Approval**. ARB may elect to approve an application that is missing a particular item and make the submittal of that item a Special Term and Condition of the Grant Agreement. For example, sometimes air district staff is unable to obtain a board resolution or minute order before the application

deadline. In such a case, ARB may allow a board resolution or minute order to be submitted with the signed Grant Agreement or prior to the air district's initial disbursement.

3. **Policies and Procedures Review**. The grant application includes the air district's statement that it is maintaining a manual of current policies and procedures consistent with the requirements above. ARB may choose to review an air district's Policies and Procedures Manual, and an air district may request ARB's review of its manual's completeness and consistency with these Guidelines. ARB comments on an air district's Policies and Procedures Manual will be provided by email or in other written format. An air district's policies and procedures as implemented can only be fully evaluated during a program review process.

4. **Grant Award Notification and Signature**. ARB will prepare and submit to qualifying air districts each year a notification of final grant awards, accompanied by a Grant Agreement for review and signature. A deadline for air district acceptance of the grant award will be specified in a cover letter sent with the Grant Agreement. The Grant Agreement package will include two copies of a cover sheet indicating the amounts of funds granted for projects and for administration, the required amount of match funds if applicable, any Special Terms and Conditions, and General Terms and Conditions for the grant. The district APCO will sign both copies of the cover sheet and return them with original signatures to ARB. Following signature by ARB Budgets Chief, ARB will return one original copy to the air district for its records.

E. Fund Disbursement

1. **Procedure**. ARB may disburse funds following signature of the Grant Agreement by both parties. To obtain funds the air district will submit a completed current Grant Disbursement Request Form, available on the Moyer Program website. The Grant Disbursement Request Form must include an original signature by a party authorized and designated by the air district's Governing Board. Any Special Terms and Conditions in the Grant Agreement must be met before ARB will disburse funds associated with the grant award. Disbursement requests must be received by ARB by May 15 each year to ensure payment within the fiscal year. Any funds not disbursed by June 30 two years following the award will be reallocated to all districts in the subsequent grant cycle.

2. **Initial and Additional Disbursements**. An air district may request an initial disbursement of $200,000 or 10 percent of its project funds, whichever is greater. The air district may request additional disbursements when the criteria below have been met.

    (A) The preceding Yearly Report demonstrates on-time liquidation consistent with Health and Safety Code section 44287(j); or if not, any funds not

liquidated on time have been received by ARB. ARB will not require a return of funds under executed contract. ARB may require an air district to change the funding years from which funds are assigned to projects in the statewide database (Clean Air Reporting Log or CARL) to facilitate on-time liquidation.

(B) The Grant Disbursement Request Form is accompanied by a list of projects under executed contract with invoices pending, approved by an air district governing board, or under air district staff review for eligibility and funding. The total cost of the projects listed should equal or exceed the amount of the disbursement request.

3. **Administration Funds**. An air district may also request some or all of its administrative funds with an initial disbursement. The air district will receive one check for both program administration and project funds, but must account for the expenditure of administration and project funds separately.

F. Redirection of Funds

1. **Procedure**. An air district may redirect funds to another air district or the Rural Assistance Program by submitting to ARB the items below. For funds already disbursed by ARB and due for liquidation by June 30 of the current fiscal year, the air district must submit these items no later than March 31 to allow time for processing new grant agreements. For funds not yet disbursed by ARB and due for disbursement by June 30 of the current fiscal year, the air district must submit these items no later than March 15 to allow time for processing new grant agreements and subsequent processing of a disbursement request for the air district receiving the redirected funds. A redirection request includes:

   (A) The Moyer Program Redirection of Funds form, with the appropriate portions completed in consultation with ARB staff and indicating the sums of project and administrative funds to be redirected, which may include interest or other earned funds due for liquidation;

   (B) Resolutions or minute orders adopted by the boards of the air districts transferring and receiving funds that authorize the redirection;

   (C) A memorandum of understanding (MOU) or equivalent signed by the air pollution control officers of the affected air districts. The MOU must:

      (1) Specify the details and conditions of the redirection of funds;

      (2) Identify which air district is responsible for any required match associated with the redirected funds;

      (3) Identify the funding year and the associated liquidation deadline for the redirected funds;

      (4) Specify how and when payment will be made to the air district receiving the funds, including one of the following:

a. If the transferring air district has not submitted a disbursement request to ARB, the MOU will specify that the air district that is receiving the funds will submit the request to ARB following ARB approval of revised grant agreements.
b. If the transferring air district has the funds already, the MOU will specify that it will pay the receiving air district directly, following ARB approval of revised grant agreements.

2. **Amended Grant Agreements**. After receiving the items above from the transferring air district, ARB staff will develop new or amended grant agreements. District APCOs must sign and return the grant agreement cover sheets for signature by the ARB Budgets Chief. After ARB signature of both revised grant agreements, the receiving air district may request either a disbursement of funds from ARB or payment from the transferring air district. An air district receiving funds from another district will submit a copy of the check to Moyer Program staff.

3. **Retention of Administrative Funds**. Air districts redirecting project funds but retaining, with approval of the receiving air district, associated administrative funds must provide to ARB by the close of the fiscal year in which the funds were transferred a description of how administrative funds were utilized for the period since the grant award, including but not limited to the following:

   (A) A summary of air district activities to solicit project applications, including copies of any written grant solicitations and lists of potential applicants to which outreach was directed;

   (B) A list of project applications submitted and reviewed;

   (C) A breakdown of staff time devoted to Moyer Program activities;

   (D) A summary of any Moyer Program training activities for air district staff.

G. Rural Assistance Program

1. **Purpose**. The Rural Assistance Program (RAP) is a partnership among rural air districts, the California Air Pollution Control Officers Association (CAPCOA), and ARB to enhance rural air district participation in the Moyer Program. RAP facilitates air district participation by streamlining the grant administrative process and by encouraging the pooling of financial and technical resources. The reduction in cost and staff resources lowers the threshold for participation in the Moyer Program and maximizes project funding in rural areas.

2. **Designation or Redirection to RAP**. An air district may designate funds to RAP in its application for Moyer Program funds (see Section C.1.(D)). An air district may also redirect funds to RAP after it has executed a grant with ARB, but must do so by March 1 of the year by which funds must be disbursed, as shown in the example timeline below. RAP funds that have been disbursed to air districts and

subsequently returned to ARB will be reallocated to other RAP projects whenever possible.

Table 3-2
Example RAP Funds Calendar:
Moyer Program Year 18 (Fiscal Year 2015-2016)

January–April 2016	Air district applies for funds and executes Year 18 Grant Agreement; funds are designated to RAP.
March 1, 2018	Deadline to redirect air district's grant funds to RAP
June 30, 2018	Deadline for air districts to receive fund disbursements. Target date to expend Year 18 grant award.
June 30, 2020	Deadline to liquidate Year 18 grant award

3. Roles and Responsibilities among RAP Program partners are as follows:

(A) ARB notifies CAPCOA of funds designated or redirected to RAP, and develops and administers grant agreements between ARB and recipient air districts.

(B) CAPCOA selects a program administrator, which may be CAPCOA staff, an air district, or a third party. CAPCOA also establishes criteria for project selection and approves projects selected by the Program Administrator.

(C) The RAP Program Administrator provides outreach for RAP, prepares the application and project solicitation, performs initial application screening, ensures project eligibility, ranks projects based on CAPCOA criteria, selects projects, and determines recipient air districts.

(D) Donor air districts designate all or a portion of their Moyer allocations to RAP on their Moyer grant award application, or redirect grant funds already accepted to RAP using the procedure in Section F of these Guidelines. Air district boards approve designation or redirection of RAP funds via resolution or minute order.

(E) Recipient air districts sign grant agreements with ARB to accept funds for RAP projects, maintain a Policies and Procedures Manual, and are responsible for grant obligations, including contracts with grantees for project implementation, project inspections, monitoring and reporting. Air district boards approve receipt of RAP funds via resolution or minute order.

H. AB 923 - $2 Motor Vehicle Fee

1. **Project Eligibility**. State law allows air districts to collect an additional $2 motor vehicle registration surcharge (MV Fee) (H&SC § 44223) which must be used to fund the following project categories (summarized) (H&SC § 44229(b)):

   (A) Projects eligible for grants under the Moyer Program.

   (B) The new purchase, retrofit, repower or add-on equipment for previously unregulated agricultural sources of air pollution (Agricultural Assistance Program, H&SC § 39011.5).

   (C) Purchase of new school buses or the repower or retrofit of emissions control equipment for existing school buses pursuant to the Lower-Emission School Bus Program adopted by the Board.

   (D) An accelerated vehicle retirement or repair program that is adopted by ARB.

   (E) Onboard natural gas tank replacements in existing school buses 14 years or older or the enhancement of deteriorating natural gas fueling dispensers of fueling infrastructure pursuant to the Lower-Emission School Bus Program adopted by the Board.

   (F) Alternative fuel and electric infrastructure projects solicited and selected through a competitive bid process.

2. **Match**. $2 MV Fees used to meet the Moyer Program match fund requirement (See Section I) are subject to the same eligibility, reporting, review and auditing requirements as State-provided Moyer Program funds. $2 MV Fee funds used to meet the match requirement are not required to be expended within two years from the date of their collection. However, air districts must expend sufficient match funds to meet the obligations for the Moyer Program funds received each year.

3. **Reporting and Oversight**. Reporting and oversight of the $2 MV Fee depends upon whether the fee is used to meet the Moyer Program's match requirement and whether the air district takes SIP credit for $2 MV Fee projects. Table 3-3 summarizes the various scenarios for treatment of $2 MV Fee funds and projects. Sections M and R of this chapter further describe $2 DMV fee reporting and oversight.

Table 3-3
Summary of $2 MV Fee Requirements and Oversight

Requirement	$2 MV Fee Used as Match	$2 MV Fee Used for SIP Credit	$2 MV Fee Not Match/ not SIP
Liquidation of funds within four years	[a]	--	--
Meet full and complete Moyer Program Guideline criteria	√	--	--
Subject to ARB Incentive Program Review	√	--	[b]
Subject to ARB project eligibility evaluation (e.g., cost-effective and surplus)	√	√	√
Fiscal reporting to ARB (list total funds expended in seven basic categories)	√	√	√
Detailed reporting to ARB (project specifics submitted in current database)	√	√	--

[a] Sufficient funds must be liquidated, regardless of their year of origin or source, to provide the required match by that year's liquidation deadline. For example, for Year 18, air districts must complete liquidation of applicable Year 18 match funds by June 30, 2020. When those funds were received is not a factor in determining this deadline.

[b] Non-match projects funded with AB 923 $2 MV Fee may be evaluated by ARB in conjunction with Incentive Program Review. Evaluation of these projects will be limited to project eligibility. Any irregularities regarding non-match AB 923 $2 MV Fee project eligibility must be reported separately from Incentive Program Review findings.

I. Air District Match Funds

1. **Requirement**. Air districts participating in the Moyer Program are required to provide match funding. Air districts implementing the Moyer Program must commit match funds equaling 15 percent of the regular Moyer Program funds received. An air district receiving the minimum grant award of $200,000 is exempt from this match requirement.

2. **Federal Funds**. Air districts may use federal funds as Moyer Program match if written confirmation is received from the administering federal agency (for example, the United States Environmental Protection Agency) that (1) the administering agency has no objection to the air district using those funds as match, and (2) the emission benefits obtained from those funds will not be used by the administering agency in a State Implementation Plan. The air district must also ensure that it will not use such funds as match for any other program and that the use of the funds as Moyer Program match does not conflict with any State or local requirements regarding the funds. If this option is used, supporting documentation must be included in all relevant project files.

3. **Program Basis**. Air districts may meet their matching fund requirement on an overall program basis rather than a project-by-project basis. In other words, air

districts do not need to provide match funds towards each project funded, but must fund enough projects (in total or in part) with match funds in order to meet the match requirement. Match funds are included in cost-effectiveness calculations and subject to the same cost-effectiveness limits as other Moyer program funds.

4. **Match Fund Sources**. Match funds may be any funds under an air district's budget authority or fiduciary control that are committed to be expended in accordance with Moyer program requirements. Match funds may also be provided by a port authority, or a local government teamed with an air district. Match funds provided by a port authority or a local government shall not exceed 30 percent of the total required matching funds in any air district that applies for more than $300,000 of the state board funds (H&SC § 44287(e)). Port authorities may participate through projects involving their own equipment, or by soliciting port tenants to apply for project funding.

5. **In-Kind Contributions**. Up to 15 percent of an air district's match requirement may be fulfilled through in-kind contributions (H&SC § 44287(h)). Air districts may use any funds under their budget authority, except for Moyer Program administrative funds and interest or other funds earned on Moyer Program funds, to cover their in-kind contributions. When using air district funds for in-kind match, air districts must follow all relevant statute, guidelines, and other legal requirements for expending such funds. In-kind contributions have the same expenditure timeline as match funds. Air district in-kind match funds spent on program administration and outreach must meet the documentation requirements in Section J.

6. **Eligible Projects**. Match funds may be used to pay for any project that meets all Moyer Program criteria. Match funds may also be used to pay for the incremental cost of electricity or alternative fuels serving a Moyer program eligible source category.

J. Air District Administration Funds

1. **Air District Funding**. Air districts with one million or more inhabitants may use up to 6.25 percent of their Moyer Program funds on program outreach and administration, while air districts with under one million inhabitants may use up to 12.5 percent of their Moyer Program funds (H&SC § 44299.1(c)-(d)). Air districts shall maintain an outreach program consistent with Health and Safety Code section 44290.

2. **Allowable Costs**. Table 3-4 lists allowable administration costs and documentation that the air district is required to maintain for Moyer Program administrative funds. Air districts will make available the documentation shown in the table for review during ARB or other State agency monitoring visits, reviews and audits. Such administrative records for a given funding year must be retained for a minimum of five years following the applicable funding year

liquidation deadline. For example, for Year 16 (fiscal year 2013-2014) funds, the funding year liquidation deadline is June 30, 2018, and administrative records would be retained through June 30, 2023.

Table 3-4
Administration and Outreach Costs and Documentation

Allowable Cost	Required Documentation
Air district staff time	Personnel documentation that may include timesheets or output of labor tracking software; duty statements or job descriptions indicating percentage of staff time; or written summaries of Moyer Program staff activities with time estimates by activity or task.
Consultant fees	Consultant contracts and invoices
Printing and mailing costs	Receipts and invoices. Copies of solicitations and outreach materials indicating availability of grants
Travel expenses	Receipts and invoices. Travel cost criteria must be consistent with written air district travel policies for other air district programs, cited in the Policies and Procedures Manual or local administrative manual.
Indirect costs	Indirect cost calculation methodologies must be described or cited in the Policies and Procedures Manual or local administrative manual, and calculated costs must be documented.

3. **Mitigation for Unallowable Costs**. An air district that charges unallowable costs for program administration or outreach must substitute eligible administration and outreach expenses equal to the dollar amount found ineligible, or return the funds for the unallowable cost to ARB.

K. Accounting Principles

Air districts must establish accounting practices for Moyer Program funds consistent with the requirements below, as early as practicable and no later than July 1, 2019.

1. **Moyer Funds Account**. Moyer Program funds (Moyer funds) must be accounted for as separate funds within the air district's general ledger following generally accepted accounting principles (GAAP). An air district receiving a total allocation of one percent or more of all Fiscal Year 2016-17 Moyer Program funds must use a Special Revenue Fund for Moyer funds accounting. Other air districts may use a Trust Fund.

2. **Timing of Recognition in Financial Statements**. Moyer Program grants are voluntary non-exchange transactions to the air district. As such the air district should recognize revenues in the fiscal period when all eligibility requirements have been met and the resources are available. For reference see Governmental Accounting Standards Board (GASB) Statements 33 and 34.

3. **Required Financial Statements**. Financial statements containing at minimum the following account balances and transaction classes, as applicable, will be prepared at least annually.

   (A) Balance Sheet:

      (1) Cash and Cash Equivalents (cash, investment pools, petty cash)

      (2) Moyer Program Fund Revenue Receivable (grant funding from ARB)

      (3) Recapture Revenue Receivable (recapture funds receivable from grant participants for unmet contractual obligations)

      (4) Salvage Revenue Receivable (revenue receivable from retired equipment sold or auctioned for scrap metal)

      (5) Accounts Payable (vendor invoices pending for Moyer projects)

      (6) Fund Balance

         a. Restricted for Air District Projects
         b. Restricted for State Reserve, Multi-District, RAP Projects
         c. Restricted for Administration and Operating Costs

   (B) **Statement of Revenues, Expenditures, and Changes in Fund Balance:**

      (1) Revenue Subsidiary Ledgers

         a. Regular Moyer Funds Project Revenue
         b. State Reserve and Multi-District Project Revenue
         c. Rural Assistance Program Project Revenue
         d. Administration and Operating Revenue
         e. Recapture Revenue
         f. Salvage Revenue
         g. Interest Revenue

      (2) Expenditure Subsidiary Ledgers:

         a. Project Expenditures (from regular Moyer grant, recapture, salvage, interest)
         b. State Reserve and Multi-District Project Expenditures
         c. Rural Assistance Program Project Expenditures
         d. Administration and Operating Expenditures including indirect costs

      (3) Awards Returned: Moyer Program air district money returned to ARB for reallocation

      (4) Transfers In/Out

4. **Interest Revenue**. Any interest earned on investment of Moyer fund cash balances must be deposited in the Moyer funds account and used to fund

Moyer-eligible projects, or to fund administration up to the portion provided for in Health and Safety Code section 44299.1(c)-(d), or be remitted to ARB.

(A) An air district electing not to invest Moyer Program fund cash balances but investing other cash balances should deposit the Moyer Program funds in a separate checking account to clearly indicate that no such moneys were invested.

(B) When invested, Moyer Program funds should receive equitable pro-rated interest earned on the total funds invested. As State funds, Moyer Program funds may be invested only in accounts or instruments that reflect the risk appetite of the State. For reference see Office of the State Treasurer Local Agency Investment Guidelines. Any loss from investments not made in accordance with standards set forth in California Government Codes must be covered by the air district.

5. **Recapture and Salvage Revenue**. Revenues earned or collected by the air district through Moyer Program resources, including revenues obtained through salvage and sale of scrapped equipment, must be reported and either retained as a supplemental source of funds for Moyer projects or forwarded to ARB for deposit to the Air Pollution Control Fund. If recaptured funds or salvage revenues are invested, such revenues must meet the requirements of Section K.4.(B) above. Air districts are not required to earn funds through program actions, or expected to base business decisions on their ability to generate returns or collect funds through program activity.

6. **Expenditures for Moyer Program Projects**. All project expenditures out of the Moyer funds account must meet the Moyer Program Guidelines current at the time of contract execution, including any revisions to those Guidelines in effect at the time of contract execution.

7. **Reporting Requirements**. No later than six months after the air district fiscal year end, the district will append to its Yearly Report a Balance Sheet and a Statement of Revenues, Expenditures and Changes in Fund Balance, in formats consistent with GAAP.

8. **Records Retention**. Grant receipts and expenditure documents including invoices, contracts, vouchers, personnel and payroll records should be retained for five years after the grant liquidation period or the last recorded grant transaction, whichever is later.

L. Co-funding Moyer Program Projects with Other Funding Sources

1. **Purpose**. Senate Bill 513 (Beall, 2015) provides new opportunities to co-fund Moyer Program projects with other funding sources. These Guidelines specify requirements that apply when multiple funding sources are proposed to support a Moyer Program eligible project. All co-funded projects must adhere to the Moyer Program objective to achieve cost-effective and surplus emission reductions to

be credited toward California's legally enforceable obligations in the SIP (H&SC § 44286(g)). There is no limit on the number of co-funding sources to fund a project as long as total project costs are not exceeded and the applicant cost share requirement is met.

2. **Designation of Non-Moyer Funds**: Funds other than Moyer Program grant funds may be used to co-fund Moyer Program eligible projects, when all program criteria associated with each funding source are met. Funding sources are grouped into the following categories. Definitions of these categories can be found in Appendix B.

   (A) Federal funds;

   (B) State funds;

   (C) Local funds;

   (D) Penalty funds;

   (E) Other applied funds.

3. **Mitigation Funds**. Mitigation funds may be used to co-fund a Moyer project if an air district submits a request for a case-by-case determination in accordance with Section U and receives ARB approval.

4. **Cost-effectiveness Calculation**. The non-Moyer funds described above are not required to be included in Moyer project cost-effectiveness calculations (H&SC § 44287.2(a)). Match funds and all AB 923 $2 DMV Fees are required to be included in project cost-effectiveness calculations.

5. **Applicant Cost Share**. An applicant that is not a public entity must provide at least 15 percent of a project's Moyer eligible cost from non-public sources. The applicant cost share cannot be covered through in-kind contributions. An air district may request a case-by-case determination from ARB to waive all or part of an applicant's cost share, in accordance with Section U. In its waiver request, an air district must identify the source(s) and amount(s) of the proposed project's funding and explain the reasons for the cost share waiver, discussing at a minimum either or both of the following factors:

   (A) The public benefit of the project that is above and beyond the emission reductions achieved;

   (B) How the project will advance newer and cleaner technology.

6. **Applicant Disclosure and Payment**. The sum of project funding from all sources may not exceed the total project cost (H&SC § 44287.2(b)). Applicants must disclose all sources of funding applied for at the time of the Moyer project application, and again when submitting each invoice to the air district, prior to payment of Moyer Program grant funds (H&SC § 44283(g)). An air district may not issue payment of Moyer Program grant funds until all funding sources have

been identified and verified and the air district can ensure that the sum of the grants awarded to the project, including both Moyer and non-Moyer funds, does not exceed the total project cost.

7. **Emission Reductions**. All covered emission reductions achieved from a project with multiple funding sources will be credited as reductions from the Moyer Program to ensure proper SIP accounting, improve the likelihood of federal credit, and avoid risk of double-counted reductions. Other emission reductions, such as greenhouse gases, may be claimed by other programs that co-fund a project.

8. **Reporting of Project Data**. For co-funded projects an air district will report in CARL consistent with the reporting requirements of Section M. The air district will also report other co-funding sources and funding amounts. When reporting project funding sources to CARL, air districts will categorize certain co-funding sources as specified below.

   (A) Funding from investor owned utilities will be reported as “other applied funds,” and funding from publicly owned utilities as “local funds.”

   (B) Supplemental environmental project funds will be reported as “other applied funds.”

   (C) Funds from local transit agencies will be reported as “local funds.”

M. Yearly Report

1. **Reporting Requirement**. Each year by June 30, ARB will prepare and make available to air districts a certification form with instructions for completion of the Yearly Report. Air districts will complete, certify and submit the Yearly Report by August 29. An air district that has designated to another air district or the Rural Assistance Program all grant funds for all years covered in the Yearly Report is not required to complete a report.

2. **Reporting in CARL**. Air districts will report project information in the Clean Air Reporting Log (CARL) database, either via CARL forms or batch import, sufficient to populate the required data fields and to calculate covered emission reductions and cost-effectiveness for source categories where required. The air district will ensure the information in CARL is complete, correct, and supported by documentation. The air district will report on projects funded in whole or part with these funds:

   (A) Granted Moyer Program funds;

   (B) Match funds;

   (C) Interest and other non-grant revenues earned to support the Moyer Program;

   (D) Multi-district and State Reserve funds;

(E) Rural Assistance Program funds;

(F) Non-Moyer funds as specified in Section L;

(G) AB 923 $2 DMV fees used for projects claimed for SIP credit;

(H) Other funds that ARB oversees relative to the Moyer Program.

3. **Report Content**. The Yearly Report will include the following information as of June 30, the end of the past fiscal year:

(A) Output generated by the Required Reports utility of CARL for the default years specified in the utility.

(B) Contract execution and liquidation status of Moyer Program funds, including match funds, earned interest funds, multi-district and State Reserve funds, RAP funds, and other funds for which the air district has a Moyer Program obligation during the fiscal years covered by the report. Funds will be reported relative to the progress milestones identified in Sections N and O below.

(C) A funding summary by project type of non-match projects funded with AB 923 $2 MV fees when no SIP credit is claimed. Projects funded with AB 923 $2 DMV fee funds not used as match and not claimed for SIP credit need not be entered into CARL, but the air district will summarize in the Yearly Report the amounts of such funds expended for each of the project categories identified in Section H.1.

(D) For the most recent fiscal year, additional funds available to the Moyer Program from the following sources. These funds will be included in the target for the funding year due for liquidation in four years unless the air district directs ARB staff to include them in an earlier year target.

(1) The amount of any interest accrued on Moyer Program funds held in local accounts. An air district may choose to designate in the Yearly Report all or a portion of this interest for remittance to ARB.

(2) Funds recaptured from liquidated projects, including funds provided back to the air district following ARB enforcement actions, identified by project name and funding year.

(3) Non-grant revenue earned for the Moyer Program by the air district, such as from the sale of scrapped engines or equipment.

(E) A list of any projects identified as non-performing and a brief narrative of any related enforcement actions.

(F) The portion of match funds to be met through in-kind contributions, as provided in Section I.5.

4. **Report Certification and Documentation.** The air district APCO, Chief Financial Officer (CFO), and Moyer Program administrator must sign and certify that the project and fiscal information contained within the Yearly Report is, to the

best of their knowledge, accurate and complete. The APCO may also serve as the Moyer Program Administrator. The APCO may designate an alternate to the CFO if the designated alternate is someone other than the APCO or Program Administrator. The air district will maintain documents in support of the report at the air district office, and make them available to ARB staff upon request.

5. **Project Eligibility**. Receipt of a Yearly Report by ARB does not imply ARB approval of project eligibility. Air district staff is responsible for project approval and funding eligibility determinations. Air districts that are found to have funded ineligible projects will be required to substitute eligible projects equal to the amount found ineligible or return the ineligible amount to ARB.

N. Progress Tracking

1. **Progress Milestones**. To support timely emission reductions and track progress toward statutory fund liquidation requirements, air districts and ARB will work together to meet recommended progress milestones as follows. After execution of a grant agreement with ARB for Moyer Program funds, air districts will make every effort to have 50 percent of the project funds awarded under executed contract by June 30 of the next calendar year, and 100 percent of the project funds under executed contract by June 30 of the second calendar year after the agreement. Air districts will also make every effort to have 50 percent of project funds liquidated within two years, and 75 percent of project funds liquidated within three years. Similar progress milestones apply to any match funds associated with granted project funds. Progress will be reported in Yearly Reports. Table 3-5 shows an example of progress milestones for the 2018 Yearly Report.

Table 3-5
Example Progress Milestones: 2018 Yearly Report

Timeline	Fiscal Year	Funding Year	Milestone
1 year	2016-17	19	50% of project funds under executed contract
2 years	2015-16	18	100% of projects funds under executed contract
			50% of project funds liquidated
3 years	2014-15	17	75% of project funds liquidated
4 years	2013-14	16	100% of grant funds liquidated (Section O)

2. **Cumulative Tracking**. ARB will provide tools in CARL to track district progress toward milestones. Except in the case of a four-year funds liquidation deadline, districts may track progress on a cumulative basis. In the table above, for

example, an air district demonstrating the portion of funding year 17 project funds liquidated would count any funds liquidated from funding years 18 to 20.

3. **Funding Targets**. To assist cumulative tracking and reporting, ARB will maintain in CARL appropriate progress tracking targets for each funding year. These funding targets will include the total funds required to meet contract execution and liquidation progress milestones. ARB will adjust progress tracking targets to account for the movement of funds into and out of an air district's account, including redirected funds, RAP grants, adjustments for in-kind match, and other changes agreed to in consultation with districts.

4. **Execution Progress for Vouchers**. For Moyer voucher programs, the voucher issue date is used in lieu of executed contract date to gauge progress in contract execution.

5. **Cancelled Contracts**. Any funds associated with an engine, vehicle, or equipment cancelled from a contract prior to the liquidation of the contract as a whole will no longer be considered executed beginning at the time of the cancellation.

6. **Follow-up Actions**. Progress milestones are advisory in nature. ARB liaisons and management will work with air districts that do not demonstrate sufficient progress toward contract execution and project liquidation targets in the Yearly Report. When an air district cannot demonstrate at least one-half of funds are under contract after two years, and one-half of funds liquidated after three years, the district will append to the Yearly Report a progress statement. The statement will address the reasons for delays in executing contracts or completing payment for projects, and the schedule for follow-up actions. Such actions may include specific steps to improve progress or the redirection of funds to air districts better equipped to meet statutory liquidation deadlines.

O. Funding Year Liquidation

1. **Liquidation Requirement**. By June 30 of each year, air districts must have liquidated all Moyer Program funds associated with the funding year four calendar years prior, as well as interest, recaptured funds, and other funds added to the funding target for that year. For example, funds awarded for Year 18 (fiscal year 2015-2016) must be fully liquidated by June 30, 2020. Before submitting the Yearly Report an air district may attempt to resolve an apparent liquidation shortfall by modifying in the CARL database the funding years from which funds are assigned to projects.

2. **Match Liquidation**. Match funds must be liquidated by the same liquidation deadline as the Moyer Program funds with which they are associated regardless of the date such funds were collected by the air district.

3. **Liquidation Terms**. Air districts are advised of the distinction between project liquidation used for cumulative progress tracking in Section N and funding year

liquidation as required in this section. Project liquidation is demonstrated when all funded equipment in a project are paid-in-full and post-inspected; liquidated projects are credited in cumulative progress tracking. Funding year liquidation is demonstrated when all funds assigned to a funding year have been paid out in full, with the exception of any withheld payments. Liquidated projects are credited in cumulative progress tracking.

4. **Data Completion**. A funding year that has been liquidated by an air district and all associated projects will be removed from cumulative tracking. Projects associated with liquidated funding years may not be revised in or removed from the CARL database after the funding year is liquidated, except in unusual circumstances following consultation with and written approval by ARB staff.

5. **Withheld Payments**. For completed projects for which all invoices have been paid except for a small amount withheld pending grantee reporting, both the paid funds and the withheld funds will be considered liquidated for the purpose of funding year liquidation. Withheld payment practices must be addressed in the project's contract and in the air district's Policies and Procedures Manual. Withheld progress payments considered to be liquidated per this section that are not ultimately paid to the grantee due to non-performance will be reported as recaptured funds.

P. Return and Reallocation of Funds

1. **Return of Unliquidated Funds**. If the Yearly Report identifies a liquidation shortfall that cannot be resolved through reassignment of liquidated funds from more recent years, and the remaining unliquidated funds are not under executed contract, the air district must submit and ARB must receive a check for the shortfall amount by September 28 (i.e., 90 days after the June 30 liquidation deadline and 30 days after the Yearly Report deadline). ARB will provide Instructions for the return of funds in the Yearly Report certification form. No additional disbursements will be made to the air district until funds subject to return have been received by ARB.

2. **Return of Other Funds**. An air district choosing to remit to ARB all or a portion of earned interest, or to return other funds following consultation with ARB, may do so following instructions in the Yearly Report certification form.

3. **Reallocation**. ARB will add funds returned by air districts to the subsequent cycle of Moyer Program funding, following the allocation requirements of Health and Safety Code section 44299.2.

Q. Program Nonperformance

1. **Monitoring Nonperformance**. As directed by Health and Safety Code section 44291(d), ARB monitors air district programs to ensure that participating air districts conduct their programs consistent with the criteria and guidelines established by the Board. Program non-performance is an air district's

non-compliance with program Guidelines or statute that is not corrected by the air district in a timely or satisfactory fashion. ARB may become aware of possible air district non-performance through Yearly Reports, Incentive Program Review, district self-reporting or other means. Examples of program non-compliance with program guidelines or statute include, but are not limited to, the following:

(A) Failure to return unliquidated funds within 90 days of the liquidation deadline (H&SC § 44287(j));

(B) Misuse of Moyer Program funds, including funding of ineligible projects;

(C) Insufficient or improper program oversight and enforcement, including widespread deficiencies in project contracting, inspections, reviews or audits;

(D) Insufficient, incomplete, or inaccurate project documentation;

(E) Failure to submit timely and accurate reports to ARB;

(F) Other non-compliance with program guidelines or statute.

2. **Nonperformance Procedures**. When ARB determines that an air district program is not complying with program guidelines, the ARB liaison and manager will work with air district staff to understand the issues, and develop a plan and timeline to resolve them. If the ARB Branch Chief determines that the issues related to program nonperformance have not been resolved, ARB will send by email to the air district program contact a program nonperformance notification, that contains the following:

(A) Description of the unresolved issues, including pertinent details such as names of involved persons and projects, dates, dollar amounts, and citations of relevant program guidelines sections, Health and Safety Code sections, and regulations; and

(B) Possible solutions to the problem, if some have been identified, and/or an offer ARB assistance; and

(C) Arrangements for a possible meeting between the ARB Branch Chief and the air district APCO to agree on a plan and timeline for resolving the problem. The plan and timeline shall be recorded by the ARB air district liaison and emailed to the air district APCO within five business days of the meeting.

3. **Withholding of Funds by ARB**. Lacking satisfactory resolution of the issues that have resulted in the nonperformance notification, the ARB Executive Officer will determine if the nonperformance warrants withholding funds that have been granted to the air district and not yet awarded to approved projects. If so, ARB will send a letter of program non-performance to the district APCO. The letter will set a public meeting to be held at the air district's offices (or other appropriate

facility within the air district). The purpose of the meeting will be to consider public comments prior to withholding any funds.

R. Incentive Program Review

1. **Purpose**. ARB conducts Incentive Program Reviews to help ensure that air district programs achieve expected emission reductions and are implemented in a manner consistent with these Guidelines and State law (H&SC § 44291, 39500). ARB Incentive Program Reviews place emphasis on collaboration with the affected air district in the review process. Features of this approach include a joint initial review of project files, ongoing and regular communication with air district staff throughout the file review process, and where possible an opportunity for districts to correct problems prior to their inclusion as findings in the final report.

2. **Scale of Review**. ARB uses a risk-based approach to select specific air district programs and projects to review, and to select fiscal years within the scope of each review. Air districts are selected for Incentive Program Review based on identified need or with consideration of program funding amount. ARB's objective is to review over a five-year period air district programs receiving at least 80 percent of Moyer Program funds. Air district implementation of other State incentive programs will be selected as appropriate for review at the same time as the Moyer Program review.

3. **Fiscal Compliance Audits**. ARB may also contract with independent auditors including the California Department of Finance Office of State Audits and Evaluations, to conduct audits of incentive program fiscal compliance. The independent auditors will conduct these audits in accordance with Generally Accepted Government Auditing Standards, and will prepare reports on the results of the audits including any findings. ARB retains final authority with respect to corrective measures and follow-up, in consultation with the air district.

4. **ARB Responsibilities**. ARB will conduct Incentive Program Reviews in a manner that reflects its entrusted accountability and responsibilities.

    (A) ARB will generally define the scope of a Moyer Program review to cover a period of up to five fiscal years not covered in the previous review. The scope of years within review may vary for other incentive programs. Once a funding year is reviewed, ARB will not review it again unless warranted. ARB may investigate possible fraud or misuse of funds in any program year.

    (B) ARB will maintain open channels of communication with the air district during the review. ARB will fully explain the review's scope and procedure at the beginning of the process, discuss preferred channels of communication with the air district, inform the air district of potential issues as they unfold, provide full and ongoing opportunity for air district input, provide the air district opportunities to correct problems that arise during

the review process, thoroughly discuss any findings and recommendations with the air district before and during the exit interview, and provide the air district an opportunity to formally respond to the Incentive Program Review report.

(C) To ensure objectivity and predictability, ARB will base its findings and recommendations on State law, applicable guidelines and Mail-Outs, grant agreements, email communications between ARB and the air district, the air district's Policies and Procedures Manual, case-by-case determinations, and the air district's local requirements.

(D) All Incentive Program Review reports, air district responses, and related documents shall be made available to the public via posting on ARB's Moyer Program website.

(E) ARB will conduct follow-up activities to ensure any deficiencies remaining following review are promptly and effectively mitigated. ARB will offer its assistance to air districts working to correct deficiencies.

5. **Air District Responsibilities**. Air district staff and management will participate in entrance and exit interviews, support collaborative review and open communication with ARB staff, ensure that program files and other requested information are available to reviewing staff of ARB and the Department of Finance, work to fully and promptly mitigate deficiencies identified during the review, work to resolve any disagreements, and request assistance from ARB as necessary.

6. **DMV Fee Project Evaluation**. AB 923 $2 MV Fee projects are subject to Incentive Program Review or evaluation as follows:

(A) A Moyer Program match project funded with the AB 923 $2 MV Fees will be subject to the same review and oversight requirements and protocols as other Moyer Program match projects.

(B) A non-match project funded with the AB 923 $2 MV Fee may be evaluated by ARB in conjunction with an Incentive Program Review. Evaluation of these projects will be limited to project eligibility. Any irregularities regarding non-match AB 923 $2 MV Fee project eligibility will be reported separately from other Incentive Program Review findings.

S. Requirements for Project Applications

1. **Data Required for CARL**. Project applications must include the information needed for calculation of project cost-effectiveness in the CARL database.

2. **Existing Engine Usage**. Project applications must include documentation of existing engine usage, such as miles traveled, hours operated, or fuel consumed per year, for 24 months or as specified in these guidelines by source category.

This information will be used to evaluate project cost-effectiveness and the maximum grant award amount.

3. **Active Duty Military Applicants**. If an applicant has been on active military duty at any time during the previous 24 months, documentation prior to deployment and covering the same length of time as the deployment period may be used to meet the title, registration, usage, and operation in California requirements as applicable for each source category. The applicant must submit a copy of DD Form 214, Certificate of Release or Discharge from Active Duty to verify military service during the deployment period.

4. **Third Party Signature**. Applications must include a signature and date section for third parties. A third party may complete an application or part of an application on an owner's behalf if the vehicle, engine, or equipment owner signs and dates the application.

5. **Applicant Certification**. Project applications must include language informing the applicant that by signing and submitting the application, the applicant certifies under penalty of perjury that the information in the application is accurate and true. In addition, the application must include the following statements that the applicant or the applicant's designee must certify as accurate and true:

   (A) A disclosure statement consistent with Section L.6. of this chapter, specifying whether the applicant has submitted an application for incentive funds to any other entity or program for the same equipment (for example, repowering of the same engine). The applicant must disclose to whom other applications were submitted, whether funds have been awarded or may be awarded, and the amount or potential amount of other funding.

   (B) A regulatory compliance statement certifying that the applicant is currently in compliance with all federal, State, and local air quality rules and regulations at time of application submittal, and is not aware of any outstanding or pending enforcement actions.

6. **Applicant Non-Disclosure**. An applicant who is found to have applied for or received incentive funds from another entity or program for the same project without disclosing that information as required by these Guidelines shall be disqualified from funding for that project from all sources within the control of an air district or ARB. The air district or ARB may also seek civil penalties for such non-disclosure.

7. **Subsequent Applications**. An applicant may re-apply for project funding if a previous application for the same project has been rejected by the air district and is no longer being considered for funding.

T. Application Evaluation and Project Selection

1. **Review for Completeness**. Air districts must review all applications for completeness upon receipt, and notify an applicant within 30 working days of receipt if the application is not complete (H&SC § 44288(a)). The air district must make every effort to clearly state to the applicant what is required to make the application complete. The application and all correspondence with the applicant should be kept in the applicant's project file. Additionally, the record of each project's rating and ranking as applicable, receipt date, and other project selection criteria must be maintained with the project file.

2. **Credibility**. Air districts are responsible for determining that project applications are credible, made in good faith, and in compliance with the Moyer Program and its objectives.

3. **Eligibility**. Air districts must ensure that the emission reductions provided by selected projects are eligible and surplus to adopted regulations and other legal requirements. This should include checking to ensure the project meets the minimum requirements in the appropriate source category chapter, including:

   (A) Documentation of historical vehicle, equipment, or engine usage;

   (B) Documentation of project costs;

   (C) Engine or retrofit device Executive Orders, if applicable;

   (D) Proof of a vehicle compliance check as needed for on-road projects;

   (E) Other documentation identified in the source category chapter.

4. **Application Tracking**. Air districts must have a system for tracking applications. CARL may be used to satisfy this requirement if an air district enters the data from all applications received into this database, whether the application is provided funding or not. Air districts not using CARL will track the information needed to populate required CARL data fields. A tracking system is not required for air districts receiving under one-half percent of the current fiscal year total Moyer Program Funds, or $450,000, whichever is less.

5. **Project Selection**. After reviewing applications for project eligibility, the air district must follow its Policies and Procedures Manual in selecting projects to fund. Projects approved for funding must meet all applicable requirements of these guidelines.

6. **Communities with Most Significant Exposure**. Air districts with a population of one million or more residents must select projects from their applicant pools in a way that ensures that 50 percent or more of their Moyer Program funds are expended to reduce air pollution in communities with the most significant exposure to air pollution, including communities of minority and low-income populations (H&SC § 43023.5). Air districts may track this on a cumulative basis.

7. **Project Evaluation**. An air district must evaluate projects to ensure each project selected for funding meets the emission reduction and cost-effectiveness

requirements of the Moyer Program as applicable. Projects may not be funded when CARL indicates these requirements are not met. In such cases, an air district representative believing a project should qualify may contact his or her ARB liaison to further evaluate project eligibility.

8. **Recordkeeping**. The air district must maintain a file for each project selected for funding. Files may be retained in an electronic format if complete and easily accessible. Unless otherwise specified by source category or in Section K.8., project files must be retained three years following the end of the contract term. In the event final payment has not been issued prior to the end of the contract term, the three-year clock is re-started upon final payment. Applications for unfunded projects must be kept a minimum of two years following the solicitation period, or two years from receipt if there is not a specified solicitation period.

9. **Subsequent Application and Double-Counting**. Moyer Program participants that received funding and are still under contract may not apply for funding for the same project from the Moyer Program (including a Voucher Incentive Program), from the Proposition 1B Goods Movement Emission Reduction Program, or any other program.

    (A) If an air district chooses to amend a contract to reduce the term, the amended project must be cost-effective during the reduced contract term, based on the cost-effectiveness values and limit that applied when the original contract was executed. If an air district agrees to accept a prorated repayment of the Moyer Program grant, the repayment and amended contract execution must both occur prior to the execution of any new contract for funding.

    (B) Emissions reductions from previously funded projects must not be included as emissions benefits of any subsequent project for the Moyer Program (including a Voucher Incentive Program) or the Proposition 1B Goods Movement Emission Reduction Program.

U. Case-by-Case Determination Process

1. **Limitations**. ARB Moyer Program staff may approve on a case-by-case basis a project that varies from specific requirements of these Guidelines only if such approval will not adversely affect achievement of surplus, quantifiable, enforceable and permanent emission reductions. Case-by-case approvals also may not result in an exceedance of the applicable cost-effectiveness limit, or reduce program transparency, or cause a violation of law or regulation. Air districts are required to request a case-by-case determination even if they believe a project is similar to previously-approved case-by-case projects.

2. **Procedure**. An air district may request ARB review of the project for a case-by-case determination using the procedure below. After receipt of all

information needed, ARB will respond to the air district within 15 business days with a determination or estimated date of determination.

(A) The air district will submit the following to the Moyer Program air district liaison:

(1) A summary of the request, with reference(s) to the pertinent area(s) of the Guidelines for which the air district is asking for additional guidance and approval;

(2) Documents providing information essential to the determination, including but not limited to: baseline and new engine information; the associated ARB engine Executive Orders and/or U.S. EPA Certificates of Conformity for baseline and new engines; other related applicant information from a completed application;

(3) Other information and documents as requested by Moyer Program staff.

(B) ARB will make one of the following determinations:

(1) Approved. Approval of a project does not imply or equate to "blanket approval" of other similar projects.

(2) Not Approved. Non-approval of a project does not imply or equate to "blanket non-approval" of other similar projects.

(3) No Action / Case-by-Case Approval Not Required: ARB evaluation concludes that a case-by-case determination is not required as the request already conforms to the requirements or intent of the Guidelines.

3. **Public Availability and Recordkeeping**. ARB will post on the Moyer Program website all case-by-case determinations submitted for review. Air districts will keep a copy of the determination, either approved or not approved, in the project file.

4. **After Contract Execution.** Air Districts should always attempt to request a case-by-case determination prior to contract execution. ARB will consider requests for case-by-case determination subsequent to contract execution only when an unforeseen event leads to a project or program element that varies from the requirements of these Guidelines.

V. Minimum Contract Requirements

1. **General Requirements**. Except as specified for on-road and off-road voucher incentive programs, air districts participating in the Moyer Program must execute contracts with prospective grantees who will receive funds under the Moyer Program. All Moyer Program project contracts must include the elements described in this section. Projects funded by the Moyer Program may not be used to generate a compliance extension or credit for regulatory compliance. All

executed project contracts and contract amendments must be kept in the air district's project files.

2. **Party Names and Date**. All contracts must state the name of the air district and the grantee as parties to the contract. Contracts must include signature blocks with an area for the dates the contract is signed, or the execution date must otherwise be clearly indicated in the contract. In any case where digital signature is used in lieu of original signature, the digital signature must comply with California Government Code section 16.5 and Title 2, California Code of Regulations, sections 22000 – 22005.

3. **Notices**. All contracts must include contact information for both parties to the contract, including how to send and receive notices.

4. **Funds from Other Sources**.

   (A) Grantees must certify that they have disclosed all funding sources that they have applied for or received for a project, and that the grantee will notify the air district of additional sources of funding received for the total cost of the project, including any sources that become available after contract execution (H&SC § 44283(g)).

   (B) Grantees that co-fund a project must meet all criteria associated with each funding source used to fund the project (H&SC § 44287(a)).

   (C) A grantee that is not a public entity must provide at least 15 percent of a project's Moyer eligible costs from non-public sources (see Section L). The contract must prohibit the grantee from receiving grants and other funds that exceed the total project cost.

   (D) A grantee may receive Moyer Program funding from multiple air districts for the same project if these entities are coordinating to jointly fund portions of the project. The contract must list the entities involved and funding provided.

5. **Contract Term**. All contracts must specify the term of the contract. The contract term shall include two time frames – "project completion" and "project implementation" – to ensure that the air district and ARB can fully enforce the contract during the life of the Moyer Program-funded project.

   (A) Project Completion. Project completion is the time frame starting with the date of execution of the contract to the date the project post-inspection confirms that the project has become operational. This includes the time period when an engine, equipment, or vehicle is ordered, delivered and installed. The contract must include a specified time frame in which project completion will occur so that the contract is liquidated within four years from the original date of contract execution. Under no circumstance may the liquidation date be extended beyond four years from the original date of contract execution.

(B) Project Implementation. The project implementation time frame is the second part of the contract term, and must equal the project life used in the project cost-effectiveness calculation. The contract must specify that the grantee is required to operate and maintain their Moyer Program funded project according to the terms of the contract for the full project implementation period.

6. **Project Specifications**. All contracts must include detailed information on the baseline and new vehicles, equipment, and/or engines that were used in the project cost-effectiveness calculation. This requirement may be met by including the project application as an attachment to the contract as long as the application is accurate and complete.

   (A) A program-eligible replacement vehicle, equipment and/or engine that is verified or certified to achieve equivalent or greater reductions than the original project replacement vehicle, equipment and/or engine may be substituted with prior approval of the air district.

   (B) At least 24 months of documented and verified historic usage is required for the baseline engine, such as miles traveled, hours operated, or fuel consumed, and in this case usage is not required to be in the contract. If this information is not available, the air district may estimate the usage for the old engine and the estimated usage must be included in the contract.

      (1) The types of acceptable documentation for establishing historical annual usage will be clearly defined in each air district's Policies and Procedures Manual and will be subject to ARB approval.

      (2) Additional forms of documentation to verify historical annual usage that are not included in an air district's Policies and Procedures Manual can be evaluated and approved by ARB on a case-by-case basis.

   (C) Contracts must also contain a statement that the project complies with the Moyer Program Guidelines and that the grantee will meet the following requirements:

      (1) Certify that the grantee's fleet, engine(s), or equipment/vehicle is in compliance with all applicable federal, State, and local air quality rules and regulations at time of contract execution.

      (2) Maintain compliance with all applicable federal, State, and local air quality rules and regulations for the full contract term.

      (3) For repower projects, the installation of the engine must be completed in a manner such that it does not void the engine warranty provided by the manufacturer and any remaining warranty provided by the equipment/vehicle manufacturer.

   (D) Contracts must specify the following:

(1) Projects funded by the Moyer Program must be included when defining the size of the fleet for determining regulatory requirements.

(2) Throughout the contract term, projects funded by the Moyer Program must not be used to generate credits or compliance extensions, and must be excluded when determining regulatory compliance.

7. **Maintenance**. All contracts must require the grantee to maintain the vehicle, equipment, engine, and/or funded infrastructure according to the manufacturer's specifications for the life of the project, and include a prohibition on engine tampering. The grantee must maintain a working hour meter for projects that use hours of operation as a means of calculating emission reductions and cost-effectiveness. If the hour meter fails, the grantee must immediately notify the air district, and remain responsible for validating any hours not recorded by the hour meter. The grantee must either repair or replace the non-operating meter or provide other documentation of equipment operating hours acceptable to the air district.

8. **Payment**. Before a Moyer Program payment may be made to a project participant, the project contract must be executed, an eligible invoice must be received by the air district, and the project post-inspection must be successfully completed to document the completion of the work specified in the invoice. The equipment must be operational before the final payment is issued. All contracts must include the following payment terms:

   (A) **Maximum Contract Amount**. The maximum contract amount must not exceed the maximum funding level corresponding to the current program cost-effectiveness limit, nor may the maximum contract amount exceed the project incremental cost. The maximum contract amount must also comply with any funding caps and other criteria for the specific project category as identified in these Guidelines.

   (B) **Itemized Invoices**. Payment terms must require itemized invoices from the engine or equipment supplier for repowers and infrastructure projects, paid invoices from the vehicle owner for new vehicles, and satisfactory post-inspection by the air district prior to payment of the owner's invoice. An invoice payment for a specific vehicle, engine, or equipment may not exceed the amount indicated on the project contract for that vehicle, engine, or equipment. The contract should be clear that the air district will pay the lower of the contract amount or the final invoice amount. Invoices must meet the minimum requirements of Section Y to be eligible for Moyer Program funding.

9. **Reporting**. All contracts must include a provision for grantees to submit annual reports commencing no later than 18 months after project post-inspection and continuing annually thereafter throughout the project implementation phase of the

contract. The air district must include the dates the grantee Annual Report is due.

(A) During the project implementation phase, the air district is responsible for monitoring the project to assure the project is operational and the project emissions reductions are realized.

(B) The contract must inform the grantee that noncompliance with the reporting requirements will require on-site monitoring or inspection(s).

10. **On-Site Inspections, Audits and Records**. All contracts must include language that allows the air district, ARB, or their designee to conduct an inspection or audit of the project, including the engine, vehicle or equipment and associated records, during the contract term. Contracts must also require the owner to maintain and retain usage and other records associated with the project for at least three years after the end of the contract term.

11. **Repercussions for Nonperformance**. Air districts must include repercussions for non-compliance with the obligations of the contract.

(A) The contract must specify that by executing the contract, the grantee understands and agrees to operate the vehicle, equipment, and/or engine according to the terms of the contract and to cooperate with the air district and ARB in implementation, monitoring, enforcement, and other efforts to assure the emission benefits are real, quantifiable, surplus, and enforceable.

(B) The contract must describe the repercussions to the grantee for noncompliance with contract requirements, including but not limited to cancelling the contract and recapturing project funds in proportion to any loss of emission reductions or underutilization as agreed to in the contract (H&SC § 44291(c)).

(C) The contract must inform the grantee that ARB and the air district have the authority to seek any remedies available under the law for noncompliance with Moyer Program requirements and nonperformance with the contract.

(D) The contract must state that ARB, as an intended third party beneficiary, reserves the right to enforce the terms of the contract at any time during the contract term to ensure emission reductions are obtained.

W. Project Pre-Inspection

1. **Requirements**. Upon confirming a project's eligibility the air district must complete a pre-inspection prior to contract execution, except as specified in this section.

(A) All projects must be pre-inspected personally by air district staff, except that air districts may choose to allow public agencies (e.g., public works departments, transit organizations, and school districts) to provide

documentation of the engine(s), equipment, and usage in lieu of a pre-inspection.

(B) Air districts receiving less than one-half of one percent of the current fiscal year total Moyer Program Funds, or $450,000, whichever is less, may reduce their required project pre-inspections to a minimum of 25 percent of the total number of projects associated with the current fiscal year funds. At least one project must be selected from each source category funded, however.

2. **Documentation**. The pre-inspection form and information to be documented must include, at a minimum, the following:

(A) Information regarding the baseline engine, vehicle, or equipment as needed to uniquely identify, establish eligibility, provide a basis for emission calculations, populate the CARL database, and ensure contract enforceability. Such information includes (as applicable) make, model, year, horsepower, fuel type, engine family, engine tier, serial number, vehicle identification number (VIN), and any additional information pertinent to the project. Engines without a visible and legible serial number must be uniquely identified by having the engine block stamped with a Moyer Program number or alternative permanent marking such as an engine tag.

(B) The project usage (hours or miles) meter reading if used in the project cost-effectiveness calculation. The inspector must verify that stated project usage is reasonable given the usage meter reading.

(C) Verification that the engine is operational (with a start-up) and that the engine is working as described in the application (document function and use).

(D) Photo documentation of the engine, vehicle, or equipment information. The photos must include the legible serial number of the engine (if available) and/or any other identifying markings.

(E) Other relevant information including, but not limited to:

(1) Name of inspector;

(2) Date of inspection;

(3) Name and contact information of engine or equipment owner; and

(4) Location of the engine or equipment.

3. **Compliance Certification**. No later than the time of pre-inspection the air district must obtain certification and submission of supporting documentation from the applicant that their engine(s), vehicle/equipment, or project fleet is currently in compliance with the applicable rules or regulations affecting the engine(s), vehicle/equipment for which they are requesting funding.

4. **Recordkeeping**. The air district must maintain a hard copy of the completed pre-inspection form in the air district's project file.

5. **Inspection after Contract Execution**. The project pre-inspection must be completed prior to a project contract execution and the information in the contract must be consistent with the information gathered during the pre-inspection. An air district may apply to ARB for approval to conduct pre-inspections after contract execution only on a case-by-case basis. Case-by-case approval of such a procedure will depend upon the following conditions being met:

   (A) The air district describes the program benefits it would achieve by conducting pre-inspections after contract signature.

   (B) The project contract includes language to indicate contract terms may be adjusted or the contract may be deemed void based upon information collected during the pre-inspection. The air district must also include a process for informing the prospective grantee of such.

   (C) The air district's Policies and Procedures Manual clearly specifies the process for conducting pre-inspections after contract execution and any additional procedures enacted to ensure the project achieves real, surplus, enforceable, and quantifiable emission reductions. Work on the project engine, vehicle, or equipment may not commence until after the pre-inspection.

X. Project Post-Inspection

1. **Requirement**. An air district must gather and document post-inspection information on all projects funded under the Moyer Program. For post-inspection of infrastructure projects, see Chapter 10 for further guidance.

   (A) The air district will conduct a post-inspection after it receives an invoice for a project from the grantee or otherwise receives notice the project is complete. Information on the invoice must be consistent with the information gathered at the post-inspection. If the post-inspection occurs before the air district receives the project invoice, the invoice must be reviewed for consistency with the new engine, vehicle, or equipment information from the post-inspection form.

   (B) When 20 or more vehicles are included in a vehicle replacement project for a public fleet or transit agency, the air district is not required to post-inspect each replacement vehicle, but must inspect no fewer than five percent of the vehicles included in the project.

   (C) The inspector must record, at a minimum, information regarding the new project engines, vehicles/equipment, and retrofit devices as needed to uniquely identify, establish eligibility, provide a basis for emission calculations, and ensure contract enforceability. Information sufficient to populate all required fields in CARL must be recorded. Submersible pump

inspections may have the applicant take a picture of the motor name plate information including, make, model, and serial number prior to installation inside the irrigation well. The air district will verify the make, model and horsepower rating information with the project invoice.

(D) The engine must be operational in the equipment or vehicle as stated in the contract. The inspector must visually witness all engine startups and operation of all mobile projects.

(E) The engine, vehicle/equipment, and retrofit information must be documented with photos. The photos must include the serial number of the engine or retrofit (if legible) and/or any other identifying markings. Photos of the scrapped or destroyed engine must be included.

(F) The post-inspection form must also contain other relevant information including, but not limited to:

(1) Name of inspector;

(2) Date of inspection;

(3) Name and contact information of engine or equipment owner; and

(4) Location of the engine or equipment.

(G) The air district must maintain a hard copy of the completed post-inspection form in the air district's project file.

2. Equipment Labels. Post-inspection of a retrofit device requires the collection of additional information from the labels affixed on both the retrofit device and the engine. If the proper labels are missing, payment may not be made until this is corrected. Potential scenarios are summarized below, which air district staff must address prior to payment:

(A) The retrofit device is properly labeled but the engine lacks a label: An engine label should be readily obtainable from the retrofit manufacturer by reference to the serial number. The air district may make payment once the grantee has been informed that the engine must also be labeled.

(B) The retrofit device is labeled but the label does not have the required items: The air district may make payment once it gets approval from ARB regarding an approved alternate label or a compliant label has been installed on the retrofit device.

(C) The engine is properly labeled but the retrofit device lacks a label: The air district may make payment once a compliant label has been installed on the retrofit device.

(D) No label is found on either the engine or the retrofit device: The air district may make payment once a compliant label has been installed on both the engine and the retrofit device.

3. **Electric Motors**. Post-inspection of a new electric motor on an agricultural pump must also include recording of the serial number of the variable frequency device if the project includes one.

4. **Verification of Destruction**. The air district must verify that the existing (old) engine is destroyed and rendered permanently unusable and irreparable, consistent with requirements in the source category chapters of these guidelines and with the air district Policies and Procedures Manual.

   (A) Air district staff must verify and document through photographic or video evidence that the destroyed engine serial number matches that on the project contract.

   (B) Air district staff must verify that engines without a visible and legible serial number are uniquely identified by the correct air district stamp or other permanent marking prior to engine destruction.

5. **Consistency with Contract**. The air district must verify that the information collected in the post-inspection is consistent with the project contract.

Y. Project Invoice and Payment

1. **Prior to Payment**. Except as specified below, an air district will make payment for a project or equipment only after air district post-inspection finds the project or equipment in place and operational, and the district receives an invoice itemized in sufficient detail to ensure that only completed and eligible project costs are reimbursed, and other sources and amounts of funding for the project are reviewed to ensure the sum of all project funds does not exceed the total project cost (per Section L). Exceptions are limited to progress or partial payments in cases where the grantee provides the air district with sufficient evidence of completing milestones specified in the contract, consistent with conditions specified in air district Policies and Procedures. The air district must maintain a clear record of progress payments in the project file and in records of the district administration or fiscal unit. Progress payments include final payments that are withheld until all reporting requirements are met (also known as “withheld payments”).

2. **Eligible Costs**. Equipment and parts on engine repower or retrofit projects are eligible for funding only if they are required to ensure the effective installation and functioning of the new engine or retrofit, and are not part of typical vehicle or equipment maintenance or repair. Taxes and the installation and transport costs for eligible hardware are eligible for funding at the air district’s discretion. For labor expenses paid, the invoice must detail the number of hours charged and the hourly wage. See source category chapters for additional specification of eligible costs.

3. **Ineligible Costs**. Ineligible repower costs include tires, axles, paint, brakes, and mufflers. See source category chapters for additional specification of ineligible costs.

4. **Limitations on Applicant Action before Air District Approval**. An applicant may not order or make a down payment on a new engine, piece of equipment, or vehicle prior to contract execution or approval by the air district governing board or board designee. Dealers ordering engines, equipment, or vehicles prior to air district approval of grant applications assume all financial risk and are in no way ensured program funds. A grantee may not receive engines, equipment, or vehicles, nor may work begin on a repower or retrofit project, until the project contract is fully executed, unless the air district has provided the potential grantee with written notification that any work performed is not guaranteed funding until a contract is executed. For infrastructure projects, discretionary costs may be accrued by an applicant prior to contract execution, but such costs are not reimbursable until after contract execution.

5. **Invoice Procedures**. The air district will maintain copies of all invoices and documentation of payment in the project file or otherwise keep copies on-site at the air district office and be readily available. Invoices received after the project post-inspection has been complete must be evaluated for consistency with the information gathered during the project post-inspection. Additional project invoicing requirements may also be included in the source category chapters of these guidelines.

6. **On-Road Compliance Checks**. For all on-road and emergency vehicle projects, should a compliance check indicate that there is an outstanding violation with any vehicle in the applicant's fleet, no payment may be made until the applicant provides proof to the air district that each violation has been corrected and each fine has been paid.

7. **Regulatory Compliance**. Where a contract requires a grantee to demonstrate that specific regulatory compliance requirements have been met in order to receive funding (such as engines subject to the Portable Equipment Airborne Toxic Control Measure), air districts may not pay invoices until the grantee has provided documentation that the requirements have been met. A project participant may demonstrate this via a detailed letter signed by the vehicle or equipment owner or legal representative or, if the regulation requires ARB (or the air district) to certify compliance, through ARB (or air district) certification. For more information, see the associated source category chapter. Air districts are not to be held liable if a grantee falsifies this documentation.

8. **Payment Recipients**. Payments typically will be made directly to the grantee. Payments may be made directly to a dealer or distributor only if such payment arrangements are specified in the contract.

Z. Grantee Annual Reporting

1. **Requirement**. Air districts will require all grantees to submit annual reports within 18 months of the project post-inspection and annually thereafter for the term of the contract.

2. **Report Format**. The air district will prescribe a format for the project annual report, to include the following information:

   (A) Grantee name, address, and telephone number.

   (B) Information needed to uniquely identify the project engine, vehicle, or equipment, such as engine make, model, horsepower, and serial number.

   (C) Estimated percentage of time the vehicle or equipment has been operated in California since the previous annual report.

   (D) Readings of the usage device (e.g., hour meter, odometer, or electronic monitoring unit).

   (E) Except for projects in which usage is not required to be specified in the contract (as allowed per Section V.6.(B)(1) above), if usage is more than 30 percent below that identified in the project application, the grantee must describe any conditions that are likely to have affected project usage, such as weather, permits, or major maintenance. In instances where annual usage is significantly lower than the contracted level due to unforeseen circumstances beyond the control of the grantee, the grantee may request a waiver from the air district per Section BB(4).

3. **Air District Review**. The air district will review the annual report for completeness, accuracy, and reported usage, and will maintain in the project file a copy of the report that is initialed and dated by the reviewing staff. An air district choosing an alternative method to indicate its review and approval of annual reports will specify the method in its Policies and Procedures Manual.

4. **Unsatisfactory Reporting**. If an annual report is incomplete, inaccurate or not received from the grantee on schedule, the air district will make a reasonable attempt to obtain a complete and accurate report from the grantee. If the air district is unable to obtain the report, the air district will identify the project for audit as described in Section AA below.

5. **Subsequent Grants**. Grantees that have not submitted complete required reports will not be granted funds for new Moyer Program projects until all reports are satisfactorily submitted.

AA. Air District Audit of Projects

1. **Requirement**. The air district will conduct audits of projects funded with Moyer Program funds. On an annual basis these audits will include five percent of

active projects or 20 active projects (whichever is less), including any audits conducted following unsatisfactory annual reporting as described in Section Z.4.

2. **Project Inspection**. Audits must be completed by air district staff and will at a minimum include an inspection that verifies that the engines, equipment, and emission control devices paid for are still owned by the grantee named in the contract, are still operational in the same equipment, and meet the mileage, fuel usage, or hours of operation indicated in the executed contract. This must be performed by checking the serial number of the engine; witnessing the operation of the engine; and checking the usage meter or fuel receipts.

3. **Multiple Equipment**. Audits of multiple equipment or engine projects of up to 25 pieces must include inspection of at least two pieces or equipment, and for projects of over 25 pieces must include inspection of at least five pieces.

BB. Nonperforming Projects

1. **Requirement**. The air district will work with nonperforming project grantees to ensure Moyer Program project requirements are met and emission reductions are achieved, consistent with procedures outlined in the district Policies and Procedures Manual. Air districts may consider unforeseen circumstances beyond the grantee's control in determining repercussions for nonperformance.

2. **Off-Road Contract Extension**. Off-road contracts for which usage requirements are not being met may be extended to capture the required usage, even if the contract extension overlaps the required compliance date. This revision only applies to off-road contracts that have been executed prior to August 15, 2008, and does not modify similar Moyer policy for other eligible categories.

3. **Recapturing Funds**. When an air district is not successful in gaining grantee compliance with the usage and program requirements specified in a contract, the district will make all reasonable efforts to recapture Moyer Program funds from the grantee. Recaptured funds will be reassigned to projects that achieve the shortfall in emission reductions or usage. The air district's efforts to recapture funds may be guided by circumstances such as suspected or actual fraud or misuse of funds, the amount of Moyer Program funding involved, or the ability of the grantee to repay the funds.

4. **Usage Threshold and Waiver Procedure**. The air district must take appropriate action to ensure emission reductions are realized for engines, equipment, vehicles or fleets, as well as usage for infrastructure projects. Except for projects in which usage is not required to be specified in the contract (as allowed per Section V.6.(B)), when average usage over a three year period for a contracted engine, equipment, vehicle or fleet is less than 70 percent of the activity required in the contract, the air district may choose, but is not limited to, the options below to address the underutilization. (In cases of projects which

may have a contracted project life of less than three years, the same activity threshold of less than 70 percent applies, averaged over the project life.)

(A) Extend the project contract for additional years (precluding overlap with an applicable rule implementation requirement).

(B) Return funds in proportion to the loss in emission reductions.

(C) Transfer ownership of the engine, vehicle, or equipment to another entity committed to complying with the contract terms.

(D) Recalculate a project's cost-effectiveness based on the reported decrease in usage. Based on this recalculation, if the project is still below the cost-effectiveness limit, consistent with the limit and methodology in effect on the date of contract execution and prior to the end of the contract, the air district must continue to monitor the project over the next year to determine if additional actions are necessary. (This option does not apply to infrastructure projects not subject to a cost-effectiveness limit.)

(E) Grant a usage waiver, without penalty, to the grantee for a defined time period. The grantee must demonstrate to the air district's satisfaction that the engine, vehicle, or equipment is not being underutilized in favor of operating other, higher-polluting equipment, and that the underutilization was due to unforeseen conditions beyond the grantee's control.

(1) The conditions under which a waiver may be issued include, but are not limited to, the following:

a. A decrease in usage due to economic recession;
b. Unforeseen fluctuations in water allocations or pumping needs for agricultural irrigation pump engines; or
c. Significant land fallowing for off-road agricultural equipment and agricultural irrigation pump engines.

(2) To be considered for a waiver, the grantee must provide a written request to the air district along with documentation that substantiates the need for the waiver and verifies that higher-polluting equipment is not consequently receiving more use.

a. The air district will specify the length of time for which the waiver is valid. The waiver will not exempt the grantee from any contract requirement to provide annual usage reports.
b. The waiver will be documented in writing, approved by the Air Pollution Control Officer or designee, and included in the project file.

(3) For projects that include multiple pieces of equipment or engines the air district may review and recalculate the funded equipment collectively to see if the project as a whole has performed as expected. A waiver is not required in this event.

5. **Funds Recaptured Following ARB Enforcement**. Program funds recaptured from a project grantee as a result of a settlement agreement executed by ARB shall be returned to the air district that granted the funds. Any penalties resulting from a settlement agreement executed by ARB or the Attorney General shall be deposited in the Air Pollution Control Fund (H&SC § 44291(e)).

CHAPTER 4: ON-ROAD HEAVY-DUTY VEHICLES

This chapter describes the minimum criteria and requirements for Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) on-road heavy-duty vehicles. All projects must also conform to the requirements in Chapter 2: General Criteria and in Chapter 3: Program Administration. Participating air quality management districts or air pollution control districts (air districts) retain the authority to impose additional requirements in order to address local concerns.

A. Projects Eligible for Funding

The Air Resources Board (ARB) has adopted many fleet rules that affect on-road heavy-duty vehicles. Various types of projects can be incentivized to provide surplus emission reductions from on-road heavy-duty vehicles. Table 4-1 summarizes project types and categories eligible for funding as well as whether those projects may be executed through contracts or the Voucher Incentive Program (VIP or Voucher). For more information on VIP, please see the VIP Guidelines at: https://www.arb.ca.gov/msprog/moyer/voucher/voucher.htm.

Table 4-1
Summary of On-Road Heavy-Duty Projects

Project Category	Project Type[(a)]		Execution Path
	Replacement	Repower/Conversion	
Heavy-Duty Trucks and Buses	✓	✓	Voucher or Contract
School Bus	✓	✓	Contract
Transit Fleet Vehicles	✓	✓	Contract
Drayage Trucks	✓	✓	Voucher or Contract
Solid Waste Vehicles	✓	✓	Contract
Public Agency/Utility Vehicles	✓	✓	Contract
Emergency Vehicles	✓		Contract

[(a)] Retrofit projects may also be eligible for funding on a case-by-case basis.

1. **Vehicle Project Types**. Projects must include commercially available technologies certified by ARB to be cleaner than the baseline engine (unless otherwise noted). Project types and applications include:

(A) Vehicle Replacements: The replacement of an older, dirtier vehicle with a newer, cleaner one. These projects may be funded through contracts or the VIP.

(B) Repowers: Repowers involve the replacement of an older, dirtier engine with a newer, cleaner one. Repowers may be funded in various applications. However, due to technological constraints presented with the limited feasibility of newer engines with advanced emissions control equipment fitting into older chassis and maintaining durability, repowers with diesel engines are rare project types for trucks. Repowers with alternative fuel engines may not have the same technological constraints and may become more prevalent. To ensure durability, certain projects may require prototype testing. However, if the project has been previously completed by the manufacturer, prototype testing is not required. Air districts that wish to fund repowers must receive prototype testing results. The testing must comply with the engine manufacturer quality assurance process that is equivalent to an Original Equipment Manufacturer (OEM) package. In these cases, a prototype vehicle (or vehicles) is thoroughly reviewed and tested to ensure that the installation meets OEM requirements, and the successful prototype installation is then replicated in other vehicles with the same chassis and engine combination. Air districts may approve repower projects that meet the OEM quality assurance process described above, subject to the following:

(1) Moyer Program funding may not be used for any costs associated with the prototype vehicle or vehicles.

(2) Repower contracts may not be executed until the prototype testing specified by the engine manufacturer is successfully completed.

(3) Written documentation from the engine manufacturer confirming that the prototype was successful must be maintained in the project file.

(4) If the proposed repower has been done previously by the manufacturer on the same chassis/engine configuration, prototype testing is not required. The manufacturer must provide written confirmation that the previous work was performed successfully and met OEM requirements.

(C) Conversions: Conversions involve the replacement or modification of the original engine or vehicle to include either a cleaner engine or other system that provides motive power and change of the fuel type used. Hybrid conversion systems using internal combustion engines must be certified according to “California Certification and Installation Procedures for Medium- and Heavy-Duty Vehicle Hybrid Conversion Systems.” The baseline engine model year for hybrid conversions must be 2010 or

newer. Tier 1 and Tier 2 certified conversion systems are certified to sell a limited number of units in California. The conversion system manufacturer must provide written confirmation that the funded vehicle would not exceed the certified allowable limit. All-electric conversion systems must receive an exemption Executive Order per Vehicle Code section 27156. The conversion system manufacturer must certify that the converted vehicle adheres to all applicable local, State, and federal requirements including safety standards issued by National Highway Traffic Safety Administration and California Highway Patrol (CHP).

2. **Project Categories**. Taking the above project types into consideration, the following categories may be eligible for funding:

   (A) Heavy-Duty Trucks and Buses: Heavy-duty diesel trucks and buses with gross vehicle weight ratings (GVWR) greater than 14,000 pounds (lbs.) are subject to the Statewide Truck and Bus Regulation. Replacement engines certified to the 2010 emissions standards or cleaner are eligible. For more information, see section C.2.(A).

   (B) School Buses: School buses as defined in Vehicle Code section 545 are subject to the Statewide Truck and Bus Regulation. They are required to be filtered unless operating under an ARB-issued extension up to January 1, 2018. Project types include replacements, repowers, and conversions. Replacement engines certified to the 2010 emissions standards or cleaner are eligible. For more information, see Section C.2.(B).

   (C) Transit Vehicles: Transit vehicles are subject to the Fleet Rule for Transit Agencies and must be compliant with final regulatory requirements. Project types for surplus reductions include replacements and repowers. All transit projects must use engines certified to optional low oxides of nitrogen (NOx) standards or cleaner. For more information, see Section C.2.(C).

   (D) Drayage Trucks: Drayage trucks are subject to the Statewide Drayage Truck Regulation. As of January 1, 2014, drayage trucks are required to be equipped with 2007 model year or newer engines. Therefore, engines older than model year 2007 are not eligible. Replacement engines certified to the 2010 emissions standards or cleaner are eligible. Cleaner technologies are currently being demonstrated, and may become available in the near future to enable opportunities for more funding. For more information on drayage truck funding opportunities, see Section C.2.(D)

   (E) Solid Waste Collection Vehicles (SWCV): Vehicles equipped with 2006 and older engines are subject to the SWCV Regulation and must meet final regulatory requirements. Vehicles equipped with 2007 and newer

engines are subject to the Statewide Truck and Bus Regulation. All solid waste collection vehicle projects must use engines certified to optional low NOx standards or cleaner. For more information, see Section C.2.(E).

(F) Public Agency and Utility Vehicles: Vehicles with GVWR over 14,000 lbs. owned by a municipality or utility that are equipped with engines certified to Particulate Matter (PM) emission standards greater than 0.01 grams per brake horsepower-hour (g/bhp-hr) are subject to the Fleet Regulation for Public Agencies and Utilities, except fleets that do not include any diesel engines. Engines are required to use the Best Available Control Technology as defined in the California Code of Regulations, title 13, section 2022.1(b). Private utilities become subject to the Statewide Truck and Bus Regulation starting January 1, 2021. Replacement engines certified to the 2010 emissions standards or cleaner are eligible.

(G) Emergency Vehicles: Emergency vehicles are not subject to in-use emissions regulations. Eligible vehicles also include prisoner transport buses. Project types mainly include replacements. Replacement engines certified to the 2010 emissions standards or cleaner are eligible. For more information, see Section C.2.(F).

(H) Case-by-Case Projects: These projects do not fall under any previously described category or do not meet all of the requirements of the Guidelines but otherwise provide real, surplus, quantifiable, enforceable, cost-effective emission reduction benefits in California for the entire project life. These may include transport refrigeration units (TRU), auxiliary power units (APU), and vehicles with 8,501-14,000 lbs. GVWR. For more information, see Section C.2.(G).

3. **Infrastructure Projects**. See Chapter 10 for details regarding applicant eligibility and project types for infrastructure projects in support of on-road applications. This includes infrastructure such as electrical charging (and solar-generated electricity) and alternative fuel stations for light, medium and heavy heavy-duty trucks. It also includes infrastructure for truck stop electrification, TRUs, transit vehicles, emergency vehicles, and school buses.

B. Determining Funding Amounts

The information contained in this section shall be used to determine the funding amount for which any given heavy-duty on-road project is eligible.

1. **State Funding Limits**. Funding for an on-road heavy-duty project includes funds from all State sources including the Moyer Program. The maximum dollar amount or maximum percentage of eligible cost (Tables 4-2 through 4-7), as applicable, represents a funding cap, or the maximum funding available for the project. If the project is co-funded with other State funds, the funding cap represents the maximum amount of funds from all State sources that can be

applied to the project. Federal, local, or other non-State grant funds can be used in addition to the funding caps stated in this chapter if the criteria for co-funded projects in Chapter 3, Section L are satisfied.

2. **Cost-Effectiveness**. The maximum amount of funding available to a project is limited by a cost-effectiveness limit (see Appendix C), in addition to the funding caps specified below.

3. **Maximum Funding Percentage**. For fleets with ten or fewer vehicles over 14,000 lbs. GVWR, the State funding amount cannot exceed 80 percent of the vehicle cost (excluding taxes and fees). For fleets with more than ten vehicles, the funding amount cannot exceed 50 percent of the vehicle cost (excluding taxes and fees). School buses, repowers, and emergency vehicles are not limited by maximum funding percentages based on fleet size. The funding caps that apply from these maximum percentages of eligible cost and maximum dollar amounts, as applicable, are summarized in Tables 4-2 through 4-7.

Table 4-2
State Funding Caps for Moyer School Bus Projects

Project Type	Funding Cap
School Bus Diesel or Alternative Fuel Replacements	$165,000
School Bus Optional Low-NOx or Hybrid Replacements	$220,000
School Bus Zero-Emission Replacements	$400,000
School Bus Repowers	$70,000
School Bus Electric Conversions	$400,000

Table 4-3
State Funding Caps for Conventional Diesel or Alternative Fuel or Hybrid Replacements (2013+ engine model year; 0.20 g/bhp-hr NOx or cleaner standard)

Weight Class	Funding Cap [(a)]
Heavy Heavy-Duty (HHD) GVWR > 33,000 lbs.	$60,000
Medium Heavy-Duty (MHD) GVWR 19,501-33,000 lbs.	$40,000
Light Heavy-Duty (LHD) GVWR 14,001-19,500 lbs.	$30,000
Emergency Vehicles GVWR > 14,000 lbs.	80% of Cost

[(a)] No more than 80 percent of vehicle cost for fleets with ten or fewer vehicles, no more than 50 percent of vehicle cost for larger fleets except for emergency vehicles.

Table 4-4
State Funding Caps for Optional Low NOx Replacements[a]

Optional Low NOx standard (g/bhp-hr)	HHD	MHD	LHD
0.02	$100,000	$80,000	$70,000
0.05	$80,000	$60,000	$50,000
0.10	$70,000	$50,000	$40,000
Transit Buses			$25,000

[a] No more than 80 percent of vehicle cost for fleets with 10 or less vehicles, no more than 50 percent of vehicle cost for larger fleets except for emergency vehicles.

Table 4-5
State Funding Caps for Optional Low NOx Repowers

Vocation Type	Funding Caps
Transit Bus	$20,000
Other Trucks and Buses	$40,000

Table 4-6
State Funding Caps for Zero Emission Replacements or Conversions

Weight Class/Vocation Type	Funding Caps[a]
Transit Bus	$80,000
HHD Truck or Bus	$200,000
MHD Truck or Bus	$150,000
LHD Truck or Bus	$80,000

[a] No more than 80 percent of vehicle cost for fleets with 10 or less vehicles, no more than 50 percent of vehicle cost for larger fleets except for emergency vehicles.

Table 4-7
State Funding Caps for Hybrid Conversions

Weight Class	Funding Caps[(a)]
LHD	$7,500
MHD	$10,000
HHD	$15,000

[(a)] No more than 80 percent of system cost for fleets with 10 or less vehicles, no more than 50 percent of system cost for larger fleets except for emergency vehicles.

4. **Project Life**. The minimum eligible project life for all projects is one year. The maximum eligible project life for each project type is summarized in Table 4-8.

Table 4-8
Maximum Project Lives for On-Road Vehicle Projects

Project Type	Maximum Project Life
Replacements	7 Years
Transit Bus Replacements	12 Years
Repowers	7 Years
School Bus Replacements	10 Years
Electric Conversions	5 Years
Emergency Vehicles	14 Years
Other On-Road Projects	3 Years

A longer project life may be approved on a case-by-case basis if applicants provide justifying documentation. The maximum project life does not consider regulatory requirements that may reduce the actual project life.

5. **Annual Usage**. Grant amounts will be based on the minimum of two 12-month periods of California usage during the previous twenty-four months. Fleet averages cannot be used. If a fleet has reported the existing vehicle in the Truck Regulations Upload and Compliance Reporting System (TRUCRS) under a limited-usage compliance option (such as the Low-Mileage Work Truck Option, the NOx Exempt Area Extension, etc.) and the historical usage exceeds the limit, the usage limit for that compliance option must be used to determine the State grant amount instead. On-road calculations shall be based on historical annual mileage instead of fuel usage or engine hours due to the fact that the mileage-based exhaust emission factors are more robust. Applicants must submit conclusive documentation of the existing engine or vehicle's mileage such

as logbooks, and maintenance records maintained for individual vehicles, or CHP inspection reports. In cases where only fuel use records are available, a case-by-case request must be submitted. The applicant must provide two years of historical fuel usage documentation to the air district. Documentation must show specific usage of the existing vehicle and may include fuel logs, International Fuel Tax Association reports for single fleets, purchase receipts or ledger entries. If the case-by-case is approved, fuel use will be converted to mileage according to the vocation.

6. **Calculating emissions**. Emission factors and deterioration rates in Appendix D, Tables D-1 through D-6 must be used to determine the emissions of the baseline and reduced engines; consequently, the engine model year and applicable emission standard will determine the relevant emission factors. Emission reductions for hybrid conversion systems must be based on the projected reduced usage of the baseline engine in the converted vehicle compared to the original vehicle. This can be based on estimated usage reductions for the specific application or vocation type provided by the dealer, installer, or manufacturer. Calculations for new hybrid vehicles will incorporate the certified emission standard and may also include projected reduced engine usage relative to a non-hybrid equivalent provided by the dealer, installer, or manufacturer. The emission factors and deterioration rates contained in Appendix D are based on ARB mobile source emissions inventory model (EMFAC2014) values. Information on EMFAC2014 is available at: http://www.arb.ca.gov/msei/modeling.htm.

7. **Two-for-One Replacement Calculations**. Projects in which two old vehicles of similar design and function are replaced with one vehicle are eligible for Moyer Program grant funding. The two baseline vehicles must be in the same weight class (LHD, MHD, or HHD) but may be in different weight classes if there is a ten percent or less variation in GVWR. If the two baseline engines are not the same model year, the newest engine model year must be used when calculating emission reductions. The maximum State funding amount must also be funded according to the lighter weight class of the two vehicles. The replacement vehicle's annual usage must be determined by adding the annual usage of both baseline vehicles together. The maximum annual usage that can count toward grant determinations for the two baseline vehicles is 30,000 miles each for a maximum total annual usage of 60,000 miles for the replacement vehicle. The replacement vehicle is eligible for only one grant based on the combined usage of the baseline vehicles.

8. **Expenses Eligible for Funding**. Moyer grant funding can only be used to pay for items essential to the operation of the vehicle. Electronic monitoring units – while they are not required by ARB – are an eligible expense if they are required by an air district. For replacements, eligible project costs include the cost of the cab and chassis including parts that are integrated into the vehicle. The cab and chassis cost may include but is not limited to the following:

(A) The capital cost of the cab.

(B) The capital cost of the chassis which may include but is not limited to:

(1) Engine

(2) Transmission

(3) Suspension system

(4) Steering system

(5) Frame

(6) Electrical system

(7) Cooling System

(8) Fuel system

(9) Emission system

C. Project Criteria

1. General Criteria

(A) Fleet Size: All fleet sizes are eligible for funding. The following criteria must be followed for each group:

(1) Fleet Size 1-10: To ensure smaller fleets have significant funding opportunities, air districts must reserve or prioritize funding for smaller fleets and should do so in a manner that works best with their programs. For example, air districts that issue on-road solicitations may review applications from smaller fleets first and award those fleets that are eligible prior to awarding fleets with more than ten vehicles. Air districts that fund projects on a first-come, first-served basis may modify or remove the reserve to meet liquidation deadlines and demand after smaller fleets have had a certain amount of time to apply for funding as specified in the air district's Policies and Procedures. Reserve funds may be used for school bus projects at any time.

(2) Fleet Size > 10: Fleets with more than ten vehicles must select optional low NOx or zero emission technologies except for certain operating vocations and locations defined in the Statewide Truck and Bus Regulation (i.e., school buses, log trucks, low mileage work trucks, agricultural vehicles, and NOx Exempt Areas).

(B) Weight Class Range:

(1) The replacement vehicle must be in the same weight class as the existing vehicle (either LHD, MHD, or HHD as defined in Appendix

B). An MHD vehicle can replace an HHD vehicle if they both have the same axle configuration (e.g. an existing HHD vehicle with two axles can be replaced with an MHD vehicle with two axles) but the funding amount must be at the MHD funding level.

(2) On-road heavy-duty vehicles (with GVWR over 14,000 lbs.) must be powered by an engine certified to the applicable heavy-duty intended service class as shown on the engine certification Executive Order. However, the following cases may be allowed:

a. MHD engines may be installed in HHD vehicles with GVWR up to 36,300 lbs. (ten percent higher than 33,000 lbs. GVWR) with written warranty verification by the engine and chassis manufacturer. A copy of the written warranty verification must be maintained in the air district project file.

b. HHD engines may be installed in MHD vehicles if necessary for vocational purposes but only if the GVWR are within ten percent of the HHD intended service class (i.e., GVWR of 29,701 lbs. or greater).

(C) At least 51 percent total annual usage must occur in California. Only usage in California can be used for on-road calculations.

(D) Compliance Check:

(1) Before contract execution, participants must be pre-screened for regulatory compliance, outstanding violations, open cases, and previous project funding by supplying to the air district the registered owner's name, company name or Doing Business As (DBA), address, Vehicle Identification Number (VIN) of the vehicle being replaced/repowered/converted, and TRUCRS ID or Drayage Truck Registry (DTR) number, if applicable. VINs of vehicles not subject to in-use diesel rules, such as CNG vehicles, need not be submitted, but every vehicle in the fleet needs to be in compliance and have no outstanding violations in order to receive funding. The air district need not validate this information and will not be held liable if participants falsify this information. The air district shall email this information to its ARB Moyer Program liaison.

a. The fleet owner will report in TRUCRS vehicles Subject to the Statewide Truck and Bus Regulation. The fleet owner must also provide the air district with the following:

i. A copy of the TRUCRS Fleet List located on the Vehicle Info tab showing the compliance option each vehicle in the fleet is using, and

ii. A copy of the TRUCRS General Fleet and Compliance Information Summary showing compliance located on Compliance Status tab ("Meets Small Fleet Option" will specify "yes" if the fleet is using the Small Fleet option), and

iii. A copy of the Compliance Certificate printed from TRUCRS, if applicable.

b. For Vehicles subject to the Drayage Truck Regulation, a copy of the DTR Compliance Search Page printout showing VIN and compliance status.

c. Vehicles Subject to Other On-Road Regulations:

i. Fleet information must be submitted by the air district to the ARB Moyer Program district liaison to check compliance with other regulations such as the Public Agency and Utility Regulation, when applicable. The fleet information needed for the compliance check may change with time.

ii. To receive funding, a fleet owner/operator must be compliant with all federal, State, and local air quality rules and regulations including the Periodic Smoke Inspection Program (PSIP). The application must include a statement of compliance in which the applicant must certify that they are in compliance at the time of application submittal. Air districts must also include the following language with a checkbox for the fleet owner/operator to indicate compliance:

I have read and understand that I am responsible for meeting the requirements of the PSIP. I am either currently in compliance with PSIP requirements or I have paid all penalties for non-compliance and continue to meet requirements since payment.

d. A regulation index for statewide on-road regulations is available at http://www.arb.ca.gov/msprog/truckstop/azregs/azregs.htm

(2) The liaison will email the air district the result of the compliance check within ten business days. All compliance check documentation must be kept in the project file.

(3) If the vehicle has already received funding and is still under contract, the air district will be notified and the project must be rejected.

(4) If there is an open case or outstanding violation, or if the fleet is not in compliance, the air district shall inform the participant in writing

that no disbursement may be made until the owner provides proof that the fleet has been brought into compliance and all fines have been paid. If the outstanding violation is based on problems with the baseline engine (e.g., gross polluter), then the violation must be cleared. The engine owner must pay the fine for each violation and submit documentation of violation correction with, or before submitting, the invoice.

(5) *Compliance Check Tool*: A compliance check tool for the Truck and Bus Regulation is available on ARB's website located at: https://www.arb.ca.gov/msprog/onrdiesel/tblookup.php. To help with the initial review, air districts may check current compliance status by entering any part of the company name, TRUCRS ID, or Motor Carrier Number in the search field. Only fleets that have confirmed compliance requirements and printed their certificate will be listed. Applicants must still meet the requirements in Section C.1.(D)(1)a.

(6) Other compliance tools issued by ARB may be used to meet the requirements of Section C.1.(D)(1) as they become available and are approved for use for the Moyer Program.

(E) Emission Reduction Technologies: Emission reduction technologies must be certified or verified by ARB and must comply with durability and warranty requirements. A technology granted a conditional certification or verification by ARB is considered certified or verified.

(F) Obtaining Financing: The participant may obtain financing to assist in the purchase of the emission reduction technology.

(G) Equipment Leasing is Not Allowed: If financing is necessary, the equipment purchase must be financed with a conventional purchase loan.

(H) Surplus requirements are determined by the regulation to which a project is subject. Any vehicle with an off-road engine that is subject to an on-road regulation must also comply with the on-road surplus requirements described in this chapter. For example, a yard truck with an off-road engine that is subject to the Statewide Truck and Bus Regulation must comply with all off-road eligibility and funding criteria described in Chapters 5, as well as all on-road surplus criteria described in this chapter.

(I) Engines operating under an extension not included in the applicable regulation, such as the Statewide Truck and Bus Regulation, or under program advisory are not eligible. This includes extensions received under enforcement settlement agreements. Fleets with PM filter availability extensions and economic hardship extensions are eligible but

PM reductions will not be funded. Fleet owners must submit documentation confirming extensions.

(J) The existing vehicle must be based in California as shown through vehicle registration. Air districts have the option to limit eligibility to applicants that reside within the district's air basin or operate their vehicles within specified air basins.

2. Project Categories and Applicable Project Types

(A) Heavy-Duty Trucks and Buses (Non-drayage)

(1) Eligibility: Heavy-duty vehicles following the Engine Model Year Schedule or taking one of the Statewide Truck and Bus Regulation compliance options below as defined in the Statewide Truck and Bus Regulation, California Code of Regulations, title 13, section 2025(f), (g), (h), (i), (m), and (p) may apply for funding:

a. Small Fleet option
b. Low Mileage Work Truck option
c. PM Filter Phase-In option
d. Log Truck Phase-In option
e. NOx Exempt Area extension
f. Agricultural Vehicle extension

Other vehicles subject to the Statewide Truck and Bus Regulation such as heavy cranes and sweepers or other vehicles approved to use credits or extensions specified in the regulation may also be eligible.

(2) Replacement Projects: Most replacement projects using engines certified to the 0.20 g/bhp-hr NOx and 0.01 g/bhp-hr PM standard are executed through the Voucher Incentive Program, including two-for-one replacements. This includes on-road vehicles subject to the Truck and Bus Regulation that are replaced with newer vehicles equipped with diesel or alternative fueled engines meeting the current standards with a surplus funding period of one to three years. Voucher replacement projects are not eligible for case-by-case requests. All requirements must be met. If the air district wishes to fund a replacement using criteria that does not meet voucher requirements such as having a longer project life or a minimum California usage of 51 percent, the project must be executed under this chapter through a contract.

(3) Repower and Conversion Projects: If the proposed repower has been done previously by the manufacturer on the same chassis/engine configuration, prototype testing is not necessary. The manufacturer must provide written confirmation that the

previous work was performed successfully and met OEM requirements. If it has not been done previously, prototype testing as described in Section A.1.(B) must be completed. Conversion systems must meet certification or aftermarket exemption requirements described in Section A.1.(C).

(4) Other Project Types: Other project types may be eligible if approved through case-by-case and must be funded through contract.

(5) Surplus: Vehicles can have a filter compliance deadline that is less than one year from the post-inspection date as long as PM emission reductions are not funded. The 2010 standard compliance deadline must be at least one full year from when the replacement vehicle is delivered and post-inspected.

(6) Maximum State Funding Amounts: The maximum amount of State funding that can go toward the purchase of a replacement vehicle equipped with either a diesel or alternative fuel engine meeting 0.20 g/bhp-hr NOx and 0.01 g/bhp-hr PM standards is shown in Table 4-3. Maximum funding for Optional Low NOx and Zero-Emission replacements are shown in Tables 4-4 and 4-6.

(7) Log Truck Requirements: Log trucks using the Log Truck Phase-In option must have log bunks permanently attached at pre- and post-inspection. Vehicles taking the Log Truck Phase-In option are not eligible for two-for-one replacements as described in Section B.7.

(B) School Buses

(1) General Eligibility: School buses are eligible for Moyer Program funding if they meet the general program criteria in Section C.1., as well as additional criteria in this subsection.

(2) Eligible Applicants: Public school districts in California that own their own school buses are eligible for funding. Where a Joint Power Authority (JPA) has been formed by several public school districts and the JPA holds ownership of the school buses, then the JPA is also eligible for funding. School transportation contractors, non-profit agencies, private schools, and other private companies are not eligible to receive funding for school bus projects.

(3) Truck and Bus Regulation Compliance: School buses subject to the Truck and Bus Regulation are only eligible if they meet one of the following requirements:

a. The existing school bus must have an OEM diesel particulate filter (DPF) installed.

b. The existing school bus must be retrofitted with a DPF that reduces diesel PM emissions by at least 85 percent.

c. The existing school bus must be reported in TRUCRS under the Low-Use exemption.

d. The existing school bus must be reported in TRUCRS under the Extension for the Unavailability of Verified Diesel Emission Control Strategy (VDECS). This extension expires on January 1, 2018, at which point such school buses will no longer be eligible for Moyer Program funding.

(4) Used Vehicle Eligibility: Used school buses are not eligible as replacements. The replacement vehicle for any project must be new.

(5) Maximum State Funding Amounts: School bus projects have unique maximum grant amounts as summarized in Table 4-2, and also a unique cost-effectiveness limit of $276,230/ton. This cost-effectiveness limit allows for funding amounts consistent with the Lower-Emission School Bus Program funding caps based on average school bus operating usage as determined by a limited number of previously-funded Moyer Program school bus projects. Individual vehicle usage that falls below the average may result in lower funding amounts.

(6) Calculating Emissions: Zero-emission school bus projects (including replacements, repowers, and electric conversions) are eligible for NOx, reactive organic gases (ROG), and PM emission reductions. All other school bus projects are eligible only for NOx and ROG emission reductions.

(7) Engine Intended Service Class: The weight class range for school buses is determined as in Section C.1.(B), but in cases where the Executive Order of the baseline school bus engine does not list an intended service class, the intended service class of the engine shall be assumed to be MHD.

(8) CHP Safety Certification. All existing school buses must have a current CHP safety certification (CHP Form 292) at the time funding is awarded for the project (i.e., the school bus may not have a lapsed CHP safety certification), and it must be currently registered with the Department of Motor Vehicles (DMV).

(9) School Bus Electric Conversion Projects. The baseline vehicle chassis must be ten years old or newer. CHP requires engineering plans, certified by a California licensed engineer, to be able to safety certify the school bus.

(C) Transit Vehicles (Urban Buses and Transit Fleet Vehicles)

(1) Eligibility: Transit vehicles that have achieved compliance with all applicable regulatory requirements are eligible for surplus emission reduction funding. New regulation requirements may affect surplus and funding amounts in the future.

(2) Replacement Projects: A replacement engine for a replacement vehicle project must be an ARB certified engine meeting emissions levels of 0.10 g/bhp-hr NOx or cleaner.

(3) Repower and Conversion Projects: A replacement engine for a repower project must be an ARB certified engine meeting emissions levels of 0.10 g/bhp-hr NOx or cleaner. If the proposed repower has been done previously by the manufacturer on the same chassis/engine configuration, prototype testing is not required. The manufacturer must provide written confirmation that the previous work was performed successfully and met OEM requirements. If it has not been done previously, prototype testing must be completed as described in Section A.1.(B). Conversion systems must meet certification or aftermarket exemption requirements described in Section A.1.(C).

(4) Maximum State Funding Amounts: The Federal Transit Administration (FTA) provides up to an 80 percent grant (Federal funding) for new urban bus purchases and repowers. Maximum State funding for transit projects has been specified to account for greater access to other funding resources. Funding caps for various project types are shown in Tables 4-4 through 4-6. If the Moyer Program grant is used to co-fund an eligible project, the sum of all grant funds received cannot exceed the total project cost. Additional criteria on co-funding projects with a Moyer Program grant can be found in Chapter 3, Section L.

(5) Applicable Emission Factors: Emission factor tables for urban transit buses are included in Appendix D as Tables D-3 and D-4. Other transit fleet vehicles such as shuttle buses must use the MHD or HHD emission factor tables, Tables D-1 and D-2. Cost-effectiveness calculations for transit urban buses do not include deterioration since those fleets are generally well-maintained per EMFAC 2014. Deterioration must also not be

included in the cost-effectiveness calculations for other transit vehicles.

(6) Calculating Emission Reductions: Cost-effectiveness calculations can only include emission reductions from the 2007 engine model year for a 12-year maximum project life. No other additional emission reductions may be included. Only NOx and ROG surplus emission reductions can be funded. PM emission reductions may also be funded for zero emission projects.

(D) Drayage Trucks

(1) Eligibility: Drayage trucks as defined in California Code of Regulations, title 13, section 2027(c)(15), are eligible for Moyer Program funding for up to one year before the applicable compliance deadline.

(2) Existing Engine: The baseline engine must be 2007 or newer. Beginning on January 1, 2023, drayage trucks will be subject to the Statewide Truck and Bus Regulation and must be compliant to the regulation to be eligible for funding (i.e., baseline engine must be model year 2010 or newer). If the baseline truck is not currently used for drayage activities and the engine is older than 2007, the replacement truck will be added to the DTR as non-compliant for the contract term.

(3) Replacement Projects: Replacements may be funded through voucher or contract.

(4) Repower and Conversion Projects: If the proposed repower has been done previously by the manufacturer on the same chassis/engine configuration, prototype testing is not necessary. The manufacturer must provide written confirmation that the previous work was performed successfully and met OEM requirements. If it has not been done previously, prototype testing as described in Section A.1.(B) must be completed. Conversion systems must meet certification or aftermarket exemption requirements described in Section A.1.(C).

(5) Calculating Emission Reductions: Only NOx and ROG emission reductions can be funded. PM emission reductions may be funded for zero-emission projects.

(E) Solid Waste Collection Vehicles (SWCV such as Transfer Trucks and Refuse Trucks)

(1) Eligibility: SWCV fleets that have achieved compliance with the final SWCV Regulation (CCR, title 13, sections 2020-2021.2)

deadline are eligible for funding. Solid waste transfer trucks and vehicles equipped with 2007 and newer engines are subject to the Statewide Truck and Bus Regulation and surplus will be determined according to that regulation.

(2) Replacement Projects: A replacement engine for a replacement project must be an ARB certified engine meeting emissions levels of 0.10 g/bhp-hr NOx or cleaner.

(3) Repower and Conversion Projects: A replacement engine for a repower project must be an ARB certified engine meeting emissions levels of 0.10 g/bhp-hr NOx or cleaner. If the proposed repower has been done previously by the manufacturer on the same chassis/engine configuration, prototype testing is not necessary. The manufacturer must provide written confirmation that the previous work was performed successfully and met OEM requirements. If it has not been done previously, prototype testing as described in Section A.1.(B) must be completed. Conversion systems must meet certification or aftermarket exemption requirements described in Section A.1.(C).

(4) Applicable Emission Factors: Emission factor tables for refuse trucks are included in Appendix D as Tables D-5 and D-6. Transfer trucks use Tables D-1 and D-2.

(5) Calculating Emission Reductions: Only NOx and ROG emission reductions can be funded. PM emission reductions may be funded for zero emission projects.

(F) Emergency Vehicles

(1) Eligible Vehicles: Authorized emergency vehicles as described in the California Vehicle Code 165 including, but not limited to fire apparatus, pumpers, ladder trucks, and water tenders. Other MHD HHD diesel authorized emergency vehicles, such as prisoner buses, are also eligible for funding under this chapter.

(2) Replacement Projects: Eligible projects are those in which a new or used replacement vehicle with an engine meeting the current model year California emission standard replaces an older, more polluting equipment or vehicle. The older, replaced vehicle must be destroyed. A fire truck reuse option is also available on a case-by-case basis. The fire truck reuse option allows fire departments to give away the existing old vehicle and destroy another older vehicle in its place.

(3) Eligible Costs: Eligible project costs include those parts specified in Section B.8. but excludes parts that are not bolted on and

movable, such as the tank on the water tender. In addition, the following costs are eligible:

a. Tax and transport for eligible parts or costs.

b. Labor for installation of or modification to parts eligible for funding.

(G) Case-By-Case Projects

(1) On-road heavy-duty diesel vehicles with GVWR of 8,501-14,000 lbs. may be considered for Moyer Program funding on a case-by-case basis.

(2) Retrofits

a. Only projects that reduce NOx emissions, including alternative fuel retrofit systems, are eligible for funding. The retrofit must be certified or verified by ARB to reduce NOx by at least 15 percent and reduce emissions to the 0.02 g/bhp-hr optional low NOx standard or cleaner. If the baseline engine does not meet 0.01 g/bhp-hr PM standards, the retrofit must also reduce emissions by at least 85 percent (verified Level 3).

b. The maximum State funding amount for retrofit projects is $20,000.

(3) Transport Refrigeration Units (TRUs): TRU projects are eligible for limited funding opportunities, but emission benefits are generally low because many older TRUs have already been replaced to meet regulatory requirements.

a. Funding opportunities may exist for zero emission replacement projects only.

b. Alternative technologies such as pure cryogenic systems are not required to be verified, but ARB must review and approve such systems in writing on a case-by-case basis.

c. The participant shall install an hour-meter or other means to measure usage on the TRU to track operating hours, and shall provide this information to ARB or the air district upon request.

d. The maximum State funding percentage is 50 percent.

(4) Auxiliary Power Units (APUs): Limited funding will be available for APUs, and only for projects approved through case-by-case. APUs are subject to the Airborne Toxic Control Measure to Limit

Diesel-Fueled Commercial Motor Vehicle Idling, California Code of Regulations, title 13, section 2485.

(5) Cost-effectiveness calculations for projects with power take-off (PTO) will be considered by ARB on a case-by-case basis. Hours of PTO operation must be documented through hour meter records or data from the emission control module.

(6) Case-by-case projects must receive approval from ARB prior to contract execution. These projects must follow the requirements as described in Chapter 3, Section U.

3. Participant Requirements

(A) Ownership: The participant must currently be the sole owner of the existing vehicle, documented through a copy of the existing vehicle title. The title must show no active lienholders. The title need not be a California title. In addition, the participant must have owned and operated the vehicle the previous 24 months. If the title does not show sole ownership for the previous 24 months, the applicant must be listed as one of the owners or shown as a registered owner on registration documentation for the previous 24 months. If the existing vehicle title is not available, then all three of the following must be used as alternative documentation until a duplicate title is received from the California DMV: 1) a copy of the current and valid vehicle registration, 2) a copy of the DMV Vehicle Registration Record (printout), and 3) a copy of the DMV receipt for duplicate title request. A copy of the duplicate title must be received by the air district before contract execution. If it is unclear whether a vehicle is owned or leased by a participant, the air district will determine whether the vehicle is eligible.

(B) Usage Documentation and Self-Certification for California Minimum Usage: Covering each 12-month period for the previous 24 months, the participant must:

(1) Submit conclusive documentation (logbooks, maintenance records, tax records, etc.) of annual miles traveled in California, and

(2) Certify that at least 51 percent of total usage has been in California.

(C) Military Service Provision: If an applicant has been on active military duty at any time during the previous 24 months, documentation prior to deployment and covering the same length of time as the deployment period may be used to meet the title, registration, usage, and operation in California requirements as described in Sections C.3.(A)-(B) and C.4.(C). The applicant must submit a copy of DD Form 214, Certificate of Release or Discharge from Active Duty to verify military service during the deployment period.

(D) Participants may only apply to one air district at a time for each project.

(E) Participants must submit an application for funding consideration.

(F) Participants must provide the air district with the full contact information of the seller/dealer of the replacement vehicle, or the business that performs the conversion or repower.

(G) The participant must be the sole registered owner of the replacement engine or vehicle for the duration of the contract term. Throughout the contract term (project life), the participant must annually:

(1) Provide registration and proof of insurance to the air district.

(2) Provide reports that include items specified by the air district which may include miles driven in the air district and in California, and details regarding maintenance and servicing.

(3) Operate the engine/vehicle within California for at least the percentage of time specified in the contract.

(H) Report accident or loss of vehicle: If the replacement engine/vehicle is in an accident or is stolen, the accident or theft must be reported to the air district within 10 business days. The participant must provide the police report, a letter from the insurance company regarding the accident or theft, and other information requested by the air district. The participant must repair the vehicle and return it to operation, if possible. If the vehicle is totaled, the participant and the air district staff must come to an agreement regarding any requirements that still need to be met. If the participant will continue the business, efforts should be made to obtain a substitute vehicle that can take over the terms of the contract. The substitute vehicle must be at least as clean as the original Moyer Program funded vehicle, be in the same weight class, and cannot have more miles than would have been accumulated based on the mileage used to determine the funding amount, or no more than 600,000 miles for HHD vehicles, 350,000 miles for MHD vehicles, and 250,000 miles for LHD vehicles.

(I) Any change of ownership, change in registration status, or change of mailing address during the contract term must be reported to the air district within 10 business days.

4. Existing Engine and Vehicle Requirements

(A) The existing vehicle must currently operate on diesel fuel or alternative fuel such as compressed natural gas.

(B) The existing vehicle must have an engine of model year 2010 or older, except if it is a school bus or log truck which may be powered by an

engine of any model year. The maximum chassis age for all-electric conversions must be no more than ten years old.

(C) The existing vehicle must either be: 1) currently registered and have been registered in California for the past 24 months supported by documentation showing no lapses (except for seasonal vehicles and those eligible under the military service provision); or 2) must have been registered in California for the previous eight consecutive months with supporting documentation supplemented by alternate documentation showing California operation for the past 24 months. California International Registration Plan (IRP) documents are acceptable. Out of State IRP or registration is not eligible. The existing vehicle must be based in California.

(D) If the existing vehicle operates seasonally, then the existing vehicle may be eligible to participate if it has been registered in California for three to six continuous months per 12 month period for the previous 24 months. DMV partial year registration documentation for each period the vehicle was registered must be included with the application.

(E) The participant must provide proof of insurance for the old vehicle for the previous 24 months.

(F) The existing vehicle must meet the criteria for either an LHD vehicle, MHD vehicle, or an HHD vehicle, as defined below:

(1) LHD vehicles must have a manufacturer GVWR of 14,001-19,500 lbs.

(2) MHD vehicles must have a manufacturer GVWR of 19,501-33,000 lbs.

(3) HHD vehicles must have a manufacturer GVWR of 33,001 lbs. or greater.

(4) GVWR may be documented with a photo of the vehicle manufacturer tag or a copy of the manufacturer build sheet. Air districts may request ARB approval of alternate GVWR documentation on a case-by-case basis.

(G) Engine Verification:

(1) The air district file must include a copy of the existing engine Executive Order. If an Executive Order is not available, the air district may request approval of alternative documentation on a case-by-case basis.

(2) If the old vehicle engine tag is missing, then verification of the engine information can be satisfied with the engine serial number. The participant must provide verification of the engine make, model, model year, engine serial number, and horsepower from the manufacturer. The participant may also verify the horsepower with the results of a dynamometer test. The dynamometer test will take into account a 15 percent loss in actual horsepower, accounting for transmission loss. Verification can include a letter or a printout from an engine manufacturer or dealership. On a case-by-case basis, ARB may approve other means of obtaining the information.

(H) The existing vehicle must be in operational or roadworthy condition, as determined through a CHP Biennial Inspection of Terminals (BIT) or equivalent air district-approved inspection. If the air district does not conduct a pre-inspection, the following methods may be used:

(1) The vehicle owner may submit a completed CHP 90-Day Safety Inspection Form documenting an inspection that occurred within 90 days of the application date; or

(2) An air district approved contractor may conduct the inspection of the old vehicle and provide pictures verifying that the vehicle is in operational condition.

(I) Glider Kits: Glider kits are replacement chassis and cabs for on-road heavy-duty vehicles. Glider kits are generally identified with a VIN starting with the letters “GL”. In situations where the model years of the glider kit vehicle’s chassis and engine differ, approval determination shall be made using the model year of the engine. Existing glider kit vehicles are eligible to participate but the replacement vehicle has to be a complete Original Equipment Manufacturer vehicle; i.e., the replacement vehicle cannot be a glider kit.

(J) Existing Vehicle Body Components: The body of the existing vehicle does not play a part in the participation in the program. Program funds can only be used to purchase the new vehicle, not external body components or parts used for a particular vocation (e.g., dump body). The common practice for vehicle owners to remove non-emission related body components from the existing vehicle and place them on the replacement vehicle is still permissible as long as the components do not exist on the replacement vehicle and are not a part of the paid components for the replacement vehicle.

(K) Operation of Existing Vehicle After Approval: If the existing vehicle is in an accident or has an engine failure after receiving approval from the air district but prior to replacement, then the existing vehicle will still be

eligible for receiving funds from the program as long as all other on-road requirements have been met.

5. Replacement Engine and Vehicle Requirements

(A) Emission Standards: Replacement vehicles with a 2013 model year or newer engine certified to a PM emission standard of 0.01 g/bhp-hr and a NOx family emission limit or NOx standard level of 0.20 g/bhp-hr or lower are eligible for funding (unless noted otherwise). New electric vehicles and non-combustion hybrid vehicles (e.g., electric vehicles powered by a hydrogen fuel cell) must have an ARB approval letter confirming the vehicle does not emit any vehicle exhaust emissions or fuel-based evaporative emissions. If the baseline engine model year is 2010, the replacement engine must be certified to a NOx standard level of 0.10 g/bhp-hr NOx or lower.

(B) Engine class: The engine's primary intended service class must match the replacement vehicle's weight class (i.e., an MHD diesel engine is used in a vehicle with a GVWR of 19,501- 33,000 lbs. and an HHD diesel engine is used in a vehicle with a GVWR greater than 33,000 lbs.). As an exception, an HHD engine may be installed in an MHD vehicle if necessary for vocational purposes, but only if the GVWR is within 10 percent of the engine's intended service class (i.e., GVWR of 29,701 lbs. or greater). Also, an MHD engine may be installed in an HHD vehicle, but only if the GVWR is within 10 percent of the engine's intended service class (i.e., GVWR of 36,300 lbs. or less).

(C) Mileage: A used HHD replacement vehicle must have less than 500,000 miles, a used MHD replacement vehicle must have less than 250,000 miles, and a used LHD replacement vehicle must have less than 150,000 miles with odometer verification to occur at the post-inspection.

(D) All-Electric Range: Electric vehicles and hybrid vehicles (new or converted) must demonstrate an all-electric range of at least 35 miles. Those with fast charge capability must demonstrate an all-electric range of at least 20 miles. If a vehicle is not certified to meet this range, it may only be approved for funding following ARB evaluation of demonstration test data verifying that minimum all-electric range requirements are met. If demonstration data has already been submitted to another ARB funding program and approved, demonstration requirements may be waived.

(E) Horsepower: The replacement engine horsepower must be no more than 25 percent greater than the existing engine horsepower. In limited situations, such as the non-availability of the original horsepower range for the specific application, the air district may approve a greater than 25 percent increase in horsepower.

(F) Weight Class: The replacement vehicle must be in the same weight class as the existing vehicle (either LHD, MHD, or HHD). An MHD vehicle can replace an HHD vehicle if they both have the same axle configuration (e.g. an existing HHD vehicle with two axles can be replaced with an MHD vehicle with two axles) but the funding amount must be at the MHD funding level.

(G) Body and Axle Configuration: The replacement vehicle must have the same axle and body configuration as the old vehicle. The air district may allow slight changes based on the latest technology. Changes must be requested and approved prior to the purchase of the replacement vehicle.

(H) Title: The replacement vehicle must have a clean title prior to purchase. The replacement vehicle must not have a salvage title and must not have been in an accident, repaired, and became available for resale.

(I) California Registration: The replacement vehicle must be registered in California or in the California IRP.

(J) The participant must maintain insurance coverage for the replaced/repowered/converted vehicle as required by law for the duration of the project life. The participant is encouraged to have replacement value insurance coverage to ensure complete repair or replacement in the event of major damage to the vehicle. If the vehicle is not repaired and replaced during the project life, the applicant must return prorated funds. See Section C.6.(I)(3).

(K) Warranty requirements: The following warranty requirements apply:

(1) Except for school buses, hybrids, and zero-emission vehicles, all participants must purchase a minimum of a one-year or 100,000 mile major component engine warranty for the replacement new or used vehicle or repowered engine. The warranty must cover parts and labor. If the purchase of a new or used replacement vehicle already includes a minimum one year or 100,000 mile warranty as specified above, a separate supplemental warranty is not required. However, it is recommended that the highest grade warranty be purchased in order to avoid expensive repairs in the future.

(2) Electric vehicles, hybrid vehicles, and conversion systems must have a minimum warranty period of 3 years or 50,000 miles. The warranty must cover the engine (if applicable) or motor, drivetrain, battery or energy storage, and parts and labor (including any part on the converted vehicle or engine that is damaged by the hybrid conversion system).

(3) For school buses, the vendor warranty must provide protection for a minimum of 60 months or 75,000 miles, whichever comes first, and provide full warranty coverage of, at a minimum, zero-emission or all-electric motor, drive train, batteries/energy storage system(s), parts and labor. Warranties must be fully transferrable to subsequent school bus purchasers for the full warranty coverage period. Warranties must cover the following for the full warranty period (unless otherwise denoted):

a. Extended Motor, Drivetrain (including Battery), and Zero-Emission Components: Provide warranty coverage against defects in material and workmanship for the motor, transmission, rear axle, and electric or zero-emission system components including the battery. Gaskets and seals are not required to be included under the warranty coverage.

b. Frame Rails, Cross Members, and Cab: For new school buses, coverage extends to structural cracks in the frame caused by defects in material workmanship and against corrosion perforation of the cab. For school bus conversions, the all-electric school bus vendor is only responsible for damage or corrosion tied to, or resulting from, their workmanship on, or handling of, these parts.

c. Battery Degradation Warranty: Provide warranty coverage against battery degradation below 80 percent of capacity.

(4) No Moyer Program funds will be issued for maintenance or repairs related to the operation of the vehicle. The participant takes sole responsibility for ensuring that the vehicle is in operational condition throughout the agreement period.

(L) Engine and Emission Control Modifications: Emission controls on the replacement vehicle engine cannot be modified except as permitted by law. Unauthorized modification to engine performance including, but not limited to, changes in horsepower, emission characteristics, engine emission components (not including repairs with like-original equipment manufacturers replacement parts), and modifications to the engine's emission control function or the electronic monitoring unit are not allowed.

(M) Service: At least one California service provider approved by the manufacturer must be available to repair and service the engine/vehicle.

6. Air District Requirements

(A) Requirements described in Chapter 3: Program Administration must be met unless otherwise stated in this chapter.

(B) Air districts must include the on-road category as a funding option in the air district's Moyer Program Policies and Procedures Manual before funding on-road projects. The Policies and Procedures must include the administrative tools that are needed to manage on-road projects, including memoranda of understanding (MOU) or agreements with vehicle dealerships/providers (if applicable) and dismantlers, reimbursement procedures, inspections, monitoring and enforcement, contract development, etc. Air districts are not required to submit the initial Policies and Procedures to ARB for approval, but it must be available upon request.

(C) Air districts may fund on-road projects through a regional program administered by one designated air district. The designated air district may be located within the region, or may be a large air district located outside the region.

(D) Air districts are responsible for ensuring all Moyer Program requirements are met. Air districts are encouraged but not required to have agreements or MOUs with vehicle dealerships. However, agreements or MOUs with participating dismantlers are required. Agreements or MOUs, should contain, at a minimum, the program requirements (including, but not limited to, the requirement that the dealer delivers the existing vehicle to a qualified dismantler within 60 calendar days of the date that the old vehicle was turned in to the dealer by the applicant) that are expected of each entity and the repercussions for noncompliance with the terms of the agreement or MOU for each entity. Air districts that fund projects through both VIP and this chapter can have one agreement with each dealer and dismantler for both programs as long as the dealer and dismantler agree to follow requirements of each program. State funds must not be provided by the air district for any dismantler or material costs, including hazardous waste abatement fees, labor costs, fines, permits, or other charges resulting from destruction or disposal.

(E) Reimbursement: To ensure that an application package is complete, the following items must be included and complete prior to reimbursement:

(1) Signed and complete application and fully executed contract.

(2) Documentation showing that the existing vehicle is roadworthy. This includes documentation showing that the old vehicle has passed a CHP BIT inspection in the past 90 days or conduct an equivalent vehicle inspection and sign as appropriate. If documentation is provided by a dealership, the air district reserves the right to audit the dealership's record of inspection.

(3) Invoices of the purchase and all work performed. If work was performed on the replacement vehicle, the invoices must include all

engine, transmission, engine horsepower derating, body and other work performed on the replacement vehicle.

(4) Digital photographs of the existing vehicle and the replacement vehicle or engine. If a contractor conducts any inspections, the air district will specify the required digital format. Reimbursement will not be processed until all photographs are received and verified by the air district. All photographs must be clear, and all VIN and engine serial numbers must be legible.

a. Photographs of the old vehicle must include the following views:

i. Right Side - hood down.
ii. Front - hood down.
iii. Left Side - hood down.
iv. Rear.
v. VIN Tag - inside vehicle or on frame rail.
vi. Engine serial number and engine information, if available (make, model year, engine family) - either tag or stamp on block.
vii. License plate.
viii. Left and right side of engine.

b. Photographs of the replacement engine or vehicle must include the following views:

i. At least one side of the vehicle.
ii. VIN Tag - inside vehicle or on frame rail.
iii. Engine serial number and engine information – tag (or primary motive power components).
iv. License plate.
v. Odometer reading.
vi. Left and right side of engine.
vii. Modifications (if any).

(5) Dealer/Provider/Installer certification that the old engine and/or vehicle will be delivered to a qualified dismantler within 60 calendar days of receipt of the old engine or vehicle. The certification must include the make, model, year, VIN, engine make, engine serial number, and the date the engine or vehicle is expected to be delivered to the dismantler. The location of the dismantler yard where the engine/vehicle will be destroyed must also be provided.

(6) Documentation of replacement vehicle warranty and registration (if applicable).

(7) Proof of Project Financing: The financing package will enable the air district to determine the reimbursement costs that may be

accrued in case the participant defaults on the contracted performance requirements. Proof of project financing can be a document showing the lender and the amount loaned, which at a minimum is a copy of the check given to the dealer equal to the portion of the project that was not Moyer Program funded. Proof of project financing is always required unless the grantee paid cash for the portion of the project that was not Moyer Program funded.

(8) For replacements, dealerships must possess pre-inspection documentation of the existing and replacement vehicles prior to releasing the replacement vehicle to the participant. If the air district conducts the inspections, the dealership must receive approval from the district before releasing the replacement vehicle. Upon request of the air district, ARB may waive inspection requirements.

(9) Proof of sale after the application and all required documentation have been approved by the air district.

(10) Copy of Title of Existing Vehicle. For replacement projects, the title must be signed and dated by the applicant.

(F) A third party (e.g., engine dealer or distributor) may complete an application or part of an application on an owner's behalf only if the vehicle owner signs and agrees to the application. Applications must include a signature section for third parties. The third party signature section must include signature and date lines, and sections for the third party to disclose how much they are being paid, if anything, to complete the application and the source of funds used to pay them. To make the Moyer Program accessible to all potential applicants, including those that cannot afford to hire third party assistance, air districts are encouraged to provide assistance to applicants.

(G) Air districts must ensure the vehicle and engine are scrapped within 60 calendar days of the dismantler's receipt of the vehicle. This must be confirmed through post-inspection by the air district or an air district approved contractor. The destruction of the old vehicle and engine must be properly documented in accordance with the Moyer Program requirements.

(H) Inspections: The following inspections must be performed for each funded engine/vehicle (exceptions are allowed for public fleets and transit agencies as specified in Chapter 3) as shown in Table 4-9:

Table 4-9
Required Inspections for On-Road Projects

Inspection Type	Purpose(s)	Timing
Pre-inspection	• Verify existing vehicle is in operational condition. • Verify existing vehicle application information.	After application is submitted to air district but prior to approving the application.
Post-inspection	• Verify replacement vehicle meets emission standard. • Verify application information.	Before replacement engine/vehicle is delivered, and prior to payment being issued.
Pre-dismantle inspection (Replacements Only)	• Verify existing vehicle is in operational condition and has not been stripped of parts (except those allowed in Section C.4.(J)) per Section C.7.(F). • Verify existing vehicle application information.	• After existing truck is delivered to dealership before payment is issued. • Existing truck is at dealership location and must be delivered to dismantler within 60 days.
Dismantle inspection	• Verify engine destruction (see Section C. 8.(C)(4)). • Verify that frame rails are completely severed. • Obtain copy of REG 42 form filed with DMV.	• After engine and frame rail destruction. • Within 60 days after dismantler receipt. • If dismantler takes photos, they must be provided to the air district within 10 business days of dismantling.

Documentation requirements are specified in Chapter 3, Section W. and X. Air districts may enter into a contract, written agreement, or memorandum of understanding with a contractor to perform project inspections (pre-inspections, post-inspections, pre-dismantle, or dismantle inspections). If an air district chooses to use contractors to perform inspections, air district staff must conduct and document at least one inspection on each project without the use of a contractor. Air districts must ensure all inspection requirements are met and shall retain legal responsibility for full compliance with the inspection provisions of these

Guidelines, regardless of the use of contractors. Air districts that do not conduct 100 percent of required inspections themselves must audit 5 percent of each type of inspection (pre, post, pre-dismantle, and dismantle). Audits should be done randomly and occur throughout the implementation timeline of the air district.

(I) Recovery of Moyer Program Grant Funds: The air district must establish a mechanism to assure the participants fulfill all contractual obligations, including owning and operating the funded vehicle for the project life. The air district will determine noticing requirements and the method to achieve fund recovery. Air districts may consider the following options:

(1) List the air district as co-lien holder on the title of the funded vehicle for the term of the agreement. The participant must submit a completed Uniform Commercial Code-1 Financing Statement Form to the California Secretary of State, with a copy sent to the air district, within 30 days of the project sale. The financing statement must have the air district as the secured party and the vehicle should be listed as collateral.

(2) If the funded vehicle is sold during the project life, the new owner must assume the obligations under the participant's contract with the air district and comply with the terms and conditions of the contract. The air district must approve the change in ownership prior to the sale.

(3) The grant recipient may return funds according to the following prorated formula:

$$Recapture\ Amount\ (\$) =$$

$$Funding\ Amount(\$) - \frac{Elapsed\ Portion\ of\ Project\ Life(Yrs) * Funding\ Amount(\$)}{Project\ Life(Yrs)}$$

(J) Air districts and ARB reserve the right to deny funding to applicants that have previously received funds and did not meet the terms and conditions of the funding agreement.

(K) Projects may be reviewed through a solicitation process or first-come, first-served as described in the air district's Policies and Procedures.

(L) Air districts must perform compliance checks (see section C.1.(D)).

(M) Air districts must provide training, as described in Section C.7.(A)(3) and C.8.(B)(2), and additional training in a timely manner whenever there have been substantive Moyer Program revisions.

7. Dealership/Installer Requirements

(A) Dealerships and installers must warrant that they meet the following minimum qualifications and will continue to meet these qualifications throughout participation in the Program:

(1) Dealership/Installer has had a valid business license issued in California for a minimum of the last two years.

(2) Dealership has had a valid vehicle dealership license with DMV for a minimum of the last two years. The installer is authorized by the manufacturer.

(3) Dealership/Installer maintains a minimum of one employee that has successfully completed the training by the air district regarding terms, conditions and requirements of the Program. If a participating dealership maintains more than one location for truck sales, then each location must have at least one employee trained.

(4) Dealership/Installer agrees to allow the air district or ARB to inspect vehicles or audit program records covered under the Moyer Program Guidelines during normal business hours.

(B) Vehicle dealers must:

(1) Provide basic information to vehicle owners about the Moyer Program.

(2) Help participants complete the application, if necessary. It is important to make sure that all information is filled out correctly and that the participant understands the meaning of the program and the contract. Once complete, the dealer may submit the application package to the air district according to the agreement or MOU, if applicable.

(C) Dealerships and installers must adhere to agreements or MOUs established with the air district, if applicable.

(D) Dealerships and installers must submit all supporting documentation required under the Guidelines and if applicable, air district agreement for each project. Once all dealership/installer requirements have been met, reimbursement will be issued to the dealer/installer according to the agreement or MOU, when applicable.

(E) Dealerships and installers must possess pre-inspection documentation of the existing and replacement engines/vehicles prior to releasing the replacement engine/vehicle to the participant. If the agreement or MOU specifies that the air district or other third party will perform any inspections, the dealership/installer must receive air district approval

before releasing the replacement engine/vehicle. Upon request of the air district, ARB may waive inspection requirements.

(F) For replacements, the dealership must ensure the existing vehicle is in similar condition as found in the pre-inspection. The dealer should reject the condition of the existing vehicle if it is deemed unroadworthy or if parts were stripped from the existing vehicle (except for parts essential to vocation that will be installed on the replacement vehicle). Reimbursement to the dealer or release of funds to the grantee will be withheld until the dealer (or air district) approves of the condition of the existing vehicle and it is delivered to the dealership.

(G) The dealer or installer must deliver the existing engine/vehicle to a qualified dismantler within 60 calendar days of delivering the replacement engine/vehicle to the grantee. The dealer or installer must immediately notify the air district of the location and date of delivery of the existing engine/vehicle to the dismantler. The participating dismantler may also pick up the existing engine/vehicle.

(H) Use of Engine or Vehicle Pending Destruction: The dealer/installer may not use or permit the use of, the engines or vehicles, except use necessary to move it for destruction or storage.

(I) For electric or hybrid vehicles (new or converted), the dealership/installer/manufacturer must provide the air district with a copy of the owner's manual and other materials that will be provided to the purchaser/participant. The owner's manual and other materials must at least include the following information:

(1) A brief description of the vehicle/conversion system, including major components and their theory of operation and proper operating procedures;

(2) Battery maintenance best practices and charging procedures and protocols, if applicable;

(3) A listing of necessary service intervals and service requirements that differ from the base vehicle's or engine's original manufacturer's, if applicable;

(4) A statement that the hybrid converted vehicle is subject to all in-use vehicle inspection and maintenance programs applicable to its size, type, and class;

(5) The name, physical address, e-mail address, phone number, and website, if available, of the manufacturer and authorized installer, as well as a list of the names, addresses, and phone numbers of the major dealers who supply parts for, or service the vehicle;

(6) All information necessary for the proper and safe operation of the vehicle, including information on safe handling of the battery or energy storage system, and emergency procedures to follow in the event of battery leakage or other malfunctions that may affect the safety of the vehicle operator, emergency personnel, or laboratory personnel;

(7) The product warranty statement.

8. Dismantler Requirements

(A) If the existing engine or vehicle is replaced or removed, it must be dismantled. This requirement has been established to ensure that emission reductions are real, preventing the engine from continuing to emit high levels of pollutants. Destruction of the existing vehicle chassis and engine permanently removes the old, high emitting vehicle from service. The existing vehicle and engine specified in the application (or engine only for repower and conversion projects) must be dismantled, and may not be substituted with a different vehicle.

(B) To participate in the Program, dismantlers must:

(1) Enter into an agreement with the air district.

(2) Have at least one active employee who received training by the air district on the requirements of the Moyer Program. If a dismantler has more than one location, then the dismantler must have at least one active employee trained by the air district at each location that will be accepting engines/vehicles for the Moyer Program.

(3) Be licensed by DMV as an dismantler for at least the previous two years.

(4) Have had a valid business license issued in California for a minimum of the last two years.

(5) Possess a current, valid California Environmental Protection Agency Hazardous Materials Generators Permit.

(6) Be in compliance with all local, State, and federal laws and regulations.

(C) The dismantler must do the following for each engine/vehicle:

(1) Dismantle the old vehicle in accordance with Moyer Program Guidelines within 60 calendar days of receipt. Upon dismantler request, the air district may approve an extension.

(2) Destroy and render useless the existing vehicle and/or engine. At a minimum, the destruction must include the following:

a. Both frame rails must be completely severed between the front and rear axles.

b. A hole must be put in the engine block with a diameter of at least three inches at the narrowest point. The hole must be irregularly shaped (i.e. no symmetrical squares or circles). A section of the oil pan flange must be removed as part of the hole or have a line cut through it that connects to the hole.

(3) If the vehicle is to be scrapped, the dismantler must completely sever the frame rails of the old vehicle to ensure that the vehicle will not be used again.

(4) Air district staff or the dismantler must take photographs of the destroyed engine and severed frame rails. Dismantler photographs of the destroyed engine block and severed frame rails must be provided to the air district within ten (10) business days of dismantling the vehicle. The following picture views must be taken:

a. Front, right, and left side of vehicle with hood down including license plate if available (vehicle scrap).

b. VIN tag (vehicle scrap).

c. Engine serial number either stamped on the block or on the tag (engine or vehicle scrap).

d. Left and right side of destroyed engine block either in-frame or out of frame (engine or vehicle scrap).

e. Hole in engine block (engine or vehicle scrap).

f. Completely severed frame rails (vehicle scrap).

g. Odometer Reading (vehicle scrap).

(5) Prepare and submit to DMV either a “Non-Repairable Vehicle Certificate” using an “Application for Salvage Certificate or Non-Repairable Vehicle Certificate” (REG 488C), or a Notice of Acquisition/Report of Vehicle To Be Dismantled (REG 42) ensuring the VIN can never be registered again in California. Within 90 calendar days of the dismantle inspection date, the dismantler must provide verification to the air district that the existing vehicle has been registered with DMV as non-revivable with a type transaction code (TTC) L10 or C26 on the DMV Reconciliation

transaction receipt or other DMV documentation that satisfies this requirement.

(6) Upon request of the air district, ARB may approve an alternative disposition for the old engine/vehicle.

(D) As specified in California Code of Regulations, title 13, section 2706(i)(3)(G), no party shall advertise, sell , lease, or offer for sale or lease, a used verified diesel emission control strategy.

(E) Dismantler Inspection: Once the air district is notified, a dismantler inspection will be scheduled and photos documenting the destruction of the engine will be taken in accordance with the Guidelines. The dismantler shall not move the vehicle off of their property or part out a vehicle until a dismantler inspection by the air district or a designated contractor has been performed and given approval by the air district.

(F) Use of Engine or Vehicle Pending Destruction: The dismantler may not use or permit the use of, the engines or vehicles, except use necessary to move it for destruction or storage.

CHAPTER 5: OFF-ROAD EQUIPMENT

This chapter describes the minimum criteria and requirements for Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) mobile, portable and stationary, off-road compression-ignition (CI or diesel), and large spark-ignition (LSI) projects such as construction, agricultural, and industrial equipment. Air quality management districts or air pollution control districts (air districts) may set more stringent requirements based upon local priorities.

A. Projects Eligible for Funding

The following off-road equipment projects may be eligible for funding.

1. **Repower of Existing Equipment**. The replacement of the existing engine with a newer emission-certified engine instead of rebuilding the existing engine to its original specifications.

2. **Retrofit Purchase**. The installation of an Air Resources Board (ARB) verified emission control system on an existing engine. Examples include, but are not limited to particulate filters and diesel oxidation catalysts.

3. **Equipment Replacement**. The purchase of new or used equipment with an engine certified to the current emission standard or Tier to replace an older, fully functional piece of equipment that is to be scrapped.

4. **Infrastructure**. See the infrastructure chapter (Chapter 10) for details regarding applicant eligibility and project types for infrastructure in support of off-road equipment. This includes infrastructure such as alternative fuel and charging stations for construction, cargo handling, and ground support equipment, as well as agricultural pump electrification.

Please see Sections C and D for determining maximum grant amounts and minimum eligibility requirements for all off-road project categories.

B. Engine Emission Standards

ARB and the United States Environmental Protection Agency (U.S. EPA) have adopted regulations for exhaust emission standards for new off-road CI and LSI engines and equipment. For reference, Tables 5-1 and 5-2 below summarize the hydrocarbon (HC), oxides of nitrogen (NOx), and particulate matter (PM) standards in grams per brake-horsepower-hour (g/bhp-hr) for off-road CI Tier 1, 2, 3, and 4 engines. The actual standards, in grams per kilowatt-hour (g/kW-hr), may be found in the California Code of Regulations (CCR), title 13, sections 2449, et seq. Table 5-3 summarizes the exhaust emission standards for LSI engines. The complete emission standards for LSI engines may be found in the CCR, title 13, sections 2430, et seq.

Table 5-1
ARB and U.S. EPA Tier 1, 2, and 3 Exhaust Emission Standards for New Off-Road Diesel Engines ≥ 25 Horsepower (hp)
grams per brake horsepower-hour (g/bhp-hr)

Maximum Rated Power hp (kW)	Tier	Model Year	NOx	HC	NOx + NMHC	PM
25≤hp<50 (19≤kW<37)	Tier 1	1999-2003[a]	—	—	7.1	0.60
	Tier 2	2004-2007	—	—	5.6	0.45
50≤hp<75 (37≤kW<56)	Tier 1	1998-2003[a]	6.9	—	—	—
	Tier 2	2004-2007	—	—	5.6	0.30
	Tier 3[b]	2008-2011	—	—	3.5	0.30
75≤hp<100 (56≤kW<75)	Tier 1	1998-2003[a]	6.9	—	—	—
	Tier 2	2004-2007	—	—	5.6	0.30
	Tier 3	2008-2011	—	—	3.5	0.30
100≤hp<175 (75≤kW<130)	Tier 1	1997-2002[a]	6.9	—	—	—
	Tier 2	2003-2006	—	—	4.9	0.22
	Tier 3	2007-2011	—	—	3.0	0.22
175≤hp<300 (130≤kW<225)	Tier 1	1996-2002	6.9	1.0	—	0.40
	Tier 2	2003-2005	—	—	4.9	0.15
	Tier 3[c]	2006-2010	—	—	3.0	0.15
300≤hp<600 (225≤kW<450)	Tier 1	1996-2000	6.9	1.0	—	0.40
	Tier 2	2001-2005	—	—	4.8	0.15
	Tier 3[c]	2006-2010	—	—	3.0	0.15
600≤hp≤750 (450≤kW≤560)	Tier 1	1996-2001	6.9	1.0	—	0.40
	Tier 2	2002-2005	—	—	4.8	0.15
	Tier 3[c]	2006-2010	—	—	3.0	0.15
hp>750 (kW>560)	Tier 1	2000-2005	6.9	1.0	—	0.40
	Tier 2	2006-2010	—	—	4.8	0.15

[a] EPA model year. ARB model year for Tier 1 starts at 2000 for 25 hp ≤ to <175 hp.
[b] Engine families in this power category may meet the Tier 3 PM standard instead of the Tier 4 interim PM standard in exchange for introducing the final Tier 4 PM standard in 2012.
[c] Caterpillar, Cummins, Detroit Diesel Corporation, and Volvo Truck Corporation agreed to comply with these standards by 2005.

Table 5-2
ARB and U.S. EPA Tier 4 Exhaust Emission Standards for New Off-Road Diesel Engines ≥ 25 hp (g/bhp-hr)

Maximum Rated Power hp (kW)	Tier	Model Year	NOx	HC	NOx + NMHC	PM
25≤hp<50 (19≤kW<37)	Tier 4 Interim	2008-2012	—	—	5.6	0.22
	Tier 4 Final	2013 and later	—	—	3.5	0.02
50≤hp<75 (37≤kW<56)	Tier 4 Interim[(a)]	2008-2012	—	—	3.5	0.22
	Tier 4 Final	2013 and later	—	—	3.5	0.02
75≤hp<100 (56≤kW<75)	Tier 4 Phase-In	2012-2014	0.30	0.14	—	0.01
	Tier 4 Phase-Out		—	—	3.5	0.01
	Tier 4 Alternate NOx[(b)]		2.50	0.14	—	0.01
	Tier 4 Final	2015 and later	0.30	0.14	—	0.01
100≤hp<175 (75≤kW<130)	Tier 4 Phase-In	2012-2014	0.30	0.14	—	0.01
	Tier 4 Phase-Out		—	—	3.0	0.01
	Tier 4 Alternate NOx[(b)]		2.50	0.14	—	0.01
	Tier 4 Final	2015 and later	0.30	0.14	—	0.01
175≤hp<750 (130≤kW<560)	Tier 4 Phase-In	2011-2013	0.30	0.14	—	0.01
	Tier 4 Phase-Out		—	—	3.0	0.01
	Tier 4 Alternate NOx[(b)]		1.50	0.14	—	0.01
	Tier 4 Final	2014 and later	0.30	0.14	—	0.01
hp>750 (kW>560)	Tier 4 Interim	2011-2014	2.60	0.30	—	0.07
	Tier 4 Final	2015 and later	2.60	0.14	—	0.03

[(a)] Engine families in this power category may meet the Tier 3 PM standard instead of the Tier 4 interim PM standard in exchange for introducing the final Tier 4 PM standard in 2012.
[(b)] The implementation schedule shown is the three-year alternate NOx approach. Other schedules are available.

Table 5-3
Exhaust Emission Standards for
New Off-Road LSI Engines >1.0 liter
(g/bhp-hr)

Model Year	NOx+ Non-Methane Hydrocarbons (NMHC)
2001-2006[(a)]	3.0
2007-2009	2.0
2010 and later	0.6

[(a)] Standards phased in from 2001 – 2004

C. Maximum Eligible Funding Amounts (Determining Grant Amounts)

1. Table 5-4 summarizes the maximum eligible funding for each project type as a percentage. All projects are also subject to the cost-effectiveness limits specified in Appendix C.

Table 5-4
Maximum Percentage Eligible for
Moyer Program Off-Road Projects

Project	Maximum Percentage Eligible
Diesel repower	85**%**
LSI repower	85%
Repower to zero-emission	85%
Mobile equipment replacement	80%
Portable equipment replacement (excludes stationary)	80%
Retrofit	100**%**

The ARB has adopted in-use fleet rules affecting equipment with off-road CI and off-road LSI engines. For equipment subject to these rules, additional limitations may apply according to Sections E through I.

2. Project Life:

(A) Maximum project life

Table 5-5
Maximum Project Life

Type		Project Life
Repower only (no retrofit)		7 years
Farm equipment[1] (all projects)		10 years[a]
Replacement and repower to zero-emission		10 years[b]
Retrofit only		5 years
Replacement	Excavators Skid steer loaders Rough terrain forklifts	3 years
	All other non-farm (existing diesel only)	5 years
	All other non-farm (existing LSI only)	3 years

[a] Air districts are required to offer a ten year project life for farm equipment; however, applicants may request a project life fewer than ten years. Farm equipment is defined in Appendix B and does not include stationary agricultural equipment.

[b] Section C.2.(E) allows a maximum project life of ten years for zero-emission replacements.

(B) The maximum project life does not consider regulatory requirements that may shorten the eligible project life. Regulatory requirements may reduce actual project lives below these maximum values.

(C) Unless otherwise stated in this chapter (see Sections D.2.(I) and E.2.(H)(1)), the minimum project life allowed is three years.

(D) In accordance with SBx2 3 (Health and Safety Code (H&SC) § 44282.5(a)), mobile and portable farm equipment may be eligible for funding up to the compliance date of an applicable in-use regulation and a 10-year project life. In order to be eligible, farm equipment projects must be under a fully executed contract, and must be installed in the equipment and in operation prior to the applicable compliance date.

(E) For zero-emission replacement equipment, Senate Bill 467 (H&SC § 44287.1) allows the replacement of off-road internal combustion equipment with zero-emission off-road equipment to incorporate the maximum life allowed of the equipment being scrapped (three to five years, as applicable per Section C.2.(A)) and the remaining useful life up to ten years of the equipment the applicant would have bought at the time

of normal attrition (five to seven years, as applicable). For zero-emission replacement of off-road equipment, the emission benefits from two separate transactions may be included in the cost-effectiveness calculations:

(1) Emission reductions from existing older equipment, as applicable, to zero-emission equipment.

(2) Emission reductions from a new piece of equipment meeting the emission standards at the time of purchase to zero emission.

2. **Usage**. Cost-effectiveness calculations must be hour-based. Calculation of funding amounts must be based on the average of at least the two most recent years of documented equipment usage. For projects in which the two most recent years of documented usage are not available, the minimum annual usage is required to be specified in the contract (Chapter 3, Section V.6.(B)). Fleet averages cannot be used. All project engines or equipment must have a fully operational hour meter for the project life. If during the project life the hour meter fails for any reason, the hour meter must be repaired or replaced as soon as possible at the owner's expense.

D. Project Criteria

The minimum qualifications for off-road projects are listed below. All projects must also conform to the requirements in Chapter 2: General Criteria and in Chapter 3: Program Administration. Participating air districts retain the authority to impose additional requirements in order to address local concerns.

1. General Criteria:

(A) New and existing CI and LSI engines greater than or equal to 25 horsepower on mobile or portable off-road equipment and stationary agricultural equipment are eligible for funding. LSI engines above 25 horsepower but with a displacement of less than or equal to one liter may be eligible for funding on a case by case basis.

(B) Air districts have discretion to use good engineering judgment to determine project horsepower for an existing or new engine or equipment based on the engine label, manual, engine records, or other verifiable records.

(C) For existing equipment in which the actual engine horsepower cannot be determined based upon the engine label, manual, and engine records, air districts may determine existing engine horsepower by the following formula: Engine horsepower = Power Take Off (PTO) x 120 percent.

(D) Future annual hours of equipment operation for determining emission reductions must be based upon readings from an installed and fully operational hour meter.

(E) The certification emission standard and/or Tier designation for the existing engine (if applicable) and the new engine must be determined from the ARB Executive Order or U.S. EPA Certificate of Conformity (for federally preempted engines) issued for that engine. ARB Executive Orders for off-road engines may be found at http://www.arb.ca.gov/msprog/offroad/cert/cert.php.

(F) For existing equipment with engines manufactured under the flexibility provision, detailed in CCR, title 13, section 2423(d), the baseline emission rates shall be determined by using the previous applicable Tier emission standard for the existing engine model year and horsepower rating. Alternatively, the baseline emission rates may be determined based upon the standard or Tier associated with the actual reference family listed on the emission control information label of the existing equipment. The ARB Executive Order for these engines indicates that the engines are certified under the flexibility provision. Air districts must retain this documentation in the project file.

(G) New engines that are participating in the "Tier 4 Early Introduction Incentive for Engine Manufacturers" program, as detailed in CCR, title 13, section 2423(b)(6), are eligible for funding provided that they are certified to the Tier 4 Final emission standards. The ARB Executive Order for these engines indicates that the engines are certified under this provision. The emission rates for these engines used to determine cost-effectiveness shall be equivalent to the emission factors associated with Tier 3 engines. Air districts must retain this documentation in the project file.

(H) Notwithstanding Section D.1.(J) below, new engines certified to the interim Tier 4 (interim Tier 4, Tier 4 Phase-Out, Tier 4 Phase-in/Alternate NOx) and Tier 4 Final emission standards participating in the averaging, banking, and trading program that are certified to FEL higher than the applicable emission standards are eligible for funding. The appropriate emission factor for calculating emission reductions and cost-effectiveness shall be equivalent to the emission factors associated with the Tier 3 for engines 50 to 750 horsepower and Tier 2 for engines less than 50 horsepower or greater than 750 horsepower.

(I) Notwithstanding section D.1.(J) below, new engines certified to the interim Tier 4 and Tier 4 Final emission standards participating in the averaging, banking, and trading program that are certified to a FEL below the applicable emission standards are eligible for funding. The appropriate emission factor for calculating emission reductions and cost-effectiveness

shall be the emission factor associated with the applicable interim Tier 4 (interim Tier 4, Tier 4 Phase-Out, Tier 4 Phase-in/Alternate NOx) or Tier 4 Final emission standard.

(J) New engines eligible for off-road projects must meet the current applicable standard or Tier. If repowering or replacing with an engine meeting the current applicable standard is technically infeasible, unsafe, or not available when the air district commits to the proposed project, the new engine must meet the most practicable previously applicable emission standard. For purposes of this section, the air district's commitment (as defined in Appendix B) to a proposed project shall be consistent with that stated in their Policies and Procedures Manual. The air district shall determine eligibility of repower and replacement projects using an engine certified to a previous emission standard using the criteria listed below:

(1) At the applicant's request, confirmation of availability of an engine meeting the most recent emission standards or Tier may be limited to the same manufacturer as the existing engine.

(2) If the air district and the applicant do not execute a contract for the project within six months of project commitment, then the air district must recheck for the availability of engines meeting the current standard.

(3) Documentation that engines meeting the current applicable standards are unavailable must be included in the air district's project file. Acceptable documentation that engines meeting the most recent emission standards are unavailable include:

a. Verifiable information from the engine manufacturer, engine distributor, and/or engine dealer regarding the unavailability of engines meeting the current emission standards or Tier.

b. Confirmation (a written declaration by the air district is acceptable) that engines from a specific manufacturer meeting the current emission standards or Tier are not certified (Executive Order is not available on ARB website). Executive Orders for off-road engines may be found at http://www.arb.ca.gov/msprog/offroad/cert/cert.php.

c. For repower projects, a written statement of reason(s) provided by the engine manufacturer verifying that a particular piece of equipment cannot accommodate an engine meeting current standards without major modifications or safety risks. The letter must include information on the equipment being repowered, the engine being replaced, the reason why an engine meeting the currently applicable standard cannot be used (including

applicable supporting documentation), and the proposed replacement engine. Air districts must retain the written statement of reasons in the project files.

d. For repower projects, the engine manufacturer has provided ARB with sufficient information on engine and/or equipment models for which repowers are available, and engine and/or equipment models for which repowers are not available or feasible. Engine manufacturers who are interested in pursuing this option should contact ARB. ARB staff will maintain a list of such engines and/or equipment models and make that list available to air district staff.

(K) Existing zero- or low-emission equipment are required for worker safety in the following industries, and therefore these projects are not eligible for funding: food retail stores, cold storage, and confined space operations (such as freezers).

(L) The horsepower rating for the replacement engine must not be greater than 125 percent of the original manufacturer rated horsepower (baseline horsepower) for the existing engine. In limited situations, such as where equipment in the original horsepower range is not available or the higher horsepower equipment will result in equal or lower annual emissions, the air district may approve a greater than 25 percent increase in horsepower.

(M) Notwithstanding D.1.(L), at an air district's discretion, new engines or equipment may be funded with horsepower greater than 125 percent of existing equipment. However, the eligible funding amount must be based upon the cost of an engine or equipment whose horsepower is no higher than 125 percent of the existing engine horsepower. The applicant must pay the additional costs associated with the higher horsepower engine, and the emission reduction calculation must be based upon the funded (higher horsepower) engine. The air district's project file must include documentation of the cost of the funded (higher horsepower) equipment as well as the method used to determine the basis for the project grant amount (e.g. dealership cost estimate of lower horsepower equipment).

(N) New electric motors and equipment that are rated less than 19 kW are eligible for funding provided it can serve the same function and perform the same work as equipment with a 25 horsepower or greater engine that it is replacing.

(O) No funds will be issued for maintenance or repairs related to the operation of the existing or new equipment. The participant takes sole responsibility for ensuring that the engine and/or equipment is/are in operational condition throughout the agreement period.

(P) Existing engines replaced as part of an off-road project must be destroyed and rendered useless. At a minimum, the destruction of an engine must include:

(1) A hole in the engine block with a diameter of at least three inches at the narrowest point. The hole must be irregularly shaped (i.e. no symmetrical squares or circles) and

(2) A section of the oil pan flange must be removed as part of the hole or have a line cut through it that connects the hole.

(Q) For portable/stationary agricultural projects, State and air district rules impacting agricultural sources must be considered when determining whether projects provide emission reductions surplus to regulatory requirements. Moyer eligibility may be based on the requirements of the local rule if the local rule meets the requirements of Health and Safety Code section 39666(d). An air district requesting to have eligibility based on local rules must have its Air Pollution Control Officer self-certify via email or letter to their ARB Moyer liaison that the local rule is equally as effective as or more stringent than the Airborne Toxic Control Measure for Stationary Compression Ignition Engines (CCR, title 17, section 93115 et. seq.). Note: The self-certification described in this section applies solely to the Moyer Program and does not relieve the air district of their responsibilities under Health and Safety Code section 39666 or any other ARB program or requirement.

2. Repower

(A) New engines manufactured under the “Flexibility Provisions for Equipment Manufacturers” as detailed in CCR, title 13, section 2423(d), are ineligible for funding to repower equipment.

(B) New engines manufactured under the “replacement engine” provisions of CCR, title 13, section 2423(j) and/or the provisions of 40 Code of Federal Regulations (CFR) 1068.240 which are used to repower equipment are eligible for funding.

(C) For repower plus retrofit projects, the cost of data logging the replacement engine is not eligible. Please refer to Section D.3. for additional criteria.

(D) For repower projects with new off-road compression-ignition engines equipped with original engine manufacturer after treatment devices, addition of a retrofit is ineligible due to issues with engine warranty and anti-tampering provisions.

(E) Repower to convert to zero-emission technology is eligible for funding. Except for stationary agricultural equipment, zero-emission repower

projects must include a three-year or 5,000-hour warranty. The warranty must cover zero-emission system parts and labor.

(F) Variable frequency devices (VFD) may be eligible for funding provided the air district reports VFD cost and serial number information in the Clean Air Reporting Log (CARL).

(G) In stationary electric motor projects, the grantee must provide documentation of application or payment to the local utility company for power installation.

(H) An electric motor on an agricultural irrigation pump project that is under contract may be considered for invoice payment once the motor has been delivered to the project site, and the motor has been connected to the electricity grid.

(I) For portable/stationary agricultural projects, except for remotely located or less than 50 hp agricultural engines (as defined in Appendix B), only Tier 3 engines are eligible to be repowered. These must repower to Tier 4 Final engines. Air districts with a local rule may repower uncontrolled, Tier 1, and Tier 2 engines to Tier 4 Final engines as long as there is at least one year of surplus emissions reductions prior to the compliance date of the local rule for the specific tier. The minimum project life in these instances is one year. When repowering a Tier 3 engine, air districts are encouraged to consider the feasibility of repowering with zero-emission technology, such as an electric motor, over a Tier 4 Final engine.

3. Retrofit

(A) Existing off-road CI engines equipped with original engine manufacturer aftertreatment devices are ineligible for funding.

(B) The retrofit must be verified by ARB to the highest level available for the engine being retrofitted.

(C) Eligible project costs include:

(1) Retrofit system (including all essential components)

(2) Installation

(3) Maintenance (for duration of project life)

(4) Hour meter (if none existed on existing equipment)

(D) The data logging cost of a retrofit-only project is not eligible.

(E) Additional information on verified diesel retrofit systems may be found on ARB's website at http://www.arb.ca.gov/diesel/verdev/verdev.htm. Information on verified LSI retrofit systems may be found at: http://www.arb.ca.gov/msprog/offroad/orspark/verdev.htm.

4. Equipment Replacement

(A) Equipment replacement projects are limited to mobile and portable equipment.

(B) Equipment manufactured under the "Flexibility Provisions for Equipment Manufacturers" (Flex equipment), as detailed in CCR, title 13, section 2423(d) is eligible for funding as replacement equipment, provided the equipment meets the requirements of section D.1.(J) above.

(1) Eligible Flex equipment whose reference engine family is certified to an FEL is also subject to the provisions of Section D.1.(H) and (I).

(2) Flex equipment with an engine whose reference engine family meets a standard, Tier, or FEL less stringent than Tier 3 standard (or Tier 2 standard for engines less than 50 horsepower or greater than 750 horsepower), is ineligible for funding.

(C) The replacement of two (or more) pieces of existing equipment with one piece of replacement equipment is eligible for funding. Each piece of existing and replacement equipment must comply with all of the appropriate criteria in this section. The replacement equipment must execute the same job as the existing pieces of equipment. For baseline emissions calculation, the annual emissions of the two pieces of existing equipment are summed. For the replacement equipment emissions calculation, the annual usage of the two pieces of existing equipment is summed for the replacement equipment usage. The horsepower rating for the replacement equipment must not be greater than 125 percent of the original manufacturer rated horsepower (baseline horsepower) for the lowest horsepower of the two existing equipment engines (unless the grantee pays for the horsepower upgrade as specified in Section D.1.(M)).

(D) If air districts use equipment dealers in implementing the equipment replacement program, reimbursement cannot be issued until all necessary documentation is received and approved by the air district. Participants may purchase the replacement equipment from a private party, provided all required documentation is submitted and approved by the air district. This includes warranty requirements and all other equipment replacement requirements.

(E) Existing Equipment Requirements:

(1) Equipment Ownership: the applicant must have owned the existing equipment in California for the previous two years. The applicant must provide documentation of the following specific to the existing equipment (select one):

a. Bill of sale for the old existing equipment (preferred)

b. Tax depreciation logs

c. Property tax records

d. Equipment insurance records

e. Bank appraisals for equipment

f. Maintenance/service records

g. General ledgers

h. Fuel records specific to the existing equipment that identify the equipment owner

i. Other documentation approved by ARB

(2) Operational Requirements: the existing equipment must be in operational condition to qualify for funding. A pre-inspection of the existing equipment must be performed prior to funding to verify the operational status of the equipment. In addition, the applicant must provide documentation to demonstrate that the equipment was operational for the previous year. The following types of documents are acceptable:

a. Revenue and usage records that identify operational, standby, and down hours for the equipment

b. Routine inspections which document the operating condition of the existing equipment (Occupational Safety and Health Administration or workplace required)

c. Employee timesheets linked to specific equipment use

d. Preventative maintenance/service records tied to specific hours of equipment use

e. Repair work orders specific to the equipment

f. Other documents approved by ARB

(3) Pre-Inspection Requirements: Pre-inspection must verify the operational condition of the existing equipment. The pre-inspection must verify, at a minimum, the following items:

a. Tires in usable condition (able to hold air, sufficient tread or tracks, etc.)

b. Steering wheel operational

c. Equipment able to start up and move backwards and forwards

d. Buckets, blades, rollers, etc. are working

e. Undercarriage structurally sound

f. Fuel tank in usable condition

g. No parts stripped

h. Equipment not vandalized

i. Clear photographs of the existing equipment must include the following views listed below. The air district will specify the required digital format.

i. Right side - hood down

ii. Front - hood down

iii. Left side - hood down

iv. Equipment serial number

v. Engine serial number - either tag or stamp on block

vi. Diesel Off-Road Online Reporting System (DOORS) Equipment Identification Number (EIN), if applicable

vii. Rear

(4) Destruction and Salvage Requirements: Equipment replacement requires that the existing equipment be scrapped to permanently remove it from service. This ensures that emission reductions are real and prevents the existing equipment from being moved into another locale to continue emitting high levels of pollutants.

a. Destruction of the equipment may occur either at an air district approved salvage yard or another facility in conjunction with an air district salvage inspection.

b. Both the existing engine and equipment must be destroyed. Refer to Section D.1.(P) for the engine destruction method. The destruction method of the equipment will vary depending on the structure of the equipment:

   i. Equipment with permanent frame rails running the length of the equipment: complete cuts of both frame rails between the front and rear axles.

   ii. Equipment with removable/bolt-on frame rails: structural damage, with cuts or otherwise, that renders the main body of the equipment inoperable and unrepairable.

   iii. Equipment without frame rails: structural damage, with cuts or otherwise, that renders the main body of the equipment inoperable and unrepairable.

   iv. Articulated equipment: damage, cuts or otherwise, to the articulation joints of front and rear halves of the equipment so that neither half can be joined.

   v. Other equivalent methods of destruction are acceptable if approved by the air district.

c. The existing engine and equipment must be destroyed within 60 days of being replaced. Documentation of the destruction must be provided to the air district within 10 days of destruction.

d. Funding is not available for the salvage of any existing equipment.

e. The existing equipment salvage value will be negotiated between either the applicant, the dealership, and/or the salvage yard.

f. A salvage inspection of the existing equipment must be performed by either the air district or a contracted salvage yard.

g. Air districts which perform their own salvage inspections must be notified within 10 days of destruction so that a salvage inspection can occur.

h. Salvage inspection must include clear photographs of the following views:

   i. DOORS EIN (if applicable)

   ii. Equipment serial number

iii. Engine serial number either stamped on the block or on the tag

iv. Destroyed engine block as described in Section D.1.(P).

v. Cut structural components as described in Section D.4.(E)(4)b.

vi. Other views dependent on the method of equipment destruction

i. Salvage inspection of the existing equipment must be completed prior to disbursement of funds.

(F) Replacement Equipment Requirements

(1) The replacement equipment must serve the same function and perform the same work equivalent as the existing equipment (e.g., replacement of an agricultural tractor with another agricultural tractor).

(2) Only items essential to the operation of the equipment and the minimum attachments normally sold with the original equipment, as determined by the air district, are eligible for reimbursement on the replacement equipment. Equipment owners may remove non-emission related body components and place them on the replacement equipment as long as the components do not exist on the replacement equipment and are not part of the paid components for the replacement equipment.

(3) Applicants may purchase the replacement equipment from a private party, provided all required documentation is submitted and approved. This includes warranty requirements and all other equipment replacement requirements.

(4) If an applicant elects to install a retrofit with the replacement equipment, then the retrofit must be installed prior to equipment delivery to the grantee and must stay in operation on the replacement equipment for the project life. The retrofit must meet all the requirements per Section D.3.

(5) Warranty Requirements

a. All new or used replacement equipment must have a minimum one-year or 1600-hour powertrain warranty. The warranty must cover parts and labor. A separate supplemental minimum one-year or 1600-hour power and drivetrain warranty must be

purchased if the equipment does not have one. The supplemental warranty costs are not eligible for funding.

b. It is recommended that the highest grade warranty be purchased in order to avoid expensive repairs in the future.

c. Warranty documentation must be provided to the air district.

(6) Post-Inspection Requirements

a. Post-inspection of the replacement equipment must be completed prior to disbursement of funds.

b. The post-inspection must include clear photographs of the following views:

i. Pictures(s) of full equipment

ii. Equipment serial number

iii. Engine serial number and engine information

iv. Retrofit (if available)

v. Hour meter reading

(G) Air District Requirements

(1) Air districts must establish an off-road equipment replacement plan before funding projects. The plan must include criteria for the following:

a. Development of grantee contracts which must include a generic statement of work

b. Inspections (pre-, post-, salvage). The required digital format for the inspections photographs must be specified.

c. Reimbursement procedures

d. Monitoring and enforcement considerations

e. If applicable, for air districts that contract with dealers and salvage yards, the off-road equipment replacement plan must identify the air district's requirements for dealer and/or salvage yard contracts, and the process for oversight and review of program requirements that are expected of each entity, and the repercussions for non-compliance with the terms of the contract

for each entity. For air districts that contract with dealer(s), liaison training must be provided to the dealership staff.

(2) Air districts may fund equipment replacement projects through a regional program administered by a designated air district. The designated air district could be either an air district located within the regional program or a large air district located outside of the regional program. A regional equipment replacement implementation plan must be established, containing all the required components as required in an individual air district's equipment replacement implementation plan. A regional equipment replacement plan must also contain a detailed description of the funding mechanism among the participating air districts. All air districts participating in the regional program must sign the regional equipment replacement implementation plan and must adhere to all the requirements specified in such regional implementation plan.

(3) Air districts are encouraged, but are not required to establish contracts with dealers and salvage yards for participation in the program.

(4) Air districts must ensure the following are performed:

a. Pre-inspection of the existing equipment. This may be performed by an air district approved dealer.

b. Verification that the replacement equipment proof of sale and if applicable, proof of financing have been received from the dealer or participant.

c. Post-inspection of the replacement equipment. This may be performed by an air district approved dealer.

d. Salvage inspection of the existing equipment. This may be performed by an approved salvage yard.

e. Verification that all post-inspection of replacement equipment and salvage inspection of existing equipment were completed and all documentation is submitted and approved prior to disbursement of funds.

(5) The air district is allowed to make full payment to the dealer at the time the dealer delivers the replacement equipment to the applicant under the following framework:

a. The air district must complete the pre-inspection of the existing equipment and post-inspection of the replacement equipment to

make sure that all equipment complies with program requirements.

b. The air district must sign a contract with the dealer and the salvage yard that contains, at a minimum, the program requirements that are expected of each entity and the repercussions for non-compliance with the terms of the contract for each entity. This shall include, but is not limited to, the requirement that the dealer delivers the existing equipment to a qualified salvage yard within 30 days of the date that the existing equipment was turned in to the dealer by the applicant.

c. The air district must ensure the equipment is scrapped within 60 days of the salvage yard's receipt of the equipment through salvage inspection with the salvage yard to properly document the destruction of the existing equipment in accordance with the Moyer Program equipment replacement program requirements.

(H) Dealer Requirements

(1) Equipment dealers that enter into a contract with an air district must:

a. Provide basic information to potential applicants about the equipment replacement category. Air districts must also provide liaison training to dealership staff.

b. Inform potential applicants of rights and responsibilities as outlined in the air district and ARB guidelines.

c. Help the potential applicants correctly complete the application. It is important that the participant understands the meaning of the program and the subsequent air district contract if approved for funding. The air district will provide all forms and certificates as appendices to the application.

d. Ensure that an application package is complete. The dealer must verify that all the following items are included in the application package:

i. A signed and complete application.

ii. All documentation as required in Sections D.4.(E)(1) and (2).

iii. The following information must also be included in the documentation:

(a) Make

(b) Model

(c) Model year

(d) Equipment serial number

(e) Engine make

(f) Engine serial number

(g) Expected delivery date of existing equipment

iv. Documentation of replacement equipment warranty.

e. Submit the completed application package to the air district.

(2) After the application and all required documentation have been approved by the air district, the dealer must provide the air district with proof of sale and if applicable, proof of financing of the replacement equipment. The financing package will enable the air district to determine the reimbursement costs that may be accrued in case the participant defaults on the contracted performance requirements. Proof of project financing can be a document showing the lender and the amount loaned, which at a minimum is a copy of the check given to the dealer equal to the portion of the project that was not Moyer Program funded. Proof of project financing is always required unless the grantee paid cash for the portion of the project that was not Moyer Program funded.

(3) Prior to releasing the replacement equipment to the participant, the dealer must have documentation of an air district pre-inspection of the existing equipment and the post-inspection of the replacement equipment. Alternatively, if approved by the air district to do pre- and post-inspections, the dealer must verify that photographs of the existing equipment and the replacement equipment, as defined in Sections D.4.(E)(3)i. and (F)(6)b., are clear prior to submitting them to the air district.

(4) Provide documentation certifying that the existing equipment will be received by a contracted salvage yard within 30 days.

(I) Salvage Yard Requirements

(1) Equipment salvage yards must enter into an agreement with the air district to qualify for participation.

(2) Contracted salvage yard(s) must:

a. Destroy the existing equipment and engine within 60 days of receipt of the existing equipment in accordance with the program guidelines.

b. Provide the air district with all photographs required under the air district's salvage inspections requirements per Section D.4.(E)(4)h. below within ten business days of salvaging the existing equipment.

c. For each project, provide the following information:

i. Make

ii. Model

iii. Model year

iv. Serial number

v. Engine make

vi. Engine serial number

vii. Delivery date of the existing equipment

d. Submit a completed certificate of equipment destruction or other similarly approved documentation to the air district.

E. Projects subject to the In-Use Off-Road Diesel-Fueled Fleets Regulation (Off-Road Regulation) (CCR, title 13, section 2449 et. seq.)

1. The existing equipment must be registered in DOORS.

2. Fleets must be in compliance with the regulation in order to be eligible for and receive funding. Fleets subject to the Off-Road Regulation that meet the final compliance requirements of the Off-Road Regulation are eligible for funding, and are exempt from the requirements of Section E.2.(E) through (I).

(A) Applicants must submit information regarding fleet size and compliance status. All documentation submitted must be signed and dated by the applicant and include language certifying that the fleet list provided is accurate and complete. Air districts are not required to validate submitted information and will not be held liable if fleet owners falsify fleet information. The following information shall be submitted at the time of application:

(1) DOORS ID of the fleet.

(2) DOORS EIN of the existing equipment.

(3) Fleet size information (total horsepower) as reported to DOORS

(4) Information to determine compliance with the Off-Road Regulation

a. Large fleets and medium fleets are required to show compliance with the Off-Road Regulation.

b. Prior to 1/1/2019, small fleets are not required to show compliance with the Off-Road Regulation.

(5) For those fleets that have previously received Moyer Program funding, a list of funded equipment with the DOORS EIN of the funded equipment.

(6) Large fleets must certify that they have not applied for Moyer Program funding for their off-road diesel fleet in another fiscal year (July 1-June 30) after January 1, 2017, excluding applications for which no funding was ultimately received.

(B) Applicants must submit to the air district the DOORS EIN of the replacement equipment no later than at post-inspection of replacement equipment.

(C) Applicants are not required to submit information on exempted equipment. Information on exempted off-road equipment can be found in the Off-Road Regulation.

(D) No emission reductions achieved from a funded project can count towards a fleet's regulatory requirements for the duration of the contract term.

(E) Eligibility for a project is based upon the Best Available Control Technology (BACT) requirements of the Off-Road Regulation.

(1) Any equipment funded through the Moyer program, and that is still under contract, must be deducted from the amount of equipment eligible for funding. For instance, a fleet that is eligible for funding to reduce emissions for 50 percent of its horsepower, but which has already received funding in previous years to reduce emissions from 20 percent of its horsepower, is only eligible for funding to reduce emissions from 30 percent of its horsepower.

(2) Equipment funded through the Moyer program must be included in the fleet's total horsepower from which the BACT requirements of the regulation are calculated.

(F) Large Fleets

(1) Eligible projects for large fleets, as defined in the Off-Road Regulation must provide at least three years emission reductions surplus to the regulation with a corresponding minimum project life of at least three years.

(2) Projects must be installed and in operation at least three years before the BACT requirements become effective for the funded equipment.

a. The first compliance date for large fleets, as defined in the Off-Road Regulation, is January 1, 2014. The final compliance date is January 1, 2023. Funding for these fleets is available through December 31, 2019.

b. Large fleets are eligible for funding once after January 1, 2017. After January 1, 2017, for those large fleets eligible for funding a second or subsequent time, only zero-emission projects are eligible.

c. Large fleets may have alternative requirements per Section E.2.(I) below.

(G) Medium Fleets

(1) Eligible projects for medium fleets, as defined in the Off-Road Regulation must provide at least three years emission reductions surplus to the regulation with a corresponding minimum project life of at least three years.

(2) Projects must be installed and in operation at least three years before the BACT requirements become effective for the funded equipment.

(3) The first compliance date for medium fleets, as defined in the Off-Road Regulation is January 1, 2017. The final compliance date is January 1, 2023. Funding for these fleets is available through December 31, 2019.

(H) Small Fleets (includes Captive Attainment Area Fleets)

(1) Eligible projects for small fleets, as defined in the Off-Road Regulation must provide at least two years emission reductions surplus to the regulation, with a corresponding minimum project life of at least two years.

(2) Projects must be installed and in operation at least two years before the BACT requirements become effective for the funded equipment.

(3) The first compliance date for small fleets, as defined in the Off-Road Regulation is January 1, 2019. The final compliance date is January 1, 2028. Funding for these fleets is available through December 31, 2025.

(I) Surplus Off-Road Opt-In for NOx (SOON) Program

(1) Fleets located in air districts that have opted into the SOON program and that are subject to the SOON provisions are eligible for funding in accordance with the Off-Road Regulation (CCR, title 13, section 2449.2) and must meet the applicable criteria in Sections A. through D. in this chapter.

(2) Projects funded under SOON, are not subject to Section E above, except for the requirements of Sections E.1., E.2.(A) through (C), and E.2.(I).

3. For more information on eligibility of off-road diesel equipment, please see the Regulation for In Use Off-Road Diesel-Fueled Fleets Carl Moyer Program Implementation Chart available at http://www.arb.ca.gov/msprog/moyer/guidelines/supplemental-docs.htm.

F. Projects subject to the Regulation for Cargo Handling Equipment at Ports and Intermodal Rail Yards (CHE Regulation) (CCR, title 13, section 2479)

1. Eligible Engines

(A) For repower or replacement projects in which the equipment is subject to the CHE Regulation, only Tier 4 Final engines or cleaner are eligible for funding.

(B) Replacement engines participating in the averaging, banking and trading program that are certified to FEL higher than the applicable emission standards, as designated on the Executive Order, are not eligible for funding.

2. Eligible projects must provide at least three years of emission reductions surplus to the regulation, with a corresponding minimum project life of at least three years. Cargo handling fleets that have met the final compliance requirements of the CHE Regulation are eligible for funding.

G. Projects subject to the Large Spark Ignition Engine Fleet Requirements (LSI Fleet Regulation) (CCR, title 13, section 2775 et. seq.)

1. Eligible funding must provide at least three years of emission reductions surplus to the LSI Fleet Regulation, with a corresponding minimum project life of at least three years.

2. Large and Medium Forklift Fleets and Fleets of Four or More Sweeper/Scrubbers, Ground Support Equipment, and/or Industrial Tow Tractors: In order to be eligible for funding, large and medium forklift fleets and fleets of four or more non-forklift LSI equipment must meet the final fleet average emission level applicable on January 1, 2013.

3. Agricultural Crop Preparation Forklift Fleets Model Year 1990 and Newer: These fleets are required to either retrofit, repower, or replace 100 percent of their fleet by January 1, 2012, or currently meet a 3.0 g/bhp hr fleet average HC + NOx level. Fleets that have met the 3.0 g/bhp-hr fleet average can apply for funding. Additionally, in accordance with SBx2 3 (H&SC § 44282.5(a)), fleets that have retrofitted/repowered 20 percent of their fleet in compliance with the regulation are eligible for funding up to the final compliance date. In order to be eligible, these projects must be under executed contract and must be installed and in operation prior to the applicable compliance date.

4. LSI fleets that have met the final compliance requirements of the LSI Fleet Regulation are eligible for funding. Due to the regulatory requirements for rental and lease equipment subject to the LSI Fleet Regulation, projects that include rented or leased equipment are not eligible.

5. Fleets with equipment not subject to the LSI Fleet Regulation are eligible for funding, including:

(A) Agricultural crop preparation non-forklift equipment and pre-1990 forklifts.

(B) Forklifts used exclusively in fields to harvest and maintain crops.

(C) Non-forklift LSI equipment such as aerial lifts, lawn and garden tractors, commercial turf equipment, mining and construction equipment, and industrial equipment.

(D) Small fleets (one to three forklifts and/or one to three sweepers/scrubbers, industrial tow tractors, or pieces of airport ground support equipment (airport GSE)).

6. Required Off-Road LSI Fleet Information: For forklifts, sweeper/scrubbers, airport GSE, and/or industrial tow tractors, an applicant's fleet size impacts project eligibility. Applicants must submit information regarding fleet size and compliance status. All documentation submitted must be signed and dated by the applicant and include language certifying that the fleet list provided is accurate and complete. Air districts are not required to validate submitted information and will not be held liable if fleet owners falsify fleet information.

(A) Large/Medium/Non-Forklift Fleets: For large, medium, and non-forklift fleets subject to the LSI Fleet Regulation, applicants are required to report compliance records for the entire statewide fleet as described in the regulatory language (CCR, title 13, section 2775.2).

(1) DOORS ID of the fleet.

(2) DOORS EIN of the existing equipment.

(3) Fleet size information (total number of forklifts; total number of non-forklift LSI equipment).

(4) Information to determine compliance with the LSI fleet Regulation. Large and medium fleets are required to show compliance with the applicable final fleet average emission level.

(B) Small Fleets: Small fleets are not required to maintain compliance records, but for the purposes of determining project eligibility, air districts must obtain the following information for the entire statewide fleet:

(1) Equipment identification number (equipment identification number, fleet assigned identification, etc.)

(2) Equipment type (e.g., forklift, GSE, etc.)

7. If applicable, applicants must submit to the air district the DOORS EIN of the replacement equipment not later than at post-inspection of the replacement equipment.

8. Applicants are not required to submit information on exempted equipment (except as noted above for small fleets). Information on exempted LSI equipment can be found in CCR, title 13, sections 2775(b), 2775.1(c) (4), and 2775.1(d-f) of the Final Regulation Order (http://www.arb.ca.gov/regact/lore2006/oalapprovedfro.pdf).

H. Projects subject to the Airborne Toxic Control Measure for Diesel Particulate Matter from Portable Engines Rated at 50 Horsepower and Greater (Portable Engine ATCM) (CCR, title 17, section 93116 et. seq.)

1. In order to be eligible for repower projects, diesel engines regulated under the Portable Engine ATCM must be permitted or registered in an air district or registered in the Portable Equipment Registration Program. If the portable engine is not required to be permitted or registered, documentation must be included in the project file from the air district stating that a permit or registration is not required to operate in the air district.

2. In order to be eligible for funding, fleets must be fully compliant with the regulatory requirements in effect in 2020.

3. For more information on eligibility of engines used in portable equipment, please see the Portable Engine Airborne Toxic Control Measure Implementation Chart available at: http://www.arb.ca.gov/msprog/moyer/guidelines/supplemental-docs.htm.

I. Projects subject to the Regulation to Reduce Emissions of Diesel Particulate Matter, Oxides of Nitrogen and Other Criteria Pollutants from In-Use Heavy-Duty Diesel-Fueled Vehicles (Statewide Truck and Bus Regulation) (CCR, title 13, section 2025)

This regulation impacts the eligibility of all on-road heavy-duty diesel-fueled and alternative diesel-fueled vehicles operated in California with a manufacturer's GVWR greater than 14,000 pounds. Although this regulation primarily affects vehicles with on-road engines, some vehicles with off-road engines are also covered. Any application for Moyer Program funding to replace a vehicle with an off-road engine that is subject to an on-road regulation must comply with the applicable surplus requirements described in Chapter 4. For example, a yard truck with an off-road engine that is subject to the Statewide Truck and Bus Regulation (including yard trucks used primarily in agricultural operations) must meet the applicable on-road surplus requirements described in Chapter 4, Section C.2., and must also comply with all off-road project criteria described in this chapter.

CHAPTER 6: LOCOMOTIVES

This chapter describes the minimum criteria and requirements for Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) locomotive projects. Air quality management districts or air pollution control districts (air districts) may set more stringent requirements based upon local priorities.

A. Projects Eligible for Funding

The Moyer Program provides incentive to upgrade old high-polluting locomotives to new Tier 4 units. Rail equipment, designed for use on tracks, such as on-rail vehicles, railcar movers, sweepers, and wheel cranes which have tires or mounted tracks, that replace switcher locomotives, are also considered locomotives for the purposes of the Moyer Program. Funding opportunities may be limited due to the availability of Goods Movement Emission Reduction Bond Program (Proposition 1B Goods Movement Program) funding, and the South Coast and Statewide Memoranda of Understanding (MOU) with these railroads (See Table 6-1).

Table 6-1
Summary of Locomotive Funding Opportunities

Railroad Class	Subject to ARB Rule or MOU	Moyer Funding Opportunities
Class 1 Freight Railroads (Burlington Northern Santa Fe Railroad and Union Pacific Railroad)	*2005 Statewide Railyard Agreement* and *1998 South Coast MOU*[(a)]	Projects in California's goods movement trade corridors are generally ineligible for Moyer Program funding if Proposition1B funds are available.[(b)] These projects are only eligible for Moyer Program funding on a case-by-case basis.
Class 2 and 3 Freight Railroads and Passenger Railroads	No	Class 2 and 3 and passenger railroad projects are not limited.

[(a)] The South Coast MOU limits funding eligibility for Class 1 freight railroad new purchase or engine remanufacture/repower projects in the South Coast. See: http://www.arb.ca.gov/msprog/offroad/loco_flt.pdf
[(b)] For a map of the trade corridors, see: http://www.arb.ca.gov/bonds/gmbond/docs/gmtradecorridors.jpg

Project Types: Three types of locomotive projects are eligible for Moyer Program funding:

1. Locomotive Replacement
2. Locomotive Engine Repower
3. Head End Power Unit (HEP)

B. Maximum Eligible Funding Amounts

Table 6-2 summarizes the maximum eligible funding for each project type. All projects are also subject to the cost-effectiveness threshold defined in Appendix C.

Table 6-2
Maximum Grant Amount for Moyer Program Locomotive Projects

Railroad Class/Type	All Project Types
Class 1/Class 2	75%
Class 3 and Passenger	85%

C. Emission Standards

The U.S. EPA has adopted regulations for exhaust emission standards for new and remanufactured locomotives. For reference, Tables 6-3 and 6-4 below summarize the hydrocarbon (HC), oxides of nitrogen (NOx) and particulate matter (PM) standards in grams per brake horsepower-hour (g/bhp-hr) for the 1998 Federal Standards and the 2008 Federal Standards.

Table 6-3
U.S. EPA Locomotive Emission Standards (g/bhp-hr)
Based on 1998 Federal Standards

Tier and Engine Model Year	Type	NOx	HC	PM10
Uncontrolled Pre-1973	Line-haul and Passenger	13.5	1.00	0.60
	Switcher	17.4	2.10	0.72
Tier 0 1973 - 2001	Line-haul and Passenger	9.5	1.00	0.60
	Switcher	14.0	2.10	0.72
Tier 1 2002-2004	Line-haul and Passenger	7.4	0.55	0.45
	Switcher	11.0	1.20	0.54
Tier 2 2005 - 2011	Line-haul and Passenger	5.5	0.30	0.20
	Switcher	8.1	0.60	0.24

Table 6-4
U.S. EPA Locomotive Emission Standards (g/bhp-hr)
Based on 2008 Federal Standards

Tier and Engine Model Year	Type	NOx	HC	PM10
Tier 0+ 1973-2001	Line-haul and Passenger	7.4	0.55	0.22
	Switcher	11.8	2.10	0.26
Tier 1+ 2002-2004	Line-haul and Passenger	7.4	0.55	0.22
	Switcher	11.0	1.20	0.26
Tier 2+ 2005-2011	Line-haul and Passenger	5.5	0.30	0.10
	Switcher	8.1	0.60	0.13
Tier 3 2011-2014	Line-haul and Passenger	5.5	0.30	0.10
	Switcher	5.0	0.60	0.10
Tier 4 2015	Line-haul and Passenger	1.3	0.14	0.03
	Switcher	1.3	0.14	0.03

D. Project Criteria

The minimum qualifications for locomotives are listed below. All projects must also conform to the requirements in Chapter 2: General Criteria, and in Chapter 3: Program Administration. Participating air districts retain the authority to impose additional requirements in order to address local concerns. Note that railroad classes are defined in Appendix B.

1. General Locomotive Project Criteria

(A) Baseline emission factors must reflect the tier level required by federal locomotive remanufacture standards (i.e., the baseline emission factors are the required remanufacture standards, which may not be the certification standard of the baseline locomotive).

(B) Class 1 freight locomotive projects meeting the eligibility requirements for the Proposition 1B Goods Movement Program are only eligible for Moyer Program funding on a case-by-case basis. Moyer Program funds cannot be co-funded with Proposition 1B Goods Movement Program funds.

(C) Class 1 freight locomotives subject to the South Coast Memorandum of Understanding (MOU) are only eligible for Moyer Program funding on a case-by-case basis. These locomotive projects must be excluded from the fleet average emission rate calculations which demonstrate compliance with the MOU provisions. The baseline emission rates used to determine emission reductions and cost-effectiveness for these locomotive projects reflect the U.S. EPA Locomotive Tier 2 emission rates for line-haul and switch locomotives.

(D) Military and industrial railroads are considered Class 3 railroads for the purposes of the Moyer Program.

(E) Locomotive project activity must be based upon fuel consumption. If fuel consumption is not available, megawatt hours from the electronically logged data may be used.

(F) Moyer Program funds cannot be used to pay for labor or parts used during routine maintenance.

(G) Air districts may enter into contract and work may begin on a locomotive project prior to U.S. EPA certification and/or Air Resources Board (ARB) verification. In this instance, the air district contract with the grantee must specify that any work performed is done grantee's own risk. Air districts cannot make payment until certification and verification have been received.

(H) Participant must have owned the baseline locomotive for at least one year prior to application submittal, and the locomotive must be operational.

(I) At a minimum the destruction of a locomotive engine must include a hole in the engine block with a diameter of at least eighteen inches at the narrowest point. The hole must be irregularly shaped (i.e. no symmetrical squares or circles).

(J) Unless otherwise stated in this chapter, the minimum project life allowed is three years.

2. Locomotive Replacement

(A) New locomotives with an aggregate engine power rating greater than or equal to 1,006 horsepower (750 kW) must be certified by U.S. EPA and verified by ARB to achieve Tier 4 locomotive emission standards (or cleaner).

(B) New locomotives with an aggregate engine power rating less than 1,006 horsepower are not required to be certified by U.S. EPA to locomotive standards, but are required to be certified U.S EPA off-road (non-road) emission standards. This lower horsepower equipment must

also be verified by ARB to meet or exceed the Tier 4 locomotive standards.

(C) Zero-emission locomotives must have ARB verification.

(D) Due to the design of alternative technology switchers, fuel consumption for the new locomotive may differ from baseline fuel consumption. For contractual purposes only, when specifying the annual usage requirement in the contract the air district may assume a fuel savings of 20 percent from that used in the cost-effectiveness calculation. This fuel savings is already embedded into the cost-effectiveness calculation, and therefore it should not be applied when determining cost-effectiveness for the project.

(E) The baseline locomotive engine(s) must be destroyed. The grantee may choose to retain the baseline locomotive chassis since locomotive components have a long lifespan, ARB recognizes the benefits of reusing and/or recycling baseline locomotives. To prevent the baseline locomotive body from being fitted with a similar high-polluting engine, the grantee must sign an agreement with the air district which will ensure, with due diligence, that the baseline locomotive, if brought back into service, will be repowered to a Tier 4 or cleaner locomotive engine standard.

(F) Project life:

(1) Class 1 locomotive replacement projects in air districts other than the South Coast must have a minimum project life of ten years.

(2) All other locomotive replacement projects have a minimum project life of three years.

(3) The maximum project life for a locomotive replacement project is 15 years.

3. Locomotive Engine Repower

(A) Purchase and installation of an engine meeting Tier 4 locomotive emission standards or cleaner. The engine must be certified by U.S. EPA and verified by ARB to be eligible for Moyer Program funding.

(B) The maximum project life for a locomotive engine repower project is 15 years.

4. Head End Power Unit (HEP)

(A) HEP repower is eligible on a case-by-case basis.

(B) The baseline engine must be certified to the applicable off-road standard at the time of manufacture.

(C) The new engine must be certified to the U.S. EPA Tier 4 final or cleaner off-road (non-road) emission standards.

CHAPTER 7: MARINE VESSELS

This chapter describes the minimum criteria and requirements for Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) marine vessel projects. Air quality management districts or air pollution control districts (air districts) may set more stringent requirements based upon local priorities.

A. Projects Eligible for Funding

The Air Resources Board (ARB) has adopted two regulations that impact funding opportunities for marine vessel projects: 1) Amendments to the Regulations to Reduce Emissions from Diesel Engines on Commercial Harbor Craft Operated Within California Waters and 24 Nautical Miles of the California Baseline (Commercial Harbor Craft regulation or CHC) and 2) Regulations to Reduce Emissions from Diesel Auxiliary Engines on Ocean-Going Vessels While At-Berth at a California Port (Shore Power Regulation). There are limited funding opportunities for marine vessels subject to this regulations.

Table 7-1
Summary of Funding Opportunities

Project Type	Subject to ARB Rule	Moyer Funding Opportunities[(a)]
Vessels subject to Commercial Harbor Craft Regulation Schedules for Meeting Tier 2 or Tier 3 Standards (ex: barge, crew & supply, dredge, excursion, ferry, towboat, tugboat) - engine repower, remanufacture, retrofit or new purchase	Commercial Harbor Craft Regulation[(b)]	Opportunities depend on compliance status
Vessels *not* subject to Commercial Harbor Craft Regulation Schedules for Meeting Tier 2 or Tier 3 Standards (ex: fishing vessel or pilot/work boat) - engine repower, remanufacture, retrofit or new purchase	No	Not limited by regulation
Shore power - vessel retrofit	Shore Power Regulation[(c)]	Limited opportunity

[(a)] A fleet's compliance status with the ARB regulations must be determined. Contact air district Moyer Program staff or consult CHC regulation Moyer Program Implementation Charts at: http://www.arb.ca.gov/msprog/moyer/guidelines/supplemental-docs.htm in addition to these guidelines.
[(b)] Harbor Craft Regulation: http://www.arb.ca.gov/ports/marinevess/harborcraft.htm
[(c)] Shore Power Regulation: http://www.arb.ca.gov/ports/shorepower/shorepower.htm

Project Types:

1. **Engine Repower.** Replacing an old vessel engine with a newer, lower emission engine. Limited opportunities remain for those vessel engines subject to the in-use compliance requirements of the CHC regulation. Repower must be completed at least three years prior to the vessel's in-use compliance date. Based on the vessel's operation, the newer engine's emissions must be surplus to the currently required United States Environmental Protection Agency (U.S. EPA) marine engine emission standard (i.e., Tier 3 or cleaner).

2. **Remanufacture Kit.** Kits are comprised of engine component parts that, when installed, reduce the engine's emissions. Limited Moyer funding opportunities remain for those vessel engines subject to the in-use compliance requirements of the CHC. Remanufacture must be completed at least three years prior to the vessel's in-use compliance date.

3. **Retrofit Device.** The installation of an ARB verified diesel emission control strategy (VDECS). This project type will be considered for funding on a case-by-case basis.

4. **Hybrid System.** The installation of an EPA verified hybrid system. A hybrid system implements various strategies (e.g. engine switching, electric power) to reduce emissions of NOx, ROG, and PM.

5. **Ship-Side Shore Power Projects.** The retrofit of a marine vessel to enable shore power connection. Ship-side shore power projects are not eligible unless the applicant can demonstrate that it will be surplus to the implementation requirements of ARB's Shore Power Regulation. For marine infrastructure projects, including Shore-Side Shore power, see Chapter 10: Infrastructure.

6. **Marine Vessel Exhaust Capture and Control System.** The purchase of an EPA verified marine vessel exhaust capture and control system. EPA verifications of exhaust capture systems include specific percentage reductions of NOx and PM. In lieu of EPA verification an ARB Executive Order will suffice.

Please see Section C (Project Criteria) for detailed minimum eligibility requirements.

B. Maximum Eligible Funding Amounts

Table 7-2 summarizes the maximum funding for each project type as a percentage of eligible costs. All projects are also subject to the cost-effectiveness threshold defined in Appendix C.

Table 7-2
Maximum Percentage of Eligible Costs for
Moyer Program Marine Projects

	Baseline Technology	Project Type	Maximum Percentage
Vessels subject to Commercial Harbor Craft Regulation Schedules for Meeting Tier 2 or Tier 3 Standards (ex: barge, crew & supply, dredge, excursion, ferry, towboat, tugboat)	Tier 0,1[(a)]	Engine repower or remanufacture kit compliant to EPA marine Tier 3	50%
		Engine repower or remanufacture kit compliant to EPA marine Tier 4[(b,c)]	85%
	Tier 2	Engine repower or remanufacture kit compliant to EPA marine Tier 3	80%
		Engine repower or remanufacture kit compliant to EPA marine Tier 4[(b,c)]	85%
Vessels ***not*** subject to Commercial Harbor Craft Regulation Schedules for Meeting Tier 2 or Tier 3 Standards (ex: fishing, pilot, work boat)	Tier 0,1,2	Engine repower or remanufacture kit compliant to EPA marine Tier 3	80%
		Engine repower or remanufacture kit compliant to EPA marine Tier 4[(b,c)]	85%
Any vessel propulsion engine repower with an off-road Tier 3 or cleaner certified engine			Case-by-case basis
EPA Verified Marine Retrofit Device			Case-by-case basis
Installation of an EPA verified Hybrid System			85%
Shore Power- ship side			100% of retrofit cost 50% of transformer cost
Purchase of an EPA verified marine vessel exhaust capture and control system			Case-by-case basis

[(a)] Chapter 1, Section A, Part 2 requires projects to provide three years of surplus reductions prior to any applicable regulatory compliance deadline

[(b)] Due to the absence of emission factors, 2016 and newer model year Tier 4 emission standards (Table D-16) will be used for funding calculations.

[(c)] Engines using a Family Emission Limit (FEL) or Averaging, Banking, and Trading (ABT) to meet the Tier 4 emission standards will be funded at Tier 3 engine levels. Tier 3 emission factors will be used for funding calculations.

C. Project Criteria

The minimum qualifications for marine vessels are listed below. All projects must also conform to the requirements in Chapter 2: General Criteria, and in Chapter 3: Program Administration. Participating air districts retain the authority to impose additional requirements in order to address local concerns.

1. General Marine Project Criteria

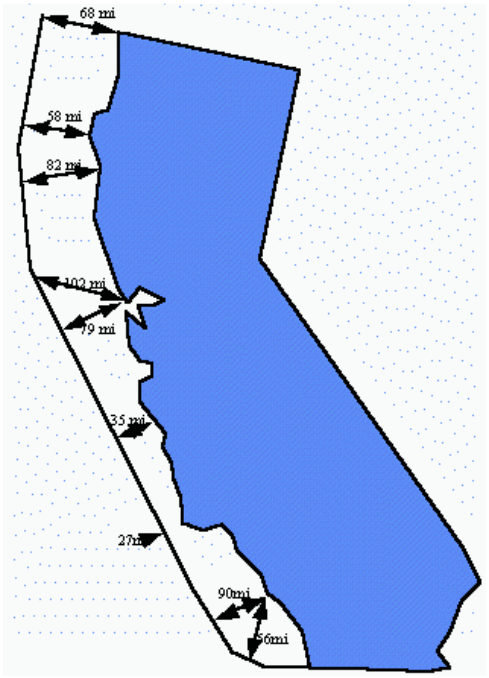
(A) To be eligible for Moyer Program funding, an applicant for harbor craft funding must have a United States Coast Guard Documentation Number, except in cases where such documentation is not required (such as fishing boats constructed outside the United States, vessels of less than five net ton displacement, or vessels owned by non-United States citizens). In such cases, the applicant must include with the application documentation at least one of the following:

(1) A valid California vessel registration (CF) number and a copy of the California Department of Fish and Game license can be provided instead of a Coast Guard Documentation Number.

(2) The vessel's Lloyd's/International Maritime Organization (IMO) number for an oceangoing vessel that does not have any of the above documentation.

(B) Both propulsion and auxiliary engines may be eligible for Moyer Program funding.

Figure 7-1
California Coastal Water Boundaries



(C) Only marine vessel activity in California coastal waters and internal waters may be used to determine project emission reductions. Figure 7-1 depicts the boundary of California coastal waters (defined as that area between the California Coastline and a line starting at the California-Oregon border at the Pacific Ocean, thence to 42.0°N 125.5°W, thence to 41.0°N 125.5°W, thence to 40.0°N 125.5°W, thence to 39.0°N 125.0°W, thence to 38.0°N 124.5°W, thence to 37.0°N 123.5°W, thence to 36.0°N 122.5°W, thence to 35.0°N 121.5°W, thence to 34.0°N 120.5°W, thence to 33.0°N 119.5°W, thence to 32.5°N 118.5°W, and ending at the California-Mexico border at the Pacific Ocean).

(D) Marine projects are not required to meet the minimum California usage requirement in Chapter 2, Section S. Air districts may impose more stringent operational requirements.

(E) Non-captive California fleets and vessels may be considered for funding on a case-by-case basis if their operation in California coastal waters can be properly documented.

(F) Funding is not available for projects where spark-ignition engines are replaced with diesel engines. Repowering a diesel engine to a spark-ignited engine may be considered on a case-by-case basis.

(G) Only marine engines equal to or greater than 25 horsepower are eligible for Moyer Program funding.

(H) Harbor craft engines less than 50 horsepower are exempt from the in-use compliance requirements of the Harbor Craft Regulation. Emission reductions from projects involving these engines are surplus.

(I) Engines on marine vessels with wet exhaust systems are eligible for Moyer Program funding if the project vessel meets all other applicable program requirements. The wet exhaust systems themselves are not eligible for Moyer Program funding. A wet exhaust factor of 0.80 must be applied to the baseline and reduced emission propulsion and auxiliary engine emission calculations for all projects on vessels with wet exhaust systems.

(J) New engines must be installed and operational at least three years prior to the compliance deadline specified by the CHC regulation. Project life for an engine cannot extend beyond that engine's compliance deadline. For compliance deadlines, see implementation charts at: http://www.arb.ca.gov/msprog/moyer/guidelines/supplemental-docs.htm.

(K) Air districts have the option of calculating the project cost-effectiveness on a per vessel basis.

(L) All harbor craft vessels are required to install and maintain a functioning hour meter as required by the CHC Regulation.

(M) Moyer Program funding can be based on engine hours or fuel use. Hours of operation are the preferred basis for project cost-effectiveness calculations and eligibility. Applicants must submit historical usage data as part of the application process. This data must be based on the previous two years of historical usage documentation specific to the vessel being funded. Acceptable forms of documentation may include hour meter readings, maintenance records, fuel logs, purchase receipts or ledger entries. Grant funding that is based on historical fuel usage may not exceed the grant funding amount that would be based on hours of operation; the more conservative calculation must be used.

(N) Owners and operators of engines subject to the CHC Regulation must include a copy of the most recent Initial Report in their project application. The reporting requirements are outlined under California Code of Regulations, title 17, section 93118.5(h)(1).

2. Repower. Repower projects involving the replacement of an older harbor craft engine with a newer, cleaner engine must meet the following criteria:

(A) All new engines and replacement engines purchased for Moyer Program marine vessel repower projects must meet the requirements of the CHC Regulation set forth under California Code of Regulations, title 17, sections 93118.5(e). The regulation includes requirements for newly acquired engines and requirements for replacement engines in vessels subject to the schedules to meet Tier 2 and Tier 3 standards. Use of an off-road certified engine must adhere to the requirements set forth under California Code of Regulations, title 17, sections 93118.5(e)(3) and (e)(4),

especially the marinization requirements set forth in Code of Federal Regulations, title 40, part 1042.605. Project proposals for repower of propulsion engines with off-road engines will be considered on a case-by-case basis.

(B) For all marine engine repower projects, the replacement engine must provide at least a 15 percent NOx reduction relative to the baseline engine. The replacement engine cannot be significantly modified or reconfigured in any way during the project life.

(C) Funding of Tier 4 marine repower projects:

(1) Due to the absence of emission factors, 2016 and newer model year Tier 4 emission standards (Table D-16) will be used for emission reduction calculations.

(2) Tier 4 Engines using a Family Emission Limit (FEL) or Averaging, Banking, and Trading (ABT) to meet the Tier 4 emission standards will be funded at Tier 3 engine levels. Tier 3 emission factors will be used for emission reduction calculations.

(D) The maximum project life for a marine vessel repower project is 16 years. A longer project may receive case-by-case approval if applicants provide justifying documentation. The maximum project life does not consider regulatory requirements and may be shorter.

(E) The total project repower cost may include charges for the following:

(1) The capital cost of the new engine.

(2) Purchase of or modifications to the cooling system; fuel and exhaust system; wiring, panel, and harness system; power take-offs; propulsion control system; gauges and alarms; and radiator and ventilation, if attached to or integral to the functioning of funded engine.

(3) Costs related to the purchase and/or installation of a new transmission may be eligible when it is a necessary part of the engine repower; and an ineligible expense when it is required for maintenance or repair purposes. Ordinarily, a statement from the vendor or applicant that the new reduced emissions engine is not compatible with the existing baseline transmission is sufficient justification for eligibility; please retain a copy of the vendor or applicant’s statement(s) or other documentation in the project file.

(4) Frames needed to be extended or other parts needed to be cut or modified in order to accommodate the new engine, as well as paint

or coating needed to protect those specific areas that were cut or modified.

(5) Tax and transport for eligible parts or costs.

(6) Labor for installation of or modification to parts eligible for funding.

(F) The total project repower cost may not include charges for the following:

(1) Rudders or propellers.

(2) Steering system.

(3) Sea trials and dry docking.

(4) Paint, coatings, or hull work not directly related to the engine repower.

(5) Tax and transport for ineligible parts or costs.

(6) Labor for installation of or modification to parts ineligible for funding.

(7) Any parts or labor typically included as part of the vessel or engine overhaul, maintenance, repair, or upkeep.

(8) These and other items may be eligible for funding on a case-by-case basis if it can be proven that they are not part of the typical vessel overhaul, repair, upkeep or maintenance and are a necessary part of the engine repower.

(G) All engines replaced as part of a marine vessel repower project must be scrapped, consistent with the requirements of Chapter 3: Section BB.

3. Engine Remanufacture Kit. Engine remanufacture kit projects must meet the following criteria:

(A) A remanufacture kit for a specific vessel type may be certified by the U.S. EPA, IMO, or approved by ARB to meet the requirements of the CHC Regulation, but must be surplus to the current in-use requirements of CHC Regulation.

(1) Engine remanufacture kits specific to vessels not subject to the in-use requirements of the CHC Regulation must meet U.S. EPA Tier 3 marine or Tier 3 non-road engine emission standards or cleaner (e.g., Tier 3 or higher).

(2) Engine remanufacture kits specific to vessels subject to the in-use requirements of the CHC Regulation must be surplus to the current requirements of the regulation.

(B) The applicant must provide a copy of the regulatory compliance letter from ARB (similar to an Executive Order) to the air district demonstrating that the remanufacture kit is compliant with the CHC Regulation. Remanufacture kits which reduce NOx only are not eligible for Moyer Program funding.

(C) Remanufacture kit projects have a maximum project life of six years.

(D) If the U.S. EPA Emissions Warranty for the project kit requires fuel injectors to be replaced before the end of the project life, the applicant must replace the injectors with equivalent low-emission injectors. The Moyer Program project cost may include the replacement injectors. The project annual report must include documentation that all required maintenance identified in the U.S. EPA Emissions Warranty (if applicable) is completed on schedule. Maintenance other than replacement of low-emission fuel injectors is not eligible for Moyer Program funding.

4. **Retrofits**. Retrofits include selective catalytic reduction, diesel oxidation catalysts or diesel particulate filters. A retrofit device must be verified by ARB to reduce emissions from the project engine in order to be eligible for funding. This project type will be considered for funding on a case-by-case basis.

5. **Hybrid System**. A Hybrid System project must meet the following criteria:

(A) The hybrid system must be verified by the United States EPA to reduce the total vessel emissions of NOx, ROG, and PM by specific percentages compared to the baseline vessel.

(B) The hybrid system must be verified to reduce NOx by at least 15 percent compared to the baseline vessel.

(C) The vessel must meet the EPA verification parameters (i.e. vocation, duty cycle, horsepower range) for the proposed hybrid system.

(D) The vessel must be compliance with the CHC Regulation engine replacement schedule for meeting Tier 2 or Tier 3 standards.

(E) The vessel must have Tier 3 or cleaner propulsion engines and Tier 2 or cleaner auxiliary engines.

(F) The applicant must be able to provided individual usage history for each engine on the baseline vessel.

(G) Hybrid system installation projects have a maximum project life of five years.

(H) The hybrid system must include a manufacturer’s warranty for the duration of the project life.

(I) Eligible costs for a Hybrid System project include the components and labor costs directly related to the purchase and installation of a hybrid system.

(J) Ineligible costs for a hybrid system include the following:

(1) Paint, coatings, or hull work not directly related to the hybrid system installation.

(2) Tax and transport for ineligible parts or costs.

(3) Sea trials and dry docking.

(4) Labor for installation of or modification to parts ineligible for funding.

(5) Any parts or labor typically included as part of the vessel or engine overhaul, maintenance, repair, or upkeep.

(6) Other items may be eligible for funding on a case-by-case basis if it can be proven that they are not part of the typical vessel overhaul, repair, upkeep or maintenance and are a necessary part of the hybrid system.

(K) All engines replaced as part of Hybrid System project must be scrapped, consistent with the requirements of Chapter 3: Section BB.

6. Ship-Side Shore Power Projects. The retrofit of a marine vessel to enable shore power connection. For shore-side projects see Chapter 10: Infrastructure.

(A) Only a marine vessel owner may apply to receive Moyer Program funding for a ship-side power project.

(B) Vessels subject to the Shore Power Regulation:

(1) Applications for Moyer Program funding of shore power projects must include a copy of the most recent Vessel Plan, Annual Statement of Compliance as identified in Section (g) of the Shore Power Regulation. All subsequent project reports to air districts must include any new or updated Vessel Plans in order to evaluate compliance with the project contract.

(2) The commitment of visits and hours made by the applicant, above those required by the Shore Power Regulation, must be used in the project cost-effectiveness calculation and is required in the contract between the applicant and the air district.

(3) The entire fleet roster and all the California ports of harbor the fleet will be visiting. From the locales submitted, the fleet must indicate

per location, the number of vessel visits and hours per year the fleet will be utilizing shore-side power.

(C) Up to 100 percent of necessary vessel (non-transformer) retrofit costs, specifically required to allow the vessel to plug into shore-side power, are eligible for Moyer Program funding. Up to 50 percent of any necessary transformer costs on board the vessel are eligible for Moyer Program funding.

(D) Docking at ports or terminals funded by the Proposition 1B Goods Movement Program is not prohibited; however, vessel retrofits funded with Moyer Program funds cannot claim emission reductions resulting from ship visits to ports or terminals during the active Proposition 1B Goods Movement Program contract period.

(E) The Moyer Program shall not pay for energy costs (fuel or electricity), shore power routine maintenance, or labor costs for connection and disconnection of the vessel to shore-side power.

(F) All contracts for Moyer Program funding of shore power projects must include a stipulation that receipt of program funding is contingent on the project being post-inspected and operational. The project contract must include a provision that if the shore power is not used for the total hours committed to in the contract, the project participant shall return the pro-rated contract amount (commensurate with the shortfall in usage) to the air district. If the contract activity is not met, air districts may refer to Chapter 3 Section FF.4. to address this underutilization. However, the contract must include language prohibiting the grantee from obtaining a waiver from the contracted usage, specifically Section FF.4.(D).

(G) Shore power projects have a maximum project life of 20 years. A longer project may receive case-by-case approval if applicants provide justifying documentation. The maximum project life does not consider regulatory requirements and may be shorter.

(H) The emissions from vessels using grid power in lieu of auxiliary engines when the vessel is at berth are assumed to be reduced by 90 percent. The emission reductions from a shore-side transformer project are calculated as the total emission reductions from each participating ship. Each ship's emission reductions calculated as: (Ship emission rate * berthing time * power requirements * number of visits * 0.9).

(I) Estimated berthing time shall include the time needed to connect and disconnect the vessel to shore power. Ship emission rates and power requirements are included in Appendix D.

7. **Marine Vessel Exhaust Capture and Control System**. Funding for the purchase of exhaust capture and control systems may be approved on a case-by-case basis.

CHAPTER 8: LIGHT-DUTY VEHICLES

This chapter describes the minimum criteria and requirements for Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) light-duty vehicle projects.

A. Projects Eligible for Funding

Voluntary Accelerated Vehicle Retirement (VAVR) projects are eligible for Moyer Program funding. VAVR projects scrap older, more-polluting vehicles earlier than their expected lifetime that are still operational and have useful remaining life. Two types of VAVR projects are allowed: conventional and high emitting. Retirement of a high emitting vehicle results in emission reductions greater than those generated by conventional projects. To be eligible for a high emitting VAVR project, a vehicle's Smog Check results must exceed the pass/fail emission standards for the vehicle's model year and class.

The Bureau of Automotive Repair (BAR) concurrently administers two different vehicle retirement programs similar to the Moyer Program, the Enhanced Fleet Modernization Program's (EFMP) Retirement-Only component and their own Consumer Assistance Program (CAP). Although the Moyer Program, EFMP Retirement-Only Program, and CAP are administered and operated in a consistent manner, each program has different eligibility requirements, funding sources, and accepts vehicles at different times within the Smog Check cycle. The Moyer Program accepts vehicles that have passed their most recent Smog Check, while CAP accepts vehicles that have failed their most recent Smog Check. EFMP Retirement-Only however, accepts vehicles that have either passed or failed their most recent Smog Check, but is limited to income eligible applicants only.

B. Maximum Eligible Funding Amounts

VAVR projects are subject to the Moyer Program cost-effectiveness limit and must meet all other relevant criteria in Section D of this chapter. Incentives paid for eligible VAVR projects are limited to a maximum of $1,500 per vehicle. Air quality management districts or air pollution control districts (air districts) have the authority to set more stringent project requirements.

C. Regulatory Background

Moyer Program VAVR projects are subject to the requirements of the VAVR Regulation, California Code of Regulations (CCR), title 13, section 2601 et seq. Air districts may choose to act as the enterprise operator in lieu of contracting out this work to a third party. However, costs incurred by the air district to perform the duties of an enterprise operator shall be considered administrative costs.

VAVR projects funded through AB 923 are authorized by Health and Safety Code section 44229(b)(4) which states that these projects must be in compliance with

guidelines adopted by the Air Resources Board (ARB). This chapter constitutes ARB's adopted guidelines for VAVR projects.

D. Project Criteria

The following criteria provide the minimum requirements for Moyer Program VAVR projects. All projects must also conform to Chapter 2: General Criteria, as well as the project application, contract, reporting, and other requirements as described in Chapter 3: Program Administration. Participating air districts retain the authority to impose additional or more restrictive requirements to address local concerns.

Vehicle Eligibility Requirements:

1. Participation shall be entirely voluntary for vehicle owners.

2. A vehicle volunteered for retirement must be a diesel or gasoline powered passenger car or light-duty truck up to 10,000 pounds gross vehicle weight.

3. A vehicle volunteered for retirement must be currently registered with the Department of Motor Vehicles (DMV) as an operating vehicle and must have been registered for at least 24 consecutive months, to an address within the air district in which the VAVR enterprise is operated, prior to the date of the sale to a VAVR enterprise. Smog Checks must be performed as required by DMV in order for the vehicle to be considered registered.

(A) A vehicle may also be eligible if the owner of the vehicle placed the vehicle in planned non-operational status, per Vehicle Code section 4604 et seq., for up to 60 days during the previous 24 month registration period and occurring at least 90 days immediately prior to its sale to the VAVR enterprise.

(B) A vehicle may also be eligible if the registration has lapsed for a period not to exceed 181 days during the previous 24 months and all appropriate registration fees and late penalties have been paid to DMV, provided that the vehicle is registered for at least 90 days immediately prior to its sale to a VAVR enterprise.

4. A vehicle volunteered for retirement shall be driven to the VAVR enterprise purchase site to be retired under its own power.

5. A vehicle volunteered for retirement whose emission control systems have been tampered with as defined in CCR, title 16, section 3340.41.5 is not eligible until such tampering has been completely corrected.

6. A vehicle volunteered for retirement shall not be operating under a Smog Check repair cost waiver or economic hardship extension.

7. If a vehicle volunteered for retirement is within 60 days of its next required Smog Check, the vehicle shall pass a Smog Check without receiving a repair cost waiver or economic hardship extension prior to acceptance by a VAVR enterprise.

8. If a vehicle volunteered for retirement is within 61-90 days of its next required Smog Check, the air district shall verify that the vehicle has not failed a Smog Check during this time frame.

9. A vehicle volunteered for retirement shall pass functional and equipment eligibility inspections as specified in the VAVR Regulation, CCR, title 13, section 2603(b).

10. For high emitting VAVR projects, a vehicle volunteered for retirement must receive a confirmatory Smog Check to establish its baseline emissions, and the emissions must exceed the pass/fail emission standards for the model year and vehicle class as defined in CCR, title 16, section 3340.

    (A) Only vehicles identified as potential high emitters through a technology operated in accordance with the VAVR Regulation, CCR, title 13, section 2610 and approved by ARB are eligible to receive extra emission reductions credit for VAVR projects.

    (B) If a vehicle's emissions are within the pass/fail standards, the vehicle is not a high emitter and does not quality for high emitter projects but may be retired for default emission reductions through a conventional VAVR project.

    (C) For pre-1974 model years, the pass/fail emission standards for the 1974 model year may be used to qualify vehicles for the project.

    (D) Smog Checks must be full tests and not "fast pass" tests. The test must be conducted only by BAR-licensed technicians according to BAR protocols and completed as close to the retirement date as reasonably possible.

    (E) Diesel powered vehicles are not eligible for high emitting VAVR projects.

E. Emissions Measurement Methods

1. Smog Checks for model year 1999 and older gasoline powered vehicles are performed via a conventional Acceleration Simulation Mode (ASM) test. For certain vehicles, such as four-wheel and all-wheel drive vehicles, the Smog Check cannot be performed via an ASM test for safety or other mechanical reasons. In those limited cases, the Two Speed Idle (TSI) test may be used. TSI tests must be performed in strict compliance with BAR protocols.

    (A) Consistent with the model's limitations, TSI test results and the BAR protocol may only be used to predict ROG emissions, as TSI tests do not

directly measure either NOx or PM. For high emitting vehicles that are retired, default evaporative ROG, NOx, and PM emission reductions may be claimed.

2. Smog Checks for model year 2000 and newer gasoline powered vehicles and 1998 and newer diesel powered vehicles are performed via an On-Board Diagnostic Inspection (OIS) test. The OIS test must be performed in strict compliance with BAR protocols.

(A) Consistent with the model's limitations, OIS test results and the BAR protocol may only be used to predict ROG, NOx, and PM emissions, as the OIS test does not directly measure tailpipe emissions.

F. Air District Project Plan Requirements

1. An air district shall submit a detailed VAVR program project plan to ARB for approval and must receive written approval from ARB's Executive Officer (EO) prior to implementing a VAVR program. The program must follow the approved plan, and any substantive changes must be pre-approved by ARB in writing.

2. The air district project plan shall include, at a minimum, the following:

(A) The name, title, and telephone number of the air district program contact.

(B) An evaluation of environmental justice considerations including, but not limited to, outreach addressing community needs.

(C) An estimate of the number of vehicles to be retired, and an estimate of the cost-effectiveness with all assumptions and calculations used.

(D) Copies of contracts with enterprise operators, consultants, and any other third party contractor(s) participating in the project.

(E) A description of and timetable for monitoring and auditing enterprise operators, consultants, and other third party contractor(s).

(F) A copy of the statement of certification that an enterprise operator(s) has demonstrated compliance with all applicable provisions of the VAVR Regulation.

(G) The protocol for verifying vehicle eligibility including confirmation of compliance with any Smog Check requirements and for informing the public of the availability of vehicles eligible for retirement.

(H) A sample of the records that will be required of the enterprise operator(s).

(I) A description of any project criteria elements stricter than the ARB minimum requirements.

3. For high emitter projects, the air district project plan shall also include, at a minimum, the following:

(A) A detailed operating description of the technology and software used to identify high emitting vehicles including, but not limited to, set up, typical operation, location and location criteria, calibration, and maintenance.

(B) A copy of the standard operating procedures for that technology including software maintenance and the criteria to be used to identify a high emitting vehicle with documentation that operating personnel are trained and qualified.

(C) A detailed description of the methodology used to calculate extra emission reductions, including changes to any ARB-recommended method.

(D) If an air district intends to include an evaporative emissions testing element, the plan must specify the test equipment and include a copy of the test protocol.

(E) If an air district intends to include a PM measuring element, the plan must specify the test equipment and include verification that the methodology for measuring PM is scientifically valid, documentation that the results are reproducible, and a complete copy of the methodology.

(F) An itemized breakdown of estimated project costs including, but not limited to, funds allocated to identifying high emitters, the number of vehicles to be retired, data analysis, outreach to and solicitation of vehicle owners.

G. Recordkeeping and Reporting

1. For each VAVR project, the air district shall retain the following records for inclusion in the annual report to ARB.

(A) Vehicle Identification Number and license plate digits

(B) Vehicle odometer reading

(C) Vehicle make and model

(D) Name, address, and phone number of legal vehicle owner(s)

(E) Name and business address of the enterprise operator

(F) Emission reductions claimed

(G) Total air district cost to retire each vehicle

(H) Date of vehicle purchase and retirement by the enterprise operator

(I) Data identifying vehicles as potential high emitters along with confirmatory Smog Check date and results (High Emitter VAVR)

2. For each VAVR project, the enterprise operator shall maintain the following records. These records are not required for the annual report but must be made available to ARB for review.

(A) Reproduction of California Certificate of Title and registration, as signed-off by the seller at time of final sale to the enterprise operator.

(B) Reproduction of the applicable certificate of functional and equipment eligibility.

(C) Reproduction of the applicable Notice to Dismantler (DMV Registration 42 form).

(D) Reproduction of written documentation from DMV verifying that a vehicle meets the vehicle registration requirements of ARB's VAVR Regulation.

(E) Copies of documentation demonstrating that the retired vehicle did not fail a Smog Check within 90 days prior to its sale to the enterprise operator.

3. Air districts and enterprise operators shall retain these records for the three year life of the project plus an additional two years.

H. Minimum Project Application Requirements

Air districts must ensure project applications include the specific information needed to determine program eligibility and populate the Clean Air Reporting Log (CARL), including the information needed to track the project and calculate project cost-effectiveness.

I. Offering Vehicles/Parts to the Public

1. Enterprise operators must inform the air district of the vehicles ready for dismantling, and the air district must provide an easily accessible and detailed description of the vehicles to interested parties including collectors and enthusiasts as defined in CCR, title 13, section 2605(a)(1).

2. The enterprise operator must wait a minimum of ten days after informing the air district of vehicles ready for dismantling before submitting a Notice to Dismantle to DMV, and if interested parties contact the enterprise operator, the enterprise operator must hold the vehicle for a minimum of seven additional days as defined in CCR, title 13, section 2605(a).

3. Upon completion of the ten day waiting period (and additional seven day extension as applicable), the emission-related and drive train parts must be removed from the retired vehicle and destroyed prior to offering the remaining

non-emission-related and non-drive train parts for resale, as defined in CCR, title 13, section 2606(b).

4. If a vehicle, or a vehicles emission-related or drive train parts, are resold instead of retired, no emission reductions will be generated; and no Moyer Program funds may be used for retiring the vehicle. However, non-emission-related and non-drive train parts from the vehicle may be sold at the discretion of the enterprise operator.

J. Emission Benefits

Emission reductions from conventional VAVR projects are calculated using the VAVR Regulation methodology as described in CCR, title 13, section 2608(g). They are equal to the retired vehicle's emission rates minus those of the replacement vehicle with the difference multiplied by the average vehicle miles traveled by light-duty vehicles in the year of vehicle retirement and then multiplied by the three year project life. The retired vehicle's emission rates are equal to those for gasoline powered, light-duty vehicles for the model year of the retired vehicle in the year of vehicle retirement. Replacement vehicle emissions are the fleet average emissions for all gasoline powered light-duty vehicles for model years 1990 through the year of vehicle retirement. Emission rates and average vehicle miles traveled are generated by ARB's motor vehicle emissions model. ROG, NOx, and PM emission reductions over the three year project life by vehicle model year are located in Tables 8-1 through 8-5 below. These tables will be updated on an as needed basis through a mail-out to reflect revisions to the motor vehicle emissions model or to include additional years.

Table 8-1
Retired Vehicle Emission Reductions, CY 2016 (lbs/3yr)

MY	ROG	NOx	PM10
	Total	Exhaust	Exhaust
pre 1973	376.3	141.8	2.21
1973	382.2	146.1	2.28
1974	340.8	147.3	2.35
1975	288.9	146.3	2.37
1976	271.2	182.9	2.43
1977	254.4	194.7	2.40
1978	166.9	107.5	2.41
1979	161.5	102.8	2.44
1980	150.9	106.1	2.38
1981	136.3	83.7	0.94
1982	149.1	84.3	0.95
1983	165.1	85.0	0.92
1984	164.9	90.5	0.94
1985	155.3	88.5	0.96
1986	166.4	89.4	0.98
1987	153.9	86.9	1.01
1988	146.8	85.0	1.04
1989	133.6	76.3	1.05
1990	123.1	66.0	1.04
1991	100.4	68.2	0.55
1992	99.2	71.7	0.57
1993	92.2	69.6	0.59
1994	84.0	63.9	0.60
1995	71.6	51.4	0.60
1996	56.6	38.4	0.13
1997	46.3	36.5	0.14
1998	23.5	30.5	0.14
1999	19.6	27.8	0.14
2000	14.5	21.5	0.14
2001	12.4	19.9	0.14
2002	10.9	19.8	0.14
2003	8.3	19.1	0.15

Source: EMFAC2014 V1.0.7

Table 8-2
Retired Vehicle Emission Reductions, CY 2017 (lbs/3yr)

MY	ROG	NOx	PM10
	Total	Exhaust	Exhaust
pre 1974	377.5	143.3	2.24
1974	338.2	144.9	2.30
1975	286.6	144.6	2.32
1976	269.5	182.1	2.38
1977	252.3	192.2	2.36
1978	165.3	105.4	2.36
1979	160.3	101.2	2.39
1980	149.6	103.9	2.34
1981	135.1	82.0	0.92
1982	148.3	82.6	0.93
1983	165.8	83.5	0.90
1984	165.3	88.9	0.92
1985	155.8	87.1	0.93
1986	167.6	88.1	0.96
1987	154.8	85.0	0.99
1988	149.0	84.3	1.02
1989	137.0	75.7	1.02
1990	127.4	66.4	1.02
1991	103.1	68.7	0.54
1992	102.3	72.3	0.56
1993	95.9	70.4	0.57
1994	88.2	64.8	0.59
1995	75.7	52.7	0.59
1996	60.4	39.7	0.13
1997	49.7	37.8	0.13
1998	25.6	31.7	0.13
1999	21.7	29.0	0.13
2000	16.7	22.8	0.13
2001	14.7	21.4	0.14
2002	13.1	21.1	0.14
2003	10.6	20.5	0.14

Source: EMFAC2014 V1.0.7

Table 8-3
Retired Vehicle Emission Reductions, CY 2018 (lbs/3yr)

MY	ROG	NOx	PM10
	Total	Exhaust	Exhaust
pre 1975	333.7	140.9	2.24
1975	283.0	141.3	2.25
1976	265.2	177.2	2.31
1977	250.7	189.7	2.30
1978	163.6	102.4	2.30
1979	158.7	98.3	2.33
1980	148.3	101.1	2.28
1981	133.9	79.5	0.89
1982	147.4	80.3	0.90
1983	166.0	81.1	0.87
1984	166.2	86.7	0.90
1985	156.6	84.8	0.91
1986	169.2	86.1	0.93
1987	156.0	83.2	0.95
1988	150.4	82.0	0.98
1989	139.8	74.6	0.99
1990	130.6	65.5	0.98
1991	105.3	68.6	0.52
1992	105.2	72.3	0.54
1993	99.3	70.5	0.55
1994	92.4	65.5	0.57
1995	80.0	53.3	0.57
1996	64.3	40.5	0.12
1997	53.2	39.0	0.13
1998	28.0	32.8	0.13
1999	24.1	30.2	0.13
2000	19.0	24.0	0.13
2001	17.1	22.6	0.13
2002	15.6	22.5	0.13
2003	13.0	21.8	0.14

Source: EMFAC2014 V1.0.7

Table 8-4
Retired Vehicle Emission Reductions, CY 2019 (lbs/3yr)

MY	ROG	NOx	PM10
	Total	Exhaust	Exhaust
pre 1976	279.3	137.8	2.19
1976	262.3	174.9	2.24
1977	246.6	184.8	2.23
1978	161.5	99.6	2.23
1979	157.1	95.7	2.26
1980	146.5	98.1	2.21
1981	132.8	77.4	0.86
1982	146.5	78.0	0.88
1983	166.0	78.7	0.84
1984	166.5	84.2	0.87
1985	157.8	82.6	0.88
1986	171.1	83.9	0.90
1987	157.3	81.3	0.92
1988	152.0	80.2	0.95
1989	141.4	72.4	0.96
1990	133.1	64.6	0.95
1991	106.6	67.6	0.50
1992	107.4	72.1	0.52
1993	102.3	70.5	0.53
1994	96.1	65.8	0.55
1995	84.1	54.0	0.55
1996	68.1	40.7	0.12
1997	56.6	39.7	0.12
1998	30.2	34.0	0.12
1999	26.5	31.4	0.12
2000	21.3	25.1	0.12
2001	19.3	23.6	0.12
2002	17.9	23.5	0.13
2003	15.4	23.0	0.13

Source: EMFAC2014 V1.0.7

Table 8-5
Retired Vehicle Emission Reductions, CY 2020 (lbs/3yr)

MY	ROG	NOx	PM10
	Total	Exhaust	Exhaust
pre 1977	257.3	169.2	2.18
1977	244.9	182.3	2.17
1978	159.5	96.4	2.17
1979	155.3	93.1	2.20
1980	145.0	95.2	2.15
1981	131.3	74.8	0.84
1982	145.6	75.9	0.85
1983	165.7	76.2	0.82
1984	166.6	81.8	0.84
1985	158.6	80.2	0.85
1986	173.7	81.7	0.87
1987	158.9	79.2	0.89
1988	153.7	78.5	0.92
1989	143.3	70.9	0.93
1990	134.3	62.5	0.92
1991	107.5	66.5	0.49
1992	108.7	71.0	0.50
1993	104.7	70.3	0.52
1994	99.4	66.1	0.53
1995	87.6	54.4	0.53
1996	71.6	41.0	0.12
1997	59.8	40.0	0.12
1998	32.1	34.6	0.12
1999	28.7	32.6	0.12
2000	23.6	26.3	0.12
2001	21.5	24.6	0.12
2002	20.0	24.3	0.12
2003	17.5	24.0	0.13

Source: EMFAC2014 V1.0.7

1. Emission reductions from retired diesel powered vehicles are also calculated using the VAVR Regulation methodology. Because of limited data and minor differences in emission rates from one year to another, average emission reductions are shown for only two model year ranges in the four calendar year intervals shown. Replacement vehicle emission rates are the same as those used for gasoline powered vehicles. Average ROG, NOx, and PM emission reductions over the three year project life by model year range are located in Tables 8-6 and 8-7. There are no evaporative emission reductions for the retirement of a diesel powered vehicle.

Table 8-6
Retired Diesel Powered Vehicle Emission Reductions

Model Year Range	Pollutant	CY 2014-2017 (lbs/3 yrs)
Pre-1984	ROG	11.6
	NOx	53.4
	PM	11.5
1984-1992	ROG	10.8
	NOx	42.8
	PM	8.4

Source: EMFAC2014 V1.0.7

Table 8-7
Retired Diesel Powered Vehicle Emission Reductions

Model Year Range	Pollutant	CY 2018-2021 (lbs/3 yrs)
Pre-1984	ROG	10.8
	NOx	48.9
	PM	10.1
1984-1992	ROG	10.3
	NOx	39.6
	PM	7.4

Source: EMFAC2014 V1.0.7

2. Please refer to Appendix C for a discussion of the methodology for estimating emission reductions and how to calculate VAVR project cost-effectiveness.

3. Currently, none of the air district VAVR programs have components for high emitter projects. ARB will provide the methodology for any new plans which include special cases, such as high emitter projects, through a mail-out as needed.

CHAPTER 9: LAWN AND GARDEN EQUIPMENT REPLACEMENT

This chapter describes the minimum criteria and requirements for the Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) Lawn and Garden Equipment (L&GE) replacement projects. L&GE replacement provides a streamlined approach to reduce emissions by replacing existing gasoline lawn mowers with cordless, zero-emission electric lawn mowers. Zero-emission lawn mowers are not required by regulation, so the emission benefits are surplus. The Moyer Program provides funding for vouchers to offset part of the cost of the replacement electric lawn mower.

A. Projects Eligible for Funding

New Replacement Cordless, Zero-Emission Electric Lawn Mower Purchase: The purchase of a new cordless, zero-emission electric lawn mower to replace the existing gasoline lawn mower that is to be scrapped is eligible for funding under this program.

No emission reductions generated by the Moyer Program shall be used as marketable emission reduction credits, or to offset any emission reduction obligation of any person or entity. Therefore, an electric lawn mower model that generates credits by participating in the Air Resources Board's (ARB) zero-emission equipment credit averaging, banking, and trading program is not eligible for funding.

B. Maximum Eligible Funding Amounts

The maximum total project funding amount associated with reducing the eligible costs of a L&GE replacement project has been predetermined as $145 per lawn mower.

C. Project Criteria

The criteria listed below are the minimum requirements for L&GE replacement project participants: air quality management districts or air pollution control districts (air districts); cordless zero-emission electric lawn mower manufacturers and merchants; hazardous waste material disposal companies and recycling companies. All projects must also conform to the requirements in Chapter 2: General Criteria and in Chapter 3: Program Administration, except for the following Sections: S. Project Application Requirements, W. Project Pre-Inspection, X. Project Post-Inspection, Y. Project Invoice and Payment, Z. Grantee Annual Reporting, AA. Air District Audit of Projects, BB. Nonperforming Projects; and as noted elsewhere below.

1. **General Lawn and Garden Equipment Replacement Criteria**. As allowed under Chapter 2, Sections I, N, O, P, and Q, an air district may contribute additional non-Moyer Program incentive funds towards the purchase of the individual lawn mower. However, Moyer Program and AB 923 funds combined cannot exceed $145. Bulk-purchasing discounts from the electric lawn mower manufacturer or merchant are also allowed.

2. **Participant Requirements.** All participants must meet the following requirements to be eligible for funding**:**

   (A) *Application Form*: To be approved for L&GE replacement funds, the applicant must meet L&GE replacement program requirements and submit an application. Once an application is approved by the air district, the air district will return the application form to the applicant. The applicant must turn in the approved application form with applicant's signature at the location designated by the air district.

   (B) *Applicant must certify in the application*:

      (1) California Residence: Participants must reside in California. Air districts may add the requirement that participants reside within the air district.

      (2) Own and Operate: The participant must currently own and operate the existing gasoline lawn mower in California.

      (3) Replacement Cordless, Zero-Emission Electric Lawn Mower Operation in California: The participant must intend to own and operate the new replacement cordless, zero-emission electric lawn mower in California for a minimum of 36 months from the date of purchase.

3. **Existing Lawn Mower Requirements.** Each existing lawn mower must meet the following conditions before the L&GE replacement application can be approved and awarded a voucher.

   (A) *Operational Gasoline Lawn Mowers*: The existing lawn mower must be in operational condition. The lawn mower must operate on gasoline, be able to start, move, and have all operational parts. Applicant certifies operability on the application form.

   (B) *Delivery of the Existing Lawn Mower to the Air District or Air District-specified Facility*: The participant must deliver the existing lawn mower to the air district or air district-specified facility. The air district or air district-specified facility must reject the existing lawn mower if it is deemed inoperative.

4. **Replacement Lawn Mower Requirements.** All replacement lawn mowers must meet the following requirements before a voucher is awarded to the participant:

   (A) *New, Cordless, Zero-Emission Electric Lawn Mower*: The replacement lawn mower must be a new, cordless, zero-emission electric lawn mower.

(B) *Not Used for Credit Generation*: Only an electric lawn mower model that does not generate credit or participate in ARB's zero-emission equipment credit averaging, banking and trading program is eligible for funding.

(C) *Purchase*: The replacement lawn mowers must be purchased from a participating air district, or a third party, participating manufacturer or participating merchant, as chosen by the implementing air district.

5. Air District Requirements. An air district implementing the program must meet the following requirements:

(A) *Add an addendum to the air district's Moyer Program Policies and Procedures*: An air district must create an addendum to its current Moyer Program Policies and Procedures (P&P's) describing their program within two (2) months after they begin implementation of the L&GE replacement program. Air districts are not required to submit this addendum to ARB but it must be available to ARB upon request.

(B) *Agreements*:

(1) An air district must have written agreements with both of the following parties:

a. A hazardous waste materials disposal company.

b. A recycling company.

The agreements can be included as part of the air district's agreements with the same entities for other Moyer Programs. The recycling company and the hazardous waste material company can be the same company.

(2) If an air district is working with either or both of the following parties,

a. A cordless, zero-emission electric lawn mower manufacturer, or

b. A cordless, zero-emission electric lawn mower merchant,

the air district must have a written agreement with that party. The agreement must include the requirements of subsection 6 (Participating Manufacturer Requirements) or 7 (Participating Merchant Requirements) of this chapter, as applicable, and Chapter 3: Program Administration, Section V. Minimum Contract Requirements, except for the following subsections: 6. Project Specifications, 7. Maintenance, 9. Reporting, and 11. Repercussions of Nonperformance - equipment operation requirement.

(C) *Third Party*: An air district may enter into an agreement with a third party to manage some of the air district's program requirements. The third party

must agree to comply with all L&GE replacement program requirements. The air district must train the third party on L&GE replacement program requirements and include an example of the agreement in its P&P's.

(D) *Application*: Applications, at a minimum, must have the following information:

(1) Information about the Applicant:

a. Name.

b. Mailing Address (including city, state, zip code).

c. Physical Address (if different from mailing address).

d. Phone Number.

e. Date of Application.

(2) Information about the Applicant's Existing Gasoline Lawn Mower:

a. Manufacturer (if known).

b. Model Year (if known).

c. Engine family (if known).

(3) Section for the applicant to certify the following information is accurate and true:

a. Existing gasoline lawn mower is operational.

b. Applicant resides in California.

c. Applicant currently owns and operates the gasoline lawn mower in California.

d. From the date of purchase, applicant intends to own and operate the new, cordless zero-emission electric lawn mower in California for a minimum of 36 months.

e. The information provided in the application is true and correct and meets the minimum requirements of the L&GE replacement program.

f. "I understand that an incomplete or illegible application may be immediately rejected, and I will be notified."

g. “I understand as an applicant that incentive programs have limited funds and shall terminate upon depletion of program funding.”

(4) A box for the applicant to check to certify the information included in (3) is correct and signify the applicant’s agreement with the above statements.

(E) *Application Approval*: The application approval process consists of the following steps:

(1) Applicant submits application to the air district.

(2) Air district or designated third party reviews and approves application (if appropriate), and returns it to applicant. Application review and approval may be conducted on-site at a lawnmower exchange event.

(3) Applicant turns in approved application with applicant’s signature per subsection C. 2.(A).

(F) *Rejected Application*: If a submitted application is incomplete, ineligible, or illegible, the air district must reject the application immediately and notify the applicant within five days of receipt. Air districts may follow up with an applicant in order to complete an incomplete or illegible application.

(G) *Disbursement Request Requirements*: An air district may request Moyer Program funds as these funds become available. In order for an air district to be approved for a disbursement request, the air district must follow Chapter 3: Program Administration, Section E requirements, and also provide the following to ARB:

(1) Verification of board approval to implement the L&GE replacement program for the requested disbursement amount or more; and

(2) If applicable per Section 5(B)(2) a copy of at least one cordless zero-emission electric lawn mower manufacturer or merchant agreement; and

(3) A copy of at least one active hazardous waste materials disposal company agreement; and

(4) A copy of at least one active recycling company agreement; and

(5) A history (up to five years, if applicable) of previous years of the air district’s lawn and garden equipment exchange programs, including the following information:

a. Yearly amount funded.

b. Yearly number of mowers funded.

c. Yearly program administration costs.

d. Cordless, zero-emission electric lawn mower cost breakdown:

i. Amount air district paid to manufacturer.

ii. Amount air district pays from air district's local funds.

iii. Amount of any additional funds.

iv. Amount participant pays.

(H) *Operational Condition of Existing Lawn Mower*: Air district or air district-specified facility must ensure that each existing lawn mower is in apparently operational condition. The air district or air district-specified facility must reject the existing lawn mower if it is deemed inoperative.

(I) *Project Payment*: Air districts must include in their P&P's a detailed description of the process through which the air district provides payment to the cordless, zero-emission electric lawn mower manufacturer, merchant and/or applicant.

(J) *Merchant Reimbursement Package*: Prior to receiving reimbursement, an air district-specified third party, participating manufacturer or participating merchant must submit a reimbursement package to the air district. The following documents should be included in the reimbursement package:

(1) Invoice signed by the applicant that shows the final purchase price less the voucher award. In the case of an online merchant, the invoice does not have to be signed by the applicant.

(2) If a recycling code is used in addition to a voucher in order to purchase the lawn mower, the recycling code.

(3) The name and address of the participant.

(K) *Lawn Mower Destruction Documentation*: All existing gasoline lawn mowers must be destroyed. Air districts must collect from their participating Recycling Companies signed receipts that show the number of lawn mowers destroyed.

(L) *Audit and Monitoring*: Air districts must allow ARB to monitor their L&GE replacement program which may include audits of the air district's implementation of the program.

(M) *Meeting Environmental Justice (EJ) Requirements*: Air districts with environmental justice requirements shall not apply these requirements to the L&GE replacement application review until after each year of implementation. The air district must then review each project to determine if it helps to meet the air district's EJ requirements. If EJ requirements have not been met, then other Moyer Program funded projects will need to be used to fulfill this EJ requirement.

(N) Reporting in CARL: For liquidation reporting requirements the following information must be entered into the CARL database:

(1) Total number of lawn mowers exchanged.

(2) Date of the exchange of the final lawn mower.

(3) Total amount of Moyer Program funds liquidated.

(4) Date of liquidation of the final project.

(5) The Moyer Program funding year.

(O) *Records Retention*: Air districts must retain all records of approved projects for a minimum of three years from the date of issuing the voucher. For rejected projects, air districts must maintain a copy of the application, the rejection letter, and method of notification for three years from the date the application was received.

6. Participating Manufacturer Requirements. Participating manufacturers' agreements must include the following information:

(A) *Covered Lawn Mowers*: Information about the cordless zero-emission electric lawn mowers covered by the agreement:

(1) Lawn mower model name.

(2) Lawn mower year of production.

(3) Lawn mower cutting radius.

(4) Lawn mower battery description (voltage).

(5) Total number of cordless, electric lawn mowers covered by the agreement.

(6) The cost of each cordless, electric lawn mower.

(7) The total contract amount, or total contract amount not to exceed.

(8) The date by which the work shall be completed.

(9) Lawn mower warranty description.

(B) *Manufacturer Qualifications*: A statement that the manufacturer meets the following minimum qualifications for participation in the L&GE replacement program, and shall continue to meet these qualifications throughout its participation in the L&GE replacement program.

(1) Manufacturer has had a valid business license for a minimum of the last two years.

(2) Manufacturer agrees to allow the air district or ARB to inspect cordless, zero-emission electric lawn mowers or audit program records covered under this agreement during normal business hours.

(C) *Aftermarket Service*: A statement that the manufacturer shall provide aftermarket service to customers for defects in materials or workmanship as defined by the Terms and Conditions listed in the product warranty.

(D) *Recalls*: A statement that as soon as reasonably possible, manufacturer shall notify the air district and individually notify any and all purchasers of equipment through this program of any recall of the lawn mower or any of its constituent parts ordered by manufacturer or by a government agency.

(E) *Air District Does Not Warrant or Endorse Lawn Mowers*: A statement that the air district does not warrant or endorse the manufacturer's lawn mowers for any purpose, including materials, workmanship, merchantability or fitness for use. Nothing in the air district/manufacturer contract shall be construed as a warranty or endorsement.

(F) *Averaging, Banking, and Trading Program Exclusion*: A statement that no emission reductions generated by the Moyer Program shall be used as marketable emission reduction credits, or to offset any emission reduction obligation of any person or entity. Therefore, electric lawn mower models included in the agreement are not generating credits by participating in ARB's zero-emission equipment credit averaging, banking, and trading program or any similar program.

(G) *Return of Funds*: A statement that, should the manufacturer fail to show that they are implementing the program consistent with the L&GE replacement program requirements, the manufacturer or merchant shall return to the air district funds in proportion to any loss of emission reductions compared with the projected reductions of the agreement.

7. **Participating Merchant Requirements**. Participating merchants' agreements must include the following:

(A) *Covered Lawn Mowers*: Information about the cordless, zero-emission electric lawn mowers covered by the agreement:

(1) Lawn mower model name.

(2) Lawn mower year of production.

(3) Lawn mower cutting radius.

(4) Lawn mower battery description (voltage).

(5) Estimate of total number of cordless electric lawn mower units covered by the agreement.

(6) The cost of each cordless, electric lawn mower.

(7) The total contract amount, or total contract amount not to exceed.

(8) The date by which the agreement ends.

(9) Lawn mower warranty description.

(B) *Merchant Qualifications*: A statement that the merchant meets the following minimum qualifications for participation in the L&GE replacement program, and shall continue to meet these qualifications throughout its participation in the L&GE replacement program.

(1) Merchant has had a valid business license issued in California for a minimum of the last two years.

(2) Merchant agrees to allow the air district or ARB to inspect cordless, zero-emission electric lawn mowers or audit program records covered under this Agreement during normal business hours.

(C) *Invoice*: A statement that the merchant shall show on the replacement lawn mower invoice the voucher amount. The receipt of voucher funds does not lower the base price of the lawn mower nor does it reduce the tax basis of the lawn mower, but is an incentive to the lawn mower owner that will result in a lower price paid by the participant.

(D) *Average, Banking and Trading Program Exclusion*: A statement that no emission reductions generated by the Moyer Program shall be used as marketable emission reduction credits, or to offset any emission reduction obligation of any person or entity. Therefore, electric lawn mower models included in the agreement are not generating credits by participating in ARB's zero-emission equipment credit averaging, banking and trading program or any similar program.

(E) *Return of Funds*: A statement that, should the merchant fail to show that they are implementing the program consistent with L&GE replacement program requirements, the manufacturer or merchant shall return to the air district funds in proportion to any loss of emission reductions compared with the projected reductions of the agreement.

8. **Participating Recycling Company Requirements**. Participating recycling companies' agreements must include the following:

(A) *Destruction of Lawn Mowers*: A statement that the recycling company shall destroy the lawn mower and engine within 60 days of receipt such that the lawn mower is no longer operable or repairable.

(B) *Receipt of Lawn Mower Destruction*: A statement that the recycling company shall notify the air district that a lawn mower is destroyed by sending the air district a signed receipt indicating the number of lawn mowers destroyed.

D. Emission Benefits

L&GE replacement provides emission benefits by providing lawn mower owners the incentivized option of purchasing a zero-emission lawn mower instead of a higher polluting gasoline lawn mower. Zero-emission lawn mowers are not required by regulation, so the emission benefits are surplus. Emission reductions are the difference in emissions from a new gasoline lawn mower engine and the emissions of a zero-emission lawn mower for the operational lifetime of the zero-emission lawn mower. The average operational lifetime of a replacement zero-emission lawn mower is estimated to be approximately 10 years. L&GE replacement project emission reductions are shown in Table 9-1.

Table 9-1
Gasoline Lawn Mower Emission Reductions (lbs/yr)

Model Year	ROG			NOx	PM10
	Exhaust	Evap	Total	Exhaust	Exhaust
2010	0.290	0.847	1.137	0.071	0.048

CHAPTER 10: INFRASTRUCTURE

Senate Bill 513 (Beall, Chapter 610, Statutes of 2015) provides the Air Resources Board's (ARB) Carl Moyer Memorial Air Quality Standards Attainment Program (Moyer Program) the ability to incorporate infrastructure projects into its program. It authorizes the funding of projects that enable the deployment of alternative, advanced, and cleaner technologies to support the State's air quality goals. Specifically, Health and Safety Code section 44281(c) gives ARB the ability to provide funding toward the installation of fueling or energy infrastructure to fuel or power covered sources. Statute does not require infrastructure projects to meet a cost-effectiveness threshold.

This chapter provides project criteria for selecting and funding infrastructure projects that enable emission reductions in meeting State and local air quality goals. All infrastructure projects must be used to fuel or power a covered source as defined by Health and Safety Code section 44275(a)(7). These covered sources include but are not limited to on-road, off-road, agricultural and marine vessel emission sources.

A. Funding

Air quality management districts or air pollution control districts (air districts) determine project priority and select projects funded within their region.

Table 10-1
Maximum Percentage of Eligible Cost for Moyer Program Infrastructure Projects

Maximum Percentage of Eligible Cost	Infrastructure Projects
50%	All Projects
60%	Publicly Accessible Projects
65%	Projects with Solar/Wind Power Systems[(a)]
75%	Publicly Accessible Projects with Solar/Wind Power Systems[(a)]
100%	Public School Buses - Battery Charging and Alternative Fueling

[(a)] At least 50 percent of the energy provided to covered sources by the project must be generated from solar or wind.

B. Eligible Projects

Eligible projects are those that provide fuel or power to a covered source, and include, but are not limited to, the following:

1. **Battery Charging Station**. New, conversion of existing, and expansion to existing non-residential battery charging stations. (e.g. workplace charging, direct current fast chargers along freeway roadway corridors, long-term charging

at destination areas such as airports and shopping centers, and charging at distribution centers and warehouses).

2. **Alternative Fueling Station**. New, conversion of existing, and expansion to existing hydrogen and natural gas fueling stations.

3. **Stationary Agricultural Pump**. Pump electrification.

4. **Shore Power**. Shore-side electrification.

5. Additional projects may be considered on a case-by-case basis, such as residential battery charging stations for low-income and multi-unit dwellings, as well as infrastructure for transport refrigeration units and truckstop electrification. Please contact ARB Moyer staff for further guidance on these case-by-case projects.

C. Eligible Applicants

Public and private entities are eligible to apply unless otherwise stated. Public entities include but are not limited to State, metropolitan, county, city, multi-county special district (e.g. water district), school district, university, and federal agencies and organizations. Private entities include but are not limited to private organizations and corporations. Out of State applicants are eligible to apply provided that the infrastructure is situated in California.

D. Eligible Costs

Eligible costs are limited to the purchase and installation of the equipment for power delivery or fueling directly related to the infrastructure project. The eligible costs listed below must utilize commercially available technologies.

1. **Eligible project costs include:**

   (A) Cost of design and engineering, (i.e., labor, site preparation, Americans with Disabilities Act accessibility, signage).

   (B) Cost of equipment (e.g., charging/fueling units, electrical parts, energy storage equipment, materials).

   (C) Cost of installation directly related to the construction of the station.

   (D) Meter/data loggers.

   (E) On-site power generation system that fuels or powers covered sources (i.e., solar and wind power generation equipment).

2. **Air districts have the option to fund the following discretionary costs:**

   (A) Federal, sales, and other taxes.

(B) Shipping and delivery costs.

(C) Fees incurred pre-contract execution (i.e., permits, design, engineering, site preparation), license fees, environmental fees, commissioning fees (safety testing), and onsite required safety equipment.

(D) Consulting fees associated with the preparation of Environmental Assessment, Environmental Impact Statement, Environmental Impact Report, or other California Environmental Quality Act (CEQA) documents, etc.

E. Ineligible Costs

Ineligible costs include but are not limited to:

1. Existing station upgrade.

2. Fuel and energy costs.

3. Non-essential equipment hardware.

4. Operation cost (e.g., operational fees, maintenance, repairs, improvements, spare parts).

5. Extended warranty.

6. Insurance.

7. Data collection and reporting.

8. Grantee administrative costs.

9. Travel/lodging.

10. Employee training and salaries.

11. Legal fees.

12. Real estate property purchases/leases.

13. Performance bond costs.

14. Construction management.

15. Storm water plan costs.

16. Security costs.

17. Testing and soil sampling.

18. Hazardous materials, including permitting, handling and disposal.

F. Project Eligibility Criteria

The minimum qualifications for infrastructure projects are listed below. All projects must also conform to the requirements in Chapter 2: General Criteria, and in Chapter 3: Program Administration. Participating air districts retain the authority to impose additional requirements to address local concerns.

1. General Criteria

(A) The project must be installed and located in California.

(B) The project must comply with all applicable federal, State, local laws and requirements including environmental laws, and State building, environmental and fire codes. For instance, air districts may need to perform CEQA review and obtain approval prior to funding a project.

(C) A publicly accessible infrastructure project must be solicited and selected through a competitive bidding process that has been approved by the air district board.

(D) Work must be performed by a licensed contractor.

(E) For projects that contain Moyer Program funding for both infrastructure and engine replacement or repower within the same contract, only the cost of the engine replacement or repower will be considered when performing a cost-effectiveness calculation.

(F) Publicly accessible station must at a minimum be accessible to the public daily during regular business hours.

(G) Equipment and parts must be new. Remanufactured or refurbished equipment and parts are not eligible.

(H) Except for stationary agricultural pump projects, a completed Uniform Commercial Code-1 Financing Statement Form must be submitted by the air district to the California Secretary of State for infrastructure projects with a grant funding amount of $50K or greater. The financing statement must list the air district as the secured party.

2. Battery Charging Station

(A) Chargers must be a level 2 and higher to support non-residential stations.

(B) Publicly accessible light-duty charging stations must use a valid and universally accepted charge connector protocol (e.g. Society of Automotive Engineers (SAE), CHAdeMO).

(C) Charger must be certified by a Nationally Recognized Testing Laboratory (e.g., Underwriter's Laboratories, Intertek) located at https://www.osha.gov/dts/otpca/nrtl/nrtllist.html.

(D) Equipment must have at least a one year warranty.

3. **Stationary Agricultural Pump**. To be eligible for funding, infrastructure must directly power a zero-emission stationary agricultural pump funded by the air district with Moyer Program funds, including match (see Chapter 5 for specific criteria related to funding agricultural pumps).

4. **Shore Power**

(A) Funding is available to install shore-side electrical grid-based power at a berth that receives visits solely by vessels not subject to the control requirements of ARB's Shore Power Regulation (Title 17, California Code Regs., section 93118.3.).

(B) Shore-side projects meeting the eligibility criteria of the Goods Movement Program are eligible for Moyer Program funding only on a case-by-case basis. Moyer Program project funds cannot be co-funded with Proposition 1B Goods Movement Program funds.

5. **Alternative Fueling Station**. Equipment must have at least a three year warranty.

G. Applicant Requirements

1. General Criteria

(A) The applicant must be able to demonstrate to the air district that the applicant can obtain all required land use permits from agencies needed to install and operate the station.

(B) For a publicly accessible station, the applicant must provide a description of the geographic location, including an aerial map (i.e. satellite view from an internet based map or city/county map) and specific street address of the proposed station.

(C) Applicants must demonstrate that they either own the land on which the project will be located, or control it through a long-term lease, easement or other legal arrangement, for the duration of the project life. For a proposed project where the land is not owned by the applicant, an executed lease agreement or letters of commitment lasting for the duration of the project life must be signed by property owners/authorized representatives and must be submitted with the application.

(D) Applicants must be able to provide documentation that power or fuel is being provided to the site (e.g. application, payment to the local utility company for power installation, or contract).

2. Shore Power

(A) Applicants who own/operate at a terminal must submit a copy of the Initial Terminal Plan per Section (g) of ARB's Shore Power Regulation (Title 17, California Code Regs, section 93118.3). All subsequent project reports to air districts must include a copy of the terminal plan in order to evaluate compliance with the project contract.

(B) Only a port authority, terminal operator, or marine vessel owner may apply to receive Moyer Program funding for a shore power project.

H. Project Life

1. All projects must have a minimum project life of three years.

2. Maximum project life is 15 years, except stationary agricultural pump electrification projects which have a maximum project life of ten years.

I. Contract Requirements

1. General Criteria

(A) Contracts must include anticipated usage in terms of projected throughput and/or number of vehicles that will be using the station for the term of the contract.

(B) Contracts must require that the equipment be in operating condition throughout the contract term.

(C) Contracts must specify that publicly accessible infrastructure projects must maintain a 95 percent successful charging rate with 24/7 customer service available on site, via toll free telephone number. Contracts must also specify that if equipment is not functional, the grantee is responsible for ensuring that repairs are made and station is up and running within 48 hours. The grantee must notify air districts of any downtime beyond the 48 hours and work with air districts to ensure publicly accessible stations are operational.

(D) For non-publicly accessible infrastructure projects, contracts must specify that if equipment is not functional, the grantee has 15 business days to report the problem to the air district and begin working with the air district promptly to ensure infrastructure equipment is operational.

(E) Contracts must specify that, if during the project life the fuel/energy meter fails for any reason, the fuel/energy meter must be repaired or replaced as soon as possible and is considered a maintenance expense, therefore not an eligible cost.

(F) Contracts must specify the maximum grant amount.

(G) Contracts must identify milestone dates including project completion, invoice, and annual reporting dates.

2. Battery Charging Station

(A) Contracts must include the number of ports and charging units.

(B) Grantee must report all battery charging station installations to the Department of Energy Alternative Fuel Data Center located at http://www.afdc.energy.gov/locator/stations/.

3. Alternative Fueling Station. For hydrogen fueling stations, grantee must register and report to the Station Online Status System (SOSS) maintained by the California Fuel Cell Partnership (www.cafcp.org). In addition, grantee must abide by the requirements of the reporting system.

J. Post-Inspection

1. General Criteria

(A) Air districts must verify and document that each infrastructure project is operational. Inspections must include verification of operation by connecting a vehicle or equipment to the charging or fueling station, or in the case of an agricultural pump or shore power project, by connecting to the electrical grid. For projects that incorporate solar or wind power, the inspection must verify that infrastructure has been installed and connected to the power generation equipment (i.e. solar panels or wind turbines). Air districts may be exempted from this requirement if the grantee does not own a vehicle/equipment, and no vehicle/equipment can reasonably be obtained for the inspection. Air districts must document such instances and obtain other types of verification that the infrastructure is capable of dispensing fuel/electricity, or in the case of an agricultural pump or shore power project, capable of being powered by the electrical grid.

(B) Air district must take photos of the equipment and keep photos in the project file. At the minimum, the photos must include equipment manufacturers, model number, and serial number.

2. Battery Charging Station. Air district must document the following: Name of manufacturer, serial number and date of manufacture, amperage/voltage, and equipment recharge rate.

K. Invoice and Payment

A project may be considered for final payment once the necessary infrastructure has been installed and connected to the power generation equipment (i.e., solar panels, wind turbine) and/or electricity grid and has been demonstrated to the air district that it is fully operational during a post-inspection.

L. Data Collection and Annual Reporting

1. **Solar or Wind Power Generating Equipment**. For infrastructure projects that incorporate solar or wind power generating equipment, the grantee must annually provide to the air district the amount of electricity generated (e.g. kilowatt-hour) from the solar or wind power generating equipment for the duration of the project life.

2. **Battery Charging Station**. Grantee must annually provide to the air district the following data for the entire project life:

   (A) Qualitative description of public and private uses.

   (B) Annual usage per charger (e.g., kilowatt-hour) and the number of plug-in events.

   (C) Any unscheduled downtime, including duration of downtime and causes of downtime.

3. **Stationary Agricultural Pump**. Grantee must annually provide to the air district the following data for the entire project life:

   (A) Annual usage (e.g., kilowatt-hour) using an energy meter.

   (B) Episodes of electrical service interruption by the local utility company.

4. **Shore Power**. Grantee must annually provide to the air district the following data per berth for the entire project life:

   (A) Total ship visits utilizing berth and ship visits utilizing program funded equipment.

   (B) Annual usage (e.g., kilowatt-hour).

   (C) Episodes of electrical service interruption by the local utility company.

5. **Alternative Fueling Station**. Grantee must annually provide to the air district the following data for the entire project life:

   (A) Annual usage (e.g., kilograms, standard cubic feet).

(B) Any unscheduled downtime, including duration of downtime and causes of downtime.

CARL MOYER PROGRAM 2017 GUIDELINES

APPENDICES

Appendix A: Acronyms

Appendix B: Definitions

Appendix C: Cost-Effectiveness Calculation Methodology

Appendix D: Tables for Emission Reduction and Cost-Effectiveness Calculations

Appendix E: Chapter References

APPENDIX A

ACRONYMS

APPENDIX A: ACRONYMS

AAP	Agricultural Assistance Program
AB	Assembly Bill
ABT	Average Banking and Trading
AC	Alternating Current
ACS	Applicant Cost Share
ADA	Americans With Disabilities
Ah	Amp-hour
APCD	Air Pollution Control District
APCO	Air Pollution Control Officer
APU	Auxiliary Power Unit
AQMD	Air Quality Management District
ARB	Air Resources Board
ASM	Acceleration Simulation Mode
ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
BAR	Bureau of Automotive Repair
bhp	Brake Horsepower
bhp-hr/gal	Brake horsepower-hour per gallon
bhp-hr/yr	Brake horsepower-hour per year
BIT	Biennial Inspection of Terminals
C/E	Cost-Effectiveness
Cal/EPA	California Environmental Protection Agency
CAP	Consumer Assistance Program
CAPCOA	California Air Pollution Control Officers Association
CARL	Clean Air Reporting Log
CCR	California Code of Regulations
CEQA	California Environmental Quality Act
CF	Vessel Registration Number
CFO	Chief Financial Officer
CHC	Commercial Harbor Craft
CHE	Cargo Handling Equipment
CHP	California Highway Patrol
CI	Compression Ignition
CMP	Carl Moyer Memorial Air Quality Standards Attainment Program
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CRF	Capital Recovery Factor
DBA	Doing Business As
DMV	Department of Motor Vehicles
DOE	Department of Energy
DOF	Department of Finance

DOORS	Diesel Off-Road Online Reporting System
DOT	Department of Transportation
DPF	Diesel Particulate Filter
E/S	Electric Standby
EF	Emission Factor
EFMP	Enhanced Fleet Modernization Program
EGR	Exhaust Gas Recirculation
EJ	Environmental Justice
EMFAC	ARB's On-Road Motor Vehicle Emission Inventory Model
EMY	Engine Model Year
EO	Executive Order
EQIP	Environmental Quality Incentives Program
ERCs	Emission Reduction Credits
ES	Emission Standards
ESN	Engine Serial Number
EIN	Equipment Identification Number
EVSE	Electric Vehicle Supply Equipment
FEL	Family Emission Limit
FTA	Federal Transit Administration
FTF	Flow-Through Filter
FY	Fiscal Year
GAAP	Generally Accepted Accounting Principles
g	Gram
g/bhp-hr	Gram per brake horsepower-hour
gal	Gallon
gal/yr	Gallons per year
GHG	Greenhouse Gas
GMERP	Goods Movement Emission Reduction Program
GPS	Geographic Positioning System
GSE	Ground Support Equipment
GVW	Declared Gross Vehicle Weight
GVWR	Gross Vehicle Weight Rating
HC	Hydrocarbons
HD	Heavy-Duty
HDDE	Heavy-Duty Diesel Engine
HDT	Heavy-Duty Truck
HDV	Heavy-Duty Vehicle
HEP	Head End Power Unit
HHD	Heavy Heavy-Duty
HHDV	Heavy Heavy-Duty Vehicle
hp	Horsepower

hr	Hour
H&SC	Health and Safety Code
HVAC	Heating, Ventilation and Air Conditioning
ICE	Internal Combustion Engine
ILD	Idle Limiting Device
IMO	International Maritime Organization
IOU	Investor Owned Utility
IPI	Incentive Program Implementation Team
IRP	International Registration Plan
IRS	Internal Revenue Service
ITR	Innovative Technology Regulation
JPA	Joint Power Authority
kW	Kilowatt
lbs.	Pounds
lbs/bhp-hr	Pounds per brake horsepower-hour
lb/gal	Pound per gallon
lb/hp-hr	Pound per horsepower-hour
L&GE	Lawn and Garden Equipment
LDV	Light-Duty Vehicle
LESBP	Lower-Emission School Bus Program
LETRU	Low Emission Transport Refrigeration Unit
LEV	Low Emission Vehicle
LHD	Light Heavy-Duty
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas – commonly called Propane
LSI	Large Spark Ignition
MEC	Moyer Eligible Cost
MGO	Marine Gas Oil
MHD	Medium Heavy-Duty
MHDV	Medium Heavy-Duty Vehicle
mi	Mile
MIC	Moyer Ineligible Cost
MOU	Memorandum of Understanding
MPC	Moyer Paid Cost
MV Fee	Motor Vehicle Registration Fee
MY	Model Year
NMHC	Non-Methane Hydrocarbons
NFPA	National Fire Protection Association
NOx	Oxides of Nitrogen

OBD II	On-Road Diagnostics, Phase II
OEM	Original Equipment Manufacturer
OIS	On-Board Diagnostic Inspection System
ORVIP	Off-Road Voucher Incentive Program
PG&E	Pacific Gas and Electric
P&P	Policies and Procedures
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PSIP	Periodic Smoke Inspection Program
PTO	Power Take-Off
RAP	Rural District Assistance Program
REC	Remaining Eligible Cost
RFP	Request for Proposals
ROG	Reactive Organic Gas
SAE	Society of Automotive Engineers
SB	Senate Bill
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCR	Selective Catalytic Reduction
SI	Spark Ignition
SRF	Special Revenue Fund
SIP	State Implementation Plan
SMAQMD	Sacramento Metropolitan Air Quality Management District
SOON	Surplus Off-Road Opt-in for NOx Program
STD	Standard
SWCV	Solid Waste Collection Vehicle
TPC	Total Project Cost
TRU	Transport Refrigeration Unit
TRUCRS	Truck Regulations Upload and Compliance Reporting System
TSI	Two Speed Idle
ULETRU	Ultra Low Emission Transport Refrigeration Unit
ULEV	Ultra Low Emission Vehicle
U.S. EPA	United States Environmental Protection Agency
V	Volt
VAVR	Voluntary Accelerated Vehicle Retirement
VDECS	Verified Diesel Emission Control Strategy
VFD	Variable Frequency Device
VIN	Vehicle Identification Number
VIP	Voucher Incentive Program

VOC	Volatile Organic Compound
YR	Year

APPENDIX B

DEFINITIONS

APPENDIX B: DEFINITIONS

Acceleration Simulation Mode: A type of vehicle emissions test conducted with the test vehicle on a chassis dynamometer to simulate on-road acceleration operating conditions.

Administrative Funds: State funds allocated to program support and outreach costs directly associated with implementing the Moyer Program.

Agricultural Assistance Program: A program established by section 39011.5 of the Health and Safety Code (H&SC) providing funds for new purchase, retrofit, repower, or add-on for previously unregulated agricultural equipment.

Air district or District: An air pollution control district or an air quality management district.

Air Pollution Control Officer: The air pollution control officer, executive director, executive officer or designee as determined by each air district.

Airport Ground Support Equipment: Any engine- or motor-powered equipment used for service and support of aircraft operations. Airport ground support equipment (GSE) performs a variety of functions, including but not limited to: aircraft maintenance, pushing or towing aircraft, transporting cargo to and from aircraft, loading cargo, and baggage handling. GSE vehicles include equipment types such as baggage tugs, belt loaders, and cargo loaders.

Applicant Cost Share (ACS): The 15 percent or more of Moyer Eligible Cost (MEC) that is paid by the applicant, except when waived for public entity applicants.

Auxiliary Engine: An engine that is not the propulsion engine but for which the fuel, cooling, and/or exhaust systems are an integral part of the equipment or vehicle.

Auxiliary Power Unit: Any device that provides electrical, mechanical, or thermal energy to the primary diesel engine, truck cab, or sleeper berth as an alternative to idling the primary diesel engine.

Barge: A vessel having a flat-bottomed rectangular hull with sloping ends and built with or without a propulsion engine.

Baseline Technology: Engine technology applied under normal business practices, such as the existing engine in a vehicle or equipment for replacements, repowers, and retrofits.

California's Goods Movement Trade Corridor: The entirety of the South Coast Air Basin, San Joaquin Valley Air Basin, Sacramento Federal Ozone Nonattainment Area, San Francisco Bay Area Air Basin, San Diego County Air District, Imperial County Air District, and Port Hueneme.

Captive Attainment Area Fleet: A fleet or an identified subpart of the fleet (fleet portion, consistent with, California Code of Regulations, title 13, section 2449(d)) in which all of the vehicles in the fleet or fleet portion operate exclusively within the following counties: Alpine, Colusa, Del Norte, Glenn, Humboldt, Lake, Lassen, Mendocino, Modoc, Monterey, Plumas, San Benito, San Luis Obispo, Santa Barbara, Santa Cruz, Shasta, Sierra, Siskiyou, Trinity, Tehama, and Yuba. A fleet or identified fleet portion that operates one or more vehicles outside the counties listed above is not a captive attainment area fleet.

Case-by-Case Determination: A process in which local air districts may request Moyer Program staff to review and approve a project that varies from the specific requirements of these Guidelines only if such approval will not adversely affect the achievement of real, surplus, quantifiable, enforceable and cost-effective emission reductions. See Chapter 3: Program Administration, Section U for additional information.

Certification: A finding by the Air Resources Board (ARB) or the U.S. EPA that a mobile source or emissions control device has satisfied applicable criteria for specified air contaminants.

Charter Fishing Vessel: A vessel for hire by the general public, dedicated to the search for and collection of fish for the purpose of general consumption.

Class 1 Freight Railroad**:** As defined by the Surface Transportation Board (see www.stb.dot.gov<http://www.stb.dot.gov/>). As of January 2017, Union Pacific Railroad (UP), Burlington Northern and Santa Fe Railroad (BNSF), and their subsidiaries are the only Class 1 freight railroads operating in California.

Class 2 Freight Railroad**:** As defined by the Surface Transportation Board (see www.stb.dot.gov<http://www.stb.dot.gov/>). As of January 2017, Arizona and California Railroad, Central Oregon and Pacific Railroad are the only Class 2 freight railroads operating in California.

Class 3 Freight Railroad: As defined by the Surface Transportation Board (see www.stb.dot.gov<http://www.stb.dot.gov/>). Short-line railroads and military and industrial railroads are generally considered Class 3 freight railroads for the purposes of eligibility.

Clean Air Reporting Log (CARL): An on-line database tool maintained by ARB and used by air districts to track and report projects and funds under the Moyer Program.

Commercial Fishing Vessel: A vessel dedicated to the search for and collection of fish to be sold at market or directly to a purchaser.

Commitment: Under Chapter 5, a program milestone in which Moyer Program funds have been designated or applied towards an eligible project approved by the air district board, district air pollution control officer, or other delegated authority.

Competitive Bidding Process: For Moyer Program purposes, the process by which an air district competitively selects publicly accessible infrastructure projects. The process, including selection criteria, must be outlined in the air district solicitation and approved by the air district board.

Conversion of Existing Station: Infrastructure projects in which an existing non-alternative fueling station (i.e. diesel) is converted to an alternative fueling station for hydrogen or natural gas.

Cost-effectiveness: A measure of the dollars provided to a project for each ton of covered emission reduction (H&SC § 44275(a)(4)).

Cost-effectiveness Limit: The maximum amount of funds the Moyer Program will pay per weighted ton of emission reductions, using the methodology in Appendix C.

Covered Emissions: Emissions of oxides of nitrogen, particular matter, and reactive organic gases from any covered source.

Covered Source: On-road vehicles, off-road non-recreational equipment and vehicles, locomotives, marine vessels, agricultural sources of air pollution as defined in Section 39011.5, and, as determined by the State Board, other categories necessary for the State and air districts to meet air quality goals (H&SC § 44275(a)(7)).

Crawler Tractor: A tracked off-road tractor equipped with a substantial metal plate, or blade, as opposed to a bucket on a loader. This equipment is commonly referred to as a track mounted bulldozer and is used to push large quantities of soil, sand, rubble, etc., during construction and mining work. The dozing power of the crawler tractor exceeds that of the rubber tired dozer. A ripper, which is a claw-like device, may be attached to the back of a larger dozer.

Crew and Supply Vessel: A self-propelled vessel used for carrying personnel and/or supplies to and from off-shore and in-harbor locations (including, but not limited to, off- shore work platforms, construction sites, and other vessels).

Deterioration: The increased exhaust emissions over time taking into account wear and tear on engines and emissions control devices.

Deterioration Life: A factor calculated from the period of time the engine has deteriorated, plus half the project life, used to estimate deterioration over the entire project life. DL= project starting year - engine model year + (project life / 2).

Deterioration Product: The result of multiplying the deterioration rate, equipment activity, and the deterioration life for a technology.

Deterioration Rate (DR): Rates that estimate increased emissions of NOx, ROG and PM from engine wear and tear and other variables that increase engine emissions over time. On-road deterioration rates are established by weight class and engine model year, based on values in ARB's on-road emission inventory model (EMFAC2014). Off

road deterioration rates are established by horsepower and either Tier or model year, based on values in ARB category specific inventory models.

DC fast charger: A unit for 200 - 480V Direct-Current (DC) charging up to 200 amps, using an off-board charger that connects directly to the vehicle's battery. Also called DC Level 1 and DC Level 2.

Dredge: A vessel designed to remove debris or earth from the bottom of waterways. Dredges may be built with or without a propulsion engine.

Electric Vehicle Supply Equipment (EVSE): An electrical energy transfer device that conducts and regulates power from the electrical portal connection to the electrical vehicle inlet.

Emission Control System: Any device, system, or element of design that controls or reduces the emissions of regulated pollutants from a vehicle.

Emission Factor (EF): A category specific estimate of emissions per unit of activity. On-road emission factors are based on ARB mobile source emission inventory model (EMFAC2014) values. Off-road emission factors are based on values applied in ARB category specific inventory models.

Enterprise Operator: A person who conducts a voluntary accelerated vehicle retirement enterprise according to the Voluntary Accelerated Vehicle Retirement Regulation (California Code of Regulations, title 13, § 2601 et seq.), purchases vehicles, arranges for a vehicle's permanent removal from operation, and receives any emission reduction credit generated.

Excavator: An engineering vehicle consisting of an upper carriage with hydraulically rotating upper deck (revolving 360º) and attachment, directly mounted to either a wheeled or crawler undercarriage. The front end of the excavator attachment consists either of a bucket, grapple, scrap shear, or another implement.

Excursion Vessel: A self-propelled vessel that transports passengers for purposes including, but not limited to: dinner cruises; harbor, lake, or river tours; scuba diving expeditions; and whale watching tours. Excursion vessels do not include crew and supply vessels, ferries, and recreational vessels.

Executed Contract: A legally binding contract signed by the local air district Air Pollution Control Officer, or other air district designated representative, and the grantee to fund an eligible engine, equipment, or vehicle project that will reduce covered emissions. An executed contract is a program milestone in which parties agree to meet the obligations within the contract by a specified date.

Existing Lawn Mower: A gasoline-fueled, operational lawn mower owned and operated in California by the applicant.

Existing Station Upgrade: Improvements to a battery charging or alternative fueling station without increasing the output capacity.

Expansion to Existing Station: Infrastructure projects that increase the amount of fuel/energy throughput or capacity to fuel/charge equipment/vehicles at current alternative fueling and battery charging stations.

Expend: To make a full or partial payment of Moyer Program funds toward a project invoice for an eligible Moyer Program project.

Farm Equipment: As applied to off-road engines, includes equipment used in agricultural operations as defined in the Regulation for In-Use Off-Road Diesel-Fueled Fleets (California Code of Regulations, title 13, § 2449(c)(1)). As applied to portable and stationary engines, includes the agricultural sources defined in Health and Safety Code section 39011.5.

Federal Funds: Awards of financial assistance to an individual or organization from the U.S. government to carry out a government-authorized purpose, and not provided as personal benefits or assistance from the government.

Family Emission Limit (FEL): An emission level declared by the manufacturer to serve in place of an otherwise applicable emission standard under a federal or State averaging, banking, and trading program.

Ferry: Any self-propelled vessel or boat or owned, controlled, operated, or managed for public use in transportation of carrying passengers, property or vehicles on scheduled services.

Fleet Average Emission Level: The arithmetic mean of the combined hydrocarbon plus oxides of nitrogen emissions for each piece of applicable large spark-ignition engine powered equipment comprising an operator's fleet. For full definition, see California Code of Regulations, title 13, section 2775.

Forklift: Electric Class 1 or 2 rider trucks or large spark-ignition engine powered Class 4, 5 or 6 rider trucks as defined by the Industrial Truck Association. Electric Class 3 trucks are not forklifts for the purposes of these Guidelines. More information can be found at http://www.osha.gov/dcsp/products/etools/pit/forklift/types/classes.html and http://www.indtrk.org.

Freight Locomotive: A locomotive that hauls freight as its primary function.

Funding Amount: The amount of funds dedicated to a contracted project for reporting purposes in CARL; this value may never exceed the grant amount.

Funding Cap: The maximum dollar amount or maximum percentage of Moyer or State funds that may be expended on a project, as specified by source category and limited by variables that include the contribution of other incentive programs, rules, regulations, and incremental cost.

Funding Target: The total funds required to meet a program milestone such as funds executed or liquidated during a funding cycle, for purposes of cumulative tracking and reporting. Funding targets consider regular Moyer Program funds, State Reserve funds, Rural District Assistance Program funds, Moyer voucher program funds, required match funds, interest funds, reallocated funds, recaptured funds, interest and salvage revenues, and other funds associated with the Moyer Program.

Funding Year: The designation given to each year that air districts are awarded Moyer Program funds. Moyer Program grant awards were first made in fiscal year 1998 to 1999; therefore, that year is designated as Year 1; fiscal year 1999 to 2000 is Year 2, etc. Each funding year is associated with set times for achieving program milestones such as contract execution, fund expenditure, and fund liquidation.

Funding Year Adjustment: An addition or subtraction to an air district's project and/or administrative fund amounts in one funding year to account for changes (e.g., recaptured funds, errors) in liquidated funds in an earlier funding year.

Grant Amount: Contracted amount of Moyer funds for a project, which may not exceed the maximum dollar amount or maximum percentage of eligible cost specified by source category and project type.

Glider Kit: A replacement chassis and cab for on-road heavy-duty vehicles. Glider kits are identified with a vehicle identification number starting with the letters "GL".

Gross Vehicle Weight Rating (GVWR): A value specified by the vehicle manufacturer as the maximum design loaded weight of a single vehicle. Examples are shown in Table B-1.

Harbor Craft: (also called "Commercial Harbor Craft") Any private, commercial, government, or military marine vessel including, but not limited to, passenger ferries, excursion vessels, tugboats, ocean-going tugboats, towboats, push-boats, crew and supply vessels, work boats, pilot vessels, supply boats, fishing vessels, research vessels, United States Coast Guard vessels, hovercraft, emergency response harbor craft, and barge vessels that do not otherwise meet the definition of ocean-going vessels or recreational vessels.

Head End Power Unit**:** Most passenger locomotives are equipped with head end power (HEP) or hotel power, an onboard generator typically about a 500 horsepower that provides power to the passenger cars of the train for such functions as heating, lighting and air conditioning.

Heavy-Duty Vehicles (HDV): Trucks and buses in the weight classes shown in Table B-1.

Table B-1
Heavy-Duty Vehicle Classification for Moyer Program On-Road Projects

Vehicle Classification	GVWR
Light Heavy-Duty (LHD)	14,001 to 19,500 pounds
Medium Heavy-Duty (MHD)	19,501 to 33,000 pounds
Heavy Heavy-Duty (HHD)	Over 33,000 pounds

Home Port: The port in which a vessel is registered or permanently based.

Incremental Cost: The cost of the project less a baseline cost that would otherwise be incurred by the applicant in the normal course of business. Incremental costs may include added lease, energy, or fuel costs pursuant to Health and Safety Code section 44283 as well as incremental capital costs.

Interest Revenue: Interest generated from Moyer Program funds held by an air district in interest-bearing accounts. Interest earned on Moyer Program funds becomes Moyer Program funds.

Industrial Tow Tractor: An electric or large spark-ignition engine-powered Class 6 truck as defined by the Industrial Truck Association. They are designed primarily to push or pull non-powered trucks, trailers, or other mobile loads.

Investor Owned Utility: A business providing utility services such as electricity, natural gas, telephone and water services, that is managed privately rather than as a function of a government or public cooperative. Examples are Pacific Gas and Electric, Southern California Edison, and Sempra Energy.

Large Fleet: Under the In-Use Off-Road Diesel-Fueled Fleets Regulation, a fleet with a total maximum power greater than 5,000 horsepower. A fleet must meet large fleet requirements of this regulation if the total vehicles under common ownership or control would be defined as a large fleet. All fleets owned by the United States, the State of California, or agencies thereof (i.e., an agency in the judicial, legislative, or executive branch of the federal or state government) are considered as a unit whole and must meet the large fleet requirements of the In-Use Off-Road Diesel-Fueled Fleets Regulation (California Code of Regulations, title 13, § 2449). Under the Large Spark Ignition Engine Fleet Requirements Regulation, a large fleet is an operator's aggregated operations in California of 26 or more pieces of large spark-ignition equipment.

Lawn and Garden Equipment: Equipment used to maintain lawns and gardens. This equipment is generally, but not exclusively, powered by spark-ignition engines. This equipment is traditionally used in applications such as lawn mowers, edger's, trimmers, leaf blowers, and chainsaws. Equipment that does not fall into this category includes golf carts, specialty vehicles, generators, pumps, and other small utility equipment.

Lawn Mower Exchange Event: An occasion where participants' existing gasoline lawn mowers are exchanged for new cordless, zero-emission electric lawn mowers or vouchers for new, cordless, zero-emission electric lawn mowers.

Level 2: Electric vehicle supply equipment for connection to an on-board vehicle charging system, with 208V–240V alternating-current (AC) charging up to 80 amps.

Line-Haul Locomotive**:** A locomotive powered by an engine or engines typically totaling 4,000 or more horsepower that transports goods between major urban centers.

Liquidate: To spend all moneys for a specified fiscal year to reimburse grantees for valid and eligible project invoices and air district administrative costs. Payments withheld from the grantee by an air district until all contractual reporting requirements are met may be excluded from these amounts for the purposes of liquidation.(H&SC § 44275(a)(12)). For a specific project, liquidation refers to all funded equipment as paid in full and operational.

Local Funds: Monies provided by any unit of local government including a publicly owned utility and Joint Powers Authority (JPA).

Match Funds: Funds under an air district's budget authority that will be applied towards eligible Moyer Program projects in accordance with the matching requirements of the program. See Health and Safety Code section 44287(e) and 44287.2(c).

Maximum Dollar Amount: The maximum amount of funds that may be expended on a project as specified by source category and project type, often to reflect incremental cost.

Maximum Grant Amount: The maximum amount of money a grantee is eligible to receive for a cost-effective Moyer Program project. The maximum grant amount for a project is the lowest of the three following values: (a) the grant amount at the cost-effectiveness limit; (b) the maximum percentage of eligible cost; or (c) any maximum dollar amount specified in the relevant source category chapter.

Maximum Percentage: The maximum percentage of eligible cost that may be expended on a project as specified by source category and project type, often to reflect incremental cost.

Medium Fleet. Under the In-Use Off-Road Diesel-Fueled Fleets Regulation, a fleet with total minimum power of greater than 2,500 horsepower and with a total maximum power less than or equal to 5,000 horsepower. Under the Large Spark Ignition Engine Fleet Requirements Regulation, an operator's aggregated operations in California of 4 to 25 pieces of large spark-ignition equipment.

Memorandum of Agreement (MOA) or Memorandum of Understanding (MOU): A document recording the basic terms of a proposed transaction or setting forth the principles and guidelines under which parties will work together.

Mitigation Funds: Monies received for the compensation for the impacts to the environment from a proposed activity.

Mobile Cargo Handling Equipment: Any motorized vehicle used to handle cargo delivered by ship, train, or truck such as yard trucks, rubber tired gantry cranes, top picks, dozers, and excavators.

Moyer Eligible Cost: Costs associated with projects that are eligible for reimbursement under the Moyer Program, prior to considering the cost-effectiveness limit or any project funding cap restrictions. This includes the sum of Moyer Paid Cost and Remaining Eligible Cost.

Moyer Ineligible Cost: Costs associated with a project that are not eligible under the Moyer Program guidelines, but are eligible project costs under other funding sources.

Moyer Paid Cost: Project costs eligible under the Moyer Program, and are to be paid by the Moyer Program. These costs are used to determine project cost-effectiveness, except in the case of infrastructure projects.

Moyer Program Funds: State funds awarded by ARB to local air districts to implement the Moyer Program, including project and administrative, and interest revenue from the awarded funds, and revenues from salvage of equipment scrapped under the program. Local funds that are under the air district's budget authority may also qualify as Moyer Program funds or match funds (see H&SC § 44287(e)); however, certain limitations apply (see H&SC § 44287(j)).

Nationally Recognized Testing Laboratory: Is a private-sector organization that OSHA has recognized as meeting the legal requirements in 29 CFR 1910.7 to perform testing and certification of products using consensus based test standards.

New Station: Construction of a new battery charging or alternative fueling station where there is currently no station.

Non-forklift fleet: Under the Large Spark Ignition Engine Fleet Requirements Regulation, an operator's aggregated operations in California of four or more sweeper/scrubbers, industrial tow tractors, or pieces of airport ground support equipment, alone or in combination.

Non-Moyer Funds: Project funds from sources other than the Moyer Program, Moyer match funds, and AB 923 $2 DMV fees.

Off-Highway Tractors: Equipment that feature yoke hitches that oscillate four ways to reduce frame stresses. Rugged turn stops prevent excessive wagon rotation in either direction. The rear platform functions as a power train guard providing a safe, stable work area. (These are not off-highway trucks (e.g. articulated trucks or rigid haul trucks) which are bulk-handling machines, such as earthmovers or dump trucks, designed to operate on steep or rough terrain and not designed to drive on-highway.)

Off-Road Compression-Ignition Equipment: A piece of equipment that is powered by an off-road compression-ignition engine which is any internal combustion engine: in or on a piece of equipment that is self-propelled or serves as a dual purpose by both propelling itself and performing another function and is primarily used off the highways (such as garden tractors, off-highway mobile cranes and bulldozers); or in or on a piece of equipment that is intended to be propelled while performing its function (such as lawnmowers and string trimmers); or that, by itself or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of transportability include, but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform that is consistent with California Code of Regulations, title 13 section 2421.

Off-Road Large Spark-Ignition Engine: any engine that produces a gross horsepower of 25 horsepower or greater (greater than 19 kilowatts for 2005 and later model years) or is designed (e.g., through fueling, engine calibrations, valve timing, engine speed modifications, etc.) to produce 25 horsepower or greater (greater than 19 kilowatts for 2005 and later model years) used to propel an off-road piece of equipment. The engine may be designed to use gasoline fuel, liquid petroleum gas, compressed natural gas, methanol fuel, or a combination of these.

Off-Road Large Spark-Ignition Equipment: Equipment that cannot be registered and driven safely on-road or was not designed to be driven on-road. Newer equipment uses engines certified to the off-road spark ignition engine standards. These engines may be designed to use gasoline fuel, liquid petroleum gas (LPG), compressed natural gas, methanol fuel or a combination of these and are most commonly found in forklifts.

Other Applied Funds: Funds that are not local, State, or federal that are used to co-fund a Moyer eligible project.

Operator: A person, corporation, public agency, or other entity that owns, operates or maintains a vehicle, equipment, or installation.

Passenger Locomotive: A locomotive that hauls passengers as its primary function.

Penalty Funds: Funds paid to an enforcing entity as a result of enforcement action brought against a violator of a local, State or federal law, ordinance, regulation or rule.

Pilot Vessel: A vessel designed for, but not limited to, the transfer and transport of maritime pilots to and from oceangoing vessels while such vessels are underway.

Policies and Procedures: An air district manual for local implementation of the Moyer Program. For more information see Chapter 3, Section C.

Power Take-Off (PTO): A secondary engine shaft (or equivalent) that provides substantial auxiliary power for purposes unrelated to vehicle propulsion or normal vehicle accessories such as air conditioning, power steering, and basic electrical accessories. A typical PTO uses a secondary shaft on the engine to transmit power to a hydraulic pump that powers auxiliary equipment.

Program Milestone: A measure of progress toward meeting Moyer Program grant terms or statutory requirements. Examples are contract execution, liquidation and (in Chapter 5) commitment.

Project Life: The period for which the Moyer Program funds surplus emission reductions for a given project.

Project Funds: Moyer Program funds designated for eligible project costs to reduce covered emissions from covered sources.

Propulsion Engine: A marine engine that generates the power to propel a vessel through the water.

Publicly Accessible: An infrastructure project that is available to provide fuel or energy to all members of the general public with no physical access restrictions and no necessity to enter into a contract or sign release of liability.

Public Entity: The State of California, a public university or college, a county, city, district, public authority, public agency, public corporation, another state government, the federal government, or any other subdivision or agency of a state government or the federal government.

Public Fleets: Heavy-duty on-road diesel-fueled vehicles operated by a municipality. A municipality is a city, county, city and county, special district, or a public agency of the State of California, and any department, division, public corporation, or public agency of this State, or two or more entities acting jointly, or the duly constituted body of an Indian reservation or Rancheria.

Public Funds: Funds provided toward project costs by local, State or federal public entities, including grants, rebates and vouchers.

Rail equipment: Non-locomotive equipment designed for use on tracks, such as on-rail vehicles, railcar movers, sweepers, and wheel cranes that have tires or mounted tracks. Equipment that replaces switcher locomotives are considered locomotives for the purposes of the Moyer Program.

Reallocation: A process for allocating mitigation funds and/or returned funds to eligible air districts. See Chapter 3, Section P for additional information.

Rebuilt or Remanufactured: Engines offered by the original engine manufacturer (OEM) or by a non-OEM rebuilder who demonstrates to ARB that the rebuilt engine and parts are functionally equivalent from an emissions and durability standpoint to the OEM engine and components being replaced.

Recaptured Funds: Project funds that are returned by a grantee to an air district or ARB because that grantee did not meet all of its contractual obligations. Air districts must spend these funds on another project in a later funding year.

Reduced Technology: Newer technology that is used by the applicant to obtain surplus emission reductions.

Remaining Eligible Cost: Project costs that are eligible under the Moyer Program but are to be paid by other sources of funding. Remaining eligible costs exist when the Moyer Paid Cost and Applicant Cost Share provide less than 100 percent of the Moyer Eligible Cost.

Remotely Located: Agricultural engines located in a federal ambient air quality area that is designated as unclassifiable or attainment for all PM and ozone national ambient air quality standards and that are located more than one-half mile from any residential area, school, or hospital.

Replacement Lawn Mower: A cordless, zero-emission electric lawn mower.

Repower: A repower is the replacement of the existing engine with an electric motor or a newer emission-certified engine instead of rebuilding the existing engine to its original specifications.

Retrofit: Modifications to the engine and fuel system so that the retrofitted engine does not have the same emissions specifications as the original engine, or the process of installing an ARB-verified emissions control system on an existing engine.

Returned Funds: Funds returned by an air district to ARB for reallocation because they are either not liquidated by the required funding year liquidation deadline, or are associated with an ARB Incentive Program Review mitigation measure.

Rough Terrain Forklift: Class 7 forklifts powered by compression ignition engines and having pneumatic tires that handle uneven surfaces. This includes both straight-mast forklifts and extended-reach forklifts, also called telescopic forklifts or tele-handlers.

Rubber Tired Dozer: A wheeled off-road tractor equipped with a substantial metal plate, or blade as opposed to a bucket on a loader. This equipment is commonly referred to as a rubber tired bulldozer and is used to push large quantities of soil, sand, rubble or other materials during construction and mining work where the traction of a crawler tractor is not required. A ripper, which is a claw-like device, may be attached to the back of a larger dozer.

Rural District Assistance Program: An element of the Moyer Program in which air districts pool their project funds to streamline project outreach, solicitation, and review.

School Bus: Vehicles used for the express purpose of transporting students, kindergarten through grade 12, from home to school, school to home, and to any school sponsored activities.

Shore Power: Electrical power being provided to the ship at berth by either the local utility or by distributed generation.

Skid Steer Loader: A very compact and maneuverable off-road tractor that uses a bucket on the end of movable arms to lift materials and move material such as dirt, debris, building materials, bulk goods, heavy objects, or snow removal. Unlike conventional loaders, the lift arms are alongside the driver with the pivot points behind the driver's shoulders. Skid steer loaders are used in tight spaces and can be equipped with a variety of attachments, such as a hammer, augur, trencher, forklift and other attachments (never greater than 120 horsepower (hp), predominantly 40-75 hp. Skid Steer loaders are often utilized to excavate swimming pools and in landscaping residential backyards.

Small Fleet: In the on-road sector, a fleet size of three or fewer vehicles as defined in the California Code of Regulations, title 13, section 2025(d)(31)(G). Under the In-Use Off-Road Diesel-Fueled Fleets Regulation, a fleet with a total maximum power of less than or equal to 2,500 horsepower that is owned by a business, non-profit organization, or local municipality; or a local municipality fleet in a low population county irrespective of total maximum power; or a non-profit training center irrespective of total maximum power. Under the Large Spark Ignition Engine Fleet Requirements Regulation, an operator's aggregated operations in California of 1 to 3 forklifts and/or 1 to 3 pieces of non-forklift equipment.

Smog Check: the motor vehicle inspection and maintenance program established by California Health and Safety Code Section 44000, et seq.

Solid Waste Collection Vehicle (SWCV): Diesel-fueled vehicles greater than 14,000 pounds GVWR with model year 1960 through 2006 engines used to collect residential and commercial solid waste.

Spark Ignition: A gasoline-fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to a combustion cycle.

State Funds: Funds provided by a State agency for the purpose of co-funding projects under the Moyer Program. State agencies include every State office, department, division, bureau, board, commission, the University of California, and the California State University.

State Implementation Plan: Under the Clean Air Act, the plan submitted by a state that demonstrates attainment or maintenance of an air quality standard through implementation of specified control measures.

Supplemental Environmental Project: An environmentally beneficial project that a violator subject to an enforcement action voluntarily agrees to undertake in a settlement action to offset a portion of an administrative or civil penalty.

Sweeper/scrubber: A large spark-ignition engine-powered piece of industrial floor cleaning equipment designed to brush and vacuum up small debris and litter and then scrub and squeegee the floor.

Switch Locomotive: A locomotive powered by an engine or engines typically totaling less than 2,300 total horsepower, and used to separate and move railcars from track to track or transfer cars to and from regional carriers. All Class 3 railroad locomotives – including all short-line and military and industrial locomotives – are considered switch locomotives for the purposes of the Moyer Program eligibility.

Total Project Cost: The Moyer Eligible Cost and the Moyer Ineligible Cost for vehicles, equipment, engines, accessories, installation and infrastructure within a single Moyer Program project. An applicant may not accept grant funds from all sources that exceed 100 percent of total project cost excluding the Applicant Cost-Share.

Tow Boat: Any self-propelled vessel engaged in or intending to engage in the service of pulling, pushing, or hauling alongside barges or other vessels, or any combination of pulling, pushing, or hauling alongside barges or other vessels.

Transit Fleet Vehicle: On-road vehicles operated by a public transit agency, less than 35 feet in length and 33,000 GVWR, but greater than 8,500 GVWR, powered by heavy- duty engines fueled by diesel or alternative fuel; including service vehicles, tow trucks, dial-a-ride buses, paratransit buses, charter buses, and commuter service buses operated during peak commute hours with ten or fewer stops per day.

Transport Refrigeration Unit (TRU): A refrigeration system powered by an internal combustion engine designed to control the environment of temperature sensitive products transported in trucks and refrigerated trailers. TRUs may be capable of both cooling and heating.

Truck Stop Electrification: The installation at a truck stop of electric power infrastructure and/or external systems that provide heating, cooling, and other energy needs for trucks.

Tug Boat: Any self-propelled vessel engaged in, or intending to engage in, the service of pulling, pushing, maneuvering, berthing, or hauling alongside other vessels, or any combination of pulling, pushing, maneuvering, berthing or hauling alongside such vessels in harbors, over the open seas, or through rivers and canals. Tug boats generally can be divided into three groups: harbor or short-haul tugboats, ocean-going or long-haul tugboats, and barge tugboats. “Tug boat” is interchangeable with “tow boat” and “push boat” when the vessel is used in conjunction with barges.

Tier 1, 2, and 3 Engines: Engines that are subject to California Code of Regulations, title 13, section 2423(b)(1)(A) and/or Code of Federal Regulations, title 40,part 89.112(a). This also includes engines certified under the averaging, banking, and trading program with respect to the Tier 1, 2, and 3 Family Emission Limits (FEL) listed in California Code of Regulations, title 13, section 2423(b)(2)(A) and/or Code of Federal Regulations, title 40, part 89.112(d).

Tier 4 Engine: Engines that are subject to interim or final after-treatment based Tier 4 emission standards in California Code of Regulations, title 13, section 2423(b)(1)(B) and/or Code of Federal Regulations, title 40, part 1039.101. This also includes engines

certified under the averaging, banking, and trading program with respect to the Tier 4 FEL listed in California Code of Regulations, title 13, section 2423(b)(2)(B) and/or Code of Federal Regulations, title 40, part 1039.101. For locomotives, the term refers to the Tier 4 (2015 engine model year) emission standards in the Code of Federal Regulations, title 40, Part 1033.

Uncontrolled Large Spark-Ignition Engines: Means pre-2001 uncertified engines and 2001-2003 certified "non-compliant' large spark-ignition engines.

Urban Bus: A passenger carrying vehicle owned or operated by a public transit agency, powered by a heavy heavy-duty engine, or of a type normally powered by a heavy heavy-duty engine, intended primarily for intra-city operation. The buses are generally greater than 35 feet, and or greater than 33,000 pounds gross vehicle weight rating.

Utility: A privately-owned company that provides the same or similar service for water, natural gas, and electricity as a public utility operated by a municipality.

Voluntary Accelerated Vehicle Retirement Enterprise (VAVR): a privately owned and/or operated business by an enterprise operator.

Verification: A determination by ARB or the U.S. EPA that a diesel emission control strategy meets specified requirements, based on both data submitted and engineering judgement.

Violator: An individual, company, or entity responsible for a violation of an environmental law, regulation or rule.

Voucher Incentive Program (VIP): An air district incentive program using Moyer Program funds to provide a streamlined approach to replace or retrofit older, high-polluting heavy-duty vehicles or equipment with cleaner-than -required vehicles or equipment providing early or extra emission reductions. Funds for VIP projects are used to reduce some of the costs associated with replacing or retrofitting a vehicle.

Workover Rig: Mobile self-propelled rigs used to perform one or more remedial operations on an existing well. The primary function of a workover rig is to act as a hoist so that pipe, sucker rods and down-hole equipment can be run into and out of a well. Operations include deepening, plugging back, or pulling and resetting liners, usually on a producing oil or gas well to try to restore or increase the well's production.

APPENDIX C

COST-EFFECTIVENESS CALCULATION METHODOLOGY

APPENDIX C: COST-EFFECTIVENESS CALCULATION METHODOLOGY

A. Introduction

Cost-effectiveness is the measure of dollars provided to a project for each ton of covered emissions reduced. Statute requires that the Air Resources Board (ARB) update the cost-effectiveness limit and capital recovery factors (CRF) annually. In addition, changes in statute per SB 513 now allow ARB, in consultation with air quality management districts and air pollution control districts (air districts), to establish new cost-effectiveness limits that reflect the cost of regulations and technology.

To determine a project's cost-effectiveness, all Moyer Program funds, air district match funds, and local AB 923 funds must be included. Non-Moyer funds used to co-fund a Moyer eligible project do not need to be included in the cost-effectiveness calculation. Projects that include such funds must meet all Moyer requirements and the other funding source requirements.

Projects are subject to the cost-effectiveness limits in Table C-1, which shows the changes in the cost-effectiveness limit over time based on changes in the Consumer Price Index. Historically, one limit has been applied to all Moyer Program projects. Per SB 513, a second cost-effectiveness limit for school buses was added in 2016 as shown in the table.

Table C-1
Cost-Effectiveness Limit Criteria 1998-2016

Year	Annual CA CPI	Percentage change (inflation rate)	Annual Change	Revised C/E Limit
1998	163.7	NA	NA	$12,000
1999	168.5	2.93%	$352	$12,352
2000	174.8	3.74%	$462	$12,814
2001	181.7	3.95%	$506	$13,319
2002	186.1	2.42%	$323	$13,642
2003	190.4	2.31%	$315	$13,957
2004	195.4	2.63%	$367	$14,324
2005	202.6	3.68%	$528	$14,852
2006	210.5	3.90%	$579	$15,431
2007	217.4	3.28%	$506	$15,938
2008	224.8	3.40%	$541	$16,479
2009	224.1	-0.31%	-$51	$16,428
2010	227.0	1.29%	$212	$16,640
2011	233.0	2.66%	$443	$17,084
2012	238.3	2.25%	$385	$17,469
2013	241.8	1.46%	$255	$17,724
2014	246.1	1.77%	$313	$18,037
2015	249.1	1.25%	$225	$18,262
2016 Base	No C/E update pending 2017 guideline update			$18,262
2016 School Bus	New C/E Limit under SB 513			$276,230

Table C-2 shows the cost-effectiveness limits proposed under the 2017 Guidelines. As shown, two cost-effectiveness limits are now available: one to support conventional projects and a second higher cost-effectiveness limit that air districts may choose to apply to the additional reductions provided by the cleanest engines, including those needed for long-term SIP commitments.

Base Limit: The base cost-effectiveness limit is $30,000 per weighted ton of emissions reductions. This level allows full funding for a wide range of currently typical projects, such as diesel replacement projects for early compliance with the Truck and Bus Regulation. The level is consistent with the cost of compliance with regulations and will enable grants of sufficient size to encourage off-road engines to be replaced or repowered sooner to a Tier 4 standard.

Optional Advanced Technology Limit: For advanced technology projects that are zero-emission, or alternatively meet the cleanest optional standard level certified, air districts have the option to apply a cost-effectiveness limit of up to $100,000 per weighted ton for the emissions reductions beyond those achieved by the required standard. The higher cost-effectiveness limit is not technology or vocation specific, but

available for technologies like the 0.02 g/bhp-hr optional low-NOx engine. To be eligible, the engine must be:

- Zero-emission or meet the cleanest optional emission standard where applicable (0.02 g/bhp-hr in the case of on-road);
- Commercially available and offered for sale; and
- Certified or verified by ARB or the United States Environmental Protection Agency

The higher cost-effectiveness limit is applied only to the incremental emission reductions beyond what the conventional project would achieve. An air district would apply the base cost-effectiveness limit for costs associated with getting engines to the cleanest required standard, and then could apply the advanced technology limit to the additional costs of getting emissions down to or below the cleanest optional standard.

Table C-2
Cost-Effectiveness Limit Criteria 2017

Year	Project	Proposed Change or Status	Revised C/E Limit
2017	Base Limit	New C/E Limit	$30,000
	Optional Advanced Technology Limit	New C/E Limit for incremental reductions from specified advanced technologies	$100,000
	School Bus	2016 C/E Limit retained in 2017 Guidelines	$276,230

For projects in source categories without optional standards, only vehicles certified as zero-emission would be eligible for the higher cost-effectiveness limit. In these cases, the higher limit would apply to the incremental reductions below the most stringent standard for that category. General calculations for determining cost-effectiveness and other calculations needed to administer the Moyer Program are described in the following pages.

B. General Cost-Effectiveness Calculations

1. Determining the Maximum Grant Amount

The calculation methodology below must be applied in order to ensure final grant amounts meet the cost-effectiveness limit requirement, and do not exceed incremental cost based on the maximum percentage or any other funding caps. For advanced technology projects that include a baseline vehicle dirtier than the cleanest required standard, the calculations in (A), (B), and (C) below must be applied twice. The project life may differ between the first and second series of calculations, depending on availability of surplus emission reductions. The first series of calculations is made using the base cost-effectiveness limit and the emission reductions going up to the cleanest required standard (including

deterioration), and the second series of calculations is made using the advanced technology cost-effectiveness limit and the emission reductions beyond the cleanest required standard. The final maximum grant amount is equal to the combined total of the lowest values from each series. Note that school bus projects are subject to funding caps and a separate cost-effectiveness limit as listed above in Table C-2. The maximum grant amount for any given project is the lowest of the three following calculations:

- The potential grant amount at the cost-effectiveness limit;
- The potential grant amount based on maximum percentage of eligible cost; or
- The potential grant amount based on any maximum dollar amount or other funding cap specified in the relevant source category chapter.

Each of the above values is calculated as follows:

(A) The potential grant amount at the cost-effectiveness limit is determined by multiplying the cost-effectiveness limit by the estimated annual emission reductions and dividing by the CRF in formula C-1 below.

Formula C-1: Potential grant amount at the cost-effectiveness limit ($)

Potential grant amount ($) =
*cost-effectiveness limit ($/ton) * estimated annual emission reductions (weighted tons/yr) / CRF*

The CRF is based on a discount rate. The CRF uses an interest rate and project life to determine the rate at which earnings could reasonably be expected to accrue if the same funds were invested over that length of time. The CRF may be calculated using Formula C-2 below, or you may refer to Tables D-24 and D-25 in Appendix D for CRFs at various project lives. Each source category chapter will specify which project lives are acceptable to determine which CRF value to use.

Formula C-2: Capital recovery factor

Capital recovery factor =
*(1 + discount rate[(a)]) ^ project life * discount rate /((1 + discount rate) ^ project life - 1)*

[(a)] Discount rate varies from year to year. See Tables D-24 and D-25 in Appendix D for CRF values at a one percent and two percent discount rate, respectively.

(1) Calculating the Annual Weighted Surplus Emission Reductions

Annual weighted surplus emission reductions are calculated using Formula C-3 below. Note that particulate matter (PM) is weighted by a factor of 20.

Formula C-3: Annual weighted surplus emission reductions (weighted tons/yr)

Weighted emission reductions (weighted tons/yr) =
*NOx reductions (tons/yr) + ROG reductions (tons/yr) + (20 * PM reductions (tons/yr))*

The result of Formula C-3 is used to complete Formula C-1 to determine the potential grant amount at the cost-effectiveness limit, as well for Formula C-14 to determine the cost-effectiveness if not at the limit.

In order to determine the annual surplus emission reductions by pollutant, Formula C-4, C-5, C-6, C-7,or C-8 below must be completed for each pollutant (NOx, ROG, and PM), for the baseline technology and the reduced technology. Formula C-4 is the general calculation and can be applied to any project, whereas Formulas C-5, C-6, C-7 and C-8 are specific variations of Formula C-4 for use with mileage, hours of operation, fuel use, and shore power systems, respectively.

All five fomulas involve multiplying the engine emission factor (found in Appendix D) by the annual activity level and by other adjustment factors (such as load factor in the case of off-road equipment calculations) as specified for the calculation methodologies presented. Emission factors are also adjusted to account for in-use deterioration where applicable.

Formula C-4: Estimated annual emissions (tons/yr)

Annual emissions by pollutant (tons/yr) =
*(emission factor + deterioration product (if applicable)) * annual activity * adjustment factor(s) (if applicable) * percentage operation in California / 907,200 (g/ton)*

Deterioration product =
*deterioration rate * total equipment activity*

Total equipment activity =
*annual activity * deterioration life (yrs)*

Deterioration life (baseline equipment) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced equipment) (yrs) =
project life / 2

The Moyer Program allows the emission reductions from a project to be calculated using a variety of methods, but mileage and hours of operation are the primary methods. Specific activity factors allowed for each project category may differ and are identified in the source category chapters.

a. Calculating Annual Emissions Based on Annual Miles Traveled

Calculations based on annual miles traveled are used for on-road projects only. Mileage records must be maintained by the engine owner as described in Chapter 4: On-Road Heavy-Duty Vehicles. Formula C-5 below describes the method for calculating pollutant emissions based on miles traveled, including the method for calculating mile-based deterioration products.

Formula C-5: Estimated annual emissions based on mileage (tons/yr)

Annual emissions by pollutant (tons/yr) =
*(emission factor (g/mi) + deterioration product (g/mi) (if applicable)) * annual activity (mi/yr) * percentage operation in California / 907,200 (g/ton)*

Mile-based deterioration product (g/mi) =
*deterioration rate (g/mi-10,000 mi) * total equipment activity (mi)*

Total equipment activity[(b)] (mi) =
*annual activity (mi/yr) * deterioration life (yrs)*

Deterioration life (baseline equipment) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced equipment) (yrs) =
project life / 2

[(b)] Total equipment activity for mile-based calculations is limited to 400,000 miles for school buses or 800,000 miles for other on-road vehicles. Used heavy heavy-duty replacement vehicles add 500,000 miles, medium heavy-duty vehicles add 250,000 miles, or light heavy-duty vehicles add 150,000 miles.

b. Calculating Annual Emissions Based on Hours of Operation

When hours of equipment operation are the basis for determining emissions, the horsepower rating of the engine and an engine load factor found in Appendix D must be used. The method for calculating emissions based on hours of operation is described in Formula C-6 below, and includes the method for calculating hour-based deterioration product.

Formula C-6: Estimated annual emissions based on hours of operation (tons/yr)

Annual emissions by pollutant (tons/yr) =
*(emission factor (g/bhp-hr) + deterioration product (g/bhp-hr) (if applicable)) * horsepower (hp) * load factor * annual activity (hrs/yr) * percentage operation in California / 907,200 (g/ton)*

Hour-based deterioration product (g/bhp-hr) =
*deterioration rate (g/bhp-hr-hr) * total equipment activity (hrs)*

Total equipment activity[(c)] (hrs) =
*annual activity (hrs/yr) * deterioration life (yrs)*

Deterioration life (baseline equipment) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced equipment) (yrs) =
project life / 2

The engine load factor is an indicator of the nominal amount of work done by the engine for a particular application. It is given as a fraction of the rated horsepower of the engine and varies with engine application. Load factors for a variety of equipment types may be found in Appendix D.

c. Calculating Annual Emissions Based on Fuel Consumption

In some cases as outlined in each source category chapter, fuel consumption may be used to calculate annual emissions. In such cases a fuel consumption rate factor must be used to convert

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[(c)] Total equipment activity for hour-based calculations is limited to a maximum of 12,000 hours for diesel engines, 3,500 hours for large-spark ignition (LSI) engines with a model year of 2006 or older, or 5,000 hours for LSI engines with a model year of 2007 or newer.

emissions given in g/bhp-hr to units of grams of emissions per gallon of fuel used (g/gal). The fuel consumption rate factor is a number that combines the effects of engine efficiency and the energy content of the fuel used in that engine into an approximation of the amount of work output by an engine for each unit of fuel consumed. Formula C-7 below is used to calculate the annual emissions based on annual fuel consumed.

Formula C-7: Estimated annual emissions based on fuel consumption (tons/yr)

Annual emissions by pollutant (tons/yr) =
*emission factor (g/bhp-hr) * fuel consumption rate factor (bhp-hr/gal) * annual activity (gal/yr) * percentage operation in California / 907,200 (g/ton)*

d. Calculating Annual Emissions for Shore Power Systems

For marine shore power systems, calculate the estimated annual emissions by pollutant as shown in Formula C-8 below.

Formula C-8: Estimated annual emissions for shore power systems (tons/yr)

Annual emissions by pollutant (tons/yr) =
ship emission factor (g/kW-hr) * power requirements (kW) * berthing time (hrs/visit) * annual number of visits (visits/yr) * 0.9 / 907,200 (g/ton)

(2) Calculating Annual Surplus Emission Reductions by Pollutant

Subtract the annual emissions for the reduced technology from the annual emissions for the baseline technology as shown in Formula C-9 below, for NO_x, ROG and PM emissions.

Formula C-9: Annual surplus emission reductions (tons/yr)

Annual surplus emission reductions by pollutant (tons/yr) =
annual emissions for the baseline technology (tons/yr) –
annual emissions for the reduced technology (tons/yr)

For marine vessels with a wet exhaust system, a wet exhaust factor of 0.80 must be applied; calculate the annual surplus emission reductions as shown in Formula C-10 below.

Formula C-10: Annual surplus emission reductions for marine vessels with wet exhaust systems (tons/yr)

*Annual surplus emission reductions by pollutant (tons/yr) = 0.80 * (annual emissions for the baseline technology (tons/yr) – annual emissions for the reduced technology (tons/yr))*

For retrofits, multiply the baseline technology pollutant emissions by the percentage of emission reductions that the ARB-verified reduced technology is verified to following Formula C-11 below.

Formula C-11: Annual surplus emission reductions for retrofits (tons/yr)

*Annual surplus emission reductions by pollutant (tons/yr) = annual emissions for the baseline technology (tons/yr) * reduced technology verification percentage*

For on-road heavy-duty projects, the baseline will be the newer vehicle emissions.

For marine vessel hybrid systems, calculate the annual surplus emission reductions as shown in Formula C-12 below.

Formula C-12: Annual surplus emission reductions for marine vessel hybrid systems (tons/yr)

*Annual surplus emission reductions by pollutant (tons/yr) = total annual emissions (all engines on vessel) for the baseline technology (tons/yr) – (total annual emissions (all engines on vessel) for the baseline technology (tons/yr) * reduced technology verification percentage)*

For marine vessels, calculate the annual surplus emission reductions for each pollutant as shown in Formula C-13 below.

Formula C-13: Total annual surplus emission reductions for marine vessels (tons/yr)

*Total annual surplus emission reductions for marine vessels by pollutant (tons/yr) = (propulsion engine annual surplus emission reductions (tons/yr) * number of propulsion engines) + (auxiliary engine annual surplus emission reductions (tons/yr) * number of auxiliary engines)*

(B) The potential grant amount based on maximum percentage of eligible cost is a measure of the incremental cost as determined by multiplying the cost of the reduced technology by the maximum percentage of eligible cost (from the applicable chapter) as described in Formula C-14 below.

Formula C-14: Potential grant amount based on maximum percentage of eligible cost ($)

Potential grant amount ($) =
*cost of reduced technology ($) * maximum percentage of eligible cost*

(C) The potential grant amount based on any maximum dollar amount or other funding cap is specified in the relevant source category chapter

2. Calculating Two for One Projects

In Two for One equipment replacement projects, two baseline technology equipment are replaced with one reduced technology equipment. First, calculate the emission reduction benefits based on activity for each baseline engine separately using Formulas C-4, C-5, C-6, C-7, or C-8. These emission reductions will then be summed together before deducting the emission reduction benefits of the reduced technology using Formula C-9. See the sample calculations supplemental document for an example on this calculation methodology.

3. Calculating Split Project Life Projects

Split Project Life: Split Project Life Projects must use a separate project life for the two baseline technology scenarios. First, Formulas C-4, C-5, C-6, C-7, or C-8 must be used to calculate emission reduction by pollutant for the two baseline scenarios:

(A) Baseline technology to phase 1 reduced technology
(B) Phase 1 reduced technology to phase 2 reduced technology

Formula C-3 is used to calculate the annual emission reductions for each baseline technology. Next, a fraction of the project life must be applied to the annual emission reductions for each of the baseline scenarios, as outlined below in Formula C-15.

Formula C-15: Split project life

Total annual weighted surplus emission reductions (tons/yr) =
*(fraction project life (yrs) * annual weighted surplus emissions from transaction 1 (tons/yr) /*
*total project life (yrs)) + (fraction project life (yrs) **
annual weighted surplus emissions from transaction 2 (tons/yr) / total project life (yrs))

Total annual weighted surplus emission reductions (tons/yr) =
$(n_1 * a_1 / t) + (n_2 * a_2 / t)$
where:
n_1 = *fraction project life from transaction 1 (yrs)*
n_2 = *fraction project life from transaction 2 (yrs)*
a_1 = *annual weighted surplus emissions from transaction 1 (tons/yr)*
a_2 = *annual weighted surplus emissions from transaction 2 (tons/yr)*
t = total project life (yrs)

4. Calculating the Applicant Cost Share

Moyer eligible costs are costs associated with a project that are eligible for reimbursement under the program prior to considering the cost-effectiveness limit or any project cap restrictions. Guidance on these costs is contained in Chapters 2, 3, and the applicable chapter for the Moyer project. The applicant cost share is determined by multiplying the Moyer eligible cost by 15 percent, as described in Formula C-16 below. Applicant cost share is determined from the Moyer eligible costs, but the value itself is not an ineligible Moyer cost. A public entity applicant may other use public funds toward meeting this requirement.

Formula C-16: Applicant cost share ($)

Applicant cost share ($) ≥
*15 percent * Moyer eligible costs ($)*

5. Calculation for Co-funding Moyer Funds with Other Sources

Air districts must request information from grantee to determine what other funds will be used toward the project. This information will be utilized to ensure that the applicant is not overpaid for the project by adding the Applicant Cost Share contribution and the grants paid toward the project, as shown in Formula C-17 below and comparing against the total project cost value. The total project cost includes both Moyer eligible and Moyer ineligible costs. Refer to Chapters 2 and 3 for additional criteria and guidance related to co-funding projects.

Formula C-17: Project overpayment check ($)

Total project cost ≥
applicant cost share ($) + ∑grants paid ($)

If the total project cost is exceeded then adjustments must be made to ensure the project applicant is not overpaid for the project.

6. Calculating the Cost-Effectiveness of a Grant Amount

The cost-effectiveness of a grant amount is determined by multiplying the CRF as calculated in Formula C-18 by the grant amount, and dividing that by the annual weighted surplus emission reductions that will be achieved by the project as calculated in Formula C-3.

Formula C-18: Cost-effectiveness of weighted surplus emission reductions ($/tons)

Cost-effectiveness ($/tons) =
*grant amount ($) * CRF / annual weighted surplus emission reductions (weighted tons/yr)*

C. List of Formulas

The necessary formulas to calculate the cost-effectiveness of surplus emission reductions for a project funded through the Moyer Program are provided below.

Formula C-1: Potential grant amount at the cost-effectiveness limit ($)

Potential grant amount ($) =
*cost-effectiveness limit ($/ton) * estimated annual emission reductions (weighted tons/yr) /CRF*

Formula C-2: Capital recovery factor (CRF)

Capital recovery factor =
*(1 + discount rate[(d)]) ^ project life * discount rate* /((1 + discount rate*) ^ project life - 1)*

Formula C-3: Annual weighted surplus emission reductions (weighted tons/yr)

Weighted emission reductions (weighted tons/yr) =
*NO_x reductions (tons/yr) + ROG reductions (tons/yr) + (20 * PM reductions (tons/yr))*

Formula C-4: Estimated annual emissions (tons/yr)

Annual emission by pollutant (tons/yr) =
*(emission factor + deterioration product (if applicable)) * annual activity * adjustment factor(s) * percentage operation in California / 907,200 (g/ton)*

Deterioration product =
*deterioration rate * total equipment activity*

Total equipment activity =
*annual activity * deterioration life (yrs)*

Deterioration life (baseline) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced) (yrs) =
project life / 2

(d) *Discount rate varies from year to year. See Tables D-24 and D-25 in Appendix D for CRF values at a 1 percent and 2 percent discount rate, respectively.*

Formula C-5: Estimated annual emissions based on mileage (tons/yr)

Annual emissions by pollutant (tons/yr) =
*(emission factor (g/mi) + deterioration product (g/mi) (if applicable)) * annual activity (mi/yr) * percentage operation in California / 907,200 (g/ton)*

Mile-based deterioration product (g/mi) =
*deterioration rate (g/mi-10,000 mi) * total equipment activity (mi)*

Total equipment activity[(e)] (miles) =
*annual activity (mi/yr) * deterioration life (yrs)*

Deterioration life (baseline) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced) (yrs) =
project life / 2

Formula C-6: Estimated annual emissions based on hours of operation (tons/yr)

Annual emissions by pollutant (tons/yr) =
*(emission factor (g/bhp-hr) + deterioration product (g/bhp-hr) (if applicable)) * horsepower (hp) * load factor * annual activity (hrs/yr) * percentage operation in California / 907,200 (g/ton)*

Hour-based deterioration product (g/bhp-hr) =
*deterioration rate (g/bhp-hr-hr) * total equipment activity (hrs)*

Total equipment activity[(f)] (hrs) =
*annual activity (hrs/yr) * deterioration life (yrs)*

Deterioration life (baseline) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced) (yrs) =
project life / 2

[(e)] Total equipment activity for mile-based calculations is limited to 400,000 miles for school buses or 800,000 miles for other on-road vehicles. Used heavy heavy-duty replacement vehicles add 500,000 miles, medium heavy-duty vehicles add 250,000 miles, or light heavy-duty vehicles add 150,000 miles.

[(f)] Total equipment activity for hour-based calculations is limited to a maximum of 12,000 hours for diesel engines, 3,500 hours for large-spark ignition (LSI) engines with a model year of 2006 or older, or 5,000 hours for LSI engines with a model year of 2007 or newer.

Formula C-7: Estimated annual emissions based on fuel consumption (tons/yr)

Annual emissions by pollutant (tons/yr) =
*Emission factor (g/bhp-hr) * fuel consumption rate factor (bhp-hr/gal) * annual activity (gal/yr) * percentage operation in California / 907,200 (g/ton)*

Formula C-8: Estimated annual emissions for shore power systems (tons/yr)

Annual emissions by pollutant (tons/yr) =
*Ship emission factor (g/kW-hr) * power requirements (kW) * berthing time (hrs/visit) * annual number of visits (visits/yr) * 0.9 / 907,200 (g/ton)*

Formula C-9: Annual surplus emission reductions (tons/yr)

Annual surplus emission reductions by pollutant (tons/yr) =
annual emissions for the baseline technology (tons/yr) –
annual emissions for the reduced technology (tons/yr)

Formula C-10: Annual surplus emission reductions for marine vessels with wet exhaust systems (tons/yr)

Annual surplus emission reductions by pollutant (tons/yr) =
*0.80 * (annual emissions for the baseline technology (tons/yr) –*
annual emissions for the reduced technology (tons/yr))

Formula C-11: Annual surplus emission reductions for retrofits (tons/yr)

Annual surplus emission reductions by pollutant (tons/yr) =
*annual emissions for the baseline technology (tons/yr) **
reduced technology verification percentage

Formula C-12: Annual surplus emission reductions for marine vessel hybrid systems (tons/yr)

Annual surplus emission reductions by pollutant (tons/yr) =
total annual emissions (all engines on vessel) for the baseline technology (tons/yr) –
*(total annual emissions (all engines on vessel) for the baseline technology (tons/yr) **
reduced technology verification percentage)

Formula C-13: Total annual surplus emission reductions for marine vessels (tons/yr)

*Total annual surplus emission reductions for marine vessels by pollutant (tons/yr) = (propulsion engine annual surplus emission reductions (tons/yr) * number of propulsion engines) + (auxiliary engine annual surplus emission reductions (tons/yr) * number of auxiliary engines)*

Formula C-14: Potential grant amount based on maximum percentage of eligible cost ($)

*Incremental cost ($) = cost of reduced technology ($) * maximum percentage of eligible cost*

Formula C-15: Split project life

*Total annual weighted surplus emission reductions (tons/yr) = (fraction project life (yrs) * annual weighted surplus emissions from transaction 1 (tons/yr) / total project life (yrs)) + (fraction project life (yrs) * annual weighted surplus emissions from transaction 2 (tons/yr) / total project life (yrs))*

Total annual weighted surplus emission reductions (tons/yr) =
$(n_1 * a_1 / t) + (n_2 * a_2 / t)$
where:
n_1 = *fraction project life from transaction 1 (yrs)*
n_2 = *fraction project life from transaction 2 (yrs)*
a_1 = *annual weighted surplus emissions from transaction 1 (tons/yr)*
a_2 = *annual weighted surplus emissions from transaction 2 (tons/yr)*
t = *total project life (yrs)*

Formula C-16: Applicant cost share ($)

Applicant cost share ($) ≥ 15 percent * moyer eligible costs ($)

Formula C-17: Project overpayment check ($)

Total project cost ≥ applicant cost share ($) + ∑grants paid ($)

Formula C-18: Cost-effectiveness of weighted surplus emission reductions ($/ton)

*Cost-effectiveness ($/ton) = grant amount ($) * CRF / annual weighted surplus emission reductions (weighted tons/yr)*

APPENDIX D

TABLES FOR EMISSION REDUCTION AND COST-EFFECTIVENESS CALCULATIONS

APPENDIX D:

TABLES FOR EMISSION REDUCTION AND COST-EFFECTIVENESS CALCULATIONS

This appendix presents tables summarizing the data needed to calculate the emission reductions and cost-effectiveness of potential projects. Included are data such as engine emission factors, load factors, and other conversion factors used in the calculations discussed in Appendix C: Cost-Effectiveness Calculation Methodology.

	Table Number
Heavy-Duty On-Road Projects	D-1 to D-6
Off-Road Diesel and Non-Mobile Agricultural (Ag) Projects	D-7 to D-9
Large Spark-Ignition (LSI) Projects	D-10 to D-13
Locomotive Projects	D-14a to D-14b
Marine Projects	D-15a to D-20
All Engines – Fuel Consumption	D-21
Reference Tables	D-22 to D-25

Table D-1
Heavy-Duty Vehicles
14,001-33,000 pounds (lbs) Gross Vehicle Weight Rating (GVWR)
Emission Factors (g/mile)[a] (EF) and Deterioration Rates (g/mile-10k miles) (DR)

Engine Model Year	NOx[b]		ROG[b],[c]		PM[b],[i]	
	EF[d]	DR[e]	EF[d]	DR[e]	EF[d]	DR[e]
Pre-1987	14.52	0.031	0.89	0.051	0.713	0.0283
1987-90	14.31	0.041	0.70	0.060	0.774	0.0252
1991-93	10.70	0.054	0.37	0.031	0.425	0.0193
1994-97	10.51	0.063	0.27	0.036	0.241	0.0129
1998-02	10.33	0.072	0.28	0.036	0.266	0.0116
2003-06	6.84	0.071	0.23	0.021	0.175	0.0067
2007-09	3.99	0.090	0.18	0.007	0.014	0.0008
2007+[f] (0.21-0.50 g/bhp-hr NOx FEL)	1.27	0.079	0.06	0.002	0.002	0.0001
2010-12 (0.20 g/bhp-hr NOx std)	1.03	0.079	0.06	0.002	0.002	0.0001
2013+[g] (0.20 g/bhp-hr NOx std)	1.03	0.045	0.06	0.001	0.002	0.0001
2016+[h] (0.10 g/bhp-hr NOx std)	0.52	0.023	0.06	0.001	0.002	0.0001
2016+[h] (0.05 g/bhp-hr NOx std)	0.26	0.011	0.06	0.001	0.002	0.0001
2016+[h] (0.02 g/bhp-hr NOx std)	0.10	0.005	0.06	0.001	0.002	0.0001

[a] EMFAC 2014 Zero-Mile Based Emission Factors. Factors are based on diesel engines. Same factors used for alternative fuel engines due to limited alternative fuel data in EMFAC.
[b] Emission factors incorporate the ultra low-sulfur diesel fuel correction factors listed in Table D-22. NOx – Oxides of nitrogen, ROG – Reactive Organic Gases, PM – Particulate Matter.
[c] EMFAC provides HC emission factors which are converted into ROG. ROG = HC * 1.26639.
[d] Emission Factors are based on zero-mile rates contained in EMFAC 2014.
[e] Deterioration Rate per 10,000 miles.
[f] All model year 2007 and newer engines with Family Emission Limits (FEL) from 0.21 g/bhp-hr to 0.50 g/bhp-hr NOx must use different emission factors from those listed for model years 2010 and newer engines certified to 0.20 g/bhp-hr NOx standards. FEL emission factors are based on EMFAC factors for model year 2010-2012 engines that include weighted averaging of 0.5, 0.35, and 0.20 g/bhp-hr NOx standards based on sales.
[g] Deterioration rates for 2013+ engines incorporate use of on-board diagnostic system.
[h] Factors for 2016+ engines are reduced values of 2013 factors by 50 percent, 75 percent, and 90 percent to correspond with 0.10 g/bhp-hr NOx, 0.05 g/bhp-hr NOx, and 0.02 g/bhp-hr NOx optional low NOx standards.
[i] Factors for 2006 or older engines are for unfiltered trucks.

Table D-2
Heavy-Duty Vehicles
Over 33,000 pounds (lbs) GVWR
Emission Factors (g/mile)[a] (EF) and Deterioration Rates (g/mile-10k miles) (DR)

Engine Model Year	NOx[b]		ROG[b],[c]		PM[b],[i]	
	EF[d]	DR[e]	EF[d]	DR[e]	EF[d]	DR[e]
Pre-1987	21.37	0.018	1.38	0.031	1.260	0.0200
1987-90	21.07	0.024	1.08	0.037	1.369	0.0178
1991-93	18.24	0.037	0.78	0.027	0.574	0.0104
1994-97	17.92	0.043	0.58	0.031	0.377	0.0080
1998-02	17.61	0.049	0.60	0.031	0.415	0.0073
2003-06	11.66	0.049	0.49	0.018	0.267	0.0041
2007-09	6.80	0.077	0.39	0.007	0.022	0.0006
2007+[f] (0.21-0.50 g/bhp-hr NOx FEL)	2.17	0.068	0.13	0.002	0.004	0.0001
2010-12 (0. 2 g/bhp-hr NOx std)	1.76	0.068	0.13	0.002	0.004	0.0001
2013+[g] (0. 2 g/bhp-hr NOx std)	1.76	0.039	0.13	0.001	0.004	0.0001
2016+[h] (0.10 g/bhp-hr NOx std)	0.88	0.019	0.13	0.001	0.004	0.0001
2016+[h] (0.05 g/bhp-hr NOx std)	0.44	0.010	0.13	0.001	0.004	0.0001
2016+[h] (0.02 g/bhp-hr NOx std)	0.18	0.004	0.13	0.001	0.004	0.0001

[a] EMFAC 2014 Zero-Mile Based Emission Factors. Factors are based on diesel engines. Same factors used for alternative fuel engines due to limited alternative fuel data in EMFAC.
[b] Emission factors incorporate the ultra low-sulfur diesel fuel correction factors listed in Table D-22.
[c] EMFAC provides HC emission factors which are converted into ROG. ROG = HC * 1.26639.
[d] Emission Factors are based on zero-mile rates contained in EMFAC 2014.
[e] Deterioration Rate are per 10,000 miles.
[f] All model year 2007 and newer engines with Family Emission Limits (FEL) from 0.21 g/bhp-hr to 0.50 g/bhp-hr NOx must use different emission factors from those listed for model years 2010 and newer engines certified to 0.20 g/bhp-hr NOx standards. FEL emission factors are based on EMFAC factors for model year 2010-2012 engines that include weighted averaging of 0.5, 0.35, and 0.20 g/bhp-hr NOx standards based on sales.
[g] Deterioration rates for 2013+ engines incorporate use of on-board diagnostic system.
[h] Factors for 2016+ engines are reduced values of 2013 factors by 50 percent, 75 percent, and 90 percent to correspond with 0.10 g/bhp-hr NOx, 0.05 g/bhp-hr NOx, and 0.02 g/bhp-hr NOx optional low NOx standards, respectively.
[i] Factors for 2006 or older engines are for unfiltered trucks.

Table D-3
Diesel Urban Buses
Emission Factors (g/mile)[a]

Engine Model Year	NOx[b]	ROG[b],[c]	PM[b],[e]
Pre-1987	42.97	1.88	0.929
1987-1990	37.39	1.87	0.878
1991-1993	23.72	1.84	0.835
1994-1995	27.71	1.81	1.015
1996-1998	36.46	1.81	1.217
1999-2002	18.97	1.81	0.417
2003	13.02	0.77	0.084
2004-2006	3.56	0.08	0.084
2007+ (0.20 g/bhp-hr NOx std)	1.90	0.03	0.011
2016+[d] (0.10 g/bhp-hr NOx std)	0.95	0.03	0.011
2016+[d] (0.05 g/bhp-hr NOx std)	0.47	0.03	0.011
2016+[d] (0.02 g/bhp-hr NOx std)	0.19	0.03	0.011

[a] EMFAC 2014 Zero-Mile Based Emission Factors.
[b] Emission factors incorporate the ultra low-sulfur diesel fuel correction factors listed in Table D-22.
[c] EMFAC provides HC emission factors which are converted into ROG. ROG = HC * 1.26639.
[d] Factors for 2016+ engines are reduced values of 2007 factors by 50 percent, 75 percent, and 90 percent to correspond with 0.10 g/bhp-hr NOx, 0.05 g/bhp-hr NOx, and 0.02 g/bhp-hr NOx optional low NOx standards, respectively.
[e] Factors for 2006 or older engines are for unfiltered trucks.

Table D-4
Alternative Fuel Urban Buses
Emission Factors (g/mile)[a]

Engine Model Year	NOx	ROG[b]	PM[d]
Pre-2003	21.60	2.68	0.043
2003-06	15.40	3.87	0.023
2007+ (0.20 g/bhp-hr NOx std)	0.65	0.04	0.001
2016+[c] (0.10 g/bhp-hr NOx std)	0.33	0.04	0.001
2016+[c] (0.05 g/bhp-hr NOx std)	0.16	0.04	0.001
2016+[c] (0.02 g/bhp-hr NOx std)	0.07	0.04	0.001

[a] EMFAC 2014 Zero-Mile Based Emission Factors.
[b] EMFAC provides HC emission factors which are converted into ROG.
ROG (Pre-2007 engines) = HC * 0.16137.
ROG (2007+ engines) = HC * 0.013972.
[c] Factors for 2016+ engines are reduced values of 2007 factors by 50 percent, 75 percent, and 90 percent to correspond with 0.10 g/bhp-hr NOx, 0.05 g/bhp-hr NOx, and 0.02 g/bhp-hr NOx optional low NOx standards, respectively.
[d] Factors for 2006 or older engines are for unfiltered trucks.

Table D-5
Diesel Refuse Trucks
Emission Factors (g/mile)[a]

Engine Model Year	NOx[b]	ROG[b],[c]	PM[b],[g]
pre-1994	34.69	0.01	0.346
1994-97	31.53	0.01	0.137
1998-02	31.25	0.01	0.144
2003-06	21.39	0.01	0.086
2007-09	11.25	0.14	0.008
2007+[d] (0.21-0.50 g/bhp-hr NOx FEL)	1.23	0.26	0.008
2010+[e] (0.20 g/bhp-hr NOx std)	1.09	0.04	0.008
2016+[f] (0.10 g/bhp-hr NOx)	0.54	0.04	0.008
2016+[f] (0.05 g/bhp-hr NOx)	0.27	0.04	0.008
2016+[f] (0.02 g/bhp-hr NOx)	0.11	0.04	0.008

Note: These emission factors are not applicable to transfer trucks. Transfer trucks must use the emission factors from Table D-1 or D-2. Per EMFAC 2014, solid waste collection vehicles are considered to be well-maintained and have negligible deterioration which is why only zero-mile emission factors are to be used in calculations for solid waste collection vehicle projects.

(a) EMFAC 2014 Zero-Mile Based Emission Factors.
(b) Emission factors incorporate the ultra low-sulfur diesel fuel correction factors listed in Table D-22.
(c) EMFAC provides HC emission factors which are converted into ROG. ROG = HC * 1.26639.
(d) All model year 2007 and newer engines with Family Emission Limits (FEL) from 0.21 g/bhp-hr to 0.50 g/bhp-hr NOx must use different emission factors from those listed for model years 2010 and newer engines certified to 0.20 g/bhp-hr NOx standards. FEL emission factors are based on EMFAC factors for model year 2010-2012 engines that include weighted averaging of 0.5, 0.35, and 0.20 g/bhp-hr NOx standards based on sales.
(e) These 2010+ emission factors are based only on engines certified to the 0.20 g/bhp-hr NOx standard.
(f) Factors for 2016+ engines are reduced values of 2013 factors by 50 percent, 75 percent, and 90 percent to correspond with 0.10 g/bhp-hr NOx, 0.05 g/bhp-hr NOx, and 0.02 g/bhp-hr NOx optional low NOx standards, respectively.
(g) Factors for 2006 or older engines are for unfiltered trucks.

Table D-6
Alternative Fuel Refuse Trucks
Emission Factors (g/mile)[a]

Engine Model Year	NOx	ROG[b]	PM[d]
Pre-2007	53.20	9.86	0.091
2007-09	18.80	3.68	0.004
2010+ (0.20 g/bhp-hr NOx std)	0.88	0.14	0.004
2016+[c] (0.10 g/bhp-hr NOx)	0.44	0.14	0.004
2016+[c] (0.05 g/bhp-hr NOx)	0.22	0.14	0.004
2016+[c] (0.02 g/bhp-hr NOx)	0.09	0.14	0.004

Note: These emission factors are not applicable to transfer trucks. Transfer trucks must use the emission factors from Table D-1 or D-2. Per EMFAC 2014, solid waste collection vehicles are considered to be well-maintained and have negligible deterioration which is why only zero-mile emission factors are to be used in calculations for solid waste collection vehicle projects.

[a] EMFAC 2014 Zero-Mile Based Emission Factors.
[b] EMFAC provides HC emission factors which are converted into ROG.
ROG (Pre-2007 engines) = HC * 0.16137.
ROG (2007+ engines) = HC * 0.013972.
[c] Factors for 2016+ engines are reduced values of 2010 factors by 50 percent, 75 percent, and 90 percent to correspond with 0.10 g/bhp-hr NOx, 0.05 g/bhp-hr NOx, and 0.02 g/bhp-hr NOx optional low NOx standards, respectively.
[d] Factors for 2006 or older engines are for unfiltered trucks.

Table D-7
Off-Road Diesel Engines Default Load Factors

Category	Equipment Type	Load Factor
Airport Ground Support	Aircraft Tug	0.54
	Air Conditioner	0.75
	Air Start Unit	0.90
	Baggage Tug	0.37
	Belt Loader	0.34
	Bobtail	0.37
	Cargo Loader	0.34
	Cargo Tractor	0.36
	Forklift	0.20
	Ground Power Unit	0.75
	Lift	0.34
	Passenger Stand	0.40
	Service Truck	0.20
	Other Ground Support Equipment	0.34
Agricultural (Mobile, Portable or Stationary)	Agricultural Mowers	0.43
	Agricultural Tractors	0.70
	Balers	0.58
	Combines/Choppers	0.70
	Chippers/Stump Grinders	0.73
	Generator Sets	0.74
	Hydro Power Units	0.48
	Irrigation Pump	0.65
	Shredders	0.40
	Sprayers	0.50
	Swathers	0.55
	Tillers	0.78
	Other Agricultural	0.51
Construction	Air Compressors	0.48
	Bore/Drill Rigs	0.50
	Cement & Mortar Mixers	0.56
	Concrete/Industrial Saws	0.73
	Concrete/Trash Pump	0.74
	Cranes	0.29
	Crawler Tractors	0.43
	Crushing/Process Equipment	0.78
	Excavators	0.38
	Graders	0.41

Table D-7
Off-Road Diesel Engines Default Load Factors
(Continued)

Category	Equipment Type	Load Factor
Construction	Off-Highway Tractors	0.44
	Off-Highway Trucks	0.38
	Pavers	0.42
	Other Paving	0.36
	Pressure Washer	0.30
	Rollers	0.38
	Rough Terrain Forklifts	0.40
	Rubber Tired Dozers	0.40
	Rubber Tired Loaders	0.36
	Scrapers	0.48
	Signal Boards	0.78
	Skid Steer Loaders	0.37
	Surfacing Equipment	0.30
	Tractors/Loaders/Backhoes	0.37
	Trenchers	0.50
	Welders	0.45
	Other Construction Equipment	0.42
Industrial	Aerial Lifts	0.31
	Forklifts	0.20
	Sweepers/Scrubbers	0.46
	Other General Industrial	0.34
	Other Material Handling	0.40
Logging	Fellers/Bunchers	0.71
	Skidders	0.74
Oil Drilling	Drill Rig	0.50
	Lift (Drilling)	0.60
	Swivel	0.60
	Workover Rig (Mobile)	0.50
	Other Workover Equipment	0.60
Cargo Handling	Container Handling Equipment	0.59
	Cranes	0.20
	Excavators	0.55
	Forklifts	0.30
	Other Cargo Handling Equipment	0.51
	Sweeper/Scrubber	0.68
	Tractors/Loaders/Backhoes	0.55
	Yard Trucks	0.39
Other	All	0.43

Table D-8
Uncontrolled Off-Road Diesel Engines
Emission Factors (g/bhp-hr) (EF) and Deterioration Rates (g/bhp-hr-hr) (DR)

Horsepower	Model Year	NOx		ROG		PM10	
		EF	DR	EF	DR	EF	DR
25-49	Pre-1988	6.51	0.000098	1.68	0.000210	0.547	0.0000424
	1988+	6.42	0.000097	1.64	0.000210	0.547	0.0000424
20-119	Pre-1988	12.09	0.00028	1.31	0.000061	0.605	0.0000440
	1988+	8.14	0.00019	0.90	0.000042	0.497	0.0000361
120+	Pre-1970	13.02	0.00030	1.20	0.000056	0.554	0.0000403
	1970-1979	11.16	0.00026	0.91	0.000042	0.396	0.0000288
	1980-1987	10.23	0.00024	0.80	0.000037	0.396	0.0000288
	1988+	7.60	0.00018	0.62	0.000029	0.274	0.0000199

Table D-9
Controlled Off-Road Diesel Engines
Emission Factors (g/bhp-hr) (EF) and Deterioration Rates (g/bhp-hr-hr) (DR) [a]

Horsepower	Tier	NOx		ROG		PM10	
		EF	DR	EF	DR	EF	DR
25-49	1	5.26	0.0000980	1.32	0.000170	0.480	0.0000372
	2	4.63	0.0000930	0.22	0.000050	0.280	0.0000218
	4 (Interim)	4.55	0.0000950	0.09	0.000036	0.128	0.0000096
	4 (Final)	2.75	0.0000570	0.09	0.000036	0.009	0.0000010
50-74	1	6.54	0.0001500	0.90	0.000042	0.552	0.0000402
	2	4.75	0.0000710	0.17	0.000025	0.192	0.0000141
	3[b]	2.74	0.0000360	0.09	0.000023	0.192	0.0000141
	4 (Interim)	2.74	0.0000360	0.09	0.000023	0.112	0.0000080
	4 (Final)	2.74	0.0000360	0.09	0.000023	0.009	0.0000009
75-99	1	6.54	0.0001500	0.90	0.000042	0.552	0.0000402
	2	4.75	0.0000710	0.17	0.000025	0.192	0.0000141
	3	2.74	0.0000360	0.09	0.000023	0.112	0.0000080
	4 (Phase-Out)	2.74	0.0000360	0.09	0.000030	0.009	0.0000009
	4 (Phase-In or Alt. NOx)	2.15	0.0000270	0.08	0.000021	0.009	0.0000009
	4 (Final)	0.26	0.0000035	0.05	0.000015	0.009	0.0000009
100-174	1	6.54	0.0001500	0.62	0.000029	0.304	0.0000221
	2	4.15	0.0000600	0.15	0.000023	0.128	0.0000094
	3	2.32	0.0000300	0.09	0.000030	0.112	0.0000080
	4 (Phase-Out)	2.32	0.0000300	0.09	0.000030	0.009	0.0000004
	4 (Phase-In or Alt. NOx)	2.15	0.0000270	0.08	0.000020	0.009	0.0000004
	4 (Final)	0.26	0.0000040	0.05	0.000011	0.009	0.0000004

Table D-9
Controlled Off-Road Diesel Engines
Emission Factors (g/bhp-hr) (EF) and Deterioration Rates (g/bhp-hr-hr) (DR) [(a)]
(Continued)

Horsepower	Tier	NOx		ROG		PM10	
		EF	DR	EF	DR	EF	DR
175-299	1	5.93	0.0001400	0.29	0.000013	0.120	0.0000064
	2	4.15	0.0000600	0.11	0.000022	0.088	0.0000046
	3	2.32	0.0000300	0.09	0.000023	0.088	0.0000046
	4 (Phase-Out)	2.32	0.0000300	0.09	0.000023	0.009	0.0000003
	4 (Phase-In or Alt. NOx)	1.29	0.0000170	0.06	0.000017	0.009	0.0000003
	4 (Final)	0.26	0.0000036	0.05	0.000011	0.009	0.0000003
300-750	1	5.93	0.0000990	0.29	0.000010	0.120	0.0000064
	2	3.79	0.0000500	0.09	0.000023	0.088	0.0000044
	3	2.32	0.0000300	0.09	0.000023	0.088	0.0000044
	4 (Phase-Out)	2.32	0.0000300	0.09	0.000023	0.009	0.0000003
	4 (Phase-In or Alt. NOx)	1.29	0.0000170	0.06	0.000017	0.009	0.0000003
	4 (Final)	0.26	0.0000036	0.05	0.000011	0.009	0.0000003
751+	1	5.93	0.0000990	0.29	0.000010	0.120	0.0000064
	2	3.79	0.0000500	0.09	0.000023	0.088	0.0000044
	4 (Interim)	2.24	0.0000280	0.06	0.000017	0.051	0.0000021
	4 (Final)	2.24	0.0000280	0.05	0.000011	0.017	0.0000009

Note: Engines participating in the “Tier 4 Early Introduction Incentive for Engine Manufacturers” program per California Code of Regulations, Title 13, section 2423(b)(6) are eligible for funding provided the engines are certified to the final Tier 4 emission standards. The Air Resources Board (ARB) Executive Order indicates engines certified under this provision. The emission rates for these engines shall be equivalent to the emission factors associated with Tier 3 engines.

Note: For equipment with baseline engines certified under the flexibility provisions per California Code of Regulations, Titles 13, section 2423(d), baseline emission rates shall be determined by using the previous applicable emission standard or Tier for that engine model year and horsepower rating. The ARB Executive Order indicates engines certified under this provision.

[(a)] Emission factors were converted using the ultra low-sulfur diesel fuel correction factors listed in Table D-23.
[(b)] Alternate compliance option.

Table D-10
Off-Road LSI Equipment Default Load Factors

Category	Equipment Type	Load Factor
Agriculture (Mobile, Portable or Stationary)	Agricultural Tractors	0.62
	Balers	0.55
	Combines/Choppers	0.74
	Chipper/Stump Grinder	0.78
	Generator Sets	0.68
	Sprayers	0.50
	Swathers	0.52
	Pumps	0.65
	Other Agricultural Equipment	0.55
Airport Ground Support	A/C Tug	0.80
	Baggage Tug	0.55
	Belt Loader	0.50
	Bobtail	0.55
	Cargo Loader	0.50
	Forklift	0.30
	Ground Power Unit	0.75
	Lift	0.50
	Passenger Stand	0.59
	Other Ground Support Equipment	0.50
Construction	Air Compressors	0.56
	Asphalt Pavers	0.66
	Bore/Drill Rigs	0.79
	Concrete/Industrial Saws	0.78
	Concrete/Trash Pump	0.69
	Cranes	0.47
	Gas Compressor	0.85
	Paving Equipment	0.59
	Pressure Washer	0.85
	Rollers	0.62
	Rough Terrain Forklifts	0.63
	Rubber Tired Loaders	0.54
	Skid Steer Loaders	0.58
	Tractors/Loaders/Backhoes	0.48

Table D-10
Off-Road LSI Equipment Default Load Factors
(Continued)

Category	Equipment Type	Load Factor
Construction	Trenchers	0.66
	Welders	0.51
	Other Construction	0.48
Industrial	Aerial Lifts	0.46
	Forklifts	0.30
	Sweepers/Scrubbers	0.71
	Other Industrial	0.54

Table D-11a
Off-Road LSI Engines
Emission Factors (g/bhp-hr) (EF) and Deterioration Rates (g/bhp-hr-hr) (DR)
Gasoline

Horsepower	Model Year	NOx		ROG		PM10	
		EF	DR	EF	DR	EF	DR
25-50	Uncontrolled pre-2004	8.01	0.0000406	3.760	0.000412	0.060	0.000
	Controlled 2001 - 2006	1.33	0.0004710	0.710	0.000169	0.060	0.000
	Controlled 2007 - 2009	0.89	0.0001192	0.473	0.000064	0.060	0.000
	Controlled 2010+	0.27	0.0000250	0.142	0.000013	0.060	0.000
51-120	Uncontrolled Pre-2004	11.84	0.0000601	2.630	0.000287	0.060	0.000
	Controlled 2001 – 2006	1.78	0.0002070	0.260	0.000081	0.060	0.000
	Controlled 2007 - 2009	1.17	0.0000660	0.130	0.000074	0.060	0.000
	Controlled 2010+	0.35	0.0000300	0.030	0.000014	0.060	0.000
121+	Uncontrolled pre-2004	12.94	0.0001270	1.610	0.000042	0.060	0.000
	Controlled 2001 – 2006	1.94	0.0002780	0.160	0.000102	0.060	0.000
	Controlled 2007 - 2009	1.17	0.0000660	0.130	0.000074	0.060	0.000
	Controlled 2010+	0.35	0.0000300	0.030	0.000014	0.060	0.000

Table D-11b
Off-Road LSI Engines
Emission Factors (g/bhp-hr) (EF) and Deterioration Rates (g/bhp-hr-hr) (DR)
Alternative Fuels

Horsepower	Model Year	NOx		ROG		PM10	
		EF	DR	EF	DR	EF	DR
25-50	Uncontrolled pre-2004	13.00	0.0000662	1.380	0.000151	0.060	0.000
	Controlled 2001 - 2006	1.95	0.0002760	0.140	0.000106	0.060	0.000
	Controlled 2007 - 2009	1.30	0.0000011	0.093	0.000172	0.060	0.000
	Controlled 2010+	0.39	0.0000002	0.028	0.000036	0.060	0.000
51-120	Uncontrolled pre-2004	10.53	0.0000533	1.550	0.000169	0.060	0.000
	Controlled 2001 – 2006	1.58	0.0003500	0.160	0.000103	0.060	0.000
	Controlled 2007 - 2009	1.04	0.0000125	0.100	0.000047	0.060	0.000
	Controlled 2010+	0.31	0.0000380	0.030	0.000014	0.060	0.000
121+	Uncontrolled pre-2004	10.51	0.0001040	1.380	0.000035	0.060	0.000
	Controlled 2001 – 2006	1.58	0.0002640	0.140	0.000106	0.060	0.000
	Controlled 2007 - 2009	1.04	0.0000125	0.100	0.000047	0.060	0.000
	Controlled 2010+	0.31	0.0000380	0.030	0.000014	0.060	0.000

Table D-12
Emission Factors for Off-Road LSI Engine Retrofits
Verified to Absolute Emission Number (g/bhp-hr)

Manufacturers of LSI retrofit systems may verify to a percentage emission reduction or absolute emissions. If a retrofit system is verified to a percentage reduction, the emission factors will be that verified percentage of the appropriate emissions factors in Table D-11a or D-11b. If a retrofit system is verified to an absolute emission number, when calculating emission reductions use the following table for the emission factors and the deterioration rate for the baseline engine.

Fuel	Verified Value	NOx	ROG	PM10
Gasoline	3.0	1.78	0.26	0.060
	2.5	1.48	0.22	0.060
	2.0	1.19	0.17	0.060
	1.5	0.89	0.13	0.060
	1.0	0.59	0.09	0.060
	0.6	0.35	0.03	0.060
	0.5	0.29	0.03	0.060
Alt Fuel	3.0	1.58	0.16	0.060
	2.5	1.32	0.13	0.060
	2.0	1.05	0.11	0.060
	1.5	0.79	0.08	0.060
	1.0	0.53	0.05	0.060
	0.6	0.31	0.03	0.060
	0.5	0.26	0.03	0.060

Table D-13a
Off-Road LSI Engines Certified to Optional Standards
Emission Factors (g/bhp-hr) (EF) and Deterioration Rates (g/bhp-hr-hr) (DR)
Gasoline

Horsepower	Optional Standard	NOx		ROG		PM10	
		EF	DR	EF	DR	EF	DR
25-50	0.4	0.18	0.000017	0.09	0.0000087	0.060	0.000
	0.2	0.09	0.000008	0.05	0.0000043	0.060	0.000
	0.1	0.04	0.000005	0.02	0.0000027	0.060	0.000
51-120	0.4	0.24	0.000021	0.04	0.0000034	0.060	0.000
	0.2	0.12	0.000010	0.02	0.0000017	0.060	0.000
	0.1	0.06	0.000005	0.01	0.0000009	0.060	0.000
121+	0.4	0.26	0.000022	0.02	0.0000017	0.060	0.000
	0.2	0.13	0.000011	0.01	0.0000009	0.060	0.000
	0.1	0.06	0.000005	0.01	0.0000009	0.060	0.000

Table D-13b
Off-Road LSI Engines Certified to Optional Standards
Emission Factors (g/bhp-hr) (EF) and Deterioration Rates (g/bhp-hr-hr) (DR)
Alternative Fuels

Horsepower	Optional Standard	NOx		ROG		PM10	
		EF	DR	EF	DR	EF	DR
25-50	0.4	0.26	0.000022	0.02	0.0000017	0.060	0.000
	0.2	0.13	0.000011	0.01	0.0000009	0.060	0.000
	0.1	0.07	0.000006	0.00	0.0000000	0.060	0.000
51-120	0.4	0.21	0.000031	0.02	0.0000030	0.060	0.000
	0.2	0.11	0.000015	0.01	0.0000013	0.060	0.000
	0.1	0.05	0.000007	0.01	0.0000013	0.060	0.000
121+	0.4	0.21	0.000034	0.01	0.0000016	0.060	0.000
	0.2	0.11	0.000015	0.01	0.0000013	0.060	0.000
	0.1	0.05	0.000010	0.00	0.0000000	0.060	0.000

LOCOMOTIVES

Table D-14a
Locomotive Emission Factors (g/bhp-hr)
Based on 1998 Federal Standards

Engine Model Year	Type	NOx[(a)]	ROG[(b)]	PM10[(a)]
Pre-1973	Line-haul and Passenger	12.22	0.51	0.275
	Switcher	16.36	1.06	0.378
1973-2001 Tier 0	Line-haul and Passenger	8.93	1.05	0.516
	Switcher	13.16	2.21	0.619
2002-2004 Tier 1	Line-haul and Passenger	6.96	0.58	0.387
	Switcher	10.34	1.26	0.464
2005-2011 Tier 2	Line-haul and Passenger	5.17	0.32	0.172
	Switcher	7.61	0.63	0.206

Note: These factors are to be used for the project baseline emissions if the baseline locomotive is certified or required to be certified to the 1998 federal locomotive remanufacture standards, and for the reduced emission locomotive if the project locomotive is remanufactured to these 1998 standards. Factors are based upon Regulatory Impact Analysis: Final United States Environmental Protection Agency (U.S. EPA) Locomotive Regulation (2008).

[(a)] NOx and PM10 emission factors have been adjusted by a factor of 0.94 and 0.86, respectively, to account for use of California ultra-low sulfur diesel fuel.
[(b)] ROG = HC * 1.053

Table D-14b
Locomotive Emission Factors (g/bhp-hr)
Based on 2008 Federal Standards

Engine Model Year	Type	NOx[(a)]	ROG[(b)]	PM10[(a)]
1973-2001 Tier 0+	Line-haul and Passenger	6.96	0.58	0.189
	Switcher	11.09	2.21	0.224
2002-2004 Tier 1+	Line-haul and Passenger	6.96	0.58	0.189
	Switcher	10.34	1.26	0.224
2005-2011 Tier 2+	Line-haul and Passenger	5.17	0.32	0.086
	Switcher	7.61	0.63	0.112
2011-2014 Tier 3	Line-haul and Passenger	5.17	0.32	0.086
	Switcher	4.70	0.63	0.086
2015 Tier 4	Line-haul and Passenger	1.22	0.15	0.026
	Switcher	1.22	0.15	0.026

Note: These factors are to be used for the project baseline emissions if the baseline locomotive is certified or required to be certified to the new (2008) federal locomotive remanufacture standards, and for the reduced emission locomotive if the project locomotive is remanufactured to the new standards or meets Tier 3 standards. Factors are based upon Regulatory Impact Analysis: Final U.S. EPA Locomotive Regulation (2008).

[(a)] NOx and PM10 emission factors have been adjusted by a factor of 0.94 and 0.86, respectively, to account for use of California ultra-low sulfur diesel fuel.

[(b)] ROG = HC * 1.053

Table D-15a
Uncontrolled Harbor Craft Propulsion Engine
Emission Factors (g/bhp-hr)

Horsepower	Model Year	NOx	ROG	PM10
25-50	All	7.57	1.32	0.520
51-120	pre-1997	14.27	1.04	0.575
	1997+	9.70	0.71	0.524
121-250	pre-1971	15.36	0.95	0.527
	1971-1978	14.27	0.79	0.451
	1979-1983	13.17	0.72	0.376
	1984+	12.07	0.68	0.376
251+	pre-1971	15.36	0.91	0.506
	1971-1978	14.27	0.76	0.431
	1979-1983	13.17	0.68	0.363
	1984-1994	12.07	0.65	0.363
251-750	1995+	8.97	0.49	0.260
751+	1995+	12.07	0.60	0.363

Table D-15b
Controlled Harbor Craft Propulsion Engine
Emission Factors (g/bhp-hr)

Horsepower	Tier	NOx	ROG	PM10
25-50	1	6.93	1.30	0.580
	2	5.04	1.30	0.240
	3	5.04	1.30	0.176
51-120	1	6.93	0.71	0.524
	2	5.04	0.71	0.240
	3	5.04	0.71	0.176
121-175	1	8.97	0.49	0.290
	2	4.84	0.49	0.176
	3	3.60	0.49	0.077
176-750	1	8.97	0.49	0.290
	2	4.84	0.49	0.120
	3	3.87	0.49	0.068
751-1900	1	8.97	0.49	0.290
	2	5.24	0.49	0.160
	3	3.87	0.49	0.068
1901+	1	8.97	0.49	0.290
	2	5.24	0.49	0.160
	3	4.14	0.49	0.085

Table D-16
Tier 4 Harbor Craft Propulsion Engine
Emission Standards (g/bhp-hr)
(Not applicable for engines using FEL or ABT for compliance)

Model Year	Horsepower	Tier	NOx	ROG	PM10
2016+	805-4960	4	1.34	0.142	0.030

Table D-17a
Uncontrolled Harbor Craft Auxiliary Engine
Emission Factors (g/bhp-hr)

Horsepower	Model Year	NOx	ROG	PM10
25-50	all	6.42	1.58	0.460
51-120	pre-1997	12.09	1.23	0.508
	1997+	8.14	0.85	0.417
121-250	pre-1971	13.02	1.13	0.466
	1971-1978	12.09	0.94	0.399
	1979-1983	11.16	0.86	0.333
	1984-1995	10.23	0.82	0.333
	1996+	7.75	0.59	0.255
251-750	pre-1971	13.02	1.08	0.448
	1971-1978	12.09	0.90	0.381
	1979-1983	11.16	0.81	0.321
	1984-1994	10.23	0.77	0.321
	1995+	7.60	0.58	0.230
751+	pre-1971	13.02	1.08	0.448
	1971-1978	12.09	0.90	0.381
	1979-1986	11.16	0.81	0.321
	1987-1998	10.23	0.72	0.321
	1999+	7.75	0.58	0.255

Table D-17b
Controlled Harbor Craft Auxiliary Engine
Emission Factors (g/bhp-hr)

Horsepower	Tier	NOx	ROG	PM10
25-50	1	6.54	1.54	0.511
	2	5.04	1.54	0.240
	3	5.04	1.54	0.176
51-120	1	6.93	0.85	0.464
	2	5.04	0.85	0.240
	3	5.04	0.85	0.176
121-175	1	6.93	0.58	0.255
	2	4.84	0.58	0.176
	3	3.60	0.58	0.077
176-750	1	6.93	0.58	0.255
	2	4.84	0.58	0.120
	3	3.78	0.58	0.068
751-1900	1	6.93	0.58	0.255
	2	5.24	0.58	0.160
	3	3.87	0.58	0.068
1901+	1	6.93	0.58	0.255
	2	5.24	0.58	0.160
	3	4.14	0.58	0.085

Table D-18
Harbor Craft Load Factors

Vessel Type	Propulsion Engine	Auxiliary Engine
Charter Fishing	0.52	0.43
Commercial Fishing	0.27	
Ferry/Excursion	0.42	
Pilot	0.51	
Tow	0.68	
Work	0.45	
Other	0.52	
Barge/Dredge	0.45	0.65
Crew & Supply	0.38	0.32
Tug	0.50	0.31

Table D-19
Shore Power
Default Emission Rates (Grams per kilowatt-hour (g/kW-hr))

Pollutant	Emission Rate
NOx	13.09
ROG	0.49
PM10 (marine gas oil fuel with 0.11- 0.5 % sulfur content)	0.38
PM10 (marine gas oil fuel with <= 0.10 % sulfur content)	0.25

Table D-20
Shore Power
Default Power Requirements

Ship Category	Ship Size / Type Default (Twenty-foot Equivalent Unit (TEU))	Power Requirement (kW)
Container Vessel	<1,000	1,000
	1,000 – 1,999	1,300
	2,000 – 2,999	1,600
	3,000 – 3,999	1,900
	4,000 – 4,999	2,200
	5,000 – 5,999	2,300
	6,000 – 6,999	2,500
	7,000 – 7,999	2,900
	8,000 – 9,999	3,300
	10,000 – 12,000	3,700
Passenger Vessel	No Default Value – Use Actual Power Requirement[(a)]	
Reefer	Break Bulk	1,300
	Fully containerized	3,300

[(a)] The average power requirement for passenger vessels is 7,400 kW (ARB Oceangoing Vessel Survey, 2005).

ALL ENGINES

Table D-21
Fuel Consumption Rate Factors (bhp-hr/gal)

Category	Horsepower/Application	Fuel Consumption Rate
Non-Mobile Agricultural Engines	ALL	17.5
Locomotive	Line Haul and Passenger (Class I/II)	20.8
	Line Haul and Passenger (Class III)	18.2
	Switcher	15.2
Other	< 750 hp	18.5
	≥ 750 hp	20.8

REFERENCES

The information in these tables has already been incorporated into the preceding emission factor tables. These tables are included for informational purposes.

Table D-22
Fuel Correction Factors
On-Road Diesel Engines

Model Year	NOx	PM10	HC
Pre- 2007	0.93	0.72	0.72
2007+	0.93	0.80	0.72

Table D-23
Fuel Correction Factors
Off-Road Diesel Engines

Model Year	NOx	PM10	HC
Pre-Tier 1	0.930	0.720	0.720
Tier 1 – Tier 3	0.948	0.800	0.720
Tier 4	0.948	0.852	0.720

Table D-24
Capital Recovery Factor (CRF) for Various Project Lives
At a 1% Discount Rate

Project Life	CRF
1	1.010
2	0.508
3	0.340
4	0.256
5	0.206
6	0.173
7	0.149
8	0.131
9	0.117
10	0.106
11	0.096
12	0.089
13	0.082
14	0.077
15	0.072
16	0.068
17	0.064
18	0.061
19	0.058
20	0.055

Table D-25
Capital Recovery Factor (CRF) for Various Project Lives
At a 2% Discount Rate[a][b]

Project Life	CRF
1	1.020
2	0.515
3	0.347
4	0.263
5	0.212
6	0.179
7	0.155
8	0.137
9	0.123
10	0.111
11	0.102
12	0.095
13	0.088
14	0.083
15	0.078
16	0.074
17	0.070
18	0.067
19	0.064
20	0.061

[a] Upon ARB approval of the 2017 Moyer Program Guidelines, the discount rate is one percent. Per statute ARB reviews and may update discount rates annually, using the average rates of return for U.S. Treasury securities and the California Consumer Price Index data available at the time of publication.

[b] The Discount Rate varies from year to year, and may increase beyond 2 percent. The formula used to calculate the CRF based on the Discount Rate can be found in Appendix C, Formula C-2.

APPENDIX E

CHAPTER REFERENCES

APPENDIX E: CHAPTER REFERENCES

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Indirect Source Review Program

2023 ANNUAL REPORT

July 1, 2022 - June 30, 2023

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT
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SAMIR SHEIKH

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I. EXECUTIVE SUMMARY

This "*2023 Annual Report on the District's Indirect Source Review Program"* covers the reporting period from July 1, 2022, through June 30, 2023.

The District's Indirect Source Review (ISR) rule, was originally adopted in 2005 to reduce the growth in both nitrogen oxides (NOx) and particulate matter smaller than ten microns in aerodynamic diameter (PM_{10}) emissions from mobile and area sources associated with construction and operation of new industrial, commercial, residential, transit and other non-residential development projects in the Valley. New development projects create air pollution during construction and operation by prompting more vehicle trips and other pollution-causing activities. To address the rule requirements and achieve emissions reductions at the project site and within local communities, developers incorporate clean air measures into their project designs to reduce emissions impacts at project locations. Some examples include: use of clean, newer model-year off-road construction equipment, zero emission and or near-zero emission heavy duty on-road trucks and van fleets, zero and or near-zero emission on-site equipment, installation of electric vehicle charging infrastructure, solar power, installation of bike paths and sidewalks, and high-efficiency buildings.



If on-site clean air measures implemented by a developer do not achieve the emission reductions mandated by the ISR rule, the developer must pay an off-site mitigation fee for balance of the emission reductions required for the project. One hundred percent of off-site mitigation fees are used by the District to fund emission reduction projects through its incentive grant programs. Additionally, developers pay an administrative fee equal to four percent (4%) of the required off-site fees. This administrative fee is to cover the District's cost of administering the off-site emission reduction projects through the District's grants and incentives programs.

In addition to reducing the development project's impact on air quality through compliance with the District's ISR rule, a developer can further reduce the project's impact on air quality by entering into a "Voluntary Emission Reduction Agreement" (VERA) with the District to address the mitigation requirements under the California Environmental Quality Act (CEQA) or National Environmental Policy Act (NEPA). Under a VERA, the developer may fully mitigate project emission impacts by providing funds to the District, which are then used by the District to administer emission reduction projects. The District has entered into 52 VERAs since 2005.

This annual report includes revenues, expenditures, and emission reductions achieved for both ISR and VERA (ISR-VERA program). To date, in addition to avoiding approximately over 20,800 tons of NOx and PM_{10} emissions from new development through the incorporation of on-site mitigation and clean-air design measures into projects subject to the Indirect Source Review rule, the District has achieved more than

18,689 tons of reductions in NOx and PM_{10} emissions through the investment of over $162 million dollars in ISR and VERA funds through its emission reduction grants and incentives programs.



During this reporting period, the District received 360 ISR Air Impact Assessment applications and entered into two VERAs.

The total amount of funds received for this reporting period under the ISR rule and VERA program were $7,245,676 and $5,020,240, respectively, for a total of $12,265,916. The District achieved emission reductions via grants and incentives clean-air projects totaling 1,270 tons NOx and 220 tons PM_{10}, for a combined total of 1,490 tons, at a cost effectiveness of $13,154 per ton of emissions reduced.

II. INTRODUCTION

The San Joaquin Valley's challenges in meeting national ambient air quality standards are unmatched anywhere in the nation due to the region's unique geography, meteorology and topography. Since 1992, the District has adopted more than 670 rules to implement an aggressive on-going control strategy to reduce emissions in the Valley in order to reach attainment of the federal mandates, resulting in air quality benefits throughout the Valley. Through these ongoing efforts by the District, and significant efforts by CARB to reduce emissions from mobile sources, NOx emissions across the Valley have been reduced by over 75%, while stationary source emissions, which are under the District's jurisdiction, have been reduced by over 90% since 1980.

Although significant progress has been made, the San Joaquin Valley is one of the fastest growing regions in the state. The Population Research Unit of the Department of Finance recent population growth projections, demonstrated a 13.9% increase in the Valley's population from 2020 to 2035 period. In contrast, the total population for the State of California is projected to increase by only 7.4% over the same time period.

Population growth results in increased area source emissions from activities such as consumer product use, fuel combustion for heating and cooking, and landscape maintenance. The total number of vehicle miles traveled (VMT) also increases with population growth, resulting in more emissions due to the combustion of vehicle fuels.

The projected growth in these so called "indirect source" emissions erodes some of the progress generated by emission reductions achieved through the District's stationary source air quality management program and state and federal mobile source controls.

Although the District cannot directly regulate mobile source tailpipe emissions, it does have longstanding statutory authority to regulate indirect sources of air pollution. Pursuant to this authority, the District made a federally enforceable commitment to regulate indirect sources when it adopted its PM_{10} Attainment Plan in June 2003. Subsequently, the California State Legislature passed Senate Bill 709, Florez, in the fall of 2003, which Governor Gray Davis subsequently signed and codified into the Health and Safety Code in §40604. This additional legislation required the District to adopt, by regulation, a schedule of fees to be assessed on area wide or indirect sources of emissions that are regulated by the District.





The purpose of the District's Indirect Source Review rule is to require developers to incorporate clean air measures and reduce emissions of NOx and PM10 from new development projects. It is important to note, particulate matter emissions from mobile sources are overwhelmingly PM2.5, a subset of PM10. Therefore, the PM10 emission reductions achieved under ISR result directly in PM2.5 emission reductions. In other words, PM10 emissions increases are being offset by emissions reductions that are overwhelmingly PM2.5, a positive impact on PM2.5 concentrations.

The Indirect Source Review rule applies to any applicant that seeks to gain final discretionary approval for a development project, or any portions thereof, which upon full build-out will include any one of the following:

- 50 residential units
- 2,000 square feet of commercial space
- 9,000 square feet of educational space
- 10,000 square feet of government space
- 20,000 square feet of medical or recreational space
- 25,000 square feet of light industrial space
- 39,000 square feet of general office space
- 100,000 square feet of heavy industrial space
- 9,000 square feet of any land use not identified above

Additionally, the Indirect Source Review rule applies to any applicant that seeks to gain approval from a public agency for a large development project, which upon full build out will include any of the following:

- 250 residential units
- 10, 000 square feet of commercial space
- 45,000 square feet of educational space
- 50,000 square feet of governmental space
- 100,000 square feet of medical office or recreational space
- 125,000 square feet of light industrial space
- 195,000 square feet of general office space
- 500,000 square feet of heavy industrial space
- 45,000 of square feet of space not identified above

In addition to the above, a transit or transportation development project is subject to the Indirect Source Review rule if construction exhaust emissions equal or exceed two (2.0) tons of NOx or two (2.0) tons of PM10.

This report was prepared pursuant to provisions of Rule 9510 that require the District to prepare an annual report regarding expenditure of received funds and achieved emission reductions. The annual report includes the following:

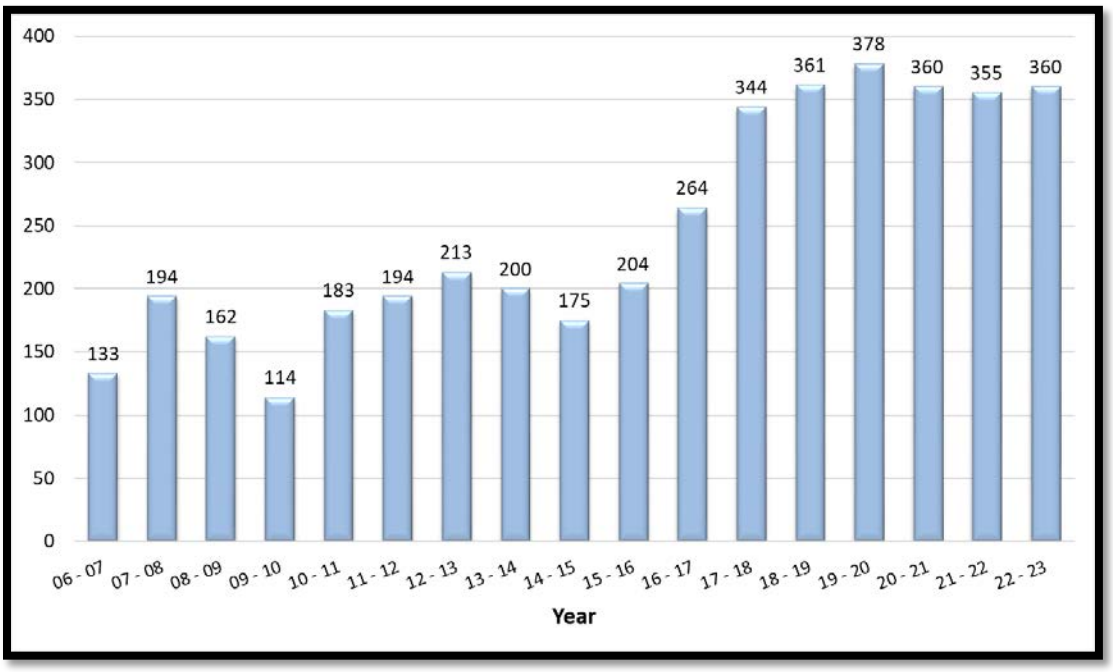
- Total amount of off-site fees received;
- Total monies spent;
- Total monies remaining;
- Any refunds distributed;
- A list of all projects funded;
- Total emissions reductions realized; and
- The overall cost-effectiveness factor for the projects funded.

III. IMPLEMENTATION

District Indirect Source Review Rule

During this reporting period, the District received 360 ISR applications. For historic context, the number of ISR applications received each year is presented in Figure 1 below.

Figure 1: Number of ISR Applications Received



Voluntary Emission Reduction Agreements

A Voluntary Emission Reduction Agreement is an air quality mitigation measure by which a developer can voluntarily enter into a contractual agreement with the District to mitigate a development project's impact on air quality, going beyond reductions achieved by compliance with the District's ISR rule. Under the agreement, the developer provides funds to the District to administer the implementation of the VERA. The District then identifies emissions reductions projects, funds those projects, and verifies that the specified emission reductions have been successfully achieved.

The types of emission reduction projects that have been funded in the past include electrification of stationary internal combustion engines (such as agricultural irrigation pumps), replacing old heavy-duty trucks with new, cleaner, more efficient heavy-duty trucks, and replacement of older farm tractors with cleaner tractors. Since 2005, the District has entered into 52 VERAs. It is the District's experience that implementation of a VERA is an effective mitigation measure under CEQA, to achieve emission reductions necessary to reduce air quality impacts to a less than significant level.

For development projects subject to the ISR rule, the developer must also comply with applicable ISR rule provisions. This report therefore includes revenues and emission reductions achieved through both the ISR and the VERA process.

During this reporting period, the District adopted the following VERAs, with their estimated dollar amounts and emissions reductions shown below:

- Majestic Gateway: $4,583,446 and 476.1 tons of emissions reductions
- Shafter-Wasco Composting and Waste Division: $197,292 and 20.4 tons of emissions reductions

Oil and Gas Emission Reduction Agreement

In 2015, Kern County adopted an EIR for amendments to the Kern County Zoning Ordinance to address oil and gas exploration and operation activities in the identified area within Kern County. Consistent with the final EIR, Kern County and the District adopted an oil and gas emission reduction agreement (OGERA) to mitigate emissions associated with future oil and gas exploration and production in the San Joaquin Valley. Under this process, Kern County collects a mitigation fee from oil and gas companies when issuing permits for the drilling of new oil or gas production wells, and transfers the funds to the District to mitigate air quality impacts through its grants and incentives programs.

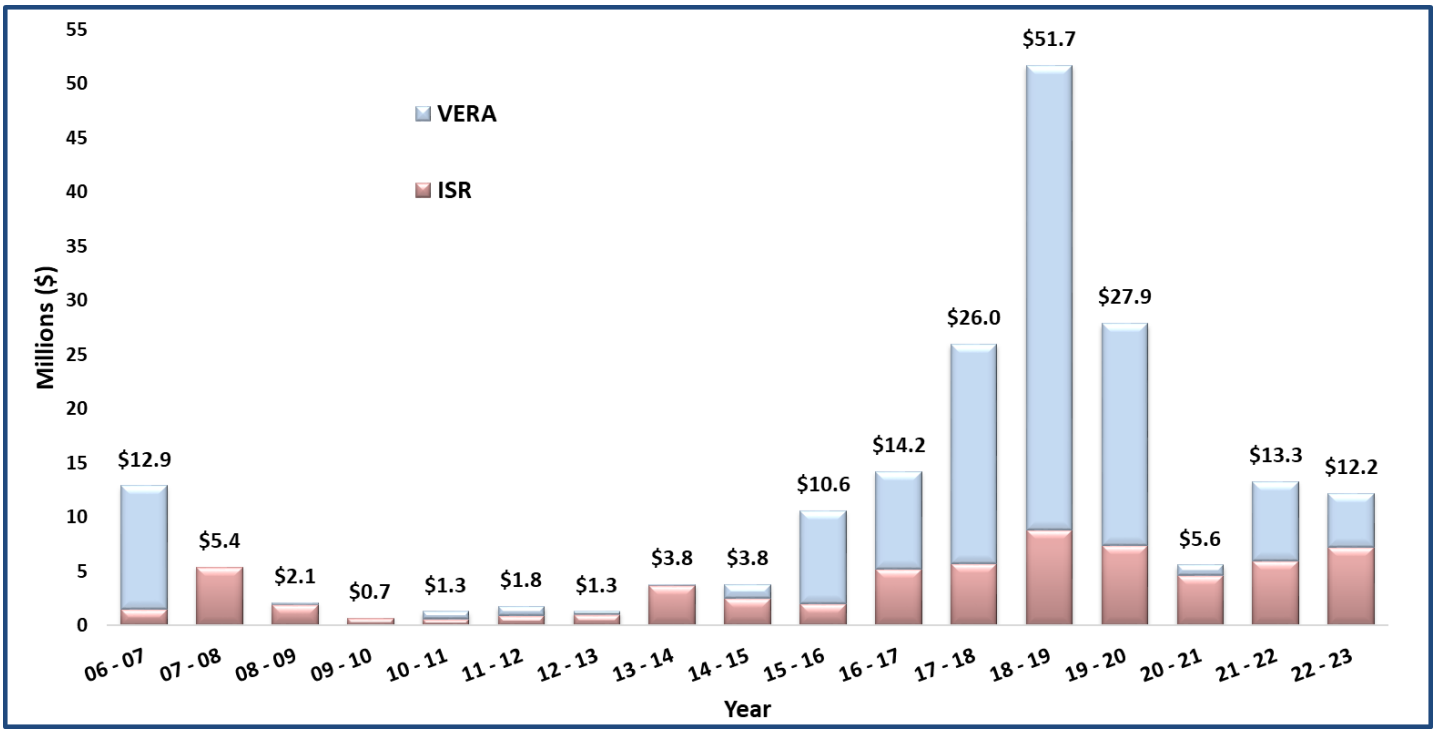
A Petition for Writ of Mandate filed in the Kern County Superior Court challenged Kern County's 2015 Ordinance. The County subsequently amended the Ordinance and accompanying EIR in 2021, which was also challenged by Petitioners. On June 7, 2022, the court issued a ruling that the 2021 amended Ordinance was defective in several respects and ordered suspension of the Ordinance. Following the County's correction of the defects, in November 2022, the court lifted suspension of the Ordinance to allow oil and gas permitting to resume.

However, following an appeal of the Superior Court's ruling, on January 26, 2023, the Court of Appeal re-imposed the suspension of oil and gas permitting in Kern County pending review of the Superior Court's ruling. The District is currently working with Kern County and monitoring the impacts of the ruling as it relates to implementation of the OGERA.

IV. FISCAL SUMMARY

The total amount of funds received for this reporting period under ISR and VERA were $7,245,676 and $5,020,240 respectively, for a total of $12,265,916.

Figure 2: ISR and VERA Program Funds Received



As presented in Table 1 below, the District's ISR and VERA accounts held a beginning balance of $34,963,884. During this reporting period, the District received $12,265,916, spent (paid out) off-site emission reduction projects totaling $19,610,101, encumbered $19,475,357 in contracts for emission reduction projects, leaving an unencumbered balance of $8,144,342.

Table 1: ISR-VERA Fiscal Summary (July 1, 2022 - June 30, 2023)

	ISR	VERA	Total
Beginning Fund Balance	$8,032,311	$26,931,573	$34,963,884
Amount Received	$7,245,676	$5,020,240	$12,265,916
Amount Refunded	$0	$0	$0
Amount Spent (Paid Out)	-$9,647,436	-$9,962,665	-$19,610,101
Ending Fund Balance	$5,630,551	$21,989,148	$27,619,699
Encumbered Amount	-$4,929,514	-$14,545,843	-$19,475,357
Ending Unencumbered Amount	**$701,037**	**$7,443,305**	**$8,144,342**

V. EMISSION REDUCTION SUMMARY

Through the District's grants and incentives programs, clean-air emissions reduction projects undergo a thorough application review before the contract for these projects between the District and the project applicant is executed. Once executed, funds are then encumbered for that project. The contract is valid for a limited time to allow for the purchase of the new equipment and to submit a reimbursement request. Once the reimbursement request is approved, the funds encumbered for the emission reduction project are spent (reimbursed to the project applicant). This process typically takes several months for completion. Therefore, depending on the types of emission reduction projects available for funding, the funds received during this reporting period may result in the funds being spent the in same reporting period or in future reporting periods.

ISR and VERA Off-Site Emission Reductions Achieved

During this reporting period, the District achieved emission reductions via grants and incentives clean-air projects totaling 1,270 tons NOx and 220 tons PM_{10}, for a combined total of 1,490 tons, at a cost effectiveness of $13,153 per ton of emissions reduced, summarized in Table 2 below. The District spent ISR and VERA monies to fund 2,741 clean-air emission reduction projects. These clean-air projects included the replacement of older, higher-emitting agricultural tractors with new latest-tier tractors, replacement of older, higher-emitting agricultural irrigation water pump



engines with electric motors, retrofit of residential open-hearth fireplaces with certified natural gas burning inserts, rebates to Valley residents and businesses for the purchase or lease of new clean-air vehicles, new zero-emission railcar moving equipment to replace an existing switcher locomotive for use within the Valley and a dairy feed mixer electrification project. A complete list of all clean-air projects funded under this annual report period is presented in Appendix A.

Table 2: Off-Site Emission Reductions Achieved (July 1, 2022 - June 30, 2023)

Program	NOx (tons)	PM_{10} (tons)	Total (tons)	Amount Paid Out	Cost Effectiveness
ISR	217.5	138.1	355.6	$9,646,815	$27,128/ton
VERA	1,052.9	82.4	1,135.3	$9,962,665	$8,775/ton
Total	**1,270.4**	**220.5**	**1,490.9**	**$19,609,480**	**$13,153/ton**

ISR and VERA Off-Site Emission Reductions Achieved - Historic Since 2006

As discussed above, mitigation funds under ISR and VERA are administered through the District's grants and incentive programs to fund clean-air projects in the Valley. The District has built a reputation for excellence in the implementation of these programs, as highlighted in multiple audits by state agencies that commended the District's incentive programs for their efficiency and effectiveness. Since inception of the District's ISR rule and VERA program, the District's programs have achieved the emissions reductions shown in Table 3 below.

Table 3: Off-Site Emission Reductions Achieved Since 2006

Program	NOx (tons)	PM_{10} (tons)	Total (tons)
ISR	5,612	1,652	**7,264**
VERA	10,603	1,027	**11,630**
Total	**16,215**	**2,679**	**18,894**

ISR Program Estimated Emission Reductions - Previous Reporting Period

Estimated emission reductions are a combination of emission reductions to be achieved through implementation of project design elements at full project build out and through funding off-site emission reductions projects through District grants and incentive programs using off-site emission reduction mitigation fees.

For this reporting period, projects assessed under ISR resulted in estimated combined on-site and off-site emission reductions as shown in Table 4 below.

Table 4: Estimated Emission Reductions from Approved ISR Projects During the Previous Reporting Period (July 1, 2022 - June 30, 2023)

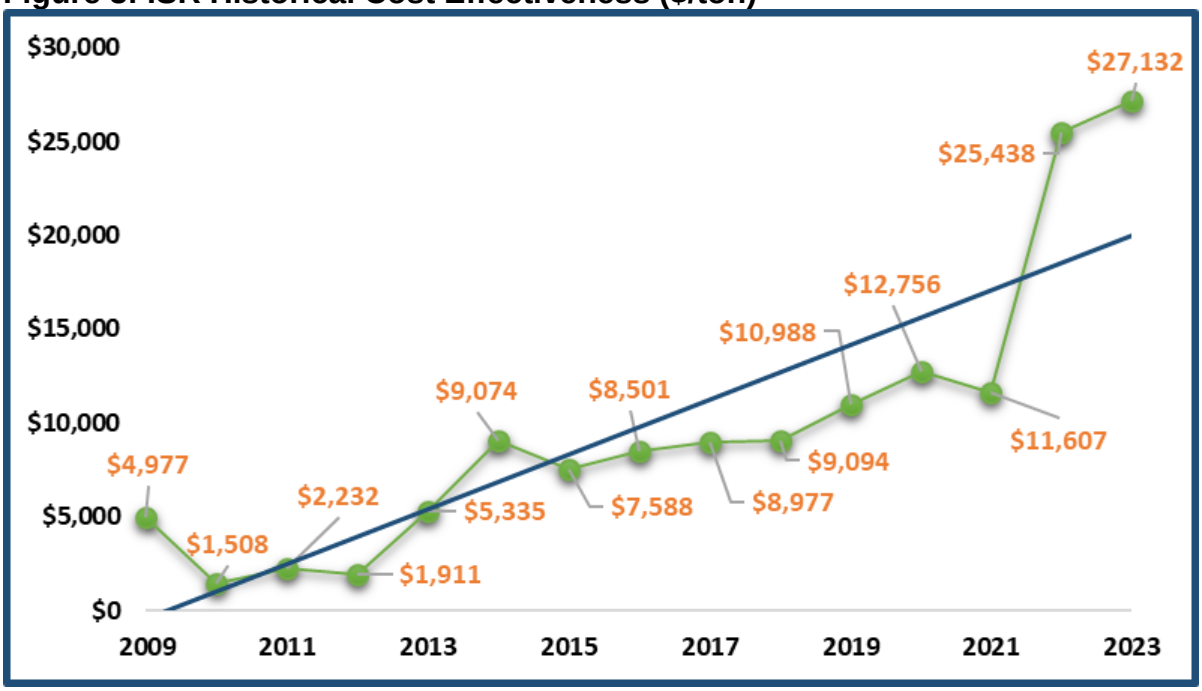
Source	NOx (tons)	PM_{10} (tons)	Total (tons)
On-site Emission Reductions	859	1,846	**2,705**
Off-site Emission Reductions	1,419	1,117	**2,536**
Total	**2,278**	**2,963**	**5,241**

VI. COST EFFECTIVENESS

Over the years, the District has had significant success achieving emission reductions under ISR, including reductions achieved through the aforementioned offsite mitigation fees. Since 2008, the offsite mitigation fees collected under the ISR is $9,350 per ton of NOx and $9,011 per ton of PM10.

Historically, determining cost effectiveness for voluntary incentive grant projects follows the methodology established by the state's perennial Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program). Cost effectiveness is defined as a measure of dollars provided to an emission reduction project for each ton of emissions reduced. Statute requires that the California Air Resources Board (CARB) updated the cost effectiveness annually based on changes to the California Consumer Price Index. In addition, SB 513 has required CARB and Air District's to establish new cost effectiveness limits that specifically reflect categories such as school bus replacement projects, as well as advanced zero-emission technology projects. These increased cost effectiveness limits reflect the significantly higher cost of new and emerging zero-emission technology, compared with the more traditional technology. With the promulgation and implementation of several statewide regulations that require a shift to zero-emission technology, the Carl Moyer Program, and other state incentive funding programs focus almost exclusively on funding zero-emission technology. The current program cost effectiveness limits must also take into account regulatory compliance dates that can limit the surplus nature of the emission reductions. These factors and the availability of voluntary incentive projects at any given time that meet these new mandates have led to an increase in the cost effectiveness year over year. The current cost effectiveness for projects funded under the Carl Moyer Program are $34,000/ton of emission reduced (combined NOx, ROG, and PM) for conventional projects and up to $522,000 for advanced, zero-emission projects, such as school buses and heavy-duty trucks. Figure 3 below illustrates the steady increase in the cost effectiveness over the years for achieving emission reductions through District incentive grant programs under ISR.

Figure 3: ISR Historical Cost Effectiveness ($/ton)



Overall as a program the District has successfully mitigated emissions associated with projects and collected mitigation fees; however over the past five years specifically (2019 - 2023), the Rule's current collection rate in $/ton is now below the actual $/ton achieved through the District's Grants and Incentives programs.

To cover the District's cost of administering these funds, the project proponent is required to pay an administrative fee equal to four percent (4%) of the required offsite mitigation fee. This administrative fee has been in place and remained at 4% since the rule's initial adoption in 2005, and is lower than all other grant programs that the District and other air districts administer, as other administrative fees range from 6.25% - 15%.

Therefore, the current mitigation fee schedule and administrative fees will be critical in ensuring the dollars collected by the District in the future are sufficient to achieve and administer the required emission reductions under ISR.

APPENDIX A - EMISSION REDUCTION PROJECTS

List of all emission reduction projects funded by the ISR-VERA Program from July 2022 through June 2023:

Grant Project Number	Program	Component	Option	NOx Reduced (tons/project life)	PM10 Reduced (tons/project life)
G-107675	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-100120	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-103917	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-104040	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-104804	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-104934	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-105619	Burn Cleaner	Wood Stove Change Out	New Device		0.3199
G-105962	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-106315	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-106544	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-106604	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-106890	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-107411	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-107556	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-107704	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-107705	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-107823	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-107839	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-107950	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-108075	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-108246	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-108397	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-108719	Burn Cleaner	Wood Stove Change Out	New Device		0.08
G-109017	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-109023	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-109932	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-110787	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-111705	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-112434	Burn Cleaner	Wood Stove Change Out	New Device		0.0618
G-112948	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-113229	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-113387	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-114307	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-114563	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-114633	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-114862	Burn Cleaner	Wood Stove Change Out	New Device		0.0796

G-114898	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-115675	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-115690	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-115763	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-115879	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-116237	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-116631	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-116641	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-117215	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-117544	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-117560	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-117577	Burn Cleaner	Wood Stove Change Out	New Device		0.0177
G-117783	Burn Cleaner	Wood Stove Change Out	New Device		0.4798
G-117921	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-118045	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-118302	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-118621	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-118669	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-119188	Burn Cleaner	Wood Stove Change Out	New Device		1.1544
G-119284	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-119294	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-119375	Burn Cleaner	Wood Stove Change Out	New Device		0.9235
G-119598	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-119673	Burn Cleaner	Wood Stove Change Out	New Device		0.4946
G-119678	Burn Cleaner	Wood Stove Change Out	New Device		0.1237
G-121158	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-121965	Burn Cleaner	Wood Stove Change Out	New Device		0.1197
G-121973	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-122783	Burn Cleaner	Wood Stove Change Out	New Device		0.3199
G-123106	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-124185	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-124508	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-125410	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-126765	Burn Cleaner	Wood Stove Change Out	New Device		0.1419
G-126984	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-127445	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-127738	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-128895	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-129431	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-130509	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-131251	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-131876	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-132276	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-132885	Burn Cleaner	Wood Stove Change Out	New Device		0.0177

G-132925	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-133166	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-133173	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-133715	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-133716	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-134058	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-136082	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-136212	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-137895	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-138343	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-138833	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-139882	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-139986	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
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G-143232	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-145139	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-145141	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-146845	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-146879	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-147147	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147189	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-147191	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147199	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
G-147202	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-147236	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147243	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147247	Burn Cleaner	Wood Stove Change Out	New Device		0.2309

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G-147306	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
G-147313	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
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G-148612	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
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G-148697	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-148706	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-148709	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
G-148710	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
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G-148730	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-148735	Burn Cleaner	Wood Stove Change Out	New Device		0.2309

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G-148757	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-148761	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
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G-90802	Burn Cleaner	Wood Stove Change Out	New Device		0.23088
G-91215	Burn Cleaner	Wood Stove Change Out	New Device		0.23088
G-83839	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.9	0.49
C-46128-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.99	0.6
C-57171-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.04	0.11
C-59505-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.7	0.46
C-59507-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.99	0.26
C-62529-1	Heavy-Duty	Dairy Feed Mixer	Electrification	59.63	4.63
G-101534	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.09	0.02
G-103338	Heavy-Duty	Off-Road	Ag Tractor Replacement	38.09	1.99
G-103392	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.74	0.15
G-103397	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.35	0.79
G-107026	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.5	0.41
G-107105	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.89	0.19
G-107121	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.49	0.68
G-107141	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.75	0.94
G-107431	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.8	0.62
G-107830	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.5	0.47
G-107832	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.25	0.21
G-107838	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.44	0.36
G-108011	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.94	0.62
G-108013	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.95	0.69
G-108706	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.28	0.93
G-108943	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.57	0.23
G-109115	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.67	0.2
G-109128	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.45	0.59
G-109418	Heavy-Duty	Off-Road	Ag Tractor Replacement	15.47	0.39
G-110225	Heavy-Duty	Off-Road	Ag Tractor Replacement	13.17	0.7
G-110530	Heavy-Duty	Off-Road	Ag Tractor Replacement	21.08	0.6
G-110587	Heavy-Duty	Off-Road	Ag Tractor Replacement	20.67	1.1
G-110695	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.49	0.75
G-110713	Heavy-Duty	Off-Road	Ag Tractor Replacement	22.55	1.67
G-110715	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110716	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110717	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29

G-110718	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110719	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110721	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110864	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.29	0.41
G-110910	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.08	0.27
G-110959	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.37	0.51
G-111049	Heavy-Duty	Off-Road	Ag Tractor Replacement	23.31	1.34
G-111249	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.73	0.23
G-111288	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.72	0.42
G-111289	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.72	0.42
G-111449	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.17	0.35
G-111623	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.71	0.35
G-111722	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.08	0.65
G-112038	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.68	0.5
G-112039	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.68	0.5
G-113687	Heavy-Duty	Off-Road	Ag Tractor Replacement	4	0.2
G-113692	Heavy-Duty	Off-Road	Ag Tractor Replacement	19.17	1.09
G-113696	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.46	0.7
G-113698	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.73	0.72
G-115004	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.98	0.35
G-116114	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.84	0.36
G-116974	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.07	0.6
G-117435	Heavy-Duty	Off-Road	Ag Tractor Replacement	16.48	0.47
G-119291	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.31	0.61
G-124495	Heavy-Duty	Off-Road	Ag Tractor Replacement	16.79	0.48
G-124546	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.27	0.65
G-125113	Heavy-Duty	Off-Road	Ag Tractor Replacement	28.24	1.96
G-125670	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.12	0.37
G-126551	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.32	0.62
G-140677	Heavy-Duty	Ag Engine	Diesel to Diesel	2.86	0.16
G-66106	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.31	0.76
G-66108	Heavy-Duty	Off-Road	Ag Tractor Replacement	17.27	1.19
G-66109	Heavy-Duty	Off-Road	Ag Tractor Replacement	13.83	1.26
G-66110	Heavy-Duty	Off-Road	Ag Tractor Replacement	25.6	0.8
G-66560	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.67	0.88
G-66565	Heavy-Duty	Off-Road	Ag Tractor Replacement	10.16	0.92
G-66568	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.67	0.88
G-66946	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.67	0.78
G-69348	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.03	0.11
G-69618	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.58	0.49
G-73414	Heavy-Duty	Locomotive	Replacement	64.69	1.5
G-73416	Heavy-Duty	Locomotive	Replacement	64.69	1.5
G-75359	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.97	0.36
G-76150	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.3	0.57

G-76304	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.39	0.33
G-78575	Heavy-Duty	Off-Road	Ag Tractor Replacement	27.13	0.69
G-80530	Heavy-Duty	Ag Engine	Alt Fuel to Electric	4.23	0.1
G-80920	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.64	0.24
G-80971	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.01	0.08
G-81259	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.98	0.63
G-81732	Heavy-Duty	Off-Road	Ag Tractor Replacement	39.25	2.08
G-81861	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.39	0.49
G-89922	Heavy-Duty	Off-Road	Ag Tractor Replacement	13.11	0.7
G-89925	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.27	0.16
G-92722	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.72	0.42
G-92840	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.91	0.85
G-92845	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.16	0.04
G-92846	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.16	0.04
G-92854	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.16	0.04
G-92856	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.34	0.1
G-93091	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.18	0.14
G-94125	Heavy-Duty	Off-Road	Ag Tractor Replacement	25.32	1.34
G-94432	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.15	0.41
G-95177	Heavy-Duty	Off-Road	Ag Tractor Replacement	23.6	1.25
G-95421	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.67	0.26
G-95474	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.29	0.47
G-95716	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.88	0.1
G-95717	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.49	0.18
G-95719	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.89	0.23
G-95721	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.88	0.23
G-95738	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.77	0.22
G-95744	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.34	0.16
G-95745	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.37	0.17
G-95746	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.48	0.18
G-95747	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.36	0.16
G-95748	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.01	0.12
G-96110	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.51	0.18
G-96111	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.51	0.18
G-96112	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.42	0.17
G-96113	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.51	0.18
G-96114	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.47	0.18
G-97962	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.56	0.56
G-98464	Heavy-Duty	Ag Engine	Alt Fuel to Electric	1.19	0.14
G-99415	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.66	0.13
G-88837	Heavy-Duty	Off-Road	Ag Tractor Replacement	35.43	1.87
C-63331-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	30.11	1.72
G-107900	Heavy-Duty	Off-Road	Ag Tractor Replacement	20.54	1.17
G-115048	Heavy-Duty	Off-Road	Ag Tractor Replacement	16.2	2.11

C-54743-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.33	0.39
G-141940	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.48	1.05
G-135044	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.11	0.38
G-114796	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.37	0.65
G-112907	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.34	0.57
C-53942-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.24	0.56
G-113329	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.36	0.33
C-51760-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	10.03	1.29
G-133703	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-116489	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-125668	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-130761	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-131764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-132155	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-132170	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-132878	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-132884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-132979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-133159	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-133189	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133384	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-133542	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133551	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133627	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-133634	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-133635	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-133638	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-133642	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133733	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133740	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-133834	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133835	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-133873	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-133879	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-133903	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-133906	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-133919	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-133929	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-133982	Light-Duty	Drive Clean	EV Vehicle Rebate	0.033	0.0055
G-133986	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134003	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-134014	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134020	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134056	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134057	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0123	0.002
G-134229	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134232	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134236	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134254	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-134257	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-134258	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-134290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134327	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134359	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134361	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-134367	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134387	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-134389	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-134390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0081	0.0013
G-134392	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-134396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-134397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134401	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134402	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0148	0.0025
G-134403	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-134413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134414	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134417	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134425	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-134426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-134428	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0186	0.0031
G-134432	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134434	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134437	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-134439	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-134440	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0072	0.0012
G-134442	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134447	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134452	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0264	0.0044
G-134458	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-134474	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018

G-134478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-134525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134526	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-134529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-134530	Light-Duty	Drive Clean	EV Vehicle Rebate	0.063	0.0105
G-134531	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134541	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134556	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-134573	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134580	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-134586	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134587	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134589	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134606	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134607	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134610	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-134671	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-134683	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134688	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-134702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134705	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134719	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134720	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-134724	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134725	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0081	0.0013
G-134726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134732	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134737	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134747	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134748	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134757	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-134764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134766	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134769	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-134775	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134778	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0091	0.0015
G-134779	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-134780	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-134781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-134799	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134802	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134812	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134815	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134816	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134817	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134819	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134821	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134827	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134841	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134846	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134876	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134880	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134885	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134890	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-134892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-134893	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134894	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-134896	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0016
G-134927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134928	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-134932	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134975	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-134977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134991	Light-Duty	Drive Clean	EV Vehicle Rebate	0.006	0.001
G-134993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-135000	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135003	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135018	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135027	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-135029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135035	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135041	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0124	0.0021
G-135053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-135070	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135093	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-135103	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-135108	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-135111	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-135112	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135114	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135123	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-135130	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135131	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135132	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135143	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135144	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135150	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135151	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-135152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135163	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135168	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-135188	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-135190	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135210	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135211	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-135239	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135241	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135246	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-135276	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135284	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-135285	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135288	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135291	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135303	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135304	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-135306	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135369	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135384	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135388	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135456	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135476	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135480	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-135490	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135528	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0049	0.0008
G-135529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135541	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-135575	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-135675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-135681	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135697	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-135809	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-135824	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135827	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-135836	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135837	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135876	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135885	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-135935	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-135945	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0162	0.0027
G-135947	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135971	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-135972	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135973	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-135974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-135979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136056	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136058	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-136059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-136071	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-136095	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-136131	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-136133	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136146	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-136186	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-136193	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136195	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0264	0.0044
G-136199	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136204	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-136213	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-136217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136224	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0107	0.0018

G-136233	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136248	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-136256	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136259	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-136286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-136288	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136346	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136370	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0258	0.0043
G-136384	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136433	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136439	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136447	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-136469	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-136473	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-136510	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-136556	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136575	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-136614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-136615	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-136637	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-136652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136662	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-136947	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-136992	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-137066	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-137069	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-137265	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-137267	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0162	0.0027
G-137460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-137495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-137513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-137519	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-137529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-137535	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-137538	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-137565	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-137588	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-137602	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-137608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-137613	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-137614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-137678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-137704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021

G-137723	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-137831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-137834	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-137844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-137914	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-137974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138072	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-138083	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138092	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-138124	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138127	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138137	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138227	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138233	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138254	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138256	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138299	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138324	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0111	0.0019
G-138328	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0116	0.0019
G-138331	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138337	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138387	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-138396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138408	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138425	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138449	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-138452	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138496	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-138568	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-138626	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-138640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138695	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138696	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138770	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-138773	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138786	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-138794	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138823	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-138841	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-138842	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-138844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0143	0.0024
G-138852	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138897	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138950	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138959	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138968	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-138978	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139144	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-139150	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139191	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139201	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139210	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-139213	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-139217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-139302	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139309	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-139317	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139333	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-139379	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139432	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-139436	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139461	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139469	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-139470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139471	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139472	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139474	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-139476	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-139483	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139506	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-139529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-139551	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139600	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013

G-139613	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139643	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-139665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139679	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139697	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139700	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139722	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-139726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-139783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139797	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139805	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139869	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139890	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-139899	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139924	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139928	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139940	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139953	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139965	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139970	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-139977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139981	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-140024	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140026	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140031	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140042	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-140053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140063	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-140069	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140141	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-140142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-140152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0141	0.0024
G-140167	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0251	0.0042
G-140246	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-140253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-140267	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-140270	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-140273	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140288	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-140292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-140294	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-140295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140296	Light-Duty	Drive Clean	EV Vehicle Rebate	0.013	0.0022
G-140305	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-140327	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-140388	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140411	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140412	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140415	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140427	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140481	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140483	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-140527	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0157	0.0026
G-140577	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140589	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140641	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140672	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140690	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140691	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-140692	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-140694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-140696	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140731	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140749	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-140768	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140773	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140774	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-140818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140828	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140838	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022

G-140868	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140921	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0125	0.0021
G-140927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0164	0.0027
G-140951	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-140977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141040	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0116	0.0019
G-141077	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-141084	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141088	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141095	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141101	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141118	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-141119	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-141120	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-141126	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141133	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-141147	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141162	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-141171	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141175	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-141182	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141193	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141207	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-141208	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141209	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141252	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-141299	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-141313	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-141378	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141451	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-141505	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141522	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141584	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141596	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-141605	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141611	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-141616	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-141622	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013

G-141633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141644	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141645	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-141646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-141648	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-141652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-141681	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-141685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0078	0.0013
G-141708	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-141729	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141732	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141763	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0113	0.0019
G-141877	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-141878	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141902	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-141933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-141936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141960	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141966	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141968	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-141983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-142000	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142004	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142012	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142016	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-142020	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-142063	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142115	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142127	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-142157	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-142253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-142259	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142265	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-142268	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-142291	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-142292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142294	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142302	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142333	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142338	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142347	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142350	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-142365	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-142368	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142389	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142398	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142403	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-142404	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142466	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0096	0.0016
G-142467	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142488	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-142494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142496	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-142497	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-142504	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142505	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-142517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-142554	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142560	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142621	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-142628	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0188	0.0031
G-142633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142649	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142650	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142651	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142653	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142671	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0098	0.0016
G-142677	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-142679	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142698	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-142699	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002

G-142701	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-142702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142710	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-142721	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142722	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142731	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142741	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0101	0.0017
G-142746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142759	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-142767	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142770	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-142775	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142782	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142838	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-142923	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-142927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142963	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0109	0.0018
G-143036	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143049	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143072	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143076	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143078	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143112	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143225	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-143265	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-143266	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143269	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-143274	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-143294	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-143298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-143317	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-143318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143320	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-143339	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-143340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-143371	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-143376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-143377	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143381	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-143383	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009

G-143385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0113	0.0019
G-143386	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-143399	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-143410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-143411	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-143414	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-143426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-143453	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-143463	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143734	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0297	0.005
G-143853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-143861	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-143899	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143946	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143975	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0211	0.0035
G-143991	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-143992	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144097	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-144103	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-144104	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144126	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144136	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144173	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144198	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144212	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-144243	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144244	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144246	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-144253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-144262	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-144272	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144277	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0129	0.0021
G-144286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-144291	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-144325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0157	0.0026
G-144326	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144373	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-144428	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-144457	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-144476	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144491	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144519	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-144571	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-144574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-144583	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-144615	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144625	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144653	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144670	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-144688	Light-Duty	Drive Clean	EV Vehicle Rebate	0.013	0.0022
G-144691	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-144707	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144713	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-144738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-144749	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144753	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144755	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144758	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-144783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-144847	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-144882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-144883	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144906	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0085	0.0014
G-144907	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-144937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-144938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144988	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145045	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145068	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-145087	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145091	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145113	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0116	0.0019
G-145161	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-145164	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145165	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-145166	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-145167	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145171	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145175	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-145180	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-145194	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-145206	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-145218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-145220	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0143	0.0024
G-145224	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-145233	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145237	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145293	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-145338	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-145340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145342	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145365	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-145393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-145412	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-145481	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145524	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-145525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145531	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-145532	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145533	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145534	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-145539	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-145545	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145546	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-145549	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145551	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-145580	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-145583	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145584	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-145585	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-145586	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0129	0.0021
G-145587	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-145588	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-145590	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145591	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145593	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145594	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145596	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145598	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-145599	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0129	0.0021
G-145607	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-145614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-145675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-145678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-145719	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-145724	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145731	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145747	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-145765	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-145776	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-145783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-145784	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145793	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145794	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145845	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145846	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-145864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145906	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145951	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145955	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0188	0.0031
G-145975	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0109	0.0018
G-145983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-145984	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-145991	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146016	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-146025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146034	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146038	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-146044	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009

G-146062	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146081	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146097	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-146133	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-146141	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146146	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-146149	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146159	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-146160	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146229	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0188	0.0031
G-146239	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146242	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0162	0.0027
G-146245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0248	0.0041
G-146281	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-146298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-146318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146328	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146344	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146346	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146373	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.006	0.001
G-146378	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0134	0.0022
G-146385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-146405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146408	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0068	0.0011
G-146436	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-146440	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-146443	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146453	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146456	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-146469	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146475	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-146481	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146500	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-146505	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146507	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-146516	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-146523	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-146552	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011

G-146560	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146566	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146573	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0169	0.0028
G-146626	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-146635	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146706	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-146718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146735	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146743	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-146744	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-146774	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146813	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-146832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-146833	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146842	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-146850	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-146865	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-146866	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-146887	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-146892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146896	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-146913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146917	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-146936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-146938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147050	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147055	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147065	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147070	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147074	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147160	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147170	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147179	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147196	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147197	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-147201	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147203	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-147215	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-147218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147222	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147225	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-147245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0072	0.0012
G-147257	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147266	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147269	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147282	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147285	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-147298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147302	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147312	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0113	0.0019
G-147338	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147342	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147343	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-147348	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147361	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147366	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147374	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-147385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147394	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147423	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147437	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147466	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147482	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147489	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147553	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147559	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-147581	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147585	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147586	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147587	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147597	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147612	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147616	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147630	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-147633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147659	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147663	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-147683	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147690	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147692	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147696	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147707	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147712	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147714	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-147734	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-147735	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147736	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-147739	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-147742	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147749	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147750	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147751	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147752	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147753	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147754	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147755	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147763	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147770	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147771	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147779	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147786	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147788	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147791	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-147816	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147819	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147837	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147838	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-147843	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147848	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147849	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147854	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147859	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147862	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147863	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147869	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147874	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147876	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147878	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147880	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-147883	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147909	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-147912	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147917	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147918	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147934	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147948	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147950	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147954	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147960	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147969	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148016	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148026	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148031	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0009
G-148034	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148041	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-148042	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148044	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-148061	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148062	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148064	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148067	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148073	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148079	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148081	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0127	0.0021
G-148084	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148093	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148096	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148101	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148104	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148108	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148109	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148111	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148144	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148145	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-148173	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-148176	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-148195	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148198	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148201	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-148205	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148207	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148212	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148237	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148263	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148267	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148268	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148281	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148296	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-148300	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148304	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0151	0.0025
G-148308	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-148320	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148321	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-148335	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148339	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-148348	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148370	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148379	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-148392	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-148395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148418	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-148448	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148464	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148514	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-148547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148550	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148562	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-148591	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148604	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148616	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148618	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148619	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-148624	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148631	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148632	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148634	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148636	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148649	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148650	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148655	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148660	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148662	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148672	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148673	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-148675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0107	0.0018
G-148685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0005
G-148694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148699	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148714	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011

G-148716	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148723	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-148744	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0206	0.0034
G-148758	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148765	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-148772	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148788	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148808	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-148818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148834	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0213	0.0035
G-148839	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148893	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-148913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148919	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148926	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148935	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-148979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148996	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149002	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-149004	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149005	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149008	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149010	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-149012	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-149054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149063	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149065	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-149076	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149091	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149093	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-149094	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-149112	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149115	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149125	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149127	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149135	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-149138	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149148	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-149162	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149188	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149191	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149216	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149221	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149236	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-149252	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149273	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-149275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149276	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149279	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149280	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-149281	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149287	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149332	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-149352	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149378	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-149389	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-149393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-149407	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149424	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-149433	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149438	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149443	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149444	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149448	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149449	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0152	0.0025
G-149454	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149461	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149473	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149475	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149479	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149497	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149499	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149504	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149508	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-149515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149516	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-149521	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149524	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-149525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-149527	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149536	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149554	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149557	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149569	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149580	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-149608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149617	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149625	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-149627	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-149628	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149632	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-149642	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0103	0.0017
G-149655	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149658	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149659	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149667	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-149683	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149691	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149698	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149700	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149705	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149707	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-149772	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149782	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149787	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-149789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149791	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-149805	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009

G-149807	Light-Duty	Drive Clean	EV Vehicle Rebate	0.013	0.0022
G-149810	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149813	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-149819	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149821	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-149831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-149833	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149867	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149871	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149886	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149897	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-149898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149900	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149904	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149907	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-149908	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149910	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149915	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149920	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149943	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149945	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149954	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-149977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149981	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149987	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149990	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149994	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150005	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150014	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-150045	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-150048	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150056	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150069	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150095	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.001

G-150096	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-150123	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-150142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150143	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0008	0.0005
G-150161	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150163	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-150176	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0143	0.0024
G-150180	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150181	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-150196	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-150197	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150206	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150222	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-150228	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-150241	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150248	Light-Duty	Drive Clean	EV Vehicle Rebate	0.012	0.002
G-150249	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-150290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0097	0.0016
G-150295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150296	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150297	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150324	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150329	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-150331	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150333	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-150345	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150347	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-150349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150358	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150381	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-150382	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0157	0.0026
G-150388	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150402	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-150407	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-150409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150416	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150418	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150423	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-150428	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0101	0.0017
G-150431	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015

G-150433	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150435	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150471	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150485	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150486	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-150512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-150517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-150518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150549	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-150561	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-150576	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-150578	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150592	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-150598	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150606	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-150607	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150609	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150610	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-150613	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150615	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-150617	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150618	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150619	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150630	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150639	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-150642	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-150646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150650	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-150694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150705	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-150712	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150736	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150741	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150756	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150769	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150775	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150776	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011

G-150824	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-150826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-150827	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150829	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-150832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150839	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150845	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-150847	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150849	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-150853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150856	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150861	Light-Duty	Drive Clean	EV Vehicle Rebate	0.033	0.0055
G-150864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-150886	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150889	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150896	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150907	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-150913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150914	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-150915	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-150927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150929	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150930	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150948	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-150953	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150989	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150994	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-151027	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-151028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-151032	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151049	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-151058	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151061	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151066	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151118	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151124	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151129	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0061	0.001
G-151132	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-151154	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151155	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-151157	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151159	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151163	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151174	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151191	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151193	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-151197	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0085	0.0014
G-151203	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151208	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-151241	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151243	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0078	0.0013
G-151249	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151258	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151260	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151268	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151270	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151280	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-151282	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151285	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151303	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151305	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151306	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-151309	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-151315	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151317	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0118	0.002
G-151320	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151321	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-151322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-151325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151335	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-151337	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151339	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-151349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-151352	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-151362	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-151364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151366	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151404	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-151406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-151409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151423	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-151430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151438	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151462	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-151470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151479	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-151480	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-151482	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151542	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-151546	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-151556	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151560	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151564	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151573	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151577	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151578	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-151579	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151581	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-151636	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-151638	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-151647	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.0079
G-151666	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-151703	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-151714	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-151717	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-151718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151740	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151742	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151754	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-151760	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151762	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-151766	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-151779	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-151782	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-151789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151803	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-151818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151851	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-151868	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151873	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151877	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151881	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-151888	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-151889	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151894	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-151900	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-151903	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151914	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151919	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151922	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-151927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151928	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0169	0.0028
G-151931	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151932	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151949	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151950	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-151955	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-151974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151980	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-151989	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152000	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-152008	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152014	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152018	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152019	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152022	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-152025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152027	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012

G-152028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-152029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-152033	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152036	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152037	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152044	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152091	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152105	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152108	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152119	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-152122	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152171	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152175	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-152180	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152190	Light-Duty	Drive Clean	EV Vehicle Rebate	0.01	0.0017
G-152194	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-152200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152222	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152226	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152228	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152232	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152236	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-152248	Light-Duty	Drive Clean	EV Vehicle Rebate	0.003	0.0005
G-152251	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-152260	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-152292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152297	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152308	Light-Duty	Drive Clean	EV Vehicle Rebate	0.002	0.0003
G-152314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-152325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-152331	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-152334	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-152335	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152337	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-152341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152343	Light-Duty	Drive Clean	EV Vehicle Rebate	0.019	0.0022
G-152344	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152346	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006

G-152347	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152350	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152352	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152356	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-152359	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152362	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152369	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0097	0.0016
G-152375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152379	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152382	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152383	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-152392	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0021	0.0004
G-152393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-152395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-152406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0169	0.0028
G-152407	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0192	0.0032
G-152417	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-152420	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0092	0.0015
G-152424	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152431	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-152432	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152450	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152455	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0096	0.0016
G-152460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-152461	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0297	0.005
G-152462	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0017	0.0003
G-152465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0045	0.0007
G-152472	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152491	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.003	0.0005
G-152516	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152520	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152521	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0021	0.0004
G-152534	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152537	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152543	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0036	0.0006
G-152563	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0036	0.0006

G-152565	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0036	0.0006
G-152618	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152623	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152627	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0101	0.0017
G-152647	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-152665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152670	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-152673	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-152674	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-152678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152679	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0446	0.0074
G-152680	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-152681	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152686	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-152738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152751	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152752	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152785	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152795	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152798	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-152801	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152805	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-152808	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0008	0.0005
G-152815	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152820	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152825	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152836	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152837	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152845	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152846	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152848	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152851	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152852	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-152854	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003

G-152858	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-152860	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152861	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152862	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152866	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152874	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152875	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152881	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0013	0.0009
G-152890	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152894	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.001	0.0006
G-152904	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152921	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152924	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152926	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152949	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152960	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152965	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-152966	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-152970	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-152971	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152972	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-152976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-152979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-152980	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153024	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153026	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-153040	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-153053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.003	0.0005
G-153054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153055	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-153059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153061	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153066	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153073	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153076	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153084	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008

G-153101	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153105	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153111	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153151	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-153152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153153	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153154	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-153166	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-153168	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0037	0.0006
G-153170	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-153174	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-153216	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153223	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0023	0.0004
G-153227	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153229	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0017	0.0003
G-153231	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153232	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0019	0.0003
G-153235	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.001
G-153240	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-153244	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-153260	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0032	0.0005
G-153262	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-153273	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0062	0.001
G-153274	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153278	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153306	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-153314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153319	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-153321	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-153340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-153359	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153360	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-153367	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153369	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153372	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012

G-153373	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-153375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153377	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153383	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.002	0.0003
G-153391	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-153396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153401	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0025	0.0004
G-153402	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153404	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-153406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153437	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153450	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-153460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153462	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-153467	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-153468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0042	0.0007
G-153470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153471	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-153483	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0037	0.0006
G-153485	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153491	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153498	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153500	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-153507	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153509	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0039	0.0006
G-153513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0013	0.0009
G-153519	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0042	0.0007
G-153520	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153523	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-153524	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0258	0.0043
G-153525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-153530	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0028	
G-153531	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153532	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153534	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153536	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153538	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153541	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-153547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-153562	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153570	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153591	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153604	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153619	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153624	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153632	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153641	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-153655	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
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G-153665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
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G-153684	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
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G-153698	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
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G-153701	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-153758	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-153761	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153762	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-153784	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153791	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153793	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153806	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153808	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
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G-153830	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
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G-153884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
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G-153905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
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G-153917	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
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G-153924	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0005
G-153930	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153932	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-153933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153934	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153941	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
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G-153967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153984	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0011	0.0007
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G-154012	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-154022	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154024	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-154028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154030	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003

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G-154049	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154051	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
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G-154054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-154055	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-154060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154067	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-154068	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
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G-154094	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
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G-154109	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
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G-154125	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
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G-154142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
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G-154227	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
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G-154726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-155245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-155271	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-155336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0011	0.0007

G-155468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0008	0.0005
G-155515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-155561	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-155700	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-155738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-155744	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-155830	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-155971	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156039	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0013	0.0009
G-156307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-156314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-156322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-156324	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156343	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-156374	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-156385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004

Appendix

San Joaquin Valley Air Pollution Control District and South Coast Air Quality Management District *Sierra Club v. County of Fresno* Amicus Curiae Briefs

SUPREME COURT COPY

CASE NO. S219783

IN THE SUPREME COURT OF CALIFORNIA

SIERRA CLUB, REVIVE THE SAN JOAQUIN, and
LEAGUE OF WOMEN VOTERS OF FRESNO,
Plaintiffs and Appellants

v.

COUNTY OF FRESNO,
Defendant and Respondent

FRIANT RANCH, L.P.,
Real Party in Interest and Respondent

SUPREME COURT
FILED
APR 13 2015
Frank A. McGuire Clerk
Deputy

After a Decision by the Court of Appeal, filed May 27, 2014
Fifth Appellate District Case No. F066798

Appeal from the Superior Court of California, County of Fresno
Case No. 11CECG00726

APPLICATION FOR LEAVE TO FILE AMICUS CURIAE BRIEF OF SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT IN SUPPORT OF DEFENDANT AND RESPONDENT, COUNTY OF FRESNO AND REAL PARTY IN INTEREST AND RESPONDENT, FRIANT RANCH, L.P.

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Counsel for San Joaquin Valley Unified Air Pollution Control District

CASE NO. S219783

IN THE SUPREME COURT OF CALIFORNIA

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LEAGUE OF WOMEN VOTERS OF FRESNO,
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APPLICATION

Pursuant to California Rules of Court 8.520(f)(1), proposed Amicus Curiae San Joaquin Valley Unified Air Pollution Control District hereby requests permission from the Chief Justice to file an amicus brief in support of Defendant and Respondent, County of Fresno, and Defendant and Real Parties in Interest Friant Ranch, L.P. Pursuant to Rule 8.520(f)(5) of the California Rules of Court, the proposed amicus curiae brief is combined with this Application. The brief addresses the following issue certified by this Court for review:

> Is an EIR adequate when it identifies the health impacts of air pollution and quantifies a project's expected emissions, or does CEQA further require the EIR to *correlate* a project's air quality emissions to specific health impacts?

As of the date of this filing, the deadline for the final reply brief on the merits was March 5, 2015. Accordingly, under Rule 8.520(f)(2), this application and brief are timely.

1. Background and Interest of San Joaquin Valley Unified Air Pollution Control District

The San Joaquin Valley Unified Air Pollution Control District ("Air District") regulates air quality in the eight counties comprising the San Joaquin Valley ("Central Valley"): Kern, Tulare, Madera, Fresno, Merced, San Joaquin, Stanislaus, and Kings, and is primarily responsible for attaining air quality standards within its jurisdiction. After billions of dollars of investment by Central Valley businesses, pioneering air quality regulations, and consistent efforts by residents, the Central Valley air basin has made historic improvements in air quality.

The Central Valley's geographical, topographical and meteorological features create exceptionally challenging air quality

conditions. For example, it receives air pollution transported from the San Francisco Bay Area and northern Central Valley communities, and the southern portion of the Central Valley includes three mountain ranges (Sierra, Tehachapi, and Coastal) that, under some meteorological conditions, effectively trap air pollution. Central Valley air pollution is only a fraction of what the Bay Area and Los Angeles produce, but these natural conditions result in air quality conditions that are only marginally better than Los Angeles, even though about ten times more pollution is emitted in the Los Angeles region. Bay Area air quality is much better than the Central Valley's, even though the Bay Area produces about six times more pollution. The Central Valley also receives air pollution transported from the Bay Area and northern counties in the Central Valley, including Sacramento, and transboundary anthropogenic ozone from as far away as China.

Notwithstanding these challenges, the Central Valley has reduced emissions at the same or better rate than other areas in California and has achieved unparalleled milestones in protecting public health and the environment:

- In the last decade, the Central Valley became the first air basin classified by the federal government under the Clean Air Act as a "serious nonattainment" area to come into attainment of health-based National Ambient Air Quality Standard ("NAAQS") for coarse particulate matter (PM10), an achievement made even more notable given the Valley's extensive agricultural sector. Unhealthy levels of particulate matter can cause and exacerbate a range of chronic and acute illnesses.
- In 2013, the Central Valley became the first air basin in the country to improve from a federal designation of "extreme" nonattainment to

actually attain (and quality for an attainment designation) of the 1-hour ozone NAAQS; ozone creates "smog" and, like PM10, causes adverse health impacts.

- The Central Valley also is in full attainment of federal standards for lead, nitrogen dioxide, sulfur dioxide, and carbon monoxide.
- The Central Valley continues to make progress toward compliance with its last two attainment standards, with the number of exceedences for the 8-hour ozone NAAQS reduced by 74% (for the 1997 standard) and 38% (for the 2008 standard) since 1991, and for the small particulate matter (PM2.5) NAAQS reduced by 85% (for the 1997 standard) and 61% (for the 2006 standard).

Sustained improvement in Central Valley air quality requires a rigorous and comprehensive regulatory framework that includes prohibitions (e.g., on wood-burning fireplaces in new residences), mandates (e.g., requiring the installation of best available pollution reduction technologies on new and modified equipment and industrial operations), innovations (e.g., fees assessed against residential development to fund pollution reduction actions to "offset" vehicular emissions associated with new residences), incentive programs (e.g., funding replacements of older, more polluting heavy duty trucks and school buses)[1], ongoing planning for continued air quality improvements, and enforcement of Air District permits and regulations.

The Air District is also an expert air quality agency for the eight counties and cities in the San Joaquin Valley. In that capacity, the Air District has developed air quality emission guidelines for use by the Central

[1] San Joaquin's incentive program has been so successful that through 2012, it has awarded over $ 432 million in incentive funds and has achieved 93,349 tons of lifetime emissions reductions. *See* SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT, 2012 PM2.5 PLAN, 6-6 (2012) *available at* http://www.valleyair.org/Workshops/postings/2012/12-20-12PM25/FinalVersion/06%20Chapter%206%20Incentives.pdf.

Valley counties and cities that implement the California Environment Quality Act (CEQA).[2] In its guidance, the Air District has distinguished between toxic air contaminants and criteria air pollutants.[3] Recognizing this distinction, the Air District's CEQA Guidance has adopted distinct thresholds of significance for *criteria* pollutants (i.e., ozone, PM2.5 and their respective precursor pollutants) based upon scientific and factual data which demonstrates the level that can be accommodated on a cumulative basis in the San Joaquin Valley without affecting the attainment of the applicable NAAQS.[4] For *toxic air* pollutants, the District has adopted different thresholds of significance which scientific and factual data demonstrates has the potential to expose sensitive receptors (i.e., children, the elderly) to levels which may result in localized health impacts.[5]

The Air District's CEQA Guidance was followed by the County of Fresno in its environment review of the Friant Ranch project, for which the Air District also served as a commenting agency. The Court of Appeal's holding, however, requiring correlation between the project's criteria

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[2] *See, e.g.*, SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT, PLANNING DIVISION, GUIDE FOR ASSESSING AND MITIGATING AIR QUALITY IMPACTS (2015), *available at* http://www.valleyair.org/transportation/GAMAQI_3-19-15.pdf ("CEQA Guidance").

[3] Toxic air contaminants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as birth defects. There are currently 189 toxic air contaminants regulated by the United States Environmental Protection Agency ("EPA") and the states pursuant to the Clean Air Act. 42 U.S.C. § 7412. Common TACs include benzene, perchloroethylene and asbestos. *Id.* at 7412(b).

In contrast, there are only six (6) criteria air pollutants: ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide and lead. Although criteria air pollutants can also be harmful to human health, they are distinguishable from toxic air contaminants and are regulated separately. For instance, while criteria pollutants are regulated by numerous sections throughout Title I of the Clean Air Act, the regulation of toxic air contaminants occurs solely under section 112 of the Act. Compare 42 U.S.C. §§ 7407 – 7411 & 7501 – 7515 with 42 U.S.C. § 7411.

[4] See, e.g., CEQA Guidance at http://www.valleyair.org/transportation/GAMAQI_3-19-15.pdf, pp. 64-66, 80.

[5] See, e.g., CEQA Guidance at http://www.valleyair.org/transportation/GAMAQI_3-19-15.pdf, pp. 66, 99-101.

pollutants and local health impacts, departs from the Air District's Guidance and approved methodology for assessing criteria pollutants. A close reading of the administrative record that gave rise to this issue demonstrates that the Court's holding is based on a misunderstanding of the distinction between toxic air contaminants (for which a local health risk assessment is feasible and routinely performed) and criteria air pollutants (for which a local health risk assessment is not feasible and would result in speculative results).[6] The Air District has a direct interest in ensuring the lawfulness and consistent application of its CEQA Guidance, and will explain how the Court of Appeal departed from the Air District's long-standing CEQA Guidance in addressing criteria pollutants and toxic air contaminants in this amicus brief.

2. How the Proposed Amicus Curiae Brief Will Assist the Court

As counsel for the proposed amicus curiae, we have reviewed the briefs filed in this action. In addition to serving as a "commentary agency" for CEQA purposes over the Friant Ranch project, the Air District has a strong interest in assuring that CEQA is used for its intended purpose, and believes that this Court would benefit from additional briefing explaining the distinction between criteria pollutants and toxic air contaminants and the different methodologies employed by local air pollution control agencies such as the Air District to analyze these two categories of air pollutants under CEQA. The Air District will also explain how the Court of Appeal's opinion is based upon a fundamental misunderstanding of these two different approaches by requiring the County of Fresno to correlate the project's *criteria* pollution emissions with *local* health impacts. In doing

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[6] CEQA does not require speculation. *See, e.g., Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.*, 6 Cal. 4th 1112, 1137 (1993) (upholding EIR that failed to evaluate cumulative toxic air emission increases given absence of any acceptable means for doing so).

so, the Air District will provide helpful analysis to support its position that at least insofar as criteria pollutants are concerned, CEQA does not require an EIR to correlate a project's air quality emissions to specific health impacts, because such an analysis is not reasonably feasible.

Rule 8.520 Disclosure

Pursuant to Cal. R. 8.520(f)(4), neither the Plaintiffs nor the Defendant or Real Party In Interest or their respective counsel authored this brief in whole or in part. Neither the Plaintiffs nor the Defendant or Real Party in Interest or their respective counsel made any monetary contribution towards or in support of the preparation of this brief.

CONCLUSION

On behalf of the San Joaquin Valley Unified Air Pollution Control District, we respectfully request that this Court accept the filing of the attached brief.

Dated: April 2, 2015



Annette A. Ballatore-Williamson
District Counsel
Attorney for Proposed Amicus Curiae

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL
DISTRICT

CASE NO. S219783

IN THE SUPREME COURT OF CALIFORNIA

SIERRA CLUB, REVIVE THE SAN JOAQUIN, and
LEAGUE OF WOMEN VOTERS OF FRESNO,
Plaintiffs and Appellants

v.

COUNTY OF FRESNO,
Defendant and Respondent

FRIANT RANCH, L.P.,
Real Party in Interest and Respondent

After a Decision by the Court of Appeal, filed May 27, 2014
Fifth Appellate District Case No. F066798

Appeal from the Superior Court of California, County of Fresno
Case No. 11CECG00726

AMICUS CURIAE BRIEF OF SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT IN SUPPORT OF DEFENDANT AND RESPONDENT, COUNTY OF FRESNO AND REAL PARTY IN INTEREST AND RESPONDENT, FRIANT RANCH, L.P.

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I. INTRODUCTION.

The San Joaquin Valley Unified Air Pollution Control District ("Air District") respectfully submits that the Court of Appeal erred when it held that the air quality analysis contained in the Environmental Impact Report ("EIR") for the Friant Ranch development project was inadequate under the California Environmental Quality Act ("CEQA") because it did not include an analysis of the correlation between the project's criteria air pollutants and the potential adverse human health impacts. A close reading of the portion of the administrative record that gave rise to this issue demonstrates that the Court's holding is based on a misunderstanding of the distinction between toxic air contaminants and criteria air pollutants.

Toxic air contaminants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as birth defects. There are currently 189 toxic air contaminants (hereinafter referred to as "TACs") regulated by the United States Environmental Protection Agency ("EPA") and the states pursuant to the Clean Air Act. 42 U.S.C. § 7412. Common TACs include benzene, perchloroethylene and asbestos. *Id.* at 7412(b).

In contrast, there are only six (6) criteria air pollutants: ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide and lead. Although criteria air pollutants can also be harmful to human health,

they are distinguishable from TACs and are regulated separately. For instance, while criteria pollutants are regulated by numerous sections throughout Title I of the Clean Air Act, the regulation of TACs occurs solely under section 112 of the Act. *Compare* 42 U.S.C. §§ 7407 – 7411 & 7501 – 7515 *with* 42 U.S.C. § 7411.

The most relevant difference between criteria pollutants and TACs for purposes of this case is the manner in which human health impacts are accounted for. While it is common practice to analyze the correlation between an individual facility's TAC emissions and the expected localized human health impacts, such is not the case for criteria pollutants. Instead, the human health impacts associated with criteria air pollutants are analyzed and taken into consideration when EPA sets the national ambient air quality standard ("NAAQS") for each criteria pollutant. 42 U.S.C. § 7409(b)(1). The health impact of a particular criteria pollutant is analyzed on a regional and not a facility level based on how close the area is to complying with (attaining) the NAAQS. Accordingly, while the type of individual facility / health impact analysis that the Court of Appeal has required is a customary practice for TACs, it is not feasible to conduct a similar analysis for criteria air pollutants because currently available computer modeling tools are not equipped for this task.

It is clear from a reading of both the administrative record and the Court of Appeal's decision that the Court did not have the expertise to fully

appreciate the difference between TACs and criteria air pollutants. As a result, the Court has ordered the County of Fresno to conduct an analysis that is not practicable and not likely yield valid information. The Air District respectfully requests that this portion of the Court of Appeal's decision be reversed.

II. THE COURT OF APPEAL ERRED IN FINDING THE FRIANT RANCH EIR INADEQUATE FOR FAILING TO ANALYZE THE SPECIFIC HUMAN HEALTH IMPACTS ASSOCIATED CRITERIA AIR POLLUTANTS.

Although the Air District does not take lightly the amount of air emissions at issue in this case, it submits that the Court of Appeal got it wrong when it required Fresno County to revise the Friant Ranch EIR to include an analysis correlating the criteria air pollutant emissions associated with the project with specific, localized health-impacts. The type of analysis the Court of Appeal has required will not yield reliable information because currently available modeling tools are not well suited for this task. Further, in reviewing this issue de novo, the Court of Appeal failed to appreciate that it lacked the scientific expertise to appreciate the significant differences between a health risk assessment commonly performed for toxic air contaminants and a similar type of analysis it felt should have been conducted for criteria air pollutants.

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A. Currently Available Modeling Tools are not Equipped to Provide a Meaningful Analysis of the Correlation between an Individual Development Project's Air Emissions and Specific Human Health Impacts.

In order to appreciate the problematic nature of the Court of Appeals' decision requiring a health risk type analysis for criteria air pollutants, it is important to understand how the relevant criteria pollutants (ozone and particulate matter) are formed, dispersed and regulated.

Ground level ozone (smog) is not directly emitted into the air, but is formed when precursor pollutants such as oxides of nitrogen (NOx) and volatile organic compounds (VOCs) are emitted into the atmosphere and undergo complex chemical reactions in the process of sunlight.[1] Once formed, ozone can be transported long distances by wind.[2] Because of the complexity of ozone formation, a specific tonnage amount of NOx or VOCs emitted in a particular area does not equate to a particular concentration of ozone in that area. In fact, even rural areas that have relatively low tonnages of emissions of NOx or VOCs can have high levels of ozone concentration simply due to wind transport.[3] Conversely, the San Francisco Bay Area has six times more NOx and VOC emissions per square mile than the San Joaquin Valley, but experiences lower

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[1] *See* United States Environmental Protection Agency, *Ground-level Ozone: Basic Information*, available at: http://www.epa.gov/airquality/ozonepollution/basic.html (visited March 10, 2015).
[2] *Id.*
[3] *Id.*

concentrations of ozone (and better air quality) simply because sea breezes disperse the emissions.[4]

Particulate matter ("PM") can be divided into two categories: directly emitted PM and secondary PM.[5] While directly emitted PM can have a localized impact, the tonnage emitted does not always equate to the local PM concentration because it can be transported long distances by wind.[6] Secondary PM, like ozone, is formed via complex chemical reactions in the atmosphere between precursor chemicals such as sulfur dioxides (SOx) and NOx.[7] Because of the complexity of secondary PM formation, the tonnage of PM-forming precursor emissions in an area does not necessarily result in an equivalent concentration of secondary PM in that area.

The disconnect between the *tonnage* of precursor pollutants (NOx, SOx and VOCs) and the *concentration* of ozone or PM formed is important because it is not necessarily the tonnage of precursor pollutants that causes human health effects, but the concentration of resulting ozone or PM. Indeed, the national ambient air quality standards ("NAAQS"), which are statutorily required to be set by the United States Environmental Protection

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[4] *San Joaquin Valley Air Pollution Control District 2007 Ozone Plan*, Executive Summary p. ES-6, available at: http://www.valleyair.org/Air_Quality_Plans/docs/AQ_Ozone_2007_Adopted/03%20Executive%20Summary.pdf (visited March 10, 2015).

[5] United States Environmental Protection Agency, *Particulate Matter: Basic Information*, available at: http://www.epa.gov/airquality/particlepollution/basic.html (visited March 10, 2015).

[6] *Id.*

[7] *Id.*

Agency ("EPA") at levels that are "requisite to protect the public health," 42 U.S.C. § 7409(b)(1), are established as concentrations of ozone or particulate matter and not as tonnages of their precursor pollutants.[8]

Attainment of a particular NAAQS occurs when the concentration of the relevant pollutant remains below a set threshold on a consistent basis throughout a particular region. For example, the San Joaquin Valley attained the 1-hour ozone NAAQS when ozone concentrations remained at or below 0.124 parts per million Valley-wide on 3 or fewer days over a 3-year period.[9] Because the NAAQS are focused on achieving a particular concentration of pollution region-wide, the Air District's tools and plans for attaining the NAAQS are regional in nature.

For instance, the computer models used to simulate and predict an attainment date for the ozone or particulate matter NAAQS in the San Joaquin Valley are based on regional inputs, such as regional inventories of precursor pollutants (NOx, SOx and VOCs) and the atmospheric chemistry and meteorology of the Valley.[10] At a very basic level, the models simulate future ozone or PM levels based on predicted changes in precursor

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[8] See, e.g., United States Environmental Protection Agency, *Table of National Ambient Air Quality Standards*, available at: http://www.epa.gov/air/criteria.html#3 (visited March 10, 2015).

[9] *San Joaquin Valley Unified Air Pollution Control District 2013 Plan for the Revoked 1-Hour Ozone Standard*, Ch. 2 p. 2-16, available at: http://www.valleyair.org/Air_Quality_Plans/OzoneOneHourPlan2013/02Chapter2ScienceTrendsModeling.pdf (visited March 10, 2015).

[10] *Id.* at Ch. 2 p. 2-19 (visited March 12, 2015); *San Joaquin Valley Unified Air Pollution Control District 2008 PM2.5 Plan*, Appendix F, pp. F-2 – F-5, available at: http://www.valleyair.org/Air_Quality_Plans/docs/AQ_Final_Adopted_PM2.5/20%20Appendix%20F.pdf (visited March 19, 2015).

emissions Valley wide.[11] Because the NAAQS are set levels necessary to protect human health, the closer a region is to attaining a particular NAAQS, the lower the human health impact is from that pollutant.

The goal of these modeling exercises is not to determine whether the emissions generated by a particular factory or development project will affect the date that the Valley attains the NAAQS. Rather, the Air District's modeling and planning strategy is regional in nature and based on the extent to which *all* of the emission-generating sources in the Valley (current and future) must be controlled in order to reach attainment.[12]

Accordingly, the Air District has based its thresholds of significance for CEQA purposes on the levels that scientific and factual data demonstrate that the Valley can accommodate without affecting the attainment date for the NAAQS.[13] The Air District has tied its CEQA significance thresholds to the level at which stationary pollution sources permitted by the Air District must "offset" their emissions.[14] This "offset"

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[11] *Id.*

[12] Although the Air District does have a dispersion modeling tool used during its air permitting process that is used to predict whether a particular project's directly emitted PM will either cause an exceedance of the PM NAAQS or contribute to an existing exceedance, this model bases the prediction on a worst case scenario of emissions and meteorology and has no provision for predicting any associated human health impacts. Further, this analysis is only performed for stationary sources (factories, oil refineries, etc.) that are required to obtain a New Source Review permit from the Air District and not for development projects such as Friant Ranch over which the Air District has no preconstruction permitting authority. *See* San Joaquin Valley Unified Air Pollution Control District Rule 2201 §§ 2.0; 3.3.9; 4.14.1, available at: http://www.valleyair.org/rules/currntrules/Rule2201041l.pdf (visited March 19, 2015).

[13] *San Joaquin Valley Unified Air Pollution Control District Guide to Assessing and Mitigating Air Quality Impacts*, (March 19, 2015) p. 22, available at: http://www.valleyair.org/transportation/CEQA%20Rules/GAMAQI%20Jan%202002%20Rev.pdf (visited March 30, 2015).

[14] *Id.* at pp. 22, 25.

level allows for growth while keeping the cumulative effects of all new sources at a level that will not impede attainment of the NAAQS.[15] In the Valley, these thresholds are 15 tons per year of PM, and 10 tons of NOx or VOC per year. *Sierra Club, supra*, 172 Cal.Rptr.3d at 303; AR 4554. Thus, the CEQA air quality analysis for criteria pollutants is not really a localized, project-level impact analysis but one of regional, "cumulative impacts."

Accordingly, the significance thresholds applied in the Friant Ranch EIR (15 tons per year of PM and 10 tons of NOx or VOCs) are not intended to be indicative of any localized human health impact that the project may have. While the health effects of air pollution are of primary concern to the Air District (indeed, the NAAQS are established to protect human health), the Air District is simply not equipped to analyze whether and to what extent the criteria pollutant emissions of an individual CEQA project directly impact human health in a particular area. This is true even for projects with relatively high levels of emissions of criteria pollutant precursor emissions.

For instance, according to the EIR, the Friant Ranch project is estimated to emit 109.52 tons per year of ROG (VOC), 102.19 tons per year of NOx, and 117.38 tons per year of PM. Although these levels well

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[15] [15] *San Joaquin Valley Unified Air Pollution Control District Environmental Review Guidelines* (Aug. 2000) p. 4-11, available at: http://www.valleyair.org/transportation/CEQA%20Rules/ERG%20Adopted%20_August%202000_.pdf (visited March 12, 2015).

exceed the Air District's CEQA significance thresholds, this does not mean that one can easily determine the concentration of ozone or PM that will be created at or near the Friant Ranch site on a particular day or month of the year, or what specific health impacts will occur. Meteorology, the presence of sunlight, and other complex chemical factors all combine to determine the ultimate concentration and location of ozone or PM. This is especially true for a project like Friant Ranch where most of the criteria pollutant emissions derive not from a single "point source," but from area wide sources (consumer products, paint, etc.) or mobile sources (cars and trucks) driving to, from and around the site.

In addition, it would be extremely difficult to model the impact on NAAQS attainment that the emissions from the Friant Ranch project may have. As discussed above, the currently available modeling tools are equipped to model the impact of *all* emission sources in the Valley on attainment. According to the most recent EPA-approved emission inventory, the NOx inventory for the Valley is for the year 2014 is 458.2 tons per day, or 167,243 tons per year and the VOC (or ROG) inventory is 361.7 tons per day, or 132,020.5 tons per year.[16] Running the photochemical grid model used for predicting ozone attainment with the

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[16] *San Joaquin Valley Unified Air Pollution Control District 2007 Ozone Plan*, Appendix B pp. B-6, B-9,
available at:
http://www.valleyair.org/Air_Quality_Plans/docs/AQ_Ozone_2007_Adopted/19%20Appendix%20B%20April%202007.pdf (visited March 12, 2015).

emissions solely from the Friant Ranch project (which equate to less than one-tenth of one percent of the total NOx and VOC in the Valley) is not likely to yield valid information given the relative scale involved.

Finally, even once a model is developed to accurately ascertain local increases in concentrations of photochemical pollutants like ozone and some particulates, it remains impossible, using today's models, to correlate that increase in concentration to a specific health impact. The reason is the same: such models are designed to determine regional, population-wide health impacts, and simply are not accurate when applied at the local level.

For these reasons, it is not the norm for CEQA practitioners, including the Air District, to conduct an analysis of the localized health impacts associated with a project's criteria air pollutant emissions as part of the EIR process. When the accepted scientific method precludes a certain type of analysis, "the court cannot impose a legal standard to the contrary." *Kings County Farm Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692, 717 n. 8. However, that is exactly what the Court of Appeal has done in this case. Its decision upends the way CEQA air quality analysis of criteria pollutants occurs and should be reversed.

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B. The Court of Appeal Improperly Extrapolated a Request for a Health Risk Assessment for Toxic Air Contaminants into a Requirement that the EIR contain an Analysis of Localized Health Impacts Associated with Criteria Air Pollutants.

The Court of Appeal's error in requiring the new health impact analysis for criteria air pollutants clearly stems from a misunderstanding of terms of art commonly used in the air pollution field. More specifically, the Court of Appeal (and Appellants Sierra Club et al.) appear to have confused the health risk analysis ("HRA") performed to determine the health impacts associated with a project's toxic air contaminants ("TACs"), with an analysis correlating a project's criteria air pollutants (ozone, PM and the like) with specific localized health impacts.

The first type of analysis, the HRA, is commonly performed during the Air District's stationary source permitting process for projects that emit TACs and is, thus, incorporated into the CEQA review process. An HRA is a comprehensive analysis to evaluate and predict the dispersion of TACs emitted by a project and the potential for exposure of human populations. It also assesses and quantifies both the individual and population-wide health risks associated with those levels of exposure. There is no similar analysis conducted for criteria air pollutants. Thus, the second type of analysis (required by the Court of Appeal), is not currently part of the Air District's process because, as outlined above, the health risks associated

with exposure to criteria pollutants are evaluated on a regional level based on the region's attainment of the NAAQS.

The root of this confusion between the types of analyses conducted for TACs versus criteria air pollutants appears to stem from a comment that was presented to Fresno County by the City of Fresno during the administrative process.

In its comments on the draft EIR, the City of Fresno (the only party to raise this issue) stated:

> [t]he EIR must disclose the human health related effects of the Project's air pollution impacts. (CEQA Guidelines section 15126.2(a).) The EIR fails completely in this area. The EIR should be revised to disclose and determine the significance of TAC impacts, and of human health risks due to exposure to Project-related air emissions.

(AR 4602.)

In determining that the issue regarding the correlation between the Friant Ranch project's criteria air pollutants and adverse health impacts was adequately exhausted at the administrative level, the Court of Appeal improperly read the first two sentences of the City of Fresno's comment in isolation rather than in the context of the entire comment. *See Sierra Club v. County of Fresno* (2014) 172 Cal.Rptr.3d 271, 306. Although the comment first speaks generally in terms of "human health related effects" and "air pollution," it requests only that the EIR be revised to disclose "the significance of TACs" and the "human health risks due to exposure."

The language of this request in the third sentence of the comment is significant because, to an air pollution practitioner, the language would only have indicated only that a HRA for TACs was requested, and not a separate analysis of the health impacts associated with the project's criteria air pollutants. Fresno County clearly read the comment as a request to perform an HRA for TACs and limited its response accordingly. (AR 4602.)[17] The Air District submits that it would have read the City's comment in the same manner as the County because the City's use of the terms "human health risks" and "TACs" signal that an HRA for TACs is being requested. Indeed, the Air District was also concerned that an HRA be conducted, but understood that it was not possible to conduct such an analysis until the project entered the phase where detailed site specific information, such as the types of emission sources and the proximity of the sources to sensitive receptors became available. (AR 4553.)[18] The City of Fresno was apparently satisfied with the County's discussion of human health risks, as it did not raise the issue again when it commented on the final EIR. (AR 8944 – 8960.)

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[17] Appellants do not challenge the manner in which the County addressed TACs in the EIR. (Appellants' Answer Brief p. 28 fn. 7.)

[18] Appellants rely on the testimony of Air District employee, Dan Barber, as support for their position that the County should have conducted an analysis correlating the project's criteria air pollutant emissions with localized health impacts. (Appellants Answer Brief pp. 10-11; 28.) However, Mr. Barber's testimony simply reinforces the Air District's concern that a risk assessment (HRA) be conducted once the actual details of the project become available. (AR 8863.) As to criteria air pollutants, Mr. Barber's comments are aimed at the Air District's concern about the amount of emissions and the fact that the emissions will make it "more difficult for Fresno County and the Valley to reach attainment which means that the health of Valley residents maybe [sic] adversely impacted." Mr. Barber says nothing about conducting a separate analysis of the localized health impacts the project's emissions may have.

The Court of Appeal's holding, which incorrectly extrapolates a request for an HRA for TACs into a new analysis of the localized health impacts of the project's criteria air pollutants, highlights two additional errors in the Court's decision.

First, the Court of Appeal's holding illustrates why the Court should have applied the deferential substantial evidence standard of review to the issue of whether the EIR's air quality analysis was sufficient. The regulation of air pollution is a technical and complex field and the Court of Appeal lacked the expertise to fully appreciate the difference between TACs and criteria air pollutants and tools available for analyzing each type of pollutant.

Second, it illustrates that the Court likely got it wrong when it held that the issue regarding the criteria pollutant / localized health impact analysis was properly exhausted during the administrative process. In order to preserve an issue for the court, '[t]he "exact issue" must have been presented to the administrative agency....' [Citation.] *Citizens for Responsible Equitable Environmental Development v. City of San Diego*, (2011) 196 Cal.App.4th 515, 527 129 Cal.Rptr.3d 512, 521; *Sierra Club v. City of Orange* (2008) 163 Cal.App.4th 523, 535, 78 Cal.Rptr.3d 1, 13. "'[T]he objections must be sufficiently specific so that the agency has the

opportunity to evaluate and respond to them.' [Citation.]" *Sierra Club v. City of Orange*,163 Cal.App.4th at 536.[19]

As discussed above, the City's comment, while specific enough to request a commonly performed HRA for TACs, provided the County with no notice that it should perform a new type of analysis correlating criteria pollutant tonnages to specific human health effects. Although the parties have not directly addressed the issue of failure to exhaust administrative remedies in their briefs, the Air District submits that the Court should consider how it affects the issues briefed by the parties since "[e]xhaustion of administrative remedies is a jurisdictional prerequisite to maintenance of a CEQA action." *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1199, 22 Cal.Rptr.3d 203.

III. CONCLUSION

For all of the foregoing reasons, the Air District respectfully requests that the portion of the Court of Appeal's decision requiring an analysis correlating the localized human health impacts associated with an individual project's criteria air pollutant emissions be reversed.

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[19] *Sierra Club v. City of Orange*, is illustrative here. In that case, the plaintiffs challenged an EIR approved for a large planned community on the basis that the EIR improperly broke up the various environmental impacts by separate project components or "piecemealed" the analysis in violation of CEQA. In evaluating the defense that the plaintiffs had failed to adequately raise the issue at the administrative level, the Court held that comments such as *"the use of a single document for both a project-level and a program-level EIR [is] 'confusing',"* and *"[t]he lead agency should identify any potential adverse air quality impacts that could occur from all phases of the project and all air pollutant sources related to the project,"* were too vague to fairly raise the argument of piecemealing before the agency. *Sierra Club v. City of Orange*, 163 Cal.App.4th at 537.

correlating the localized human health impacts associated with an individual project's criteria air pollutant emissions be reversed.

Respectfully submitted,

Dated: April 2, 2015

Catherine T. Redmond
Attorney for Proposed Amicus Curiae

SAN JOAQUIN VALLEY
UNIFIED
AIR POLLUTION CONTROL
DISTRICT

CERTIFICATE OF WORD COUNT

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Dated: April 2, 2015

Annette A. Ballatore-Williamson
District Counsel (SBN 192176)

Sierra Club et al, v. County of Fresno, et al
Supreme Court of California Case No.: S219783
Fifth District Court of Appeal Case No.: F066798
Fresno County Superior Court Case No.: 11CECG00726

PROOF OF SERVICE

I am over the age of 18 years and not a p[arty to the above-captioned action; that my business address is San Joaquin Valley Unified Air Pollution Control District located at 1990 E. Gettysburg Avenue, Fresno, California 93726.

On April 2, 2015, I served the document described below:

APPLICATION FOR LEAVE TO FILE AMICUS CURIAE BRIEF OF SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT IN SUPPORT OF DEFENDANT AND RESPONDENT, COUNTY OF FRESNO

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( ) **(BY OVERNIGHT MAIL)** I caused a true and correct copy to be delivered via Federal Express to the following person(s) or their representative at the address(es) listed below.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct and that I executed this document on April 2, 2015, at Fresno, California.

Esthela Soto

SERVICE LIST

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Supreme Court of California Case No.: S219783
Fifth District Court of Appeal Case No.: F066798
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S219783

IN THE SUPREME COURT OF C ALIFORNIA

SIERRA CLUB, REVIVE THE SAN JOAQUIN, and
LEAGUE OF WOMEN VOTERS OF FRESNO,

Plaintiffs and Appellants,

v.

COUNTY OF FRESNO,

Defendant and Respondent,

and,

FRIANT RANCH, L.P.,

Real Party in Interest and Respondent.

SUPREME COURT
FILED
APR 13 2015
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Deputy

After a Published Decision by the Court of Appeal, filed May 27, 2014
Fifth Appellate District Case No. F066798

Appeal from the Superior Court of California, County of Fresno
Case No. 11CECG00726
Honorable Rosendo A. Pena, Jr.

APPLICATION OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT FOR LEAVE TO FILE BRIEF OF *AMICUS CURIAE* IN SUPPORT OF NEITHER PARTY AND *[PROPOSED]* BRIEF OF *AMICUS CURIAE*

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TO THE HONORABLE CHIEF JUSTICE AND JUSTICES OF THE SUPREME COURT:

APPLICATION FOR LEAVE TO FILE *AMICUS CURIAE* BRIEF

Pursuant to Rule 8.520(f) of the California Rules of Court, the South Coast Air Quality Management District (SCAQMD) respectfully requests leave to file the attached *amicus curiae* brief. Because SCAQMD's position differs from that of either party, we request leave to submit this amicus brief in support of neither party.

HOW THIS BRIEF WILL ASSIST THE COURT

SCAQMD's proposed amicus brief takes a position on two of the issues in this case. In both instances, its position differs from that of either party. The issues are:

1) Does the California Environmental Quality Act (CEQA) require an environmental impact report (EIR) to correlate a project's air pollution emissions with specific levels of health impacts?
2) What is the proper standard of review for determining whether an EIR provides sufficient information on the health impacts caused by a project's emission of air pollutants?

This brief will assist the Court by discussing the practical realities of correlating identified air quality impacts with specific health outcomes. In short, CEQA requires agencies to provide detailed information about a project's air quality impacts that is sufficient for the public and decisionmakers to adequately evaluate the project and meaningfully understand its impacts. However, the level of analysis is governed by a rule of reason; CEQA only requires agencies to conduct analysis if it is reasonably feasible to do so.

With regard to health-related air quality impacts, an analysis that correlates a project's air pollution emissions with specific levels of health impacts will be feasible in some cases but not others. Whether it is feasible depends on a variety of factors, including the nature of the project and the nature of the analysis under consideration. The feasibility of analysis may also change over time as air districts and others develop new tools for measuring projects' air quality related health impacts. Because SCAQMD has among the most sophisticated air quality modeling and health impact evaluation capability of any of the air districts in the State, it is uniquely situated to express an opinion on the extent to which the Court should hold that CEQA requires lead agencies to correlate air quality impacts with specific health outcomes.

SCAQMD can also offer a unique perspective on the question of the appropriate standard of review. SCAQMD submits that the proper standard of review for determining whether an EIR is sufficient as an informational document is more nuanced than argued by either party. In our view, this is a mixed question of fact and law. It includes determining whether additional analysis is feasible, which is primarily a factual question that should be reviewed under the substantial evidence standard. However, it also involves determining whether the omission of a particular analysis renders an EIR insufficient to serve CEQA's purpose as a meaningful, informational document. If a lead agency has not determined that a requested analysis is infeasible, it is the court's role to determine whether the EIR nevertheless meets CEQA's purposes, and courts should not defer to the lead agency's conclusions regarding the legal sufficiency of an EIR's analysis. The ultimate question of whether an EIR's analysis is "sufficient" to serve CEQA's informational purposes is predominately a question of law that courts should review de novo.

This brief will explain the rationale for these arguments and may assist the Court in reaching a conclusion that accords proper respect to a lead agency's factual conclusions while maintaining judicial authority over the ultimate question of what level of analysis CEQA requires.

STATEMENT OF INTEREST OF *AMICUS CURIAE*

The SCAQMD is the regional agency primarily responsible for air pollution control in the South Coast Air Basin, which consists of all of Orange County and the non-desert portions of the Los Angeles, Riverside, and San Bernardino Counties. (Health & Saf. Code § 40410; Cal. Code Regs., tit. 17, § 60104.) The SCAQMD participates in the CEQA process in several ways. Sometimes it acts as a lead agency that prepares CEQA documents for projects. Other times it acts as a responsible agency when it has permit authority over some part of a project that is undergoing CEQA review by a different lead agency. Finally, SCAQMD also acts as a commenting agency for CEQA documents that it receives because it is a public agency with jurisdiction by law over natural resources affected by the project.

In all of these capacities, SCAQMD will be affected by the decision in this case. SCAQMD sometimes submits comments requesting that a lead agency perform an additional type of air quality or health impacts analysis. On the other hand, SCAQMD sometimes determines that a particular type of health impact analysis is not feasible or would not produce reliable and informative results. Thus, SCAQMD will be affected by the Court's resolution of the extent to which CEQA requires EIRs to correlate emissions and health impacts, and its resolution of the proper standard of review.

CERTIFICATION REGARDING AUTHORSHIP AND FUNDING

No party or counsel in the pending case authored the proposed amicus curiae brief in whole or in part, or made any monetary contribution intended to fund the preparation or submission of the brief. No person or entity other than the proposed *Amicus Curiae* made any monetary contribution intended to fund the preparation or submission of the brief.

Respectfully submitted,

DATED: April 3, 2015

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
KURT R. WIESE, GENERAL COUNSEL
BARBARA BAIRD, CHIEF DEPUTY COUNSEL

By: Barbara Baird
Barbara Baird
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SOUTH COAST AIR QUALITY
MANAGEMENT DISTICT

BRIEF OF AMICUS CURIAE

SUMMARY OF ARGUMENT

The South Coast Air Quality Management District (SCAQMD) submits that this Court should not try to establish a hard-and-fast rule concerning whether lead agencies are required to correlate emissions of air pollutants with specific health consequences in their environmental impact reports (EIR). The level of detail required in EIRs is governed by a few, core CEQA (California Environmental Quality Act) principles. As this Court has stated, "[a]n EIR must include detail sufficient to enable those who did not participate in its preparation to understand and to consider meaningfully the issues raised by the proposed project." (*Laurel Heights Improvement Assn. v. Regents of the Univ of Cal.* (1988) 47 Cal.3d 376, 405 ["*Laurel Heights I*"]) Accordingly, "an agency must use its best efforts to find out and disclose all that it reasonably can." (*Vineyard Area Citizens for Responsible Growth, Inc. v. City of Rancho Cordova* (2007) 40 Cal.4th 412, 428 (quoting CEQA Guidelines § 15144)[1].). However, "[a]nalysis of environmental effects need not be exhaustive, but will be judged in light of what is reasonably feasible." (*Association of Irritated Residents v. County of Madera* (2003) 107 Cal.App.4th 1383, 1390; CEQA Guidelines §§ 15151, 15204(a).)

With regard to analysis of air quality related health impacts, EIRs must generally quantify a project's pollutant emissions, but in some cases it is not feasible to correlate these emissions to specific, quantifiable health impacts (e.g., premature mortality; hospital admissions). In such cases, a general description of the adverse health impacts resulting from the pollutants at issue may be sufficient. In other cases, due to the magnitude

[1] The CEQA Guidelines are found at Cal. Code Regs., tit. 14 §§ 15000, *et seq.*

or nature of the pollution emissions, as well as the specificity of the project involved, it may be feasible to quantify health impacts. Or there may be a less exacting, but still meaningful analysis of health impacts that can feasibly be performed. In these instances, agencies should disclose those impacts.

SCAQMD also submits that whether or not an EIR complies with CEQA's informational mandates by providing sufficient, feasible analysis is a mixed question of fact and law. Pertinent here, the question of whether an EIR's discussion of health impacts from air pollution is sufficient to allow the public to understand and consider meaningfully the issues involves two inquiries: (1) Is it feasible to provide the information or analysis that a commenter is requesting or a petitioner is arguing should be required?; and (2) Even if it is feasible, is the agency relying on other policy or legal considerations to justify not preparing the requested analysis? The first question of whether an analysis is feasible is primarily a question of fact that should be judged by the substantial evidence standard. The second inquiry involves evaluating CEQA's information disclosure purposes against the asserted reasons to not perform the requested analysis. For example, an agency might believe that its EIR meets CEQA's informational disclosure standards even without a particular analysis, and therefore choose not to conduct that analysis. SCAQMD submits that this is more of a legal question, which should be reviewed de novo as a question of law.

ARGUMENT

I. RELEVANT FACTUAL AND LEGAL FRAMEWORK.

A. Air Quality Regulatory Background

The South Coast Air Quality Management District (SCAQMD) is one of the local and regional air pollution control districts and air quality

management districts in California. The SCAQMD is the regional air pollution agency for the South Coast Air Basin, which consists of all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino Counties. (Health & Saf. Code § 40410, 17 Cal. Code Reg. § 60104.) The SCAQMD also includes the Coachella Valley in Riverside County (Palm Springs area to the Salton Sea). (SCAQMD, *Final 2012 AQMP (Feb. 2013)*, http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan; then follow "chapter 7" hyperlink; pp 7-1, 7-3 (last visited Apr. 1, 2015).) The SCAQMD's jurisdiction includes over 16 million residents and has the worst or nearly the worst air pollution levels in the country for ozone and fine particulate matter. (SCAQMD, *Final 2012 AQMP (Feb. 2013)*, http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan; then follow "Executive Summary" hyperlink p. ES-1 (last visited Apr. 1, 2015).)

Under California law, the local and regional districts are primarily responsible for controlling air pollution from all sources except motor vehicles. (Health & Saf. Code § 40000.) The California Air Resources Board (CARB), part of the California Environmental Protection Agency, is primarily responsible for controlling pollution from motor vehicles. (*Id.*) The air districts must adopt rules to achieve and maintain the state and federal ambient air quality standards within their jurisdictions. (Health & Saf. Code § 40001.)

The federal Clean Air Act (CAA) requires the United States Environmental Protection Agency (EPA) to identify pollutants that are widely distributed and pose a threat to human health, developing a so-called "criteria" document. (42 U.S.C. § 7408; CAA § 108.) These pollutants are frequently called "criteria pollutants." EPA must then establish "national ambient air quality standards" at levels "requisite to protect public health",

allowing "an adequate margin of safety." (42 U.S.C. § 7409; CAA § 109.) EPA has set standards for six identified pollutants: ozone, nitrogen dioxide, sulfur dioxide, carbon monoxide, particulate matter (PM), and lead. (U.S. EPA, National Ambient Air Quality Standards (NAAQS), http://www.epa.gov/air/criteria.html (last updated Oct. 21, 2014).)[2]

Under the Clean Air Act, EPA sets emission standards for motor vehicles and "nonroad engines" (mobile farm and construction equipment, marine vessels, locomotives, aircraft, etc.). (42 U.S.C. §§ 7521, 7547; CAA §§ 202, 213.) California is the only state allowed to establish emission standards for motor vehicles and most nonroad sources; however, it may only do so with EPA's approval. (42 U.S.C. §§ 7543(b), 7543(e); CAA §§ 209(b), 209(c).) Sources such as manufacturing facilities, power plants and refineries that are not mobile are often referred to as "stationary sources." The Clean Air Act charges state and local agencies with the primary responsibility to attain the national ambient air quality standards. (42 U.S.C. § 7401(a)(3); CAA § 101(a)(3).) Each state must adopt and implement a plan including enforceable measures to achieve and maintain the national ambient air quality standards. (42 U.S.C. § 7410; CAA § 110.) The SCAQMD and CARB jointly prepare portion of the plan for the South Coast Air Basin and submit it for approval by EPA. (Health & Saf. Code §§ 40460, et seq.)

The Clean Air Act also requires state and local agencies to adopt a permit program requiring, among other things, that new or modified "major" stationary sources use technology to achieve the "lowest achievable emission rate," and to control minor stationary sources as

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[2] Particulate matter (PM) is further divided into two categories: fine particulate or $PM_{2.5}$ (particles with a diameter of less than or equal to 2.5 microns) and coarse particulate (PM_{10}) (particles with a diameter of 10 microns or less). (U.S. EPA, Particulate Matter (PM), http://www.epa.gov/airquality/particlepollution/ (last visited Apr. 1, 2015).)

needed to help attain the standards. (42 U.S.C. §§ 7502(c)(5), 7503(a)(2), 7410(a)(2)(C); CAA §§ 172(c)(5), 173(a)(2), 110(a)(2)(C).) The air districts implement these permit programs in California. (Health & Saf. Code §§ 42300, et seq.)

The Clean Air Act also sets out a regulatory structure for over 100 so-called "hazardous air pollutants" calling for EPA to establish "maximum achievable control technology" (MACT) for sources of these pollutants. (42 U.S.C. § 7412(d)(2); CAA § 112(d)(2).) California refers to these pollutants as "toxic air contaminants" (TACs) which are subject to two state-required programs. The first program requires "air toxics control measures" for specific categories of sources. (Health & Saf. Code § 39666.) The other program requires larger stationary sources and sources identified by air districts to prepare "health risk assessments" for impacts of toxic air contaminants. (Health & Saf. Code §§ 44320(b), 44322, 44360.) If the health risk exceeds levels identified by the district as "significant," the facility must implement a "risk reduction plan" to bring its risk levels below "significant" levels. Air districts may adopt additional more stringent requirements than those required by state law, including requirements for toxic air contaminants. (Health & Saf. Code § 41508; *Western Oil & Gas Assn. v. Monterey Bay Unified APCD* (1989) 49 Cal.3d 408, 414.) For example, SCAQMD has adopted a rule requiring new or modified sources to keep their risks below specified levels and use best available control technology (BACT) for toxics. (SCAQMD, *Rule 1401-New Source Review of Toxic Air Contaminants*, http://www.aqmd.gov/home/regulations/rules/scaqmd-rule-book/regulation-xiv; then follow "Rule 1401" hyperlink (last visited Apr. 1, 2015).)

B. The SCAQMD's Role Under CEQA

The California Environmental Quality Act (CEQA) requires public agencies to perform an environmental review and appropriate analysis for projects that they implement or approve. (Pub. Resources Code § 21080(a).) The agency with primary approval authority for a particular project is generally the "lead agency" that prepares the appropriate CEQA document. (CEQA Guidelines §§ 15050, 15051.) Other agencies having a subsequent approval authority over all or part of a project are called "responsible" agencies that must determine whether the CEQA document is adequate for their use. (CEQA Guidelines §§ 15096(c), 15381.) Lead agencies must also consult with and circulate their environmental impact reports to "trustee agencies" and agencies "with jurisdiction by law" including "authority over resources which may be affected by the project." (Pub. Resources Code §§ 21104(a), 21153; CEQA Guidelines §§ 15086(a)(3), 15073(c).) The SCAQMD has a role in all these aspects of CEQA.

Fulfilling its responsibilities to implement its air quality plan and adopt rules to attain the national ambient air quality standards, SCAQMD adopts a dozen or more rules each year to require pollution reductions from a wide variety of sources. The SCAQMD staff evaluates each rule for any adverse environmental impact and prepares the appropriate CEQA document. Although most rules reduce air emissions, they may have secondary environmental impacts such as use of water or energy or disposal of waste—e.g., spent catalyst from control equipment.[3]

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[3] The SCAQMD's CEQA program for its rules is a "Certified Regulatory Program" under which it prepares a "functionally equivalent" document in lieu of a negative declaration or EIR. (Pub. Resources Code § 21080.5, CEQA Guidelines § 15251(l).)

The SCAQMD also approves a large number of permits every year to construct new, modified, or replacement facilities that emit regulated air pollutants. The majority of these air pollutant sources have already been included in an earlier CEQA evaluation for a larger project, are currently being evaluated by a local government as lead agency, or qualify for an exemption. However, the SCAQMD sometimes acts as lead agency for major projects where the local government does not have a discretionary approval. In such cases, SCAQMD prepares and certifies a negative declaration or environmental impact report (EIR) as appropriate.[4] SCAQMD evaluates perhaps a dozen such permit projects under CEQA each year. SCAQMD is often also a "responsible agency" for many projects since it must issue a permit for part of the projects (e.g., a boiler used to provide heat in a commercial building). For permit projects evaluated by another lead agency under CEQA, SCAQMD has the right to determine that the CEQA document is inadequate for its purposes as a responsible agency, but it may not do so because its permit program already requires all permitted sources to use the best available air pollution control technology. (SCAQMD, *Rule 1303(a)(1) – Requirements*, http://www.aqmd.gov/home/regulations/rules/scaqmd-rule-book/regulation-xiii; then follow "Rule 1303" hyperlink (last visited Apr. 1, 2015).)

Finally, SCAQMD receives as many as 60 or more CEQA documents each month (around 500 per year) in its role as commenting agency or an agency with "jurisdiction by law" over air quality—a natural resource affected by the project. (Pub. Resources Code §§ 21104(a), 21153; CEQA Guidelines § 15366(a)(3).) The SCAQMD staff provides comments on as many as 25 or 30 such documents each month.

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[4] The SCAQMD's permit projects are not included in its Certified Regulatory Program, and are evaluated under the traditional local government CEQA analysis. (Pub. Resources Code §§ 21150-21154.)

(SCAQMD Governing Board Agenda, Apr. 3, 2015, Agenda Item 16, Attachment A, http://www.aqmd.gov/home/library/meeting-agendas-minutes/agenda?title=governing-board-meeting-agenda-april-3-2015; then follow "16. Lead Agency Projects and Environmental Documents Received by SCAQMD" hyperlink (last visited Apr. 1, 2015).) Of course, SCAQMD focuses its commenting efforts on the more significant projects.

Typically, SCAQMD comments on the adequacy of air quality analysis, appropriateness of assumptions and methodology, and completeness of the recommended air quality mitigation measures. Staff may comment on the need to prepare a health risk assessment detailing the projected cancer and noncancer risks from toxic air contaminants resulting from the project, particularly the impacts of diesel particulate matter, which CARB has identified as a toxic air contaminant based on its carcinogenic effects. (California Air Resources Board, Resolution 98-35, Aug. 27, 1998, http://www.arb.ca.gov/regact/diesltac/diesltac.htm; then follow Resolution 98-35 hyperlink (last visited Apr. 1, 2015).) Because SCAQMD already requires new or modified stationary sources of toxic air contaminants to use the best available control technology for toxics and to keep their risks below specified levels, (SCAQMD Rule 1401, supra, note 15), the greatest opportunity to further mitigate toxic impacts through the CEQA process is by reducing emissions—particularly diesel emissions—from vehicles.

II. THIS COURT SHOULD NOT SET A HARD-AND-FAST RULE CONCERNING THE EXTENT TO WHICH AN EIR MUST CORRELATE A PROJECT'S EMISSION OF POLLUTANTS WITH RESULTING HEALTH IMPACTS.

Numerous cases hold that courts do not review the correctness of an EIR's conclusions but rather its sufficiency as an informative document. (*Laurel Heights 1, supra*, 47 Cal.3d at p. 392; *Citizens of Goleta Valley v.*

Bd. of Supervisors (1990) 52 Cal.3d 553, 569; *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1197.)

As stated by the Court of Appeal in this case, where an EIR has addressed a topic, but the petitioner claims that the information provided about that topic is insufficient, courts must "draw[] a line that divides *sufficient* discussions from those that are *insufficient*." (*Sierra Club v. County of Fresno* (2014) 226 Cal.App.4th 704 (superseded by grant of review) 172 Cal.Rptr.3d 271, 290.) The Court of Appeal readily admitted that "[t]he terms themselves – sufficient and insufficient – provide little, if any, guidance as to where the line should be drawn. They are simply labels applied once the court has completed its analysis." (*Id.*)

The CEQA Guidelines, however, provide guidance regarding what constitutes a sufficient discussion of impacts. Section 15151 states that "the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible." Case law reflects this: "Analysis of environmental effects need not be exhaustive, but will be judged in light of what was reasonably feasible." (*Association of Irritated Residents v. County of Madera, supra,* 107 Cal.App.4th at p. 1390; see also CEQA Guidelines § 15204(a).)

Applying this test, this Court cannot realistically establish a hard-and-fast rule that an analysis correlating air pollution impacts of a project to quantified resulting health impacts is always required, or indeed that it is never required. Simply put, in some cases such an analysis will be "feasible"; in some cases it will not.

For example, air pollution control districts often require a proposed new source of toxic air contaminants to prepare a "health risk assessment" before issuing a permit to construct. District rules often limit the allowable cancer risk the new source may cause to the "maximally exposed individual" (worker and residence exposures). (*See, e.g.*, SCAQMD Rule 1401(c)(8); 1401(d)(1), *supra* note 15.) In order to perform this analysis, it

is necessary to have data regarding the sources and types of air toxic contaminants, location of emission points, velocity of emissions, the meteorology and topography of the area, and the location of receptors (worker and residence). (SCAQMD, *Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics "Hot Spots" Information and Assessment Act (AB2588), pp. 11-16*; (last visited Apr. 1, 2015) http://www.aqmd.gov/home/library/documents-support-material; "Guidelines" hyperlink; AB2588; then follow AB2588 Risk Assessment Guidelines hyperlink.)

Thus, it is feasible to determine the health risk posed by a new gas station locating at an intersection in a mixed use area, where receptor locations are known. On the other hand, it may not be feasible to perform a health risk assessment for airborne toxics that will be emitted by a generic industrial building that was built on "speculation" (i.e., without knowing the future tenant(s)). Even where a health risk assessment can be prepared, however, the resulting maximum health risk value is only a calculation of risk—it does not necessarily mean anyone will contract cancer as a result of the project.

In order to find the "cancer burden" or expected additional cases of cancer resulting from the project, it is also necessary to know the numbers and location of individuals living within the "zone of impact" of the project: i.e., those living in areas where the projected cancer risk from the project exceeds one in a million. (SCAQMD, Health Risk Assessment Summary form, http://www.aqmd.gov/home/forms ; filter by "AB2588" category; then "Health Risk Assessment" hyperlink (last visited Apr. 1, 2015).) The affected population is divided into bands of those exposed to at least 1 in a million risk, those exposed to at least 10 in a million risk, etc. up to those exposed at the highest levels. (*Id.*) This data allows agencies to calculate an approximate number of additional cancer cases expected from

the project. However, it is not possible to predict which particular individuals will be affected.

For the so-called criteria pollutants[5], such as ozone, it may be more difficult to quantify health impacts. Ozone is formed in the atmosphere from the chemical reaction of the nitrogen oxides (NO_x) and volatile organic compounds (VOC) in the presence of sunlight. (U.S. EPA, Ground Level Ozone, http://www.epa.gov/airquality/ozonepollution/ (last updated Mar. 25, 2015).) It takes time and the influence of meteorological conditions for these reactions to occur, so ozone may be formed at a distance downwind from the sources. (U.S. EPA, *Guideline on Ozone Monitoring Site Selection* (Aug. 1998) EPA-454/R-98-002 § 5.1.2, http://www.epa.gov/ttnamti1/archive/cpreldoc.html (last visited Apr. 1, 2015).) NO_x and VOC are known as "precursors" of ozone.

Scientifically, health effects from ozone are correlated with increases in the ambient level of ozone in the air a person breathes. (U.S. EPA, *Health Effects of Ozone in the General Population,* Figure 9, http://www.epa.gov/apti/ozonehealth/population.html#levels (last visited Apr. 1, 2015).) However, it takes a large amount of additional precursor emissions to cause a modeled increase in ambient ozone levels over an entire region. For example, the SCAQMD's 2012 AQMP showed that reducing NO_x by 432 tons per day (157,680 tons/year) and reducing VOC by 187 tons per day (68,255 tons/year) would reduce ozone levels at the SCAQMD's monitor site with the highest levels by only 9 parts per billion. (South Coast Air Quality Management District, *Final 2012 AQMP (February 2013)*, http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan; then follow "Appendix V: Modeling & Attainment Demonstrations" hyperlink,

[5] See discussion of types of pollutants, supra, Part I.A.

pp. v-4-2, v-7-4, v-7-24.) SCAQMD staff does not currently know of a way to accurately quantify ozone-related health impacts caused by NO_x or VOC emissions from relatively small projects.

On the other hand, this type of analysis may be feasible for projects on a regional scale with very high emissions of NO_x and VOCs, where impacts are regional. For example, in 2011 the SCAQMD performed a health impact analysis in its CEQA document for proposed Rule 1315, which authorized various newly-permitted sources to use offsets from the districts "internal bank" of emission reductions. This CEQA analysis accounted for essentially *all* the increases in emissions due to new or modified sources in the District between 2010 and 2030.[6] The SCAQMD was able to correlate this very large emissions increase (e.g., 6,620 pounds per day NO_x (1,208 tons per year), 89,180 pounds per day VOC (16,275 tons per year)) to expected health outcomes from ozone and particulate matter (e.g., 20 premature deaths per year and 89,947 school absences in the year 2030 due to ozone).[7] (SCAQMD Governing Board Agenda, February 4, 2011, Agenda Item 26, *Assessment for: Re-adoption of Proposed Rule 1315 – Federal New Source Review Tracking System* (see hyperlink in fn 6*)* at p. 4.1-35, Table 4.1-29.)

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[6] (SCAQMD Governing Board Agenda, February 4, 2011, Agenda Item 26, Attachment G, *Assessment for: Re-adoption of Proposed Rule 1315 – Federal New Source Review Tracking System, Vol. 1, p.4.0-6,* http://www.aqmd.gov/home/library/meeting-agendas-minutes/agenda?title=governing-board-meeting-agenda-february-4-2011; the follow "26. Adopt Proposed Rule 1315 – Federal New Source Review Tracking System" (last visited April 1, 2015).)

[7] The SCAQMD was able to establish the location of future NO_x and VOC emissions by assuming that new projects would be built in the same locations and proportions as existing stationary sources. This CEQA document was upheld by the Los Angeles County Superior Court in *Natural Res. Def. Council v SCAQMD*, Los Angeles Superior Court No. BS110792).

However, a project emitting only 10 tons per year of NO_x or VOC is small enough that its regional impact on ambient ozone levels may not be detected in the regional air quality models that are currently used to determine ozone levels. Thus, in this case it would not be feasible to directly correlate project emissions of VOC or NO_x with specific health impacts from ozone. This is in part because ozone formation is not linearly related to emissions. Ozone impacts vary depending on the location of the emissions, the location of other precursor emissions, meteorology and seasonal impacts, and because ozone is formed some time later and downwind from the actual emission. (EPA Guideline on Ozone Monitoring Site Selection (Aug. 1998) EPA-454/R-98-002, § 5.1.2; https://www.epa.gov/ttnamti1/archive/cpreldoc.html; then search "Guideline on Ozone Monitoring Site Selection" click on pdf) (last viewed Apr. 1, 2015).)

SCAQMD has set its CEQA "significance" threshold for NO_x and VOC at 10 tons per year (expressed as 55 lb/day). (SCAQMD, *Air Quality Analysis Handbook*, http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook; then follow "SCAQMD Air Quality Significance Thresholds" hyperlink (last visited Apr. 1, 2015).) This is because the federal Clean Air Act defines a "major" stationary source for "extreme" ozone nonattainment areas such as SCAQMD as one emitting 10 tons/year. (42 U.S.C. §§ 7511a(e), 7511a(f); CAA §§ 182(e), 182(f).) Under the Clean Air Act, such sources are subject to enhanced control requirements (42 U.S.C. §§ 7502(c)(5), 7503; CAA §§ 172(c)(5), 173), so SCAQMD decided this was an appropriate threshold for making a CEQA "significance" finding and requiring feasible mitigation. Essentially, SCAQMD takes the position that a source that emits 10 tons/year of NO_x or VOC would contribute cumulatively to ozone formation. Therefore, lead agencies that use SCAQMD's thresholds of significance may determine

that many projects have "significant" air quality impacts and must apply all feasible mitigation measures, yet will not be able to precisely correlate the project to quantifiable health impacts, unless the emissions are sufficiently high to use a regional modeling program.

In the case of particulate matter ($PM_{2.5}$)[8], another "criteria" pollutant, SCAQMD staff is aware of two possible methods of analysis. SCAQMD used regional modeling to predict expected health impacts from its proposed Rule 1315, as mentioned above. Also, the California Air Resources Board (CARB) has developed a methodology that can predict expected mortality (premature deaths) from large amounts of $PM_{2.5}$. (California Air Resources Board, *Health Impacts Analysis: PM Premature Death Relationship*, http://www.arb.ca.gov/research/health/pm-mort/pm-mort_arch.htm (last reviewed Jan. 19, 2012).) SCAQMD used the CARB methodology to predict impacts from three very large power plants (e.g., 731-1837 lbs/day). (Final Environmental Assessment for Rule 1315, *supra*, pp 4.0-12, 4.1-13, 4.1-37 (e.g., 125 premature deaths in the entire SCAQMD in 2030), 4.1-39 (0.05 to 1.77 annual premature deaths from power plants.) Again, this project involved large amounts of additional $PM_{2.5}$ in the District, up to 2.82 tons/day (5,650 lbs/day of $PM_{2.5}$, or, or 1029 tons/year. (*Id.* at table 4.1-4, p. 4.1-10.)

However, the primary author of the CARB methodology has reported that this $PM_{2.5}$ health impact methodology is not suited for small projects and may yield unreliable results due to various uncertainties. [9] (SCAQMD, *Final Subsequent Mitigated Negative Declaration for: Warren*

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[8] SCAQMD has not attained the latest annual or 24-hour national ambient air quality standards for "$PM_{2.5}$" or particulate matter less than 2.5 microns in diameter.

[9] Among these uncertainties are the representativeness of the population used in the methodology, and the specific source of PM and the corresponding health impacts. (*Id.* at p. 2-24.)

E&P, Inc. WTU Central Facility, New Equipment Project (certified July 19, 2011), http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects/permit-project-documents---year-2011; then follow "Final Subsequent Mitigated Negative Declaration for Warren E&P Inc. WTU Central Facility, New Equipment Project" hyperlink, pp. 2-22, 2-23 (last visited Apr. 1, 2015).) Therefore, when SCAQMD prepared a CEQA document for the expansion of an existing oil production facility, with very small $PM_{2.5}$ increases (3.8 lb/day) and a very small affected population, staff elected not to use the CARB methodology for using estimated $PM_{2.5}$ emissions to derive a projected premature mortality number and explained why it would be inappropriate to do so. (*Id.* at pp 2-22 to 2-24.) SCAQMD staff concluded that use of this methodology for such a small source could result in unreliable findings and would not provide meaningful information. (*Id.* at pp. 2-23, 2-25.) This CEQA document was not challenged in court.

In the above case, while it may have been technically possible to plug the data into the methodology, the results would not have been reliable or meaningful. SCAQMD believes that an agency should not be required to perform analyses that do not produce reliable or meaningful results. This Court has already held that an agency may decline to use even the "normal" "existing conditions" CEQA baseline where to do so would be misleading or without informational value. (*Neighbors for Smart Rail v. Exposition Metro Line* (2013) 57 Cal.4th 439, 448, 457.) The same should be true for a decision that a particular study or analysis would not provide reliable or meaningful results.[10]

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[10] Whether a particular study would result in "informational value" is a part of deciding whether it is "feasible." CEQA defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and

Therefore, it is not possible to set a hard-and-fast rule on whether a correlation of air quality impacts with specific quantifiable health impacts is required in all cases. Instead, the result turns on whether such an analysis is reasonably feasible in the particular case.[11] Moreover, what is reasonably feasible may change over time as scientists and regulatory agencies continually seek to improve their ability to predict health impacts. For example, CARB staff has been directed by its Governing Board to reassess and improve the methodology for estimating premature deaths. (California Air Resources Board, *Health Impacts Analysis: PM Mortality Relationship*, http://www.arb.ca.gov/research/health/pm-mort/pm-mort.htm (last reviewed Dec. 29, 2010).) This factor also counsels against setting any hard-and-fast rule in this case.

III. THE QUESTION OF WHETHER AN EIR CONTAINS SUFFICIENT ANALYSIS TO MEET CEQA'S REQUIREMENTS IS A MIXED QUESTION OF FACT AND LAW GOVERNED BY TWO DIFFERENT STANDARDS OF REVIEW.

A. Standard of Review for Feasibility Determination and Sufficiency as an Informative Document

A second issue in this case is whether courts should review an EIR's informational sufficiency under the "substantial evidence" test as argued by Friant Ranch or the "independent judgment" test as argued by Sierra Club.

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technological factors." (Pub. Resources Code § 21061.1.) A study cannot be "accomplished in a *successful* manner" if it produces unreliable or misleading results.

[11] In this case, the lead agency did not have an opportunity to determine whether the requested analysis was feasible because the comment was non-specific. Therefore, SCAQMD suggests that this Court, after resolving the legal issues in the case, direct the Court of Appeal to remand the case to the lead agency for a determination of whether the requested analysis is feasible. Because Fresno County, the lead agency, did not seek review in this Court, it seems likely that the County has concluded that at least some level of correlation of air pollution with health impacts is feasible.

As this Court has explained, "a reviewing court must adjust its scrutiny to the nature of the alleged defect, depending on whether the claim is predominantly one of improper procedure or a dispute over the facts." (*Vineyard Area Citizens v. City of Rancho Cordova, supra,* 40 Cal.4th at 435.) For questions regarding compliance with proper procedure or other legal questions, courts review an agency's action de novo under the "independent judgment" test. (*Id.*) On the other hand, courts review factual disputes only for substantial evidence, thereby "accord[ing] greater deference to the agency's substantive factual conclusions." (*Id.*)

Here, Friant Ranch and Sierra Club agree that the case involves the question of whether an EIR includes sufficient information regarding a project's impacts. However, they disagree on the proper standard of review for answering this question: Sierra Club contends that courts use the independent judgment standard to determine whether an EIR's analysis is sufficient to meet CEQA's informational purposes,[12] while Friant Ranch contends that the substantial evidence standard applies to this question.

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[12] Sierra Club acknowledges that courts use the substantial evidence standard when reviewing predicate factual issues, but argues that courts ultimately decide as a matter of law what CEQA requires. (Answering Brief, pp. 14, 23.)

SCAQMD submits that the issue is more nuanced than either party contends. We submit that, whether a CEQA document includes sufficient analysis to satisfy CEQA's informational mandates is a mixed question of fact and law,[13] containing two levels of inquiry that should be judged by different standards.[14]

The state CEQA Guidelines set forth standards for the adequacy of environmental analysis. Guidelines Section 15151 states:

> An EIR should be prepared with a sufficient degree of analysis to provide decision makers with information which enables them to make a decision which intelligently takes account of environmental consequences. An evaluation of the environmental effects of a proposed project need not be exhaustive, but the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible. Disagreement among experts does not make an EIR inadequate, but the EIR should summarize the main points of disagreement among the experts. The courts have looked not for perfection, but for adequacy, completeness, and a good-faith effort at full disclosure.

In this case, the basic question is whether the underlying analysis of air quality impacts made the EIR "sufficient" as an informative document. However, whether the EIR's analysis was sufficient is judged in light of what was reasonably feasible. This represents a mixed question of fact and law that is governed by two different standards of review.

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[13] Friant Ranch actually states that the claim that an EIR lacks sufficient relevant information is, "most properly thought of as raising mixed questions of fact and law." (Opening Brief, p. 27.) However, the remainder of its argument claims that the court should apply the substantial evidence standard of review to all aspects of the issue.

[14] Mixed questions of fact and law issues may implicate predominantly factual subordinate questions that are reviewed under the substantial evidence test even though the ultimate question may be reviewed by the independent judgment test. *Crocker National Bank v. City and County of San Francisco* (1989) 49 Cal.3d 881, 888-889.

SCAQMD submits that an EIR's sufficiency as an informational document is ultimately a legal question that courts should determine using their independent judgment. This Court's language in *Laurel Heights I* supports this position. As this Court explained: "The court does not pass upon the correctness of the EIR's environmental conclusions, but only upon its *sufficiency as an informative document.*" (*Laurel Heights I, supra,* 47 Cal.3d at 392-393) (emphasis added.) As described above, the Court in *Vineyard Area Citizens v. City of Rancho Cordova, supra,* 40 Cal.4th at 431, also used its independent judgment to determine what level of analysis CEQA requires for water supply impacts. The Court did not defer to the lead agency's opinion regarding the law's requirements; rather, it determined for itself what level of analysis was necessary to meet "[t]he law's informational demands." (*Id.* at p. 432.) Further, existing case law also holds that where an agency fails to comply with CEQA's information disclosure requirements, the agency has "failed to proceed in the manner required by law." (*Save Our Peninsula Comm. v. Monterey County Bd. of Supervisors* (2001) 87 Cal.App.4th 99, 118.)

However, whether an EIR satisfies CEQA's requirements depends in part on whether it was reasonably feasible for an agency to conduct additional or more thorough analysis. EIRs must contain "a detailed statement" of a project's impacts (Pub. Res. Code § 21061), and an agency must "use its best efforts to find out and disclose all that it reasonably can." (CEQA Guidelines § 15144.) Nevertheless, "the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible." (CEQA Guidelines § 15151.)

SCAQMD submits that the question of whether additional analysis or a particular study suggested by a commenter is "feasible" is generally a question of fact. Courts have already held that whether a particular alternative is "feasible" is reviewed by the substantial evidence test.

(*Uphold Our Heritage v. Town of Woodside* (2007) 147 Cal.App.4th 587, 598-99; *Center for Biological Diversity v. County of San Bernardino* (2010) 185 Cal.App.4th 866, 883.) Thus, if a lead agency determines that a particular study or analysis is infeasible, that decision should generally be judged by the substantial evidence standard. However, SCAQMD urges this Court to hold that lead agencies must explain the basis of any determination that a particular analysis is infeasible in the EIR itself. An EIR must discuss information, including issues related to the feasibility of particular analyses "in sufficient detail to enable meaningful participation and criticism by the public. '[W]hatever is required to be considered in an EIR must be in that formal report; what any official might have known from other writings or oral presentations cannot supply what is lacking in the report.'" (*Laurel Heights I, supra*, 47 Cal.3d at p. 405 (quoting *Santiago County Water District v. County of Orange* (1981) 118 Cal.App.3d 818, 831) (discussing analysis of alternatives).) The evidence on which the determination is based should also be summarized in the EIR itself, with appropriate citations to reference materials if necessary. Otherwise commenting agencies such as SCAQMD would be forced to guess where the lead agency's evidence might be located, thus thwarting effective public participation.

Moreover, if a lead agency determines that a particular study or analysis would not result in reliable or useful information and for that reason is not feasible, that determination should be judged by the substantial evidence test. (See *Neighbors for Smart Rail v. Exposition Metro Line Construction Authority, supra*, 57 Cal.4th 439, 448, 457:

whether "existing conditions" baseline would be misleading or uninformative judged by substantial evidence standard.[15])

If the lead agency's determination that a particular analysis or study is not feasible is supported by substantial evidence, then the agency has not violated CEQA's information disclosure provisions, since it would be infeasible to provide additional information. This Court's decisions provide precedent for such a result. For example, this Court determined that the issue of whether the EIR should have included a more detailed discussion of future herbicide use was resolved because substantial evidence supported the agency's finding that "the precise parameters of future herbicide use could not be predicted." *Ebbetts Pass Forest Watch v. California Dept. of Forestry & Fire Protection* (2008) 43 Cal.4th 936, 955.

Of course, SCAQMD expects that courts will continue to hold lead agencies to their obligations to consult with, and not to ignore or misrepresent, the views of sister agencies having special expertise in the area of air quality. (*Berkeley Keep Jets Over the Bay v. Board of Port Commissioners* (2007) 91 Cal.App.4th 1344, 1364 n.11.) In some cases, information provided by such expert agencies may establish that the purported evidence relied on by the lead agency is not in fact "substantial". (*Id.* at pp. 1369-1371.)

In sum, courts retain ultimate responsibility to determine what CEQA requires. However, the law does not require exhaustive analysis, but only what is reasonably feasible. Agencies deserve deference for their factual determinations regarding what type of analysis is reasonably feasible. On the other hand, if a commenter requests more information, and the lead agency declines to provide it but does *not* determine that the

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[15] The substantial evidence standard recognizes that the courts "have neither the resources nor the scientific expertise" to weigh conflicting evidence on technical issues. (*Laurel Heights I, supra,* 47 Cal.3d 376, 393.)

requested study or analysis would be infeasible, misleading or uninformative, the question becomes whether the omission of that analysis renders the EIR inadequate to satisfy CEQA's informational purposes. (*Id.* at pp. 1370-71.) Again, this is predominantly a question of law and should be judged by the de novo or independent judgment standard of review. Of course, this Court has recognized that a "project opponent or reviewing court can always imagine some additional study or analysis that might provide helpful information. It is not for them to design the EIR. That further study...might be helpful does not make it necessary." (*Laurel Heights I, supra,* 47 Cal.3d 376, 415 – see also CEQA Guidelines § 15204(a) [CEQA "does not require a lead agency to conduct every test. . . recommended or demanded by commenters."].) Courts, then, must adjudicate whether an omission of particular information renders an EIR inadequate to serve CEQA's informational purposes.[16]

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[16] We recognize that there is case law stating that the substantial evidence standard applies to "challenges to the scope of an EIR's analysis of a topic" as well as the methodology used and the accuracy of the data relied on in the document "because these types of challenges involve factual questions." (*Bakersfield Citizens for Local Control v. City of Bakersfield, supra,* 124 Cal.App.4th 1184, 1198, and cases relied on therein.) However, we interpret this language to refer to situations where the question of the scope of the analysis really is factual—that is, where it involves whether further analysis is feasible, as discussed above. This interpretation is supported by the fact that the *Bakersfield* court expressly rejected an argument that a claimed "omission of information from the EIR should be treated as inquiries whether there is substantial evidence supporting the decision approving the project. " *Bakersfield, supra,* 124 Cal.App.4th at p. 1208. And the *Bakersfield* court ultimately decided that the lead agency must analyze the connection between the identified air pollution impacts and resulting health impacts, even though the EIR already included some discussion of air-pollution-related respiratory illnesses. *Bakersfield, supra,* 124 Cal.App.4th at p. 1220. Therefore, the court must not have interpreted this question as one of the "scope of the analysis" to be judged by the substantial evidence standard.

B. Friant Ranch's Rationale for Rejecting the Independent Judgment Standard of Review is Unsupported by Case Law.

In its brief, Friant Ranch makes a distinction between cases where a required CEQA topic is not discussed at all (to be reviewed by independent judgment as a failure to proceed in the manner required by law) and cases where a topic is discussed, but the commenter claims the information provided is insufficient (to be judged by the substantial evidence test). (Opening Brief, pp. 13-17.) The Court of Appeal recognized these two types of cases, but concluded that both raised questions of law. (*Sierra Club v. County of Fresno* (2014) 226 Cal.App.4th 704 (superseded by grant of review) 172 Cal.Rptr.3d 271, 290.) We believe the distinction drawn by Friant Ranch is unduly narrow, and inconsistent with cases which have concluded that CEQA documents are insufficient. In many instances, CEQA's requirements are stated broadly, and the courts must interpret the law to determine what level of analysis satisfies CEQA's mandate for providing meaningful information, even though the EIR discusses the issue to some extent.

For example, the CEQA Guidelines require discussion of the existing environmental baseline. In *County of Amador v. El Dorado County Water Agency* (1999) 76 Cal.App.4th 931, 954-955, the lead agency had discussed the environmental baseline by describing historic month-end water levels in the affected lakes. However, the court held that this was not an adequate baseline discussion because it failed to discuss the timing and amounts of past actual water releases, to allow comparison with the proposed project. The court evidently applied the independent judgment test to its decision, even though the agency discussed the issue to some extent.

Likewise, in *Vineyard Area Citizens* (2007) 40 Cal.4th 412, this Court addressed the question of whether an EIR's analysis of water supply impacts complied with CEQA. The parties agreed that the EIR was required to analyze the effects of providing water to the development project, "and that in order to do so the EIR had, in some manner, to identify the planned sources of that water." (*Vineyard Area Citizens, supra,* at p. 428.) However, the parties disagreed as to the level of detail required for this analysis and "what level of uncertainty regarding the availability of water supplies can be tolerated in an EIR . . . ." (*Id.*) In other words, the EIR had analyzed water supply impacts for the project, but the petitioner claimed that the analysis was insufficient.

This Court noted that neither CEQA's statutory language or the CEQA Guidelines specifically addressed the question of how precisely an EIR must discuss water supply impacts. (*Id.*) However, it explained that CEQA "states that '[w]hile foreseeing the unforeseeable is not possible, an agency must use its best efforts to find out and disclose all that it reasonably can.'" (*Id.*, [Guidelines § 15144].) The Court used this general principle, along with prior precedent, to elucidate four "principles for analytical adequacy" that are necessary in order to satisfy "CEQA's informational purposes." (*Vineyard Area Citizens, supra,* at p. 430.) The Court did not defer to the agency's determination that the EIR's analysis of water supply impacts was sufficient. Rather, this Court used its independent judgment to determine for itself the level of analysis required to satisfy CEQA's fundamental purposes. (*Vineyard Area Citizens, supra,* at p. 441: an EIR does not serve its purposes where it neglects to explain likely sources of water and "... leaves long term water supply considerations to later stages of the project.")

Similarly, the CEQA Guidelines require an analysis of noise impacts of the project. (Appendix G, "Environmental Checklist Form."[17]) In *Gray v. County of Madera* (2008) 167 Cal.App.4th 1099, 1123, the court held that the lead agency's noise impact analysis was inadequate even though it had addressed the issue and concluded that the increase would not be noticeable. If the court had been using the substantial evidence standard, it likely would have upheld this discussion.

Therefore, we do not agree that the issue can be resolved on the basis suggested by Friant Ranch, which would apply the substantial evidence standard to *every* challenge to an analysis that addresses a required CEQA topic. This interpretation would subvert the courts' proper role in interpreting CEQA and determining what the law requires.

Nor do we agree that the Court of Appeal in this case violated CEQA's prohibition on courts interpreting its provisions "in a manner which imposes procedural or substantive requirements beyond those explicitly stated in this division or in the state guidelines." (Pub. Resources Code § 21083.1.) CEQA requires an EIR to describe *all* significant impacts of the project on the environment. (Pub. Resources Code § 21100(b)(2); *Vineyard Area Citizens, supra,* at p. 428.) Human beings are part of the environment, so CEQA requires EIRs to discuss a project's significant impacts on human health. However, except in certain particular circumstances,[18] neither the CEQA statute nor Guidelines specify the precise level of analysis that agencies must undertake to satisfy the law's requirements. (see, e.g., CEQA Guidelines § 15126.2(a) [EIRs must describe "health and safety problems caused by {a project's} physical changes"].) Accordingly, courts must interpret CEQA as a whole to

[17] Association of Environmental Professionals, 2015 CEQA Statute and Guidelines (2015) p.287.

[18] E.g., Pub. Resources Code § 21151.8(C)(3)(B)(iii) (requiring specific type of health risk analysis for siting schools).

determine whether a particular EIR is sufficient as an informational document. A court determining whether an EIR's discussion of human health impacts is legally sufficient does not constitute imposing a new substantive requirement.[19] Under Friant Ranch's theory, the above-referenced cases holding a CEQA analysis inadequate would have violated the law. This is not a reasonable interpretation.

IV. COURTS MUST SCRUPULOUSLY ENFORCE THE REQUIREMENTS THAT LEAD AGENCIES CONSULT WITH AND OBTAIN COMMENTS FROM AIR DISTRICTS

Courts must "scrupulously enforce" CEQA's legislatively mandated requirements. (*Vineyard Area Citizens, supra*, 40 Cal.4th 412, 435.) Case law has firmly established that lead agencies must consult with the relevant air pollution control district before conducting an initial study, and must provide the districts with notice of the intention to adopt a negative declaration (or EIR). (*Schenck v. County of Sonoma* (2011) 198 Cal.App.4th 949, 958.) As *Schenck* held, neither publishing the notice nor providing it to the State Clearinghouse was a sufficient substitute for sending notice directly to the air district. (*Id.*) Rather, courts "must be satisfied that [administrative] agencies have fully complied with the procedural requirements of CEQA, since only in this way can the important public purposes of CEQA be protected from subversion." *Schenck,* 198 Cal.App.4th at p. 959 (citations omitted).[20]

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[19] We submit that Public Resources Code Section 21083.1 was intended to prevent courts from, for example, holding that an agency must analyze economic impacts of a project where there are no resulting environmental impacts (see CEQA Guidelines § 15131) , or imposing new procedural requirements, such as imposing additional public notice requirements not set forth in CEQA or the Guidelines.

[20] Lead agencies must consult air districts, as public agencies with jurisdiction by law over resources affected by the project, *before* releasing an EIR. (Pub. Resources Code §§ 21104(a); 21153.) Moreover, air

Lead agencies should be aware, therefore, that failure to properly seek and consider input from the relevant air district constitutes legal error which may jeopardize their project approvals. For example, the court in *Fall River Wild Trout Foundation v. County of Shasta,* (1999) 70 Cal.App.4th 482, 492 held that the failure to give notice to a trustee agency (Department of Fish and Game) was prejudicial error requiring reversal. The court explained that the lack of notice prevented the Department from providing any response to the CEQA document. (*Id.* at p. 492.) It therefore prevented relevant information from being presented to the lead agency, which was prejudicial error because it precluded informed decision-making. (*Id.*)[21]

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districts should be considered "state agencies" for purposes of the requirement to consult with "trustee agencies" as set forth in Public Resources Code § 20180.3(a). This Court has long ago held that the districts are not mere "local agencies" whose regulations are superseded by those of a state agency regarding matters of statewide concern, but rather have concurrent jurisdiction over such issues. (*Orange County Air Pollution Control District v. Public Util. Com.* (1971) 4 Cal.3d 945, 951, 954.) Since air pollution is a matter of statewide concern, *Id* at 952, air districts should be entitled to trustee agency status in order to ensure that this vital concern is adequately protected during the CEQA process.

[21] In *Schenck,* the court concluded that failure to give notice to the air district was not prejudicial, but this was partly because the trial court had already corrected the error before the case arrived at the Court of Appeal. The trial court issued a writ of mandate requiring the lead agency to give notice to the air district. The air district responded by concurring with the lead agency that air impacts were not significant. (*Schenck,* 198 Cal.App.4th 949, 960.) We disagree with the *Schenck* court that the failure to give notice to the air district would not have been prejudicial (even in the absence of the trial court writ) merely because the lead agency purported to follow the air district's published CEQA guidelines for significance. (*Id.*, 198 Cal.App.4th at p. 960.) In the first place, absent notice to the air district, it is uncertain whether the lead agency properly followed those guidelines. Moreover, it is not realistic to expect that an air district's published guidelines would necessarily fully address all possible air-quality related issues that can arise with a CEQA project, or that those

Similarly, lead agencies must obtain additional information requested by expert agencies, including those with jurisdiction by law, if that information is necessary to determine a project's impacts. (*Sierra Club v. State Bd. Of Forestry* (1994) 7 Cal.4th 1215, 1236-37.) Approving a project without obtaining that information constitutes a failure to proceed in the manner prescribed by CEQA. (*Id.* at p. 1236.)

Moreover, a lead agency can save significant time and money by consulting with the air district early in the process. For example, the lead agency can learn what the air district recommends as an appropriate analysis on the facts of its case, including what kinds of health impacts analysis may be available, and what models are appropriate for use. This saves the lead agency from the need to do its analysis all over again and possibly needing to recirculate the document after errors are corrected, if new significant impacts are identified. (CEQA Guidelines § 15088.5(a).) At the same time, the air district's expert input can help the lead agency properly determine whether another commenter's request for additional analysis or studies is reasonable or feasible. Finally, the air district can provide input on what mitigation measures would be feasible and effective.

Therefore, we suggest that this Court provide guidance to lead agencies reminding them of the importance of consulting with the relevant air districts regarding these issues. Otherwise, their feasibility decisions may be vulnerable to air district evidence that establishes that there is no substantial evidence to support the lead agency decision not to provide specific analysis. (*See Berkeley Keep Jets Over the Bay, supra,* 91 Cal.App.4th 1344, 1369-1371.)

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guidelines would necessarily be continually modified to reflect new developments. Therefore we believe that, had the trial court not already ordered the lead agency to obtain the air district's views, the failure to give notice would have been prejudicial, as in *Fall River, supra,* 70 Cal.App.4th 482, 492.

CONCLUSION

The SCAQMD respectfully requests this Court *not* to establish a hard-and-fast rule concerning whether CEQA requires a lead agency to correlate identified air quality impacts of a project with resulting health outcomes. Moreover, the question of whether an EIR is "sufficient as an informational document" is a mixed question of fact and law containing two levels of inquiry. Whether a particular proposed analysis is feasible is predominantly a question of fact to be judged by the substantial evidence standard of review. Where the requested analysis is feasible, but the lead agency relies on legal or policy reasons not to provide it, the question of whether the EIR is nevertheless sufficient as an informational document is predominantly a question of law to be judged by the independent judgment standard of review.

Respectfully submitted,

DATED: April 3, 2015

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
KURT R. WIESE, GENERAL COUNSEL
BARBARA BAIRD, CHIEF DEPUTY COUNSEL

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SOUTH COAST AIR QUALITY MANAGEMENT DISTICT

CERTIFICATE OF WORD COUNT

Pursuant to Rule 8.520(c)(1) of the California Rules of Court, I hereby certify that this brief contains 8,476 words, including footnotes, but excluding the Application, Table of Contents, Table of Authorities, Certificate of Service, this Certificate of Word Count, and signature blocks. I have relied on the word count of the Microsoft Word Vista program used to prepare this Certificate.

DATED: April 3, 2015 Respectfully submitted,

Barbara Baird

PROOF OF SERVICE

I am employed in the County of Los Angeles, California. I am over the age of 18 years and not a party to the within action. My business address is 21865 Copley Drive, Diamond Bar, California 91765.

On April 3, 2015 I served true copies of the following document(s) described as **APPLICATION OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT FOR LEAVE TO FILE BRIEF OF *AMICUS CURIAE* IN SUPPORT OF NEITHER PARTY AND *[PROPOSED]* BRIEF OF *AMICUS CURIAE*** by placing a true copy of the foregoing document(s) in a sealed envelope addressed as set forth on the attached service list as follows:

BY MAIL: I enclosed the document(s) in a sealed envelope or package addressed to the persons at the addresses listed in the Service List and placed the envelope for collection and mailing following our ordinary business practices. I am readily familiar with this District's practice for collection and processing of correspondence for mailing. Under that practice, the correspondence would be deposited with the United States Postal Service, with postage thereon fully prepaid at Diamond Bar, California, in the ordinary course of business. I am aware that on motion of the party served, service is presumed invalid if postal cancellation date or postage meter date is more than one day after date of deposit for mailing in affidavit.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on April 3, 2015 at Diamond Bar, California.

Patricia Anderson

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AIR QUALITY EMISSION REDUCTION AGREEMENT

This Air Quality Emission Reduction Agreement ("Agreement") is entered into as of _____, 2007 by and between Developer Name ("Developer") and the SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq. ("District").

RECITALS

WHEREAS, Developer is presently seeking governmental approval of land use entitlements ("Entitlements") which will permit the development of a Project located in the City/County, California, as more particularly described on Exhibit A attached hereto (the "Project"); and

WHEREAS, the Project incorporates the design features specified on Exhibit B attached hereto ("Emission Reduction Design Features"), in order to significantly reduce the air quality impacts associated with the Project; and

WHEREAS, despite incorporation of the Emission Reduction Design Features, without additional emission reductions, the Project would cause impacts on air quality within the geographical boundaries of the San Joaquin Valley Unified Air Pollution Control District, as depicted on Exhibit C attached hereto (the "District Boundaries"); and

WHEREAS, Developer anticipates that mitigation of impacts on air quality resulting from the Project will be either required as a condition to the approval of Developer's Entitlements, or voluntarily imposed by Developer as a means of reducing such impacts; and

WHEREAS, Developer desires to fully comply with all requirements of the California Environmental Quality Act codified at California Public Resources Code section 21000, et seq. ("CEQA"), including all requirements relating to the mitigation of air quality impacts arising from or in connection with the Project; and

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WHEREAS, District is an air pollution control district formed by the counties of Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare, pursuant to California Health and Safety Code section 40150, et seq.; and

WHEREAS, District is responsible for developing and implementing air quality control measures within the District Boundaries, including air quality control measures for stationary sources, transportation sources, and indirect sources; and

WHEREAS, District has determined that with appropriate funding, District can bring about a reduction of emissions from certain projects in types and in sufficient quantities to fully mitigate the net air quality criteria pollutant impacts of the Project as quantified in the Verified Air Quality Assessment (as defined in Section 2.2 below) ("Project's Air Impact"); and

WHEREAS, Developer and District desire to enter into this Agreement in order to develop and implement air quality control measures which will fully mitigate the Project's Air Impact to the extent that the development of such Project will result in no net increase in criteria pollutant emissions over the criteria pollutant emissions which would otherwise exist without the development thereof.

AGREEMENT

NOW THEREFORE, in exchange of the mutual covenants herein contained, Developer and District hereby agree as follows:

1. **Emission Reduction by Developer and District.**

1.1. **Emission Reduction Proposals.** Developer shall identify and propose to District opportunities to reduce emissions to fully mitigate Project's Air Impact, including but not limited to opportunities for removal or retrofitting of stationary, transportation, indirect, and/or mobile pollution source equipment, and/or other opportunities therefore (each, an "**Emission Reduction Proposal**"). Each Emission Reduction Proposal shall be submitted in writing to District, using District approved forms, and shall contain a representation by Developer that the owner/operator of the identified Pollution Source Equipment has expressed interest in entering into a written funding agreement with

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District in District's then standard form ("**Funding Agreement**") requiring removal or replacement of the identified equipment with new equipment under District's "Heavy Duty Engine Emission Reduction Incentive Program", or another emission reduction program adopted by District ("**District Emission Reduction Program**"). Developer shall submit Emission Reduction Proposals to District in sufficient amounts to fully mitigate emissions from each distinct phase of the project. For each phase of the project, Developer shall submit Emission Reduction Proposals to District no later than application for grading permits for, and before generating emissions from, that phase. Any Emission Reduction Shortfall for a given phase shall be addressed according to Section 1.7.2 of this Agreement.

1.2. **District's Verification of Emission Reduction.** As quickly as practicable upon Developer's submission to District of an Emission Reduction Proposal, District shall determine the types and quantities of permanent reduction in emissions which would be realized by the proposed removal or retrofit and shall advise Developer of such determination in writing ("**Emission Reduction Verification**") thereby verifying that in District's considered opinion the removal or retrofit proposed in the Emission Reduction Proposal would result in permanent emission reduction in the locality of the Project in the types and quantities so determined by District.

1.3. **Emission Reduction Proposal Advance.** Developer shall advance to District, on the date of submittal of each Developer's Emission Reduction Proposal, a monetary sum equal to the total estimated cost (as specified in each Developer's Emission Reduction Proposal), until sufficient advance is received by District to fully mitigate the Project's Air Impact ("**Emission Reduction Proposal Advance**").

1.4. **Funding Agreements.** As soon as practicable after District's receipt of Developer's Emission Reduction Proposal Advance, District shall use diligent efforts to enter into Funding Agreements with the owners and/or operators of the pollution source equipment identified in Developer's Emission Reduction Proposal, thereby providing for the removal and/or retrofit of all of such Pollution Source Equipment, and

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providing for District's payment (from the Emission Reduction Proposal Advance) t such owner or operator, of an amount equal to the estimated cost of such opportunity, as specified in Developer's Emission Reduction Proposals. District shall use diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals within one hundred eighty (180) days following District's receipt of a complete Emission Reduction Proposal and the Emission Reduction Proposal Advance from Developer.

1.5. **Use of Emission Reduction Proposal Advance.** District shall use the Emission Reduction Proposal Advance to meet its monetary obligations under the Funding Agreements that District shall enter into with the owners of the Pollution Source Equipment identified in Developer's Emission Reduction Proposals.

1.6. **Use of Unused Portions of Emission Reduction Proposal Advance.** In the event Developer is unable to submit to District Emission Reduction Proposals providing for emission reduction in the types and quantities necessary to fully mitigate the Project's Air Impact, or in the event District is unable to enter into Funding Agreements with any of the owners or operators identified in Developer's Emission Reduction Proposals, District shall notify Developer in writing of the additional emission reductions needed to fully mitigate the Project's Air Impact, and Developer shall have a reasonable time, not to exceed one hundred eighty (180) days within which to submit to District additional or supplemental Emission Reduction Proposals in order to provide the necessary additional emission reduction.

1.7. **Unused Advance / Emission Reduction Shortfall / Additional Payment.**

1.7.1. **Unused Advance.** If, despite District's diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable, supplemental Emission Reduction Proposals submitted by Developer), District is unable to enter into Funding Agreements sufficient to fully mitigate the Project's Air Impact, then District shall use any unused portion of Developer's Emission Reduction Proposal Advance to fund emission

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reduction opportunities to mitigate the balance of the Project's Air Impact at District's actual cost of doing so, provided that such actual costs shall not exceed the costs set forth in the following Emission Reduction Cost Schedule:

Emission Reduction Cost Schedule		
Year Paid	NOx or ROG ($/ton)	PM10 ($/ton)
2007	$49,700	$55,940
2008	$65,450	$90,110
Beyond	Prevailing Costs	Prevailing Costs

District is of the considered opinion that the emission reductions listed in the above schedule can be achieved at the corresponding times and costs shown in said schedule. If, at the time of invoicing, the District has not identified Prevailing Costs for post-2008 payments, 2008 costs shall apply.

1.7.2. **Emission Reduction Shortfall/Additional Payment.** In the event the emission reduction brought about by the Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable supplemental Emission Reduction Proposals), and that brought about pursuant to Section 1.7.1 above, are not sufficient to fully mitigate the Project's Air Impact ("**Emission Reduction Shortfall**"), then Developer shall be credited for the emission reduction brought about as a result of Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals and for the emission reduction brought about pursuant to Section 1.7.1 above, and Developer thereafter shall deposit with District, within 30 days of receiving notice of the Emission Reduction Shortfall from District, an additional amount equal to the product of (i) District's cost per ton of emission reduction as shown in the Emission Reduction Cost Schedule set forth in Section 1.7.1 above, multiplied by (ii) the total number of tons of emission reduction necessary to fully mitigate the Project's Air Impact less the total number of tons of emission reduction so credited to Developer. However, in no case shall the amount paid to District and the

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amount of emission reductions achieved per this agreement be less than the amount that would be paid to District or the amount of emission reductions that would be required for this Project according to District Rule 9510 (Indirect Source Review). To allow verification of equivalency of emission reductions and off-site mitigation fee amounts, according to District Rule 9510, Developer shall submit to District an ISR Air Impact Assessment Application, using District forms, no later than concurrent with the Developer's submission of the air quality assessment, as set forth in Section 2.2.

1.8. **Surplus Mitigation.** In addition to the amounts payable under paragraph 1.3, Developer shall deliver to District an additional sum equal to five percent (5%) of the Emission Reduction Proposal Advance. Said additional sum shall be paid under the same schedule as set forth in paragraph 1.3. District shall utilize such additional sum to fund further localized emission reduction opportunities in quantities consistent with the schedule set forth in paragraph 1.7.1.

1.9 **Time of Use.** Any emission reductions brought about by this Agreement prior to the date Developer receives final approval of the Project from all applicable Governmental Authorities shall be credited to the total amount of emission reductions achieved per this agreement.

1.10. **District's Obligation.** The monies paid by Developer under this Agreement shall be used by District to obtain localized emission reductions in the types and quantities necessary to fully mitigate the Project's Air Impact as quantified in the Verified Air Quality Assessment. If necessary, District shall assist Developer in securing emission reductions, consistent with the provisions established in Section 1.7.2.

1.11. **Developer's Obligation.** District acknowledges that, if the Project is not finally approved so that such development is allowed to proceed, Developer has no obligations under this Agreement relative to the respective Project. Developer acknowledges that it must satisfy the terms of this Agreement in order to develop the Project.

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2. **CEQA Compliance/Full Mitigation.** For and in exchange of Developer's payment of funds pursuant to Section 1 above, District shall ensure, by way of entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, that the Project's Air Impact is fully mitigated, such that the Project, combined with the emission reductions brought about in accordance with Section 1 above, shall result in no net increase in air quality impacts over those air quality impacts which would otherwise exist without the development of such Project. For the purpose of this agreement, full mitigation means the sum of all NOx, ROG, and PM10 emission reductions achieved by the Emission Reductions Proposals equals, or is greater than, the sum of all NOx, ROG, and PM10 emissions increases calculated as the average annual construction and the peak annual area source and mobile source emissions of NOx, ROG, and PM10 less the average annual emissions that have occurred at the project site during the three years prior to release of the Notice of Preparation. In addition to entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, District shall do all of the following:

2.1. **District's Verification of Air Assessment Protocol.** Within ten (10) business days following the date of this Agreement, Developer shall submit to District an air assessment protocol prepared by Developer's air quality consultant reflecting the methodology, including air quality impact modeling, to be utilized in the preparation of the air quality assessment for the Project. Within twenty-one (21) business days following District's receipt of Developer's air assessment protocol, District shall review and comment upon such air assessment protocol, and, after Developer's incorporation of any revisions suggested by District, District shall verify in writing to Developer the correctness of the air assessment protocol which will be utilized in the preparation of the air quality assessment for the Project.

2.2 **District's Verification of Air Quality Assessment.** Following District's Verification of Air Assessment Protocol, Developer shall submit to District an air quality

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assessment prepared by Developer's air quality consultant assessing the air quality impacts of the Project. District shall use its best efforts to review and comment upon Developer's air quality assessment within thirty (30) days following District's receipt of Developer's complete air quality assessment, and, after Developer's incorporation of any and all revisions suggested by District, District shall verify in writing to Developer the correctness of the air quality assessment to be utilized in connection with the CEQA documents for the Project, including (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein (the "**Verified Air Quality Assessment**").

2.3. **District's Verification of Administrative Draft Environmental Impact Report**. Upon request by Developer, and submission by Developer to District of any administrative Draft Environmental Impact Report, or other applicable CEQA documents for the Project, District shall review, comment upon and, after incorporation of any and all revisions made by District, verify in writing to Developer the correctness of all portions thereof which pertain to air quality impacts, including, (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein.

2.4 **District's Acknowledgment Regarding Full Mitigation.** At such time as District is provided an opportunity as a commenting agency to comment upon the Draft Environmental Impact Report and Final Environmental Impact Report for the Project, District shall comment in writing as to the correctness of all portions thereof which pertain to air quality impacts, including (i) the methodology utilized in the

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preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein. District shall at all times fully perform its duties and obligations as a commenting agency, and the provisions of this Section 2.4 shall not be interpreted to the contrary. At such time as District has entered into Funding Agreements pursuant to Section 1.4 above and the owners/operators of equipment to be removed and/or replaced under such agreements have removed and replaced such equipment in accordance with the provisions thereof, District shall verify in writing to Developer and to the lead agency that full mitigation of the Project's Air Impact has been achieved, upon successful fulfillment of all Funding Agreements. District shall ensure that the owners/operators of equipment to be removed and/or replaced pursuant to such Funding Agreements perform all obligations to be performed on the part of such parties under said Funding Agreements. District acknowledges that the Verified Air Quality Assessment and its quantification of the Project's Air Impact will be based on the pending applications for development of the Project and that actual approvals may be for a lesser amount of development. District agrees that Developer's obligations under this Agreement shall be based on the amount of development actually approved, and the final quantification of the Project's Air Impact will be revised accordingly.

2.5. **District's Oversight of Air Quality Mitigation Monitoring Plan.** Upon request of the lead agency having jurisdiction over the Project, District shall oversee that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1 of this Agreement. Alternatively, upon request of that lead agency, District shall cooperate with the lead agency in the oversight of that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1

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of this Agreement.

2.6. **District's Documentation, Record Keeping and Monitoring.** District shall document, keep adequate records on and monitor the emission reduction brought about as a result of this Agreement, and shall from time to time, upon written request by Developer or by the lead agency for the Project, provide to Developer or to the lead agency written reports verifying that emission reduction has been and/or is being brought about so as to fully mitigate the Project's Air Impact.

3. **Subsequent Litigation, Legislation and/or Administrative Action / Credit to Developer.**

3.1. **Subsequent Litigation.** In the event that despite this Agreement, Developer is required as a result of a final judgment or District Approved Settlement (as defined below) in any subsequent third party litigation, to pay monies in addition to the monies to be paid by Developer pursuant to Section 1 above, then, provided that the project total emissions are the same as quantified in the Verified Air Quality Assessment, District shall acknowledge and credit Developer with mitigation of the air quality impacts of the Project in such types and quantities that Developer can establish, to the reasonable satisfaction of District, will result from Developer's payment of such additional monies, and shall reduce any amounts thereafter payable by Developer under this Agreement by an amount equal to the additional monies so paid by Developer. This requirement shall not apply if the additional monies are required to mitigate emissions that exceed those set forth in the Verified Air Quality Assessment. For purposes of this Section 3.1.1, a **"District Approved Settlement"** shall mean a settlement of a lawsuit filed pursuant to CEQA, the National Environmental Protection Act or other applicable environmental law which (i) provides for Developer's payment of monies in exchange for a dismissal of such lawsuit, (ii) provides for the use of such monies by the petitioner in such lawsuit in such a manner as to mitigate adverse air quality impacts of the Project, and (iii) is approved in writing by District.

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3.2. **District Rule 9510.** The performance of Developer's and District's obligations under this Agreement will fully mitigate the Project's Air Impact. Inasmuch as the mitigation provided under this Agreement exceeds the mitigation which would otherwise have been provided under Sections 6.0 and 7.0 of District's Rule 9510, and the Project's mitigated baseline (being zero emissions) is less than the threshold stated in Section 4.3 of said Rule 9510, the Project is exempt from Sections 6.0 and 7.0 of District's Rule 9510. Accordingly, no off-site Emission Reduction Fee will be required in connection with the approval or development of the Project. For each individual project developed at the project site requiring a discretionary approval by the lead agency, Developer shall provide District with a map or diagram indicating its location within the area covered by this Agreement.

4. **Term of Agreement.** This Agreement shall be effective upon the date first written above, and shall terminate upon District's meeting its obligation to implement projects that provide necessary emissions reductions to fully mitigate the Project's Air Impact (the "**Term**"). Developer may, at any time by written notice to District, terminate this Agreement, whereupon, (i) District shall acknowledge in writing to the lead agency that Developer has mitigated air quality impacts of the Project to the extent and in the types and quantities brought about by Funding Agreements theretofore funded by Developer's Emission Reduction Proposal Advance (and if applicable pursuant to Section 1.7.1 above), (ii) District shall refund to Developer any unused portion of Developer's Emission Reduction Proposal Advance less any unpaid administrative fees incurred; and (iii) neither Developer nor District shall have any further rights or obligations under this Agreement. Developer acknowledges that in the absence of this Agreement, the project is subject to all applicable provisions of District Rule 9510 (Indirect Source Review).

5. **Payment of Administrative Fees to District.** Developer agrees to pay to District, in order to reimburse District for its general overhead required for the administration of this Agreement, an administrative fee ("***ERIP Fee***") in an amount

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equal to four percent (4%) of the Emission Reduction Proposal Advance. Such ERIP Fee shall be due and payable upon Developer's delivery of the Emission Reduction Proposal Advance pursuant to Section 1.3 above. In addition to the ERIP Fee, Developer agrees to pay to District, within thirty (30) days following Developer's receipt of District's invoice, administrative fees to reimburse District for staff time spent and materials used by District in the administration of this Agreement, other than that time associated with the ERIP program covered by the ERIP Fee above, including review, verification and preparation of documents, and staff time relating to the performance of District's obligations hereunder, based on a time and materials basis at District's average weighted labor rates.

6. **Representations, Covenants and Warranties.**

6.1. **Developer's Representations, Covenants and Warranties.** Developer represents, covenants and warrants to District, as of the date of this Agreement, and as of the date of Developer's submission to District of any documents contemplated hereunder, as follows:

6.1.1. The undersigned representatives of Developer are duly authorized to execute, deliver and perform this Agreement, and upon Developer's execution and delivery of this Agreement, this Agreement will have been duly authorized by Developer.

6.1.2. Upon execution and delivery of this Agreement by Developer, Developer's obligations under this Agreement shall be legal, valid and binding obligations of Developer, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.1.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

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6.1.4. Other than the execution and delivery of this Agreement by the undersigned representatives of Developer, there are no approvals, consents, confirmations, proceedings, or other actions required by Developer or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2. **District's Representations, Covenants and Warranties.** District represents, covenants and warrants to Developer, as of the date of this Agreement, and as of the date of District's delivery to Developer of any documents contemplated hereunder, as follows:

6.2.1. The undersigned representatives of District are duly authorized to execute, deliver and perform this Agreement, and upon District's execution and delivery of this Agreement, this Agreement will have been duly authorized by District.

6.2.2. Upon execution and delivery of this Agreement by District, District's obligations under this Agreement shall be legal, valid and binding obligations of District, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.2.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative, quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

6.2.4. Other than the execution and delivery of this Agreement by the undersigned representatives of District, there are no approvals, consents, confirmations, proceedings, or other actions required by District or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2.5. No lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or

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anticipated will render invalid, void or unenforceable any right or benefit Developer is to receive under the terms and conditions of this Agreement.

6.2.6. The monies paid by Developer under this Agreement shall be sufficient to ensure that the emission reduction contemplated by this Agreement shall occur, and District shall utilize such monies in such a manner as to ensure that such emission reduction shall occur.

6.2.7. Upon the approval of this Agreement by the governing board of District, the Air Pollution Control Officer of District, or equivalent representative, or a delegee of such officer, shall have the authority to approve, deliver, verify, enter into, acknowledge and/or accept any communication, notice, notification, verification, agreement and/or other document to be issued or entered into by District under the terms and conditions of this Agreement, without further approval of the governing board of District.

7. **Indemnification**. Developer agrees to indemnify, defend and hold harmless District for, from and in connection with any third party claims, losses and/or liabilities arising from or in connection with District's performance of this Agreement, excluding only such claims, losses and/or liabilities which result from or in connection with District's sole negligence, act or omission.

8. **Inurnment**. Developer's rights and obligations under this Agreement, or applicable portions thereof, shall run with the land encompassed by the Project, and shall inure to the benefit of and be binding upon the heirs, successors and assigns of Developer who take title to such lands or applicable portions thereof. Upon Developer's conveyance of all or any portion of the lands encompassed by the Project, the rights and obligations of Developer under this Agreement shall, to the extent applicable to the lands so conveyed, be transferred to the transferee thereof, and Developer shall thereupon be released by District from, all obligations and liabilities so assigned, except for such obligations and liabilities arising prior to such transfer.

9. **Assignment**. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement. Upon any such assignment, Developer shall

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deliver to District a written assignment and assumption agreement specifying the fact and extent of the assignment, the name and address of the assignee, and the assignee's assumption of all obligations of Developer thereby assigned. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement to a third party for use in connection with the mitigation of air quality impacts resulting from one or more projects other than the Project, so long as (i) the project is located within the District Boundaries, (ii) the air quality impacts of such project(s) will in fact be mitigated, as verified by District, by the emission reductions brought about by this Agreement, and (iii) the project(s) consist of residential, commercial, industrial and/or mixed use real estate projects which incorporate the Emission Reduction Design Features. Upon any such assignment by Developer, District shall enter into an amendment of this Agreement which acknowledges the assignment and conforms the various provisions of this Agreement as may be required to be conformed in order to provide to the assignee the rights and benefits of this Agreement as if such assignee and its project were the original party and project contemplated in this Agreement.

10. **Recitals Incorporated.** The recitals set forth hereinabove are hereby incorporated into this Agreement and acknowledged, agreed to and adopted by the parties to this Agreement.

11. **Further Assurances.** Developer and District agree to execute and deliver any documents and/or perform any acts, which are reasonably necessary in order to carry out the intent of the parties with respect to this Agreement.

12. **No Joint Venture or Partnership.** District and Developer agree that nothing contained in this Agreement or in any document executed in connection with this Agreement shall be construed as making District and Developer joint ventures or partners.

13. **Notices.** Any notices or communications relating to this Agreement shall be given in writing and shall be deemed sufficiently given and served for all purposes

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when delivered, if (a) in person, (b) by facsimile (with the original delivered by other means set forth in this Section 13), (c) by generally recognized overnight courier or (d) by United States Mail, certified or registered mail, return receipt requested, postage prepaid, to the respective addresses set forth below, or to such other addresses as the parties may designate from time to time by providing written notice of the change to the other party.

To Developer: Address & Contact Name	To District: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Seyed Sadredin Executive Director/APCO
With a copy to: Address & Contact Name	with a copy to:San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Dave Warner Director of Permit Services with a copy to: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Philip M. Jay District Counsel

14. **Entire Agreement.** The terms of this Agreement, together with all attached exhibits, are intended by the parties as the complete and final expression of their agreement with respect to such terms and exhibits and may not be contradicted by evidence of any prior or contemporaneous agreement. This Agreement specifically supersedes any prior written or oral agreements between the parties with respect to

the subject matter of this Agreement.

15. **Amendments and Waivers.** No addition to or modification of this Agreement shall be effective unless set forth in writing and signed by the party against whom the addition or modification is sought to be enforced. The party benefited by any condition or obligation may waive the same, but such waiver shall not be enforceable by another party unless made in writing and signed by the waiving party.

16. **Invalidity of Provisions.** If any provision of this Agreement as applied to either party or to any circumstance shall be adjudged by a court of competent jurisdiction to be void or unenforceable for any reason, the same shall in no way affect (to the maximum extent permissible by law) any other provision of this Agreement, the application of any such provision under circumstances different from those adjudicated by the court, or the validity or enforceability of this Agreement as a whole. The parties further agree to replace any such invalid, illegal or unenforceable portion with a valid and enforceable provision which will achieve, to the maximum extent legally possible, the economic, business or other purposes of the invalid, illegal or unenforceable portion.

17. **Construction.** Unless otherwise indicated, all Section references are to the sections of this Agreement and all references to days are to calendar days. Whenever, under the terms of this Agreement the time for performance of a covenant or condition falls upon a Saturday, Sunday or California state holiday, the time for performance shall be extended to the next business day. The headings used in this Agreement are provided for convenience only and this Agreement shall be interpreted without reference to any headings. Wherever required by the context, the singular shall include the plural and vice versa, and the masculine gender shall include the feminine or neuter genders, or vice versa. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. The language in all parts of this Agreement shall be construed as a whole in accordance with its fair meaning, and shall not be

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construed against any party solely by virtue of the fact that such party or its counsel was primarily responsible for its preparation.

18. **Governing Law.** This Agreement shall be governed by the laws of the State of California applicable to contracts made and to be performed in California.

19. **No Third-party Beneficiaries.** Nothing in this Agreement, express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person other than the parties to it and their respective permitted successors and assigns, nor is anything in this Agreement intended to relieve or discharge any obligation of any third person to any party hereto or give any third person any right of subrogation or action over or against any party to this Agreement.

20. **Exhibits.** The exhibits attached to this Agreement shall be deemed to be a part of this Agreement and are fully incorporated herein by reference.

21. **Force Majeure.** The time within which any party shall be required to perform under this Agreement shall be extended on a day-per-day basis for each day during which such performance is prevented or delayed by reason of events reasonably outside of the control of the performing party, including, without limitation, acts of God, events of destruction, acts of war, civil insurrection, strikes, shortages, governmental delays, moratoria, civil litigation and the like, and/or delays caused by the non-performing party's act or omission.

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IN WITNESS WHEREOF, Developer and District have executed this Agreement and agree that it shall be effective as of the date first written above.

DEVELOPER: Developer Name,

a California limited liability company

By:_____

Name:_____

Title:_____

DISTRICT: **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT**, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq.

///

DISTRICT

San Joaquin Valley Unified Air Pollution Control District

///

By:_____

Councilmember J. Steven Worthley, Chair

Governing Board

///

Recommended for approval:

San Joaquin Valley Unified Air Pollution Control District

///

_____

Seyed Sadredin

Executive Director/APCO

///

///

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Approved as to legal form:

San Joaquin Valley Unified Air Pollution Control District

_____

Philip M. Jay

District Counsel

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Approved as to accounting form:

San Joaquin Valley Unified Air

Pollution Control District

///

_____

Roger W. McCoy

Director of Administrative Service

For accounting use only:

Program:_____

Account No.:_____

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EXHIBIT A

DESCRIPTION OF THE PROJECT

[INSERT MAP.]

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EXHIBIT B

EMISSION REDUCTION DESIGN FEATURES

The project shall incorporate the following Emission Reduction Design Features:

The project will incorporate the following on-site features:

1. Utilization of land use designs which create walkable communities and encourage pedestrian travel.
2. Utilization of interconnecting sidewalks, walking paths and/or bike paths in order to encourage travel by means other than motor vehicle.
3. Utilization of appropriate landscaping to create reasonable shade canopies for streets, parkways and parking areas.
4. Utilization of roadway designs, which enhance pedestrian safety by appropriate signaling, signage and separation from traffic.
5. Design requirements, which incorporate natural gas hookups and electrical outlets on patios.
6. Design requirements, which prohibit the installation and use of wood burning stoves and wood burning fireplaces.

Prior to issuance of grading permits for the Project, Developer shall prepare and submit to District dust control plans for the areas to be graded, in accordance with District Regulation VIII. The plan shall be prepared consistent with District Regulation VIII and must be reviewed and approved by the District prior to commencement of grading activities. Each contractor working on the Project site shall implement the dust control measures outlined in the approved dust control plan. The dust control measures selected shall be incorporated as a note on each grading plan.

District maintains New Source Review requirements that direct owners/operators of certain types of stationary equipment to obtain an Authority to Construct ("ATC") and Permits to Operate ("PTO") from the District. As part of this process, the need for emission control equipment is assessed and the District determines whether a Health Risk Assessment ("HRA") must be prepared.

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Owners/operators of all stationary sources for which such approvals are required should show proof of compliance with District Rules and Regulations prior to issuance of certificates of occupancy.

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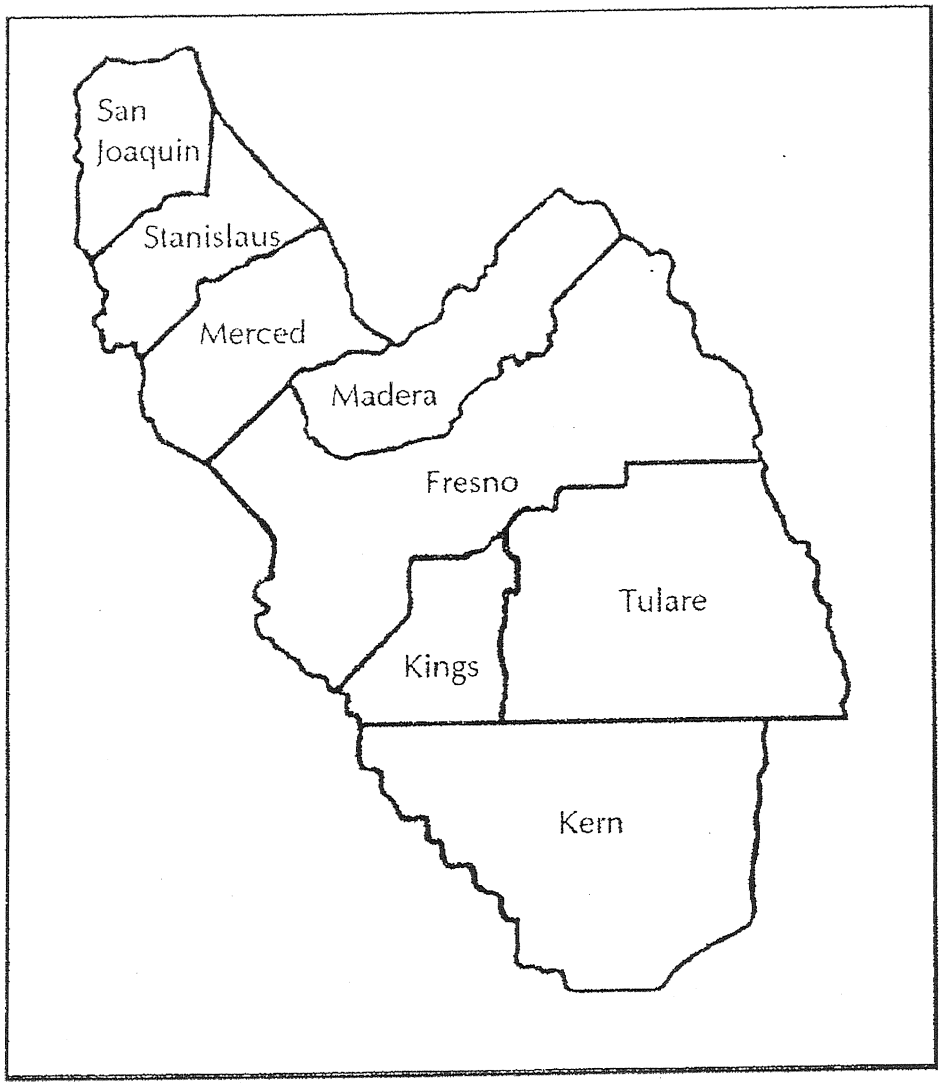
EXHIBIT C

DISTRICT BOUNDARIES



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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT.



AIR TOXICS

2022 Annual Report

March 16, 2023

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT
GOVERNING BOARD 2022

CHAIR: VITO CHIESA
Supervisor, Stanislaus County

VICE CHAIR: DEBORAH LEWIS
Councilmember, City of Los Banos

MEMBERS:

DREW M. BESSINGER
Councilmember, City of Clovis

DAVID COUCH
Supervisor, Kern County

ROBERT MACAULAY
Supervisor, Madera County

BUDDY MENDES
Supervisor, Fresno County

TANIA PACHECO-WERNER, PHD
Appointed by Governor

LLOYD PAREIRA
Supervisor, Merced County

VACANT
Small City

ALVARO PRECIADO
Mayor, City of Avenal

ROBERT RICKMAN
Supervisor, San Joaquin County

RUSTY ROBINSON
Supervisor, Kings County

ALEXANDER C. SHERRIFFS, M.D.
Appointed by Governor

AMY SHUKLIAN
Supervisor, Tulare County

VACANT
Large City

EXECUTIVE DIRECTOR/AIR POLLUTION CONTROL OFFICER:

SAMIR SHEIKH

Executive Summary

The San Joaquin Valley Air Pollution Control District (District) is a public health agency whose mission is to improve the health and quality of life for all Valley residents through efficient, effective and entrepreneurial air quality-management strategies. The District has spent nearly three decades implementing and integrating a wide variety of methods reducing toxic air contaminant emissions in the San Joaquin Valley. Based on the latest California Toxics Inventory (CTI) available from CARB, 14% of all air toxics in the Valley are now emitted from stationary sources of pollution under the direct control and regulation of the District, while 52% comes from mobile sources such as cars and trucks, and the remaining 34% is emitted from area-wide sources like road dust, paints, solvents, and other consumer products. Mobile and area-wide sources of emissions are generally under the regulatory authority of the State of California and the federal government.

The District's integrated approach to addressing and reducing risks from toxic air contaminants has taken three main paths: reducing air toxic emissions from existing stationary sources of emissions; preventing the creation of new or modified stationary sources of significant risk; and finding creative and cooperative methods of reducing risk from emissions sources that the District does not typically regulate. This approach has resulted in dramatic reductions in emissions of air toxics from sources in the San Joaquin Valley.

Under Assembly Bill (AB) 2588 (Air Toxics Hot Spots Information and Assessment Act), the District works with facilities to quantify emissions of air toxics, determines the health risk caused by those emissions, reports emissions and any significant risks through written public reports and neighborhood public meetings, and as required, takes steps to reduce such risks. As a result of these ongoing efforts, and the resulting emissions reductions, no Valley facility currently poses a significant risk under this program.

The State's Hot Spots Act, however, is only one part of the District's comprehensive program to regulate air toxics. To achieve maximum efficiency and effectiveness, the District operates an integrated air toxics program that harmonizes local, state, and federal mandates wherever possible.

A number of regulations have also been adopted by the District, the state, and the federal government, and implemented through the District's integrated air toxics program, to directly reduce existing emissions from specific types of facilities and sources of air toxic contaminants. For example, the toxic air contaminant emissions from emissions sources like dry cleaners, chrome platers, gas stations, and diesel internal combustion engines have drastically decreased in the San Joaquin Valley since the implementation of the District's air toxic program.

In addition to the above efforts to minimize emissions, the District also performs comprehensive and conservative toxic emission evaluations and air dispersion modeling before issuing permits to new and modified stationary sources of emissions. This assures the District minimizes the increase those sources add to the existing toxic load and any

potentially significant public health impacts associated with the release of those airborne toxic emissions.

Under its integrated air toxics program, the District has also implemented numerous methods of reducing emissions from mobile sources and other sources of emissions that the District does not have the authority to regulate. For instance, the District developed the first Indirect Source Review rule in the nation, designed to reduce emissions from construction equipment and mobile sources associated with new land use development projects. The District also provides assistance and guidance to the cities and counties in the San Joaquin Valley so that they can be assured that land-use decisions are based on a full understanding of the potential for increasing emissions of air toxics, and new air toxics risks can be avoided. One of the most effective methods of reducing emissions of air toxics from emissions sources not directly regulated by the District has been the incentive grant programs that have leveraged billions of dollars in reducing emissions from diesel internal combustion engines on trucks, tractors and agricultural irrigation operations.

This 2022 Annual Air Toxics Report describes the District's ongoing efforts to regulate and minimize air toxic emissions. An electronic version of this report may be found at: http://www.valleyair.org/busind/pto/air_toxics_annual_reports.htm.

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Summary of Toxic Air Contaminants in the San Joaquin Valley

The United States Environmental Protection Agency (EPA) and the California Air Resources Board (CARB) have identified over 700 substances that are emitted into the air that may affect human health. Some of these substances are considered to be carcinogens, while others are known to have short-term acute or long-term chronic health impacts. As part of ongoing efforts to identify and assess potential health risks to the public, the District has collected and compiled air toxics emissions data from industrial and commercial sources of air pollution throughout the Valley. The State has developed similar inventories for mobile sources of air pollution. These District and State inventories have been combined into the CARB's California Toxic Inventory (CTI), which provides the latest emission estimates available for hazardous air pollutants of concern from all sources. A summary of the latest available CTI data for key pollutants is presented in Table 1 below.

Table 1. Primary San Joaquin Valley Hazardous Air Pollutant Emissions

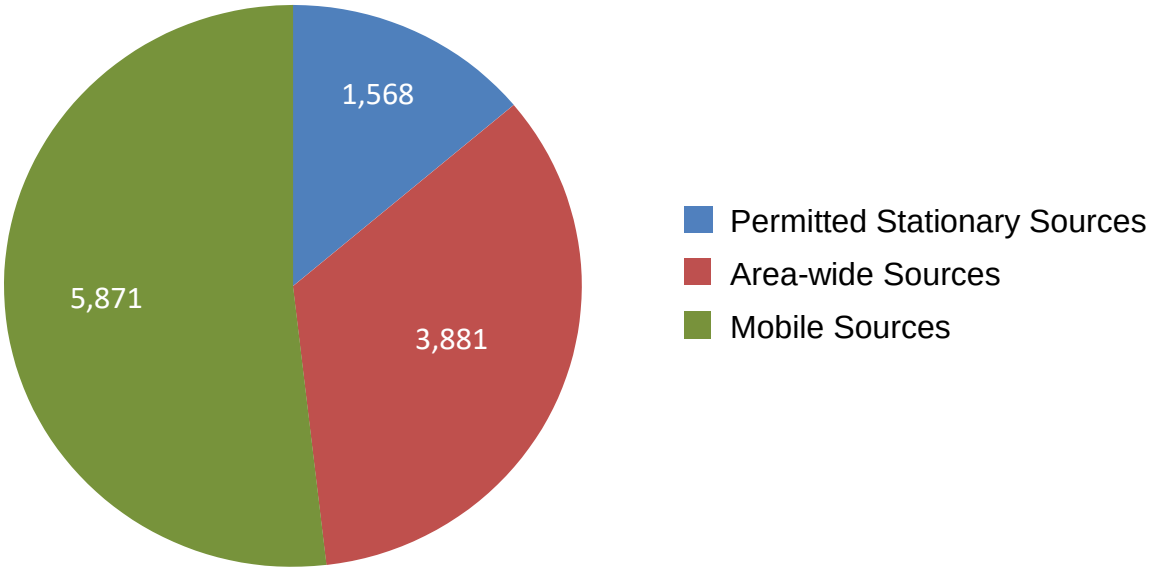
Pollutant	Inventory (tons/yr)
Acetaldehyde	3,512
Diesel Particulate Matter	2,520
Formaldehyde	2,318
Benzene	1,020
Perchloroethylene	448
1,3-Butadiene	269
Methylene Chloride	247
p-Dichlorobenzene	130
Carbon Tetrachloride	0
Chromium, Hexavalent	0

A more detailed summary of CTI emission estimates for the San Joaquin Valley is provided in Table B1 in Appendix B.

Toxic Air Contaminants (TACs), otherwise known as air toxics, are emitted from mobile sources (e.g., cars, trucks, buses, tractors, etc.), which are primarily regulated by the State and EPA; area sources (e.g., consumer products), which are regulated by the State, EPA, and the District; and from stationary sources regulated primarily by the District. Figure 1 below shows a comparison of mobile, area, and stationary source emissions of hazardous air pollutants in the San Joaquin Valley. Of these sources, approximately 86% of hazardous air pollutant emissions occurring in the Valley are from mobile sources and area sources.

Stationary sources include point source emissions provided by facility operators and/or air districts and aggregated point source emissions estimated by CARB and/or air districts. This stationary source information is included in the CTI pursuant to the Air Toxics "Hot Spots" Act of 1987 (AB 2588). Area-wide sources are those that emit over an unspecified area. This could include paved roads, unpaved roads, or consumer product emitting sources.

Figure 1. Mobile, Area-wide, and Stationary Source Air Toxics Emissions (tons) in the San Joaquin Valley



Air Toxics Screening Assessment

EPA's Air Toxics Screening Assessment (AirToxScreen), formerly known as The National Air Toxics Assessment (NATA), is a screening tool to provide communities with information about health risks from air toxics. AirToxScreen is part of EPA's approach to air toxics that provides updated data and risk analyses on an annual basis, helping state, local and tribal air agencies, EPA, and the public more easily identify existing and emerging air toxics issues. State and air district toxic emissions inventory data are compiled to create a national emissions inventory of air toxic sources, which is used by EPA to generate the AirToxScreen Mapping Tool. The AirToxScreen Mapping Tool can be found at: https://www.epa.gov/AirToxScreen/airtoxscreen-mapping-tool.

Assembly Bill (AB) 617 - Community Air Protection Program

The implementation of AB 617 (C. Garcia, 2017) has brought additional clean air resources and strategies to Valley communities. Despite the significant reductions in emissions of criteria and toxic air pollutants that have already been achieved across the Valley, there remain many Valley communities that are disproportionately burdened by the cumulative

effects of various environmental and socioeconomic factors. AB 617 requires the expedited implementation of advanced control technologies for existing stationary source facilities; development and implementation of community-specific air quality monitoring networks; development and implementation of community emission reduction programs; enhanced reporting of facility emissions inventory data, and the creation of publically accessible online clearinghouses of emission control technology determinations. Resources available through this legislation have allowed the District and Community Steering Committees, through a comprehensive public outreach and community engagement process, to develop programs for community protection and develop a robust plan for reducing local exposure to fine particulate matter and toxic air contaminants in Valley communities.

Criteria Air Pollutant and Toxics Air Contaminants Reporting Regulation

AB 617 requires CARB to develop a uniform statewide system of annual reporting of emissions of criteria air pollutants and toxic air contaminants for certain categories of stationary sources. The bill requires stationary sources to report their annual emissions of criteria air pollutants and toxic air contaminants. In order to implement these reporting requirements, CARB developed the "Regulation for the Reporting of Criteria Air Pollutants and Toxic Air Contaminants" (CTR) to implement statewide annual reporting of criteria air pollutant and toxic air contaminant emissions data from facilities, and was adopted in support of mandates under AB 617, AB 197, and AB 2588. For Valley permitted facilities, the District will implement this regulation on behalf of the state through the District's existing annual emission inventory and air toxics processes. Emissions inventory data is critical to understanding the sources of emissions that may contribute to adverse health risks or other impacts at the local, regional, and statewide level. In 2022, 221 facilities were required to report their criteria and toxic emissions under the CTR regulation for the 2021 inventory reporting year. Facility emissions reported under CTR regulation are visualized in CARB's Pollution Mapping tool. The tool provides an interactive platform where users can select facilities by name, location, or industrial sector; view their reported emissions using maps, charts and tabular formats; and download data. It can be found at: https://ww3.arb.ca.gov/ei/tools/pollution_map/.

Summary of California's Air Toxics "Hot Spots" Information and Assessment Act

Background

The *Air Toxics "Hot Spots" Information and Assessment Act* (AB 2588, 1987, Connelly) was enacted in September 1987 and later strengthened in 1992. Under this act, stationary sources are required to report the types and quantities of certain toxic substances their facilities routinely release into the air. The goals of AB 2588 are:

- to identify Valley facilities that release toxic air contaminants as a result of their day to day operations
- to collect and quantify emission data
- to identify facilities causing localized impacts
- to determine facility-wide health risks
- to notify nearby residents and businesses of significant risk facilities in their vicinity
- to require that significant-risk facilities reduce their risks below the level of significance in accordance with the provisions of the "Emissions Inventory Criteria and Guidelines Report" adopted by the Air Resources Board

The District's implementation of AB 2588 has minimized health risks to the public associated with the release of air toxic emission from sources located within the San Joaquin Valley. Under this right-to-know law, the District has worked with facilities to quantify air toxic emissions, determine the potential health risk associated with those emissions, and report any risk determined to be significant by the District through written public reports and neighborhood public meetings. A flowchart summarizing the AB 2588 implementation process is provided in Appendix C.

Assessing the Risk to the Public

The State Air Toxics "Hot Spots" Act requires the District to compile an inventory of toxic emissions from Valley facilities, prioritize facilities for health risk, evaluate public health risks for facilities ranked as high priority, and notify individuals who may be impacted by any significant health risks. Although Hot Spots is primarily a public right-to-know and notification program, the public awareness achieved through the Hot Spots program has led many Valley businesses to voluntarily reduce their toxic emissions to ease community concerns.

Implementation

The District utilizes the applicability criteria outlined in CARB's Emission Inventory Criteria and Guidelines Regulation (EICGR) to determine which facilities are evaluated under the program. Facilities are subject to quantifying and reporting their toxic emissions if one or more of the criteria below is met:

- Emit 10 or more tons per year of criteria pollutants (particulate matter, oxides of nitrogen, oxides of sulfur, or organic gasses)
- Emit less than 10 tons per year of criteria pollutants, but meet one or more of the classes listed in Appendix E of the EICGR
- Emit toxic substances that have been added to Appendix A of the EICGR
- Emit toxic substances that have new health risk values published by the state's Office of Environmental Health Hazard Assessment (OEHHA)

The risk evaluation processes were revised in 2015 as the District implemented the state Office of Environmental Health Hazard Assessment's (OEHHA's) revised *Guidance on Preparation of Health Risk Assessments* that was adopted by OEHHA in early March 2015. The District's health risk assessment processes and policies were updated accordingly and implemented July 1, 2015. This revised guidance was designed to incorporate the Governing Board's guidance to implement OEHHA's revisions to provide enhanced protection of children, and the public overall, while preventing unreasonable restrictions on permitting actions.

OEHHA's revised guidance has been incorporated into the District's implementation of the AB 2588 Hot Spots Program. Since the calculated health risk under the new methodologies is higher than previous estimates, Valley facilities are being reassessed under AB 2588. Under this health risk reassessment process, facilities are first evaluated to determine applicability to the Air Toxics "Hot Spots" program. Facilities determined to be subject to the Air Toxics "Hot Spots" program are required to prepare a Toxic Emission Inventory Plan (Plan) and a Toxic Emission Inventory Report (Report) in order to provide site-specific inventories of air emissions of toxic substances.

In 2016, the District began the outreach and reassessment of facilities by following the phased processing schedule outlined in AB 2588, which was originally implemented in the late 80's and early 90's. AB 2588 subjected three major categories (or phases) of facilities to the regulation based upon their level of annual emissions. The AB 2588 regulation also allows for "Industry-wide" toxics emissions inventory, which consist of facilities that are small businesses where emissions can be generally characterized such as gasoline dispensing facilities, auto body coating facilities, etc. These industry-wide facilities are being addressed under the fourth assessment phase. Similar to industry-wide facilities, small single source facilities, such those with only diesel internal combustion engines (DICE), are also being assessed in the fourth phase of the implementation schedule. The following summary outlines each phase within the District's implementation plan:

First phase:	Phase I Facilities (≥ 25 tons emissions per year)
Second phase:	Phase II Facilities (10 ≤ tons emissions per year < 25)
Third phase:	Phase III Facilities (< 10 tons emissions per year)
Fourth phase:	Phase IV Facilities (Industry-wide such as Gas Stations, Auto Body Shops, etc.; DICE only, Ag facilities)

AB 2588 Evaluation Process

Toxic Emission Inventory Plans and Reports

Under this act, facilities are required to prepare Toxic Emission Inventory Plans and Reports to develop site-specific inventories of air emissions from toxic substances. Plans provide an outline and methodology for calculating toxic emissions for all permitted and non-permitted stationary sources operated at the facility. This is reviewed and approved by the District prior to emission quantification. Reports include calculations of facility's toxic emissions using site-specific process rates and emission factors in order to perform a "Prioritization" of the facility's air toxic emissions.

Prioritization

AB 2588 requires air districts to prioritize facilities to determine a facility's status within the program. In establishing priorities, the air districts are to consider the potency, toxicity, quantity, and volume of hazardous materials released from the facility, the proximity of the facility to potential receptors, and any other factors that the district determines may indicate that the facility may pose a significant health risk. The District uses the prioritization methodology outlined in the California Air Pollution Control Officers Association (CAPCOA) *Facility Prioritization Guidelines* to prioritize facilities under AB 2588. Utilizing the facility's approved Plan and Report, a facility's priority status is determined using the prioritization thresholds listed in District Policy APR 1906, as identified in Table 2 below.

Table 2: AB 2588 Prioritization Thresholds and Categories

Prioritization Thresholds	Priority Category	Category Requirements
≤ 1	Low Priority	Facility is conditionally exempt from further AB 2588 requirements
>1 and ≤ 10	Intermediate Priority	Facility is required to provide an update summary on a quadrennial basis
> 10	High Priority	Facility is required to perform a Health Risk Assessment

Health Risk Assessment

Facilities that classify as "High" priority are required to perform a Health Risk Assessment (HRA) to determine whether its toxic emissions are expected to pose a significant risk to nearby residents and workers. Under AB 2588, the District and the Office of Environmental Health Hazard Assessment's (OEHHA) review each HRA. HRAs performed under the program are required to use the methodologies and procedures outlined in District guidelines and OEHHA's 2015 Air Toxic Hot Spots Program "*Guidance Manual for Preparation of Health Risk Assessments*". A facility's status under the program is determined using established health risk thresholds as identified in Table 3 below:

Table 3: AB 2588 Health Risk Assessment Thresholds

Health Risk Thresholds	Risk Category	Category Requirements
Cancer risk < 1 in a million, and Total hazard index of < 0.1	Low Risk	Facility is conditionally exempt from further AB 2588 requirements
1 ≤ Cancer risk <10 in a million, or 0.1 ≤ Total hazard index ≤ 1.0	Intermediate Risk	Facility is required to provide an update summary on a quadrennial basis
Cancer risk ≥ 10 in a million, or Total hazard index of > 1.0	High Risk	Facility is required to go through the public notification process
Cancer risk > 100 in a million, or Total hazard index of > 5.0	Risk Reduction	Facility is required to go through the public notification process and prepare a Risk Reduction Plan

Public Notification

Facilities that are determined to be high risk to nearby residents or workers are required to notify those exposed persons, through the District's Public Notification process. This process allows the District to inform the public of their potential exposure to toxic substances routinely released into the air from facilities and the potential health risks associated with those exposures. Additionally, this process allows any public questions or concerns regarding exposure and health risk associated with the facility's toxic emissions to be heard and discussed. As of 2022, no District permitted facilities have been determined to pose risks in excess of these public notification levels.

Risk Reduction Audit and Plan

Facilities that pose health risks above District action levels are required to submit risk reduction audits and plans (RRAP) to reduce their risk. The District's review of completeness of any facility RRAP includes a substantive analysis of the emission reduction measures included in the plan, and the ability of those measures to achieve emission reduction goals as quickly as feasible. If the District determines that the RRAP does not meet those requirements, the District shall return the audit and plan to the facility to remedy the deficiencies identified by the District. No District permitted facilities have been determined to pose risks in excess of the risk reduction action levels.

Update Summary Facilities

Intermediate Priority and Intermediate Risk facilities are subject to the regulation's Update Summary reporting process. At least once every four years, these facilities must provide their annual activity and resulting emissions inventory in order to provide the District with updated facility information and to determine whether any operational changes at the facility have the potential to affect the facility's health risk status under the program. Operational changes could consist of increasing process rates, or by operating new or modified stationary sources at the facility. However, it is important to note that changes to the facility that require a District permit or permit modification must be approved by the District prior to being implemented. Based on the information submittal, the District determines if an updated AB 2588 assessment is required.

Industry-wide and Small Single Source Facilities

Under the state's regulation, common types of smaller commercial facilities where the air toxics emissions from individual facilities can easily and generically be characterized and calculated, qualify for a more streamlined assessment process referred to as "industry-wide". These facility industry-wide classes include gasoline dispensing facilities, dry cleaning operations, and automotive coating facilities.

Similar in concept to the industry-wide facilities, smaller operations operating only a single type of emission unit, cannot qualify as industry-wide, and where the emissions can easily and generically be characterized and calculated, qualify for a more streamlined assessment process referred to as "small single source" facilities. Small single sources include facilities only operating a diesel-fired emergency IC engine.

CARB's Updates to AB 2588 Guidance in 2022

2022 Amendments to the Emission Inventory Criteria and Guidelines Regulation

Amendments were made to the Emission Inventory Criteria and Guidelines Regulation (EICGR) and approved by the Office of Administrative Law on March 21, 2022. CARB amended the EICGR to collect more comprehensive emission data across the state. The primary amendments to the EICGR include:

- Updated reporting requirements for diesel engines
- Added factors in determining facility exemptions, reinstatements, and update reporting provisions
- Increased the number of reportable substances in Appendix A from approximately 700 to over 1,700 substances
- Established a phase-in schedule for evaluating newly added substances, consistent with the CTR Regulation's emissions inventory schedule
- Added new source test requirements for certain source types

2022 Gasoline Service Station Industrywide Risk Assessment Guidance

To assist air districts in assessing Gasoline Dispensing Facilities (GDF) as required under AB 2588, CARB and California Air Pollution Control Officers Association (CAPCOA) prepared an updated standardized Gasoline Service Station Industrywide Risk Assessment Guidance in 2022. This guidance provides a framework for air districts to use when evaluating the public health risks from GDFs. This guidance replaces the 1997 Gasoline Service Station Industrywide Risk Assessment Guidelines that was previously used by air districts for their health risk evaluations. Changes in the 2022 technical guidance include new health risk methodologies, updated emission factors for gas stations, and new information on the toxic chemicals in gasoline. Due to the significant changes in the methodology and the state-wide effort to evaluate GDFs under AB 2588, in 2022 the District expeditiously evaluated the Valley's permitted GDF facilities (approximately 1,500 facilities).

Air Toxics Hot Spot Assessments Summary

The District has finalized 6,926 AB 2588 facility assessments from 2016 - 2022. Table 4 below identifies the number of facilities assessed in 2022 through a prioritization analysis (after completion of a Plan and Report), applicability exemption determination, or a health risk assessment (after completion of a prioritization).

Table 4: Summary of Facilities Assessed Under AB 2588 in 2022

AB 2588 Category	Number of Facilities Assessed in 2022
Low/Exempt Priority	938
Low/Exempt Risk	3
Intermediate Priority	646
Intermediate Risk	18
High Priority	8
High Risk	0
Total	**1,613**

Of the facilities evaluated under AB 2588 in 2022, approximately 1,500 were GDFs evaluated under CARB and CAPCOA's updated standardized Gasoline Service Station Industry-wide Risk Assessment Guidance that was finalized in 2022. A detailed list of the facilities evaluated in 2022 and their current status under AB 2588 can be found in Appendix A.

Preventing Creation of Significant Health Risk

The overall goal of the District's integrated approach to air toxics emissions in the San Joaquin Valley aims to maximize public health improvements and minimize public exposure to air toxic emissions. The integrated air toxics program assists in preventing, minimizing, and reducing health risks through a variety of programs.



New or Modified Stationary Source Evaluations

One goal of District risk management review efforts is to minimize the increase that new and modified stationary sources add to the existing toxic load and any potentially significant public health impacts associated with the release of those airborne toxic emissions. In order to achieve this goal, the District evaluates the health risk of stationary sources as part of the District's permitting process and engineering evaluation.

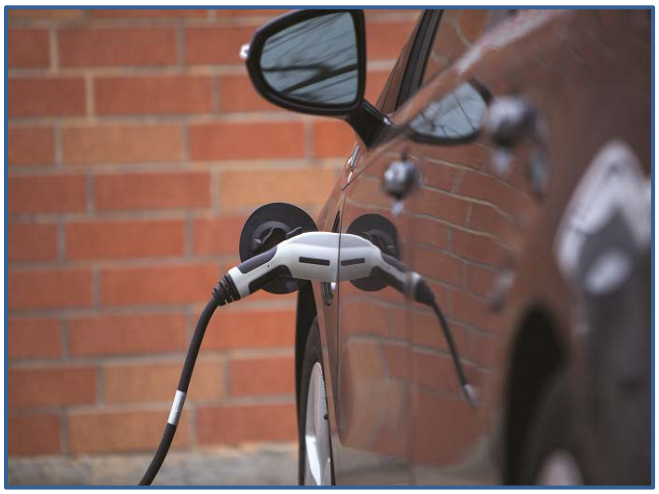
Under the District's risk management policy, Toxic Best Available Control Technology must be applied to all units that may pose greater than de minimis levels of risk (i.e., a cancer risk greater than one in one million). Projects that would pose significant impacts to nearby residences or businesses (i.e., by causing an increased cumulative facility cancer risk of 20-in-a-million or greater) are not approvable. When a project is determined not to be approvable as proposed, District staff will work with the applicant to find approvable low-risk alternatives, such as installing air toxic emissions control devices or limiting the operation of the proposed equipment. Under this program, the District has performed over 16,000 Risk Management Reviews for facilities throughout the District. As a consequence, no permit for a new or modified operation has been approved since the program was initiated in 1995 that would have created a significant health impact through increases in air toxic emissions.

Air Toxics "Hot Spots" Information and Assessment Act

As noted earlier in this report, this law is designed to provide information on the extent of emissions from existing stationary sources and the potential public health impacts of those emissions. Facilities are required to calculate and report to the District their actual emissions of air toxic emissions. "Significant Risk" facilities must disclose their impacts to the nearby residents that may be impacted. Facilities that exceed a higher risk reduction action threshold must go even further and reduce emissions of air toxics. No Valley facility currently poses a significant risk under the "Hot Spots" program, while at the beginning of the implementation of the program, in 1989, 16 facilities were classified "Significant Risk Facilities." As discussed above, the District has begun a significant risk reassessment process that incorporates the revised OEHHA guidance.

Incentive-Based Programs

To assist in reducing air toxic emissions throughout the Valley, more than $5 billion in public and private funding has been invested in clean-air projects through the District's voluntary incentive programs. In total, these programs have reduced more than 240,000 tons of harmful emissions. For example, more than 30,800 older, high-polluting heavy-duty diesel engines have been replaced with zero emission electric motors or cleaner burning engines equipped with the latest in emission control technology. These replacements have resulted in the reduction of nearly 17,000 total tons of carcinogenic diesel particulate matter emissions. In addition, the District's voluntary incentive programs provide critical funding to replace old, higher-polluting school buses, light-duty passenger vehicles, residential wood burning devices, and numerous others. Through the District's first-of-its-kind Ag Burn Alternatives Grant program, the District provides funding to support the Valley's ongoing phase-out of agricultural open burning and the development of innovative alternatives to open burning.



In 2017, AB 617 initiated a statewide effort to monitor and reduce localized air pollution, and highly improve public health, in communities that experience disproportionate burdens from exposure to air pollutants through new community-focused and community-driven actions. The communities of Shafter, South Central Fresno, Stockton and Arvin/Lamont were selected to receive clean air resources available under AB 617 through the Community Air Protection Program. This program includes a substantial investment of community-level funding through a wide variety of voluntary incentive funding measures, including the Tune-In & Tune-Up program and the Fireplace & Woodstove Change-Out Program. The Tune-In & Tune-Up program provides incentives for primarily low-income

District residents to perform much-needed smog related repairs to their personal vehicles. In some cases, the District is even able to offer greater incentives for residents to replace their old, high polluting vehicle with a much cleaner and much newer vehicle. Through the Fireplace & Woodstove Change-Out Program, the District is able to provide funding for District residents to replace, older, high polluting residential wood burning devices with new, clean burning devices or natural gas inserts. Through this program, the District offers a higher incentive for the District's low-income population.

Attainment Plans and Control Strategies

Within the District's *2018 $PM_{2.5}$ Plan*, the District prioritized strategies achieving the greatest public health benefits while satisfying applicable attainment planning requirements. The District also analyzed the health benefits that would result from implementation of the plan. Several examples of prioritized control strategies included in the *2018 $PM_{2.5}$ Plan* include new measures to further reduce emissions from commercial cooking (Rule 4692) and residential wood burning (Rule 4901). These measures will reduce some of the most harmful types of particulate matter when and where those reductions are most needed in urban, highly populated areas. The District has prioritized commitments to strengthen these programs due to the significant and well-researched public health benefits.

Indirect Source Review Rule

The District's Indirect Source Review (ISR) rule, in place since 2005, achieves combustion-related NOx and PM10 emission reductions from the construction and operation of new development projects through the incorporation of design features and on-site mitigation measures. The focus of these emissions reductions are from mobile source heavy duty off-road diesel equipment and heavy duty on-road diesel trucks, which emit diesel particulate matter, one of the most potent carcinogens.

California Environmental Quality Act and Health Risk Assessments

The California Environmental Quality Act (CEQA) requires public agencies to evaluate environmental impacts from a development project and all feasible alternatives or mitigation measures that can substantially reduce or avoid those impacts. Generally, the main responsibility for satisfying CEQA requirements, or "lead agency" role, falls under the responsibility of city or county planning agencies.

From a health risk perspective, land use decisions are critical to improving and preventing degradation of air quality within the San Joaquin Valley, as land use patterns greatly influence potential exposure of sensitive receptors to sources of air pollution. Under CEQA, land use agencies must evaluate the potential significance of health risks associated with development projects. The District provides support to land use agencies when making air quality impact determinations by assisting in the review of health risk assessments performed for the project.

Outreach and Education



As we move forward in achieving our mission, the District shall continue its ongoing efforts to educate the public about air quality, and the significant clean air investments and air quality progress that have been made in the Valley.

The District's information and educational programs include the Real-Time Air Quality Advisory Network (RAAN), Web-based Archived Air Quality (WAAQ) System, and Healthy Air Living Schools program.

RAAN uses real-time data from air monitoring stations throughout the Valley to provide hour-by-hour air quality updates to schools and other subscribers. WAAQS was implemented in 2015 and takes RAAN a step further by providing neighborhood-by-neighborhood historical air quality data for any address in the Valley air basin. Valley residents can use this information to make informed decisions and plan outdoor activities for times with the best air quality, reducing potential air quality health risks. As a high priority area of focus, the District has continued working to expand the Healthy Air Living Schools initiative to deliver an extensive set of tools and information, including the recent launch of school-based Real-Time Electronic Air-quality Displays (READ), to enable Valley schools to understand and respond to air quality conditions and protect the health of students.

Air Toxics Regulations

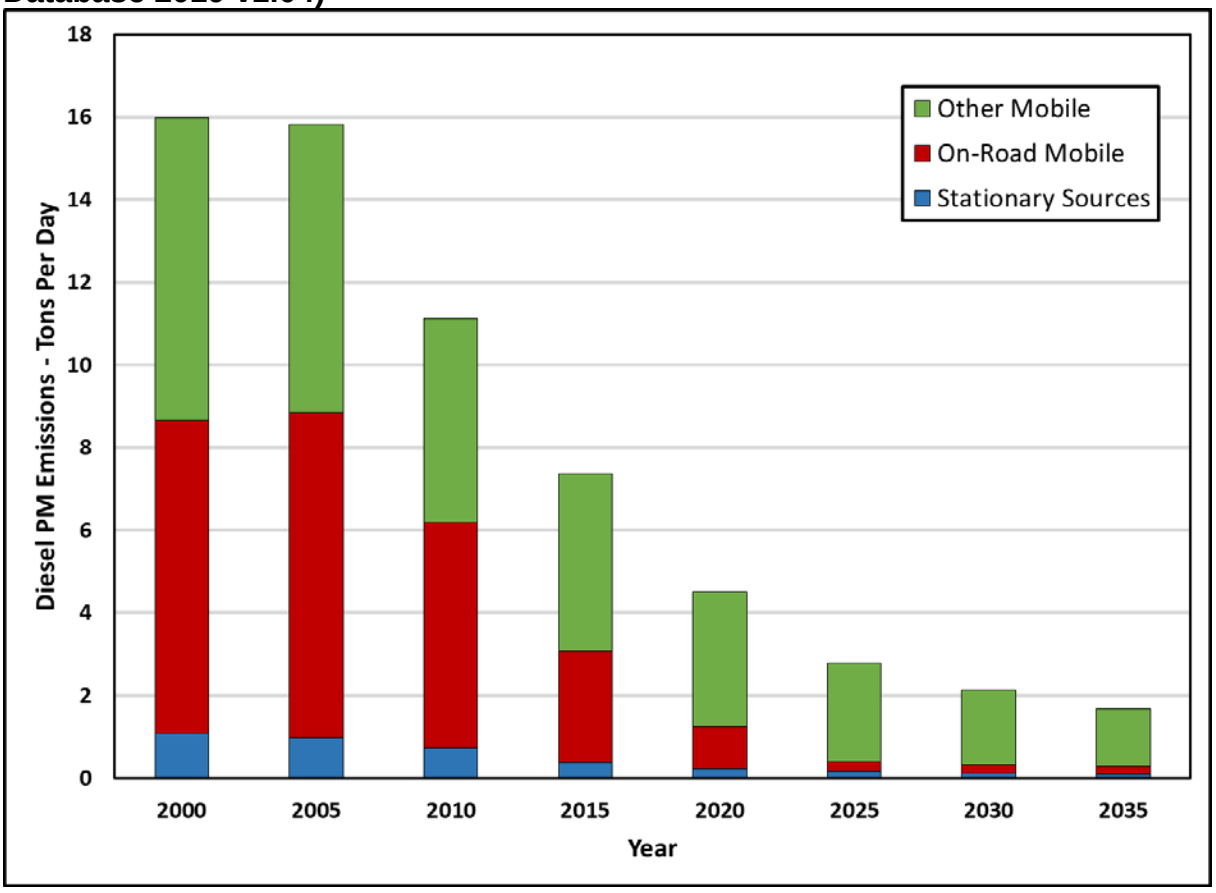
In addition, the District implements a variety of state, federal, and District rules reducing and regulating the emissions of toxic air pollutants. Such regulations have generated significant reductions in air toxics from a wide variety of sources, from requiring the gradual phase-out of perchloroethylene used at dry cleaners and mandating emissions controls at chrome platers, to a large number of rules aimed at reducing particulate emissions from diesel internal combustion engines.

Due to this diverse set of risk reduction efforts, approximately 14% of all air toxics in the San Joaquin Valley are now emitted from stationary sources of pollution under the direct control and regulation of the District, while 52% comes from mobile sources such as cars and trucks, and the remaining 34% is emitted from area-wide sources like road dust, paints, solvents, and other consumer products (per CTI). Mobile and area-wide sources of emissions are generally under the regulatory authority of the State of California and the federal government.

Diesel Exhaust Risk Reduction

CARB identified particulate matter emissions from diesel-fueled engines as a toxic air contaminant with the potential to pose a significant cancer risk to the public. Historically the cancer risk from the exhaust of diesel internal combustion engines has been determined to be far higher than the estimated cancer risk from all other sources of air pollution combined. Because of the high level of risk associated with diesel exhaust, and because of the prevalence of the engines, the State chose not to address diesel exhaust using the existing risk management guidance. Instead, the State decided to establish an advisory committee of interested parties, and developed a comprehensive risk management plan that would result in significant reductions in emissions of diesel particulate matter. CARB adopted the Risk Reduction Plan to Reduce Particulate Matter Emissions from mobile and stationary Diesel-fueled Engines. The figure below shows the trend and forecast of diesel PM emissions in the San Joaquin Valley through the year 2035.

Figure 2. Diesel PM Emissions Trend, San Joaquin Valley (CARB CEPAM Database 2019 v1.04)



Several of the following Air Toxic Control Measures (ATCMs) were developed as a part of ARB's diesel exhaust risk reduction efforts, which continue to be developed. Related information is available on CARB's ATCM website at: https://ww2.arb.ca.gov/resources/documents/airborne-toxic-control-measures.

ATCM Portable Diesel-Fueled Engines

The purpose of the CARB adopted Portable Diesel ATCM is to protect public health by controlling particulate matter (PM) emissions from diesel fueled portable engines rated at 50 horsepower and greater operating in California. All existing portable diesel engines were required to be certified by January 1, 2010, and all new portable engines were required to meet the latest certification standards. In addition, the ATCM contains stringent diesel PM fleet standards that apply after 2010.

The latest version of the ATCM became effective on November 30, 2018 and contains stringent emissions standards and operational requirements that impact new and existing portable diesel engines. The District has been implementing the requirements of the Portable ATCM in the review of applications for District Portable Registrations and permits for portable diesel engines. This ATCM is expected to continue to result in a substantial reduction in Valley diesel PM emissions over the next several years.

ATCM Stationary Diesel-Fueled Engines

The purpose of the CARB adopted Stationary Diesel ATCM is to protect public health by controlling particulate matter (PM) and criteria pollutant emissions from stationary diesel fueled portable engines rated at 50 horsepower and greater operating in California.

This ATCM is satisfied via Rule 4702 (Internal Combustion Engines) in combination with the District's permitting or Permit-Exempt Equipment Registration (PEER) program. These District programs have collectively been found by the CARB to be equivalent to the Stationary ATCM for stationary agricultural engines. This ATCM and District Rule 4702 are expected to continue to result in a substantial reduction in Valley diesel PM emissions over the next several years.

CARB Control Measure for In Use Off-road Diesel Vehicle Rule

The purpose of the CARB adopted an off-road diesel vehicle rule is to reduce diesel PM and oxides of nitrogen (NO_X) emissions from in-use (existing) off-road heavy-duty diesel vehicles. The regulation applies to self-propelled diesel-fueled vehicles that cannot be registered and licensed to drive on-road. Examples include loaders, crawler tractors, skid steers, backhoes, forklifts, and airport ground support equipment. Vehicles with engines less than 25 horsepower are exempt. The regulation is expected to reduce diesel exhaust emissions by over 1,600 tons per year statewide between 2010 and 2030.

Diesel Particulate Matter Control Measure for On-road Heavy-duty Diesel-fueled Vehicles Owned or Operated by Public Agencies and Utilities

The purpose of the CARB adopted control measure will reduce emissions from on-road heavy duty vehicles over several deadlines, with the first groups of vehicles required to be in compliance by December 31, 2007. This control measure is particularly effective because it reduces diesel PM emissions in the heart of residential communities where municipal and utility vehicles frequently conduct business, and where the public is significantly impacted by diesel PM emissions.

ATCM to Limit Diesel-Fueled Commercial Motor Vehicle Idling

CARB initially adopted an ATCM to reduce emissions of toxics and criteria pollutants by limiting idling of new and in-use sleeper berth-equipped diesel trucks. The emission performance requirements require technologies used as alternatives to idling the truck's main engine. The new engine requirements required 2008 and newer model year heavy-duty diesel engines to be equipped with non-programmable engine shutdown systems that automatically shut down the engine after five minutes of idling or, alternatively, meet a more stringent NO_X idling emission standard. Beginning January 1, 2008, in-use truck requirements require operators of both in-state and out-of-state registered sleeper berth equipped trucks to manually shut down their engine when idling more than five minutes at any location within California. Each year heavy-duty diesel truck idling contributes to hundreds of pounds of PM as well as other pollutants to the Valley. The District Incentive Program has subsidized truck stop support equipment to reduce diesel truck idling along the main goods movement corridors. Tests conducted by the District and CARB have determined that an idling truck can consume up to a gallon of diesel fuel an hour. The idling of heavy-duty trucks, at the time of delivery, represents a high percentage of emissions around developed areas in the Valley.

ATCM for Transport Refrigeration Units

The purpose of the CARB adopted ATCM is to reduce emissions of diesel PM from Transport Refrigeration Units (TRUs). TRUs are refrigeration systems powered by diesel internal combustion engines designed to refrigerate or heat perishable products that are transported in various containers, including semi-trailers, truck vans, shipping containers, and rail cars. Although TRU engines are relatively small, ranging from 9 to 36 horsepower, significant numbers of these engines congregate at distribution centers, truck stops, and other facilities, resulting in the potential for health risks to those that live and work nearby. CARB estimated that diesel PM emissions from TRUs will be reduced by 83% by 2040. CARB has recently developed amendments to this ATCM. Related information is available on their TRU ATCM website at https://ww2.arb.ca.gov/our-work/programs/transport-refrigeration-unit.

ATCM for Hexavalent Chromium for Decorative and Hard Chrome Plating and Chromic Acid Anodizing Facilities

The purpose of the CARB adopted ATCM is to established new, more stringent emission limitations that depend upon size and nearness to sensitive receptors, limited the use of chemical fume suppressants, and adopted new housekeeping, education, monitoring, recordkeeping, and reporting requirements. The District chose to implement this ATCM by revising Rule 7011 to incorporate the revised ATCM by reference. The District also required submission of a compliance plan and applications for Authorities to Construct (ATCs). A compliance workshop was held on November 17, 2007 to assist facility owners and operators in complying with the ATCM. The District's Governing Board adopted the rule on January 17, 2008.

CARB has recently begun a process to amend the ATCM to establish enhanced best management practices (e.g. building enclosures, limits, source testing, etc.) for all chrome plating facilities using hexavalent chrome. On November 29, 2022, CARB released a staff

report with the initial statement of reasons for the proposed amendments, with the stated goal of eliminating toxic hexavalent chromium emissions from the chrome plating industry in California over time. The amendments propose phasing out the use of hexavalent chromium from chrome plating operations for all new chrome plating facilities in California as early as January 2024. Subsequently, CARB staff presented the proposed amendments as a Board item during a public hearing in January of 2023. The hearing was the first of two hearings for the proposed amendments, the second hearing scheduled for a later date, at which time the chrome plating ATCM amendments will be voted on for approval.

There are numerous expected benefits from the proposed amendments, including eliminating hexavalent chromium emissions from California's chrome plating industry, reducing the potential cancer risk to individual residents and off-site workers near chrome plating facilities, and reducing occupational exposures for on-site workers.

ATCM for Perchloroethylene Emissions from Dry Cleaning Operations

The purpose of the CARB adopted ATCM is to phase out the use of perc dry cleaning machines and related equipment by January 1, 2023. In addition, the amendments will put in place revisions to the Curriculum for the Environmental Training Program for Perc Dry Cleaning Operations (Training Curriculum). There were changes to the operational requirements for dry cleaners as well. For example, the revised ATCM requires that owners/operators maintain a spare set of gaskets on-site. Also, the trained operator must now be on-site whenever the machine is operated. These amendments became effective upon final approval by the Office of Administrative Law on December 27, 2007. The District adopted the revised ATCM in 2008 by reference.

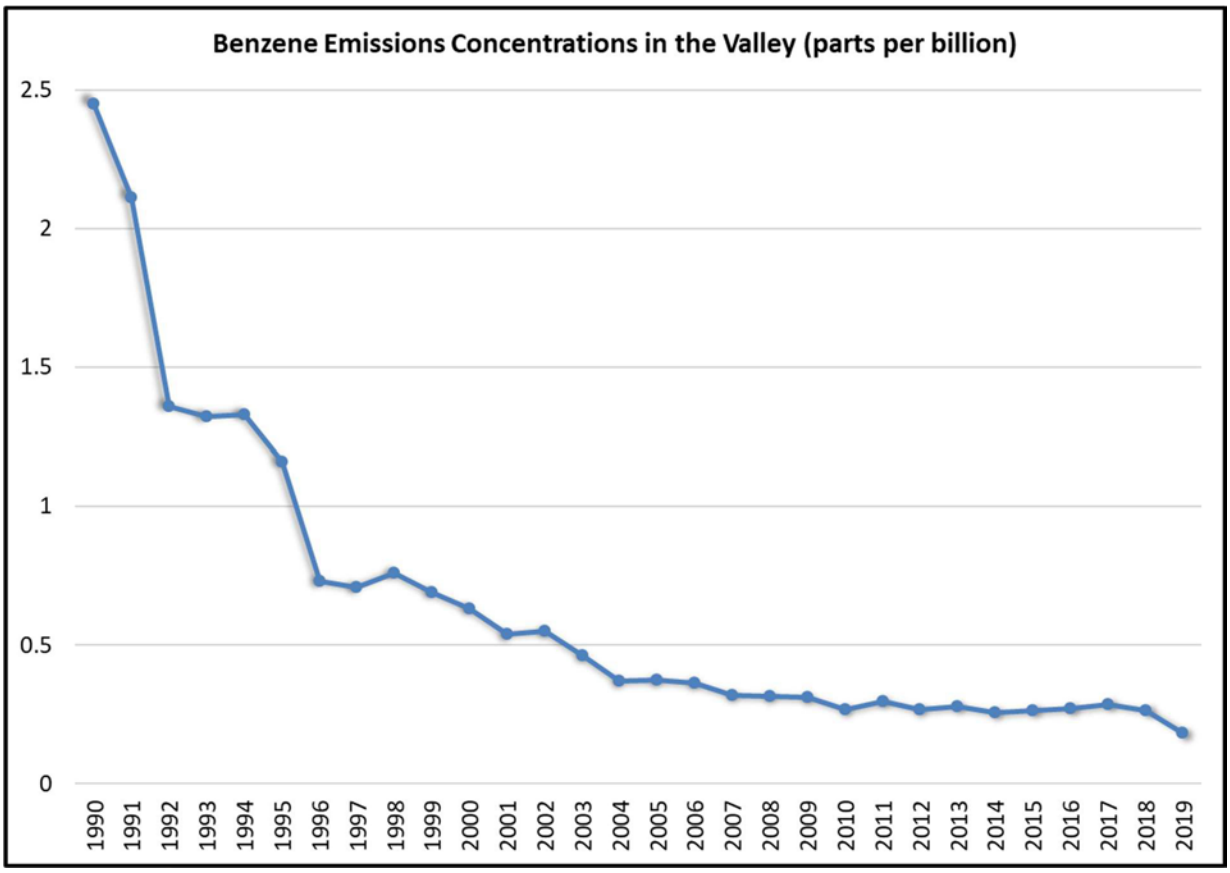
ATCM for Composite Wood Products

The purpose of the CARB approved ATCM is to reduce formaldehyde emissions from composite wood products including hardwood plywood, particleboard, medium density fiberboard, thin medium density fiberboard, and also furniture and other finished products made with composite wood products Formaldehyde is produced on a large scale worldwide. One major use includes the production of wood binding adhesives and resins. CARB developed a modified version of the Composite Wood Product ATCM that was released for a 15-day public comment period on January 31, 2008, and was approved April 18, 2008, by the Office of Administrative Law. Further amendments to this ATCM were approved in May of 2012.

ATCM for Benzene from Retail Service Stations

CARB adopted the ATCM for Emissions of Benzene from Retail Service Stations. The ATCM reflects the use of best available control technology, which requires the installation of CARB-certified Phase I and II vapor recovery control equipment at all retail service stations. The ATCM is designed to reduce benzene and total hydrocarbon emissions from uncontrolled stations by 95 percent. Figure 3 shows the trend of benzene emissions in the Valley.

Figure 3. Benzene Emissions Trend, San Joaquin Valley (CARB Annual Toxics Monitoring Data)



ATCMs Adopted by the District as Regulations:

- District Rule 7011: Chromium Plating And Chromic Acid Anodizing Facilities
- District Rule 7012: Hexavalent Chromium - Cooling Towers
- District Rule 7021: Ethylene Oxide - Sterilizers and Aerators
- District Rule 7031: Dioxin - Medical Waste Incinerators
- District Rule 7041: Fluorides - Phosphoric Acid Plants
- District Rule 7050: Asbestos - Containing Material for Surfacing Applications
- District Rule 7060: Toxic Metals from Non-Ferrous Metal Melting
- District Rule 7070: Perchloroethylene from Dry Cleaning Operations

Other ATCMs are implemented primarily through the permitting process. These include the ATCM for Stationary Compression Ignition Engines and the ATCM for Diesel Particulate Matter from Portable Engines Rated at 50 Horsepower and Greater.

Reducing Health Risk through Enforcement Delegation

On July 1, 2008, the District began enforcing California Air Resources Board's ATCM to Limit School Bus Idling and Idling at Schools and ATCM to Limit Diesel-Fueled Commercial Motor Vehicle Idling, during timeframes in which state funding is available to

support these efforts. The purpose of these ATCMs is to reduce toxic and criteria air pollutants by limiting idling time. By enforcing these requirements in the Valley, the District is able to directly reduce public exposure from toxic emissions, especially in sensitive areas.

The District was delegated the responsibility of enforcing the U.S. EPA's NESHAP for asbestos, a known carcinogen, and as a result performs hundreds of inspections of construction projects that have the possibility of disturbing asbestos containing materials. By ensuring that these materials are removed and handled correctly, the probability of harmful releases of asbestos is significantly reduced.

Implementation of Federal Air Toxics Mandates

EPA has issued NESHAPs through Part 61 and Part 63 of Title 40 of the Code of Federal Regulations (CFR). The Part 61 NESHAPs were issued prior to the adoption of the Federal Clean Air Act Amendments of 1990. Those NESHAPs are specific to a particular hazardous air pollutant (HAP). Due to little activity in adopting NESHAPs, the 1990 amendments to the Federal Clean Air Act established a new procedure for developing NESHAPs. A list of 189 HAPs was established. EPA identified industries that emitted those HAPs and established a prioritized list of over 70 source categories for which Maximum Achievable Control Technology (MACT) standards would be promulgated. These MACT standards apply to major sources of HAPs, defined as sources with emissions greater than 10 tons per year of a single HAP, or 25 tons per year of combined HAPs. Many of these source categories are already subject to state and local regulation, which have traditionally been more stringent than the federal regulations. EPA has already adopted MACT standards to address the majority of the source categories identified.

In addition to the MACT standards for major sources, EPA is also required to adopt NESHAPs standards to reduce the health risk associated with area (non-major) sources of HAPs. As the result of a lawsuit, EPA was under court order to promulgate area source NESHAPs for 4 categories of sources by December 15, 2006; for 6 categories by June 15, 2007; and for 10 categories each 6 months thereafter until June 15, 2009. Similar to the MACT standards for major sources, many of the area sources subject to these standards are already subject to state and local regulation. Area source NESHAPs have already been promulgated for Oil and Natural Gas Production Facilities; Polyvinyl Chloride and Copolymers Production, Primary Copper Smelting, Secondary Copper Smelting, and Primary Nonferrous Metals - Zinc, Cadmium, and Beryllium; Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving; Clay Ceramics Manufacturing, Glass Manufacturing, and Secondary Nonferrous Metals Processing; Electric Arc Furnace Steelmaking Facilities; and Hospital Ethylene Oxide Sterilizers. See Appendix D for the current status of the District's implementation of NESHAPs.

An amendment to 40 CFR part 63, subpart ZZZZ (control of HAPs from reciprocating internal combustion engines) was proposed on June 6, 2012, and was finalized by EPA

on January 14, 2013. This regulation requires reductions in hazardous air pollutants from stationary internal combustion engines over the next several years, and requires significant recordkeeping and monitoring of the engines affected. The District is currently developing processes and policies to assist those facilities affected to comply with the new requirements.

Many other amendments to existing NESHAPs were finalized in 2012: Chemical Manufacturing, Hard & Decorative Chrome electroplating and HCL supplements, Polyvinyl Chloride, Nitric Acid Plants, Petroleum Refineries process heaters and flares, etc. While these NESHAPs have lesser applicability in California and the San Joaquin Valley then the engine NESHAP discussed above, the District will identify, notify, and assist those facilities affected.

In December 2021, EPA issued a decision extending Toxic Release Inventory (TRI) reporting for ethylene oxide to 29 facilities across the country. These facilities were required to begin tracking their chemical activities, releases and other waste management quantities starting in January 2022 and submit TRI data to EPA in 2023. None of these facilities are located within the San Joaquin Valley.

The District currently is delegated authority by EPA to implement and enforce NESHAPs through two mechanisms. First, all major sources of HAPs are required to obtain Title V operating permits. The NESHAP requirements for these major sources are included in the Title V permits for which the District is delegated authority by EPA. Second, the District is delegated authority to implement and enforce all area source NESHAPs that are included in District Rule 4002, most recently amended on May 20, 2004. Under the District's Air Toxics Program and federal regulations, there are several options for implementing new NESHAP requirements. These options are discussed in more detail below. The District will choose the most appropriate option for implementing each Federal standard, and will hold public workshops to obtain public input on the implementation of these additional standards.

- Straight Delegation: Accepting delegation of the federal standard as written by amending Rule 4002 or by agreeing to automatic delegation with an option of opting-out for specific NESHAPs using an approach developed by the (CAPCOA);
- Rule Adjustment: Proposing minor changes to the federal MACT rule that make the adjusted rule no less stringent than the federal standard;
- Rule Substitution: Substituting one or more existing, new, or amended District rules for the federal standard (It should be noted that California Districts have been delegated authority for the chrome plating and dry cleaning NESHAPs because EPA has agreed that the ATCMs for those source categories are equivalent to the NESHAPs.);
- Streamlining Multiple Applicable Requirements: Minimizing duplicative requirements by placing the more stringent emission limit or workplace practice standard on the permit along with the corresponding monitoring, recordkeeping, and reporting requirements;
- Program Substitution: Using existing programs to assure compliance with the

requirements of federal standards;

- No Delegation: Using existing programs to reduce the emissions of hazardous air pollutants without delegation of federal standards.

The NESHAPs for which the District has received delegation through Rule 4002 are listed in Table D1 in Appendix D. All current NESHAPs for which the District has not received delegation through Rule 4002 are listed in Table D2 in Appendix D.

Regardless of the status and type of delegation, the District believes strongly in working with the affected sources to make them aware of the requirements in a timely manner, and then help them understand and comply with these public health protective regulations.

Air Dispersion Modeling



Air quality models use mathematical techniques to simulate the physical and chemical processes that affect air pollutants as they disperse and react in the atmosphere. These models form the backbone of the air toxics management process, as they are used to assess the potential exposure of the public to various toxic emissions. Using inputs of meteorological data and source parameter information such as emission rates and stack height, models predict ambient concentrations of primary pollutants that are emitted. Models are also important to the air quality management process because they determine compliance with National/State Ambient Air Quality Standards (NAAQS/SAAQS), and other regulatory requirements such as New Source Review (NSR).

EPA Regulatory Model (AERMOD)

The American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) was formed to introduce state-of-the-art modeling concepts into the EPA's air quality models. Through AERMIC, a modeling system, AERMOD, was developed to incorporate air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain.

With the promulgation of AERMOD as the preferred air dispersion model in EPA's *Guideline on Air Quality Models* (signed by the EPA Administrator on October 21, 2005 and published November 9, 2005 in the *Federal Register*), AERMOD is used for appropriate application as a replacement for ISCST3 since November 9, 2006.

Meteorological Data

The District makes available meteorological data from both the National Climatological Data Center (NCDC) and the Fifth-Generation Penn State/National Center for Atmospheric Research Mesoscale Model (MM5). The NCDC data were collected at major airports in the San Joaquin Valley. The MM5 data were derived from a numerical model for locations in the valley where there are no airports. These locations are primarily in the western part of the Valley. All processed data is freely available for download on the District's web page at:
https://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm

Appendices

Appendix A: Facilities Assessed Under AB 2588 in 2022
Appendix B: Toxic Emissions Summary
Appendix C: AB 2588 District Implementation Flow Chart
Appendix D: Current Status of NESHAP Delegation

Appendix A. Facilities Assessed under AB 2588 in 2022

Appendix A includes a detailed list of the facilities assessed under AB 2588 in 2022. Table A1 includes gasoline dispensing facilities prioritized, Table A2 includes other types of facilities prioritized, and Table A3 includes the facilities with completed health risk assessments.

Table A1. Gasoline Dispensing Facilities Prioritized in 2022

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	1123	1 Star Mini Mart	Fresno	1.04	Intermediate
C	1782	1 Stop Liquor & Gas	Madera	0.51	Exempt/Low
C	284	11th Street Chevron Inc.	Hanford	0.80	Exempt/Low
S	750	24/7 Food & Fuel LLC	Bakersfield	0.51	Exempt/Low
S	5587	2nd Generation	Visalia	0.81	Exempt/Low
C	1351	3j's Market	Kingsburg	0.51	Exempt/Low
S	1834	3way Market And Gas	Bakersfield	0.51	Exempt/Low
S	2066	4010 Arco Am/Pm	Bakersfield	2.04	Intermediate
C	1786	41 Gas & Liquor	Madera	1.23	Intermediate
S	100	4b Market & Gas	Tulare	0.60	Exempt/Low
S	8347	4ever Limited Inc. Dba Gasko Mart	Bakersfield	0.91	Exempt/Low
S	2184	51 Crown Enterprise Inc. Dba Lucky 7 Food	Delano	0.51	Exempt/Low
N	993	620 West Charter Way LLC	Stockton	0.93	Exempt/Low
S	2101	7 - Eleven Inc.	Bakersfield	0.51	Exempt/Low
S	9500	7 Eleven Facility #38628	Bakersfield	0.69	Exempt/Low
S	9280	7 Eleven Inc.	Bakersfield	0.51	Exempt/Low
S	2237	7- Eleven Inc.	Bakersfield	0.51	Exempt/Low
C	102	7- Eleven Inc.	Clovis	0.59	Exempt/Low
C	1266	7- Eleven Inc.	Fresno	0.62	Exempt/Low
S	2221	7- Eleven Inc.	Visalia	0.62	Exempt/Low
C	104	7- Eleven Inc.	Clovis	0.73	Exempt/Low
N	1407	7- Eleven Inc.	Merced	0.81	Exempt/Low
C	1943	7- Eleven Inc.	Clovis	0.83	Exempt/Low
N	1408	7- Eleven Inc.	Merced	0.84	Exempt/Low
C	1794	7- Eleven Inc.	Oakhurst	0.86	Exempt/Low
S	2225	7- Eleven Inc.	Visalia	0.92	Exempt/Low
C	91	7- Eleven Inc.	Fresno	1.00	Exempt/Low
C	100	7- Eleven Inc.	Hanford	1.08	Intermediate
C	1795	7- Eleven Inc.	Chowchilla	1.11	Intermediate
N	1403	7- Eleven Inc.	Atwater	1.16	Intermediate
C	96	7- Eleven Inc.	Hanford	1.18	Intermediate
C	79	7- Eleven Inc.	Mendota	1.23	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	2936	7- Eleven Inc.	Madera	1.38	Intermediate
C	1263	7- Eleven Inc.	Kettleman City	1.45	Intermediate
S	2235	7- Eleven Inc.	Lost Hills	1.46	Intermediate
N	1406	7- Eleven Inc.	Los Banos	1.49	Intermediate
N	1409	7- Eleven Inc.	Merced	1.69	Intermediate
C	105	7- Eleven Inc.	Reedley	1.75	Intermediate
C	83	7- Eleven Inc.	Selma	1.83	Intermediate
C	1232	7- Eleven Inc.	Fresno	1.91	Intermediate
N	1392	7- Eleven Inc.	Merced	1.93	Intermediate
C	1944	7- Eleven Inc.	Kerman	2.00	Intermediate
N	1404	7- Eleven Inc.	Santa Nella	2.11	Intermediate
N	1753	7- Eleven Inc.	Oakdale	2.82	Intermediate
N	3520	76 Express Tiger No 1	Stockton	0.47	Exempt/Low
S	3256	7-Eleven #32241	Bakersfield	1.38	Intermediate
N	9759	7-Eleven #38877	Stockton	0.51	Exempt/Low
C	9572	7-Eleven 38756	Clovis	0.76	Exempt/Low
C	1168	7-Eleven Inc.	Hanford	0.51	Exempt/Low
N	3514	7-Eleven Inc.	Stockton	0.51	Exempt/Low
S	161	7-Eleven Inc.	Visalia	0.51	Exempt/Low
S	2155	7-Eleven Inc.	Bakersfield	0.51	Exempt/Low
S	2136	7-Eleven Inc.	Oildale	0.51	Exempt/Low
C	9587	7-Eleven Inc.	Fresno	0.51	Exempt/Low
S	2093	7-Eleven Inc.	Visalia	0.51	Exempt/Low
S	2128	7-Eleven Inc.	Bakersfield	0.51	Exempt/Low
S	2138	7-Eleven Inc.	Bakersfield	0.51	Exempt/Low
S	9289	7-Eleven Inc.	Bakersfield	0.51	Exempt/Low
C	1167	7-Eleven Inc.	Lemoore	0.55	Exempt/Low
S	3268	7-Eleven Inc.	Bakersfield	0.57	Exempt/Low
S	2137	7-Eleven Inc.	Arvin	0.58	Exempt/Low
C	1114	7-Eleven Inc.	Fresno	0.87	Exempt/Low
C	3526	7-Eleven Inc.	Fresno	0.88	Exempt/Low
C	9586	7-Eleven Inc.	Fresno	0.92	Exempt/Low
S	3292	7-Eleven Inc.	Bakersfield	1.12	Intermediate
N	136	7-Eleven Inc.	Stockton	1.40	Intermediate
N	7529	7-Eleven Inc.	Ceres	1.50	Intermediate
C	3167	7-Eleven Inc. 35068	Lemoore	0.63	Exempt/Low
N	9768	7-Eleven Inc.	Ceres	0.66	Exempt/Low
N	9496	7-Eleven Inc.	Stockton	1.11	Intermediate
N	5010	7-Eleven Incorporated	Stockton	1.36	Intermediate
N	747	7-Eleven, Inc.	Stockton	0.51	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	1370	7-Eleven, Inc.	Los Banos	0.51	Exempt/Low
N	745	7-Eleven, Inc.	Manteca	0.51	Exempt/Low
N	748	7-Eleven, Inc.	Stockton	0.80	Exempt/Low
N	3940	7-Eleven, Inc.	Tracy	1.38	Intermediate
N	3810	7-Eleven, Inc.	Stockton	2.24	Intermediate
S	9298	7-Eleven, Inc.	Bakersfield	0.51	Exempt/Low
N	9781	7-Eleven, Inc. Store #38704	Los Banos	1.03	Intermediate
N	744	7-Eleven, Store #17647	Manteca	0.51	Exempt/Low
S	593	8 And 10 Market	Porterville	0.51	Exempt/Low
S	2002	9700 Rosedale LLC	Bakersfield	1.32	Intermediate
S	3003	99 Food Mart	Tulare	0.51	Exempt/Low
S	2082	99 Gas & Food Mart Inc.	Kingsburg	1.00	Exempt/Low
S	3250	A & A Express	Maricopa	0.51	Exempt/Low
N	70	A & G Gas Inc.	Stockton	2.32	Intermediate
N	365	A & S Partnership Dba Fast& Easy Mart103	Stockton	1.36	Intermediate
S	3844	A One Market Inc.	Bakersfield	0.51	Exempt/Low
N	4322	A&A Gas Inc. Dba A&A Gas And Food Mart	Manteca	3.25	Intermediate
N	1989	A&M Gas (Abdo Almolaiki)	Modesto	0.67	Exempt/Low
S	964	A-1 Food Gas Mart	Visalia	0.51	Exempt/Low
S	3070	A-1 Food Gas Mart	Lindsay	0.51	Exempt/Low
C	2026	A-1 Liquor & Gas (Pritam S. Gill)	Parlier	0.82	Exempt/Low
S	2074	Aa Gas 'N' Grub 2	Farmersville	0.67	Exempt/Low
S	977	Aa Gas-N-Grub	Exeter	0.67	Exempt/Low
N	3768	Aarti Petroleum	Turlock	2.28	Intermediate
N	8709	Aasra Petroleum, Inc.	Ripon	3.01	Intermediate
N	7841	Ab March Ln Stockton Operating Inc.	Stockton	4.84	Intermediate
C	46	Abby Arco	Fresno	0.70	Exempt/Low
N	8840	Abc Petroleum Inc. Dba Tracy Plaza Texaco	Tracy	5.83	Intermediate
N	117	Abdo Thabet Nashir	Stockton	0.56	Exempt/Low
N	103	Abdo Thabit Nashir	Stockton	0.51	Exempt/Low
N	8540	Abdo Thabit Nashir	Stockton	0.66	Exempt/Low
C	667	Abe's Liquor And Food	Clovis	0.82	Exempt/Low
N	1273	Adel's Mini Mart	Merced	0.67	Exempt/Low
N	1725	Agile Solutions & Consulting Inc.	Modesto	3.23	Intermediate
S	2183	Ahdi Enterprises Corp Dba Shafter Shell	Shafter	0.51	Exempt/Low
N	635	Ahmed's Sons Inc.	Manteca	1.53	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	2365	Ahwahnee Ez Mart	Ahwahnee	0.51	Exempt/Low
S	1584	Airport Texaco	Bakersfield	1.20	Intermediate
N	84	Aj's Mini Mart Inc.	Stockton	0.13	Exempt/Low
S	4253	Akers Texaco	Visalia	0.61	Exempt/Low
N	1986	Alex And Sons Gas And Food	Modesto	0.67	Exempt/Low
C	2297	All Star Mini Mart	Armona	0.62	Exempt/Low
S	312	Alraifi LLC	Porterville	0.67	Exempt/Low
S	933	Al's Mini Mart	Porterville	0.51	Exempt/Low
N	7689	Alves Center	Manteca	0.82	Exempt/Low
S	6749	Am Pm Arco	Tulare	3.50	Intermediate
N	1850	Amar Beer Wine & Gas	Turlock	0.00	Exempt/Low
S	3534	Amar Jyot LLC	Bakersfield	2.73	Intermediate
N	9476	American Bedliners & Truck Accessories	Stockton	2.87	Intermediate
N	1722	American United Investments Inc.	Oakdale	8.75	Intermediate
C	3837	Amigos Mini Mart	Avenal	5.82	Intermediate
C	7822	Analyst Properties LLC	Fresno	0.51	Exempt/Low
S	3689	Andreotti's Corner	Buttonwillow	0.02	Exempt/Low
N	1041	Ap Dba Billjar Valero	Tracy	0.67	Exempt/Low
N	1920	Ap Enterprise Inc. Dba Frontier Liquor	Modesto	0.51	Exempt/Low
C	4073	Ap Gill Inc. Dba Zoo Liquor & Gas	Fresno	0.51	Exempt/Low
S	7741	Apk 22 Inc	Dinuba	4.42	Intermediate
S	1000	Applegate Market (Said Kaeib)	Porterville	0.52	Exempt/Low
S	3918	Apro LLC	Visalia	0.61	Exempt/Low
N	133	Apro LLC	Stockton	1.36	Intermediate
N	132	Apro LLC	Stockton	1.48	Intermediate
C	9195	Apro, LLC Dba United Pacific #0251	Madera	1.44	Intermediate
N	1168	Arco #00237 - Mehar Petroleum Inc.	Merced	2.29	Intermediate
N	79	Arco #02186 - Khai Quang Vo	Stockton	1.36	Intermediate
N	83	Arco #05450 American United Investments	Stockton	1.97	Intermediate
N	71	Arco #06080 - Jamil Kabariti	Lathrop	3.68	Intermediate
N	9316	Arco #07071- Msco Strauch Management LLC	Merced	4.15	Intermediate
N	9711	Arco #07124 - Bp Products North America	Merced	2.83	Intermediate
N	8850	Arco #07147-Msco Strauch Management LLC	Stockton	3.03	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	78	Arco #83560 - Wight Holdings Inc.	Stockton	1.41	Intermediate
S	7081	Arco 82646	Delano	0.55	Exempt/Low
N	9463	Arco Am/Pm	Stockton	2.76	Intermediate
C	8583	Arco Am/Pm #83145	Madera	2.39	Intermediate
N	9311	Arco Am/Pm Stockton - Ken Dharni	Stockton	4.22	Intermediate
S	9015	Arco Am/Pm Wasco	Wasco	2.11	Intermediate
C	2317	Arco Am-Pm	Kingsburg	2.22	Intermediate
C	40	Arco AM-PM	Fresno	3.29	Intermediate
N	1727	Arco Fac #06043-Anshi & Ayaan Inc.	Modesto	1.81	Intermediate
N	85	Arco Fac #07049-Strauch Companies	Lodi	2.78	Intermediate
N	80	Arco Fac #2093 - Tracy Bains Inc.	Tracy	3.57	Intermediate
C	97	Arco Gas & Food Mart (Nirmal Singh Gill)	Fresno	0.63	Exempt/Low
C	3728	Arco Smog Pro	Fresno	5.83	Intermediate
C	9121	Arco Station Nees	Fresno	3.88	Intermediate
N	1745	Arco Turlock Petroleum Inc.	Turlock	1.94	Intermediate
C	3411	Arj Chevron	Avenal	0.62	Exempt/Low
N	76	Arp Minimart Corporation	Tracy	0.05	Exempt/Low
S	3418	Arvin Petroleum Inc.	Bakersfield	3.09	Intermediate
S	9035	Arvin Petroleum Inc. #47008	Arvin	1.97	Intermediate
S	2164	Asa Enterprise Inc. - Lucky 7	Bakersfield	0.51	Exempt/Low
N	4721	Ashish Boveja	Stockton	1.17	Intermediate
N	567	Ashish Boveja Dba My Mini Mart Gasoline	Stockton	0.79	Exempt/Low
C	1847	Ashlan Cedar Gas N Liquor	Fresno	2.07	Intermediate
N	9468	Asp Petroleum Inc	Manteca	4.51	Intermediate
N	1171	Atwater Shell	Atwater	1.08	Intermediate
N	4151	Au Energy, LLC	Modesto	1.06	Intermediate
S	7156	Avo's Shell (Avo Cholakian)	Bakersfield	1.75	Intermediate
N	3016	B & W Petroleum (Bait Barn)	Waterford	0.90	Exempt/Low
N	4012	B And W Petroleum	Escalon	0.90	Exempt/Low
C	4329	B&J Petroleum Sales LLC Dba Arco Am/Pm	Fresno	2.75	Intermediate
N	1185	B&V Inc. (Gurnek Bagri & Sammarbir Virk)	Los Banos	1.28	Intermediate
N	2056	B&W Petroleum	Patterson	0.79	Exempt/Low
C	2070	B&W Petroleum #103 Dba Tiny Mart	Prather	0.99	Exempt/Low
C	863	Baba Ji Market	Parlier	0.51	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	2428	Baba Properties Inc.	Bakersfield	0.54	Exempt/Low
S	9251	Bachan Singh Ghangas LLC	Bakersfield	1.07	Intermediate
C	690	Bag-O-Bag	Fresno	0.63	Exempt/Low
S	8987	Balkuver LLC	Bakersfield	1.93	Intermediate
N	8563	Ballico Mom And Pop Mini Mart	Ballico	0.67	Exempt/Low
N	1350	Balwant S Dhami, Sure Stop Market	Atwater	0.51	Exempt/Low
C	1805	Balwinder Singh Dba Madera Self Serv	Madera	0.85	Exempt/Low
C	7460	Bangar Chevron	Hanford	1.03	Intermediate
N	4748	Bap Enterprises Inc. / Wilson Way Chevron	Stockton	1.90	Intermediate
N	853	Baph 3 Inc. Dba 3 B's Truck & Auto Plaza	Lodi	2.01	Intermediate
C	1982	Barber Aviation	Madera	2.51	Intermediate
S	7609	Barn V	Visalia	0.93	Exempt/Low
S	1823	Bashaar Najdawi Chevron	Bakersfield	0.79	Exempt/Low
S	2368	Basic Properties	Delano	2.93	Intermediate
C	1718	Bass Fork Minit Mart	North Fork	0.51	Exempt/Low
C	2632	Bbs Partners Incorporated	Oakhurst	0.81	Exempt/Low
C	95	Beacon Gas & Food Mart	Fresno	0.78	Exempt/Low
C	7994	Beal Development LLC-Chevron Food Mart	Fresno	0.93	Exempt/Low
C	9439	Beal Developments	Fresno	0.94	Exempt/Low
C	9035	Beal Developments LLC	Clovis	0.71	Exempt/Low
C	7735	Beal Developments LLC, E-Z Mart	Clovis	0.73	Exempt/Low
C	297	Beal Developments, LLC	Fresno	1.37	Intermediate
C	697	Beal Properties Inc.	Fresno	0.51	Exempt/Low
C	3305	Beal Properties Inc.	Fresno	0.62	Exempt/Low
C	3677	Beal Properties Inc.	Fresno	1.04	Intermediate
S	1459	Bear Mountain Truck Stop	Bakersfield	0.63	Exempt/Low
C	109	Bee's Market/Hardeep Singh Rathore	Raisin City	0.53	Exempt/Low
C	2900	Behlo Oil Corp Dba Kingsburg Chevron	Kingsburg	1.05	Intermediate
C	112	Belmont Car Wash Inc.	Fresno	1.64	Intermediate
S	314	Ben Maddox Pik N Go	Visalia	0.51	Exempt/Low
S	850	Best Truck Stop	Pixley	0.51	Exempt/Low
C	1760	Bhaiti And Son Inc. - Dba Madera Mobil	Madera	0.93	Exempt/Low
C	3864	Bhandal Petro Dba Bulldog Gas & Mart #2	Fresno	0.94	Exempt/Low
S	6896	Bhandal Travel Center	Earlimart	8.10	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	9040	Bi Rite Liquor	Merced	0.86	Exempt/Low
S	9248	Big B's Travel Center #2	Delano	0.51	Exempt/Low
S	620	Big O Gas-Deli & Grill	Orosi	0.51	Exempt/Low
S	105	Big Stop Market Inc. Dba Big Stop Market	Shafter	0.67	Exempt/Low
C	2231	Bill's Quick Stop (Abdo Alhomedi)	Madera	0.51	Exempt/Low
N	3492	Bill's Sport & Bait Shop	Modesto	0.51	Exempt/Low
C	698	Bizzy Bee Gas & Food Mart	Fresno	3.07	Intermediate
S	2302	Bj's Express Mart	Visalia	0.86	Exempt/Low
C	1054	Bj's Food & Liquor #2	Fresno	1.01	Intermediate
C	1717	Bj's Gas And Liquor	Madera	0.73	Exempt/Low
N	261	Blackhawk Petroleum	Stockton	0.67	Exempt/Low
S	3760	Blackwells Corner Restaurant & Deli	Lost Hills	0.13	Exempt/Low
S	1261	Bob Shiralian Shell	Lebec	1.27	Intermediate
N	9362	Bobbies Food Corner	Atwater	0.51	Exempt/Low
S	970	Bob's Auto And Truck Stop	Pixley	0.51	Exempt/Low
S	621	Bob's Tiny Mart	Porterville	0.51	Exempt/Low
C	1218	Bobs Villa Food Mart	Clovis	1.43	Intermediate
N	4353	Bonfare Market #43	Modesto	0.51	Exempt/Low
C	1759	Boyal Brothers Inc. Dba Gas 'N' Grab	Madera	0.51	Exempt/Low
C	327	Boyett Petroleum	Clovis	0.51	Exempt/Low
N	2902	Boyett Petroleum	Modesto	0.51	Exempt/Low
N	3268	Boyett Petroleum	Modesto	1.20	Intermediate
N	9706	Boyett Petroleum	Modesto	2.04	Intermediate
N	1726	Bps Fuel	Modesto	5.83	Intermediate
N	612	Br Petro Inc, Dba Lakewood Chevron	Lodi	1.07	Intermediate
N	937	Brd Investments Inc./Waterloo Food Mart	Stockton	1.18	Intermediate
N	3840	Briggsmore Cruisers #11	Modesto	1.98	Intermediate
N	3963	Brother's Food Mart	Livingston	1.16	Intermediate
N	1241	Brothers Royal Crown	Atwater	1.13	Intermediate
S	2303	Br's Food Store	Porterville	0.51	Exempt/Low
S	115	Brundage Lane Am Pm	Bakersfield	1.63	Intermediate
S	8114	Brundage Petroleum Inc.	Bakersfield	2.46	Intermediate
N	7468	Bsv Inc. Dba Stop N Go	Atwater	0.51	Exempt/Low
N	1205	Bsv, Inc.	Atwater	1.52	Intermediate
C	9346	Bubble Clean	Fresno	1.59	Intermediate
S	7675	Buena Vista Concession (Rupinder Jhaj)	Taft	0.13	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	2697	Buford Oil Co	Lost Hills	0.03	Exempt/Low
C	153	Buford Oil Co (Star Mart)	Armona	0.51	Exempt/Low
C	154	Buford Oil Co (Star Mart)	Corcoran	0.51	Exempt/Low
C	162	Buford Oil Co (Star Mart)	Avenal	0.61	Exempt/Low
C	160	Buford Oil Co (Star Mart)	Hanford	1.30	Intermediate
C	1216	Buford Oil Co (Texaco)	Kingsburg	0.51	Exempt/Low
C	237	Buford Oil Co Inc. (Buford Shell #14)	Sanger	0.51	Exempt/Low
C	156	Buford Oil Co. (Little's Tex.)	Hanford	0.51	Exempt/Low
C	155	Buford Oil Co. (Star Mart #4)	Lemoore	0.51	Exempt/Low
C	158	Buford Oil Company	Riverdale	0.51	Exempt/Low
C	161	Buford Oil Company	Fowler	0.69	Exempt/Low
C	168	Buggy Bath	Pinedale	1.23	Intermediate
C	166	Buggy Bath Car Wash (Chevron)	Clovis	0.51	Exempt/Low
C	2770	Buggy Showers	Madera	0.89	Exempt/Low
C	1291	Bulldog Gas & Mart	Fresno	0.87	Exempt/Low
C	38	Bunnell & Almann's Petroleum Inc.	Fresno	2.85	Intermediate
C	7263	Bush Chevron	Lemoore	0.96	Exempt/Low
C	291	Butler Chevron 95768	Fresno	0.71	Exempt/Low
S	2797	Buttonwillow Chevron	Buttonwillow	8.75	Intermediate
S	2047	Buttonwillow Food And Gas	Buttonwillow	2.99	Intermediate
S	2432	Bye Bye Inc./Samco Oak #5	Bakersfield	1.16	Intermediate
N	1856	Bz Mart (Balwinder Dhillon)	Modesto	0.51	Exempt/Low
C	2508	C & C Fuel Company	Madera	0.92	Exempt/Low
N	8797	C & F Market Harvin Fuel	Modesto	0.67	Exempt/Low
C	5741	C A Plaza	Hanford	0.51	Exempt/Low
C	50	C&B Arco Dba H&R Enterprises	Fresno	2.00	Intermediate
N	534	C.D.& R's Oil Inc. Dba Tracy Blvd Chevron	Tracy	2.30	Intermediate
N	9231	Cagasoline Inc. Dba Cagasoline Express	Manteca	1.39	Intermediate
N	161	California Car Wash	Stockton	0.51	Exempt/Low
C	1276	California- Fresno Oil Co-Fowler 76-109	Fowler	0.86	Exempt/Low
S	484	California Fresno Oil Co-Mooney 76-114	Visalia	0.59	Exempt/Low
S	2521	California Mini Mart (Sikander Jassar)	Bakersfield	0.77	Exempt/Low
N	2165	California Pacific Connect Inc.	Modesto	0.51	Exempt/Low
N	2500	California Stop	Stockton	0.51	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	2500	California-Fresno Oil Co	Visalia	0.51	Exempt/Low
C	1120	California-Fresno Oil Co	Selma	0.69	Exempt/Low
C	2368	California-Fresno Oil Co	Fresno	1.44	Intermediate
C	468	California-Fresno Oil Co	Fresno	2.82	Intermediate
C	1917	California-Fresno Oil Co	Fresno	5.83	Intermediate
C	1300	California-Fresno Oil Company-Universit	Clovis	1.91	Intermediate
C	1124	California-Fresno Oil Co-Westside 76-107	Firebaugh	1.43	Intermediate
S	2356	Capri Food Store	Mcfarland	0.51	Exempt/Low
N	1193	Card-Gas, Inc.	Merced	0.61	Exempt/Low
C	2880	Cardlock Fuels System, LLC	Fresno	0.51	Exempt/Low
N	2288	Cardlock Fuels System, LLC	Turlock	0.51	Exempt/Low
N	1775	Cardlock Fuels System, LLC.	Modesto	0.51	Exempt/Low
C	2034	Cargo Mart	Laton	0.51	Exempt/Low
C	805	Castle B Inc. Dba Parkside Chevron	Fresno	1.04	Intermediate
C	4141	Cavalier Food	Fresno	1.23	Intermediate
N	1733	Cb 50 Yosemite Blvd Operating Inc.	Modesto	1.68	Intermediate
S	3780	Cbrr Inc.	Taft	0.02	Exempt/Low
C	694	Central Food Mart	Fresno	5.83	Intermediate
N	1770	Central Gas Oakdale	Oakdale	0.59	Exempt/Low
N	9033	Central Valley Gas Stations Atwater	Merced	5.83	Intermediate
N	1198	Century Chevron	Merced	0.69	Exempt/Low
N	1809	Century Chevron	Turlock	1.13	Intermediate
N	4989	Century Chevron Food Mart	Turlock	1.46	Intermediate
N	4766	Century Chevron Food Mart	Turlock	8.75	Intermediate
N	1343	Century Petroleum Inc./Century Chevron	Merced	1.10	Intermediate
N	1746	Ceres Cruisers #12	Ceres	0.92	Exempt/Low
N	1730	Ceres Petroleum Inc. Dba Arco Ampm	Ceres	3.46	Intermediate
N	2168	Ceres Shell	Ceres	1.37	Intermediate
S	9366	Chahal Enterprise Inc. #1	Visalia	3.48	Intermediate
C	718	Chahal Management Inc.	Kerman	0.78	Exempt/Low
S	8767	Chandi Josan Petroleum Inc.	Visalia	3.41	Intermediate
N	8933	Charanjit Jutla	Tracy	2.26	Intermediate
N	2523	Charter Way Petro Inc.	Stockton	2.53	Intermediate
C	1119	Chase Inc.	Kettleman City	1.86	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	1002	Chase Inc. - Kettleman City Exxon	Kettleman City	0.56	Exempt/Low
S	3750	Chase Inc. - Tejon Valero	Lebec	1.17	Intermediate
S	1658	Chase Inc. 76	Lost Hills	1.26	Intermediate
C	2427	Chase Inc. B P	Coalinga	1.75	Intermediate
C	2374	Chase Inc. Dba Slater Shell	Fresno	2.90	Intermediate
S	3043	Chase Inc. Buttonwillow	Buttonwillow	1.50	Intermediate
C	9166	Chase Valero Travel Center	Firebaugh	1.35	Intermediate
C	37	Chase, Inc.	Coalinga	0.53	Exempt/Low
S	8063	Chauhan & Toor Inc.	Pixley	2.60	Intermediate
S	240	Chester Liquor Market	Bakersfield	0.51	Exempt/Low
S	770	Chevron Food Mart	Tulare	0.58	Exempt/Low
N	4034	Chevron Products Co	Tracy	2.72	Intermediate
N	2363	Chevron Products Co A Chevron Usa Inc.	Stockton	1.52	Intermediate
N	4947	Chevron Products Co A Chevron Usa Inc.	Tracy	1.78	Intermediate
N	4693	Chevron Products Company	Ripon	1.38	Intermediate
N	4114	Chevron Products Company	Livingston	1.48	Intermediate
N	3919	Chevron Products Company	Modesto	1.57	Intermediate
N	4405	Chevron Products Company	Manteca	1.57	Intermediate
N	7627	Chevron Products Company	Riverbank	2.20	Intermediate
N	4087	Chevron Products Company	Stockton	2.40	Intermediate
N	7462	Chevron Products Company	Stockton	2.46	Intermediate
N	4165	Chevron Station & Mini Mart	Merced	1.86	Intermediate
C	280	Chevron U.S.A. Inc.. #96953	Kettleman City	3.06	Intermediate
N	2515	Chevron Usa Inc.	Tracy	3.11	Intermediate
S	9041	Chevron Usa Inc.	Bakersfield	0.00	Exempt/Low
S	2439	Chevron Usa Inc.	Lost Hills	1.20	Intermediate
C	279	Chevron Usa Inc. #92133	Coalinga	2.94	Intermediate
N	3315	Chevron Usa Inc.	Manteca	1.43	Intermediate
N	1813	Chevron Usa Products Company	Modesto	1.61	Intermediate
N	31	Chevron Usa Products Company	Stockton	1.84	Intermediate
N	1812	Chevron Usa Products Company	Ceres	1.98	Intermediate
N	1204	Chevron Usa Products Company	Santa Nella	2.47	Intermediate
N	325	Chevron Usa Products Company	Stockton	2.51	Intermediate
C	290	Chevron Usa, Inc. #92316	Firebaugh	2.36	Intermediate

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S	7230	Circle 7 Liquor Inc.	Visalia	0.52	Exempt/Low
C	2313	Circle D Food & Liquor	Fresno	0.67	Exempt/Low
S	1871	Circle Deli	Bakersfield	0.51	Exempt/Low
N	3200	Circle J Food & Gas	Turlock	0.51	Exempt/Low
N	8956	Circle K Los Banos	Los Banos	2.61	Intermediate
C	2325	Circle K Stores Inc.	Fresno	0.51	Exempt/Low
S	2299	Circle K Stores Inc.	Bakersfield	0.51	Exempt/Low
S	2141	Circle K Stores Inc.	Wasco	0.52	Exempt/Low
S	2146	Circle K Stores Inc.	Bakersfield	0.53	Exempt/Low
S	2143	Circle K Stores Inc.	Bakersfield	0.65	Exempt/Low
C	319	Circle K Stores Inc.	Hanford	0.66	Exempt/Low
N	1211	Circle K Stores Inc.	Dos Palos	0.89	Exempt/Low
N	1206	Circle K Stores Inc.	Atwater	0.96	Exempt/Low
C	321	Circle K Stores Inc.	San Joaquin	1.00	Exempt/Low
C	323	Circle K Stores Inc.	Avenal	1.01	Intermediate
N	1822	Circle K Stores Inc.	Modesto	1.03	Intermediate
N	1210	Circle K Stores Inc.	Los Banos	1.20	Intermediate
C	322	Circle K Stores Inc.	Selma	2.10	Intermediate
C	9207	Circle K Stores Inc.	Fresno	2.30	Intermediate
N	1821	Circle K Stores Inc.	Turlock	3.16	Intermediate
N	1405	Circle 'R' Minimart	Merced	0.73	Exempt/Low
S	325	City Food Mart Lindsay	Lindsay	0.59	Exempt/Low
N	2004	City Mart And Gas, Inc.	Modesto	0.51	Exempt/Low
C	2969	City Of Coalinga	Coalinga	0.02	Exempt/Low
N	1218	City Of Gustine	Gustine	0.63	Exempt/Low
C	3570	City Of Hanford	Hanford	2.51	Intermediate
N	9488	Cj Jutla	Ripon	1.90	Intermediate
S	3402	Ckg Mart Inc.	Lamont	1.29	Intermediate
C	9375	Clovis Arco Am/Pm	Clovis	2.85	Intermediate
C	3209	Clovis Mart & Gas (Valero Gas)	Clovis	2.12	Intermediate
C	1695	Clovis Shell	Clovis	1.53	Intermediate
N	4159	Cls Fuel Enterprises Inc.	Oakdale	1.15	Intermediate
C	1732	Coarsegold Kwik Serv/Boyett Petroleum	Coarsegold	0.92	Exempt/Low
C	1731	Coarsegold Self Service Station/S Singh	Coarsegold	0.76	Exempt/Low
C	4214	Coast To Coast Petroleum	Fresno	1.75	Intermediate
N	1836	Coffee Road Petroleum	Modesto	2.36	Intermediate
N	220	Collegeville Market & Cafe	Stockton	1.02	Intermediate
S	8147	Comanche Shell	Bakersfield	1.15	Intermediate
S	316	Convenience Corner Iii	Goshen	0.67	Exempt/Low

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N	3494	Corner Market & Deli	Stevinson	0.51	Exempt/Low
C	8848	Costco Gasoline	Hanford	2.49	Intermediate
N	4255	Costco Wholesale Loc #661	Modesto	13.60	High Priority
C	2484	Country Club Food Mart	Madera	0.55	Exempt/Low
N	3845	Country Marketplace	Stockton	1.64	Intermediate
N	450	Country Mart Gas & Food	Tracy	0.01	Exempt/Low
S	9208	Countryside Village	Bakersfield	7.29	Intermediate
S	3427	County Line Chevron	Delano	1.11	Intermediate
C	385	Cressman's - Gillett LLC	Shaver Lake	0.13	Exempt/Low
N	2104	Crowslanding Petroleum, Inc.	Modesto	1.13	Intermediate
N	8505	Cruisers Manteca - Bp #29	Manteca	1.63	Intermediate
C	3243	C's Oasis (Chuay Chhun & Cindy Yee)	Fresno	0.94	Exempt/Low
S	3848	Csg Petroleum Inc.	Bakersfield	2.45	Intermediate
S	2284	Cutler Food Mart	Cutler	0.73	Exempt/Low
S	4176	Cypress Flyers	Visalia	5.83	Intermediate
S	3982	D & R Lost Hills Co Brand Facility	Lost Hills	0.58	Exempt/Low
S	3680	D J Holding Inc.	Bakersfield	0.70	Exempt/Low
S	3038	D Street Chevron	Porterville	0.51	Exempt/Low
N	643	Dabb Corporation	Manteca	0.51	Exempt/Low
S	3310	Daffodils LLC	Visalia	0.58	Exempt/Low
N	4654	Dale Road Cruisers #22	Modesto	2.37	Intermediate
C	1778	Daljit Singh Chohan	Madera	0.51	Exempt/Low
N	518	Darrell Eppler Dba March Lane 76	Stockton	1.51	Intermediate
C	3525	Dassel's Petroleum, Inc.	Hanford	0.67	Exempt/Low
S	3568	Day N Night Mini Mart	Tulare	0.51	Exempt/Low
S	1036	Day N Nite Mini Mart	Lindsay	0.51	Exempt/Low
C	1144	Db Ashlan Inc.	Fresno	1.14	Intermediate
S	9131	Delano Chevron	Delano	0.88	Exempt/Low
S	2543	Delano City Municipal Airport	Delano	0.00	Exempt/Low
N	4484	Delhi Arco	Delhi	5.83	Intermediate
N	1229	Delhi Gas & Liquor	Delhi	0.51	Exempt/Low
N	4283	Delta Charter Inc.	Stockton	1.50	Intermediate
C	3461	Depot Development, Inc.	Friant	5.83	Intermediate
S	3252	DGC Oil Inc.	Bakersfield	2.08	Intermediate
S	587	Diamond Food Mart LLC	Tulare	0.75	Exempt/Low
N	7509	Diamond Gas & Mart	Modesto	0.67	Exempt/Low
N	9146	Diamond Gas & Mart #5	Modesto	0.67	Exempt/Low
S	6820	Dillon & Sons Dba The Barn #4	Arvin	0.51	Exempt/Low

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C	1999	Dinkey Creek Inn & General Store Inc.	Shaver Lake	0.00	Exempt/Low
S	2813	DJs Food Mart	Bakersfield	0.51	Exempt/Low
S	962	Doc's Corner Inc.	Tulare	0.51	Exempt/Low
S	742	Don's Liquor Mart	Frazier Park	1.04	Intermediate
N	4604	Dos Palos Chevron	Dos Palos	0.02	Exempt/Low
N	4209	Dos Palos Mini Mart	Dos Palos	0.51	Exempt/Low
N	1735	Dosanjh Family Partnership	Turlock	2.48	Intermediate
N	1794	Dosanjh Family Partnership	Modesto	2.53	Intermediate
N	1734	Dosanjh Petroleum	Salida	1.93	Intermediate
S	939	Double D Mini-Mart	Visalia	0.51	Exempt/Low
N	1757	Downtown Valero	Modesto	0.51	Exempt/Low
C	441	D's Mini Mart	San Joaquin	0.51	Exempt/Low
S	1033	Ducor Handy Market Inc.	Ducor	0.51	Exempt/Low
C	664	Dulai B Corporation Dba J S Mini Mart	Corcoran	0.51	Exempt/Low
S	2353	Dulai Mini Mart/Parmajeet Singh Dulai	Bakersfield	0.87	Exempt/Low
C	472	E Z Go Mini Mart	Fresno	0.51	Exempt/Low
S	3328	E Z Stop Mobil	Bakersfield	1.05	Intermediate
N	1883	E&J Kwik Serv	Modesto	0.57	Exempt/Low
N	3875	Eage Investments LLC	Stockton	2.20	Intermediate
S	2192	Earlimart Valero	Earlimart	0.51	Exempt/Low
N	8807	East Harney Arco - Ken Dharni	Lodi	3.06	Intermediate
S	4206	East Hills Cc Inc.	Bakersfield	0.99	Exempt/Low
S	7378	East Travel Plaza LLC	Arvin	4.07	Intermediate
N	755	El Dorado Food Mart	Stockton	2.13	Intermediate
N	3451	El Dorado Gas And Mart	Stockton	0.67	Exempt/Low
C	685	El Toro Market	Caruthers	0.51	Exempt/Low
C	59	Elkhorn Ave Market	Caruthers	0.67	Exempt/Low
N	2400	Elkhorn Golf Club	Stockton	2.50	Intermediate
N	308	Emil's Liquor & Sport Shop	Escalon	2.92	Intermediate
S	2642	Empire Gas & Liquor	Bakersfield	0.77	Exempt/Low
N	1887	Empire Liquors	Empire	1.59	Intermediate
S	8782	Encore Petroleum Inc.	Visalia	4.49	Intermediate
S	6748	Erin Group LLC	Visalia	0.59	Exempt/Low
N	312	Ernie's General Store	Stockton	0.64	Exempt/Low
N	313	Escalon Mini-Mart	Escalon	0.51	Exempt/Low
C	577	Evergreen Food Store	Fresno	0.51	Exempt/Low
N	4398	Excel Petroleum, Inc.	Stockton	0.70	Exempt/Low
N	388	Excel Petroleum, Inc.	Stockton	5.83	Intermediate

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S	2073	Exeter Mini Mart (Novroz Ali Rahim)	Exeter	0.51	Exempt/Low
S	481	Exeter Pik N Go	Exeter	0.73	Exempt/Low
S	3937	Express Gas Mart (Jesus Ontiveros)	Alpaugh	0.67	Exempt/Low
N	1987	Express Market (B Singh & V Sidhu)	Oakdale	0.53	Exempt/Low
S	6507	Express Mart & Gas	Porterville	1.50	Intermediate
N	8126	Express Mart 1	Modesto	1.56	Intermediate
S	2037	Express Mini Mart	Visalia	0.51	Exempt/Low
S	752	E-Z Mart	Bakersfield	0.76	Exempt/Low
C	8168	Ez Mart #4	Sanger	0.51	Exempt/Low
C	1770	E-Z Mart & Gas (Chaitanya Shah)	Oakhurst	0.67	Exempt/Low
C	1307	Ez Mart Food & Gas	Fresno	0.66	Exempt/Low
C	1755	Ez Mart Food Store # 15	Madera	5.83	Intermediate
S	923	Ez Pick N Go	Visalia	0.51	Exempt/Low
C	467	E-Z Trip Fresno	Fresno	1.30	Intermediate
S	2071	Fa&Y Venture Inc. Dba On Your Way Food St	Delano	0.78	Exempt/Low
N	1991	Fairview General Store	Ceres	0.51	Exempt/Low
C	7834	Falcon Junction Inc.	Prather	1.20	Intermediate
C	947	Family Express Food & Liquor	Fresno	0.51	Exempt/Low
C	987	Family Express Food & Liquor #2	Fresno	0.51	Exempt/Low
C	8043	Family Express Food And Deli	Fresno	0.51	Exempt/Low
C	2210	Family Food Center (Jaswant S Chera)	Madera	0.51	Exempt/Low
S	1085	Famoso Travel Center	Mcfarland	0.51	Exempt/Low
C	3488	Fareast Inc.	Fresno	0.51	Exempt/Low
S	816	Farmers Food Market	Poplar	0.51	Exempt/Low
C	3678	Farmers Market	Madera	0.51	Exempt/Low
N	9480	Farmer's Quick Stop	Dos Palos	0.67	Exempt/Low
S	6484	Farmersville Food Mart	Farmersville	0.67	Exempt/Low
C	270	Fashion Fair Chevron	Fresno	0.62	Exempt/Low
N	4120	Fast And Easy Mart #101 (Muhammad Bilal)	Modesto	1.63	Intermediate
C	430	Fast And Friendly	Armona	0.51	Exempt/Low
S	2454	Fast Break Abdul Aziz	Bakersfield	0.51	Exempt/Low
N	6517	Fast Lane Central Valley, LLC	Lathrop	1.08	Intermediate
C	1766	Fast N Esy #10	Madera	2.01	Intermediate
C	2435	Fast N Esy #11	Fresno	1.94	Intermediate
N	4085	Fast N Esy #12 (Vinay Vohra)	Atwater	2.41	Intermediate
C	1338	Fast N Esy #14	Fresno	1.13	Intermediate

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C	1229	Fast N Esy #15	Kingsburg	0.95	Exempt/Low
N	8806	Fast N Esy #16	Manteca	0.76	Exempt/Low
C	8752	Fast N Esy #20	Fresno	1.05	Intermediate
C	1395	Fast N Esy #21	Fresno	0.54	Exempt/Low
N	8721	Fast N Esy #27	Merced	0.57	Exempt/Low
C	4024	Fast N Esy #31	Fresno	1.13	Intermediate
C	295	Fast N Esy #6	Fresno	1.09	Intermediate
C	7877	Fast N Esy #7	Fresno	1.20	Intermediate
C	1278	Fast N Esy 17 Corporation	Fresno	1.06	Intermediate
C	3512	Fast N Esy 18 Corporation	Fresno	1.51	Intermediate
C	1230	Fast N Esy 22 Corp Dba Fast N Easy 24	Fresno	0.65	Exempt/Low
C	8599	Fast N Esy 22 Corporation	Fresno	0.78	Exempt/Low
C	1958	Fast N Esy 23 Corporation	Fresno	0.51	Exempt/Low
C	3566	Fast N Esy 26 Corporation	Fresno	0.59	Exempt/Low
C	3895	Fast N Esy 28 Corporation	Fresno	0.79	Exempt/Low
C	3724	Fast N Esy 29	Fresno	0.53	Exempt/Low
C	301	Fast N Esy 4 Corporation	Fresno	0.87	Exempt/Low
C	294	Fast N Esy 5 Corporation	Fresno	0.83	Exempt/Low
C	7136	Fast N Esy 9 Corporation	Clovis	0.80	Exempt/Low
S	8166	Fast N Esy Ii Inc.- Dba Fast N Esy #13	Tulare	7.04	Intermediate
C	485	Fast Trip Food Store	Mendota	2.16	Intermediate
S	667	Fast Way Market	Richgrove	0.51	Exempt/Low
C	484	Fastrip Food Store	Fresno	2.14	Intermediate
C	483	Fastrip Food Store	Fresno	2.66	Intermediate
C	482	Fastrip Food Store #4-890	Coalinga	3.36	Intermediate
S	476	Fastrip Oil Co	Delano	0.51	Exempt/Low
S	3033	Fastrip Oil Co	Earlimart	1.64	Intermediate
S	2357	Fastrip Oil Co	Lamont	1.71	Intermediate
S	6512	Fastrip Oil Co	Taft	3.06	Intermediate
S	2067	Fastrip Oil Co	Bakersfield	3.58	Intermediate
C	2765	Fastrip Oil Co Lp	Kerman	3.57	Intermediate
C	3053	Fastrip Oil Co, L P	Lemoore	9.39	Intermediate
C	3110	Fastrip Oil Company	Riverdale	0.69	Exempt/Low
C	3166	Fastrip Oil Company L P	Sanger	6.67	Intermediate
C	1741	Fastway Market	Madera	0.51	Exempt/Low
S	1262	Fiesta Liquor And Gas	Bakersfield	0.51	Exempt/Low
C	89	Fifth Wheel Truck Stop Inc.	Fresno	0.67	Exempt/Low
C	2140	Firebaugh Mart LLC	Firebaugh	0.51	Exempt/Low
C	2319	Firouza Inc.	Hanford	0.53	Exempt/Low

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N	97	First Evergreen Oil Corp Dba Tiwana Gas	Stockton	0.90	Exempt/Low
N	1902	Five Minute Car Wash	Modesto	2.05	Intermediate
C	877	Five Stars Market	Five Points	0.67	Exempt/Low
N	714	Flag City Chevron (Stars Holding Co LLC)	Lodi	0.97	Exempt/Low
N	102	Flyers Energy LLC	Stockton	0.51	Exempt/Low
S	2182	Flyers Energy LLC	Bakersfield	0.51	Exempt/Low
S	751	Flyers Energy LLC	Bakersfield	0.51	Exempt/Low
N	128	Flyers Energy, LLC	Manteca	0.51	Exempt/Low
C	8012	Foods Co #316	Fresno	3.75	Intermediate
C	7990	Foods Co #339	Fresno	2.37	Intermediate
S	7794	Foods Co #384	Bakersfield	1.91	Intermediate
N	1247	Forebay Chevron	Santa Nella	1.12	Intermediate
S	1032	Four Seasons Handy Market	Visalia	0.90	Exempt/Low
S	2437	Four Veer Inc. Dba Rosedale Chevron	Bakersfield	1.31	Intermediate
S	2139	Fox Petroleum Inc.	Shafter	2.59	Intermediate
S	616	Frank's Stop & Go Market	Porterville	0.51	Exempt/Low
S	1571	Freeway Express Mart (B Dhaliwal Inc.)	Bakersfield	0.51	Exempt/Low
C	1117	Fresno 99 Investments LLC	Fresno	8.75	Intermediate
C	532	Fresno Ashlan Gas & Mart	Fresno	0.90	Exempt/Low
C	2797	Fresno Central Market	Fresno	0.51	Exempt/Low
C	3790	Fresno Elite Carwash Inc.	Fresno	0.76	Exempt/Low
C	500	Fresno Gas And Liquor	Fresno	0.51	Exempt/Low
C	3299	Fresno Highway Fuels Inc.	Fresno	0.90	Exempt/Low
C	8710	Fresno Mall 76	Fresno	1.06	Intermediate
C	3970	Fresno Mckinley Arco	Fresno	5.83	Intermediate
C	3120	Fresno Petroleum Inc.	Fresno	0.54	Exempt/Low
N	3130	Frias Union Service	Patterson	1.28	Intermediate
S	7384	Friendly Liquor	Porterville	0.51	Exempt/Low
N	1921	Fruit Yard Produce Stand	Modesto	1.53	Intermediate
C	8844	Fueling Convenience Inc.	Fresno	0.75	Exempt/Low
N	9475	Fulkerth Chevron	Turlock	1.09	Intermediate
C	654	G Mart	Fresno	0.72	Exempt/Low
S	2046	G&G Oil Group, Inc. (Dba Arco #42542)	Bakersfield	1.68	Intermediate
S	458	G1 Mart	Lindsay	0.67	Exempt/Low
C	2346	Garreks Inc.	Clovis	2.09	Intermediate
C	3153	Garreks Inc. Dba Bubble Clean	Fresno	1.19	Intermediate
C	77	Gas & Food Shop #3406	Fresno	0.85	Exempt/Low

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S	457	Gas & Goodies	Tulare	0.51	Exempt/Low
S	2784	Gas 4 Less	Bakersfield	0.13	Exempt/Low
N	4372	Gas City (Balwinder Singh)	Modesto	0.91	Exempt/Low
N	1930	Gas Plus Mini Mart (Kamal Preet Kaur)	Modesto	0.51	Exempt/Low
S	2075	Gas Ranch Mini Mart	Woodlake	0.67	Exempt/Low
S	8897	Gas-N-Save Mini Mart Dba Arrow Gas Marke	Bakersfield	0.51	Exempt/Low
S	1002	Gasoline Alley	Woodlake	0.67	Exempt/Low
C	1793	Gateway & Olive Investments Dba Gateway	Madera	0.66	Exempt/Low
N	2298	Gawfco Enterprises Inc.	Westley	1.86	Intermediate
N	3466	George's Mini-Mart	Lockeford	1.00	Exempt/Low
S	1286	Gerges Oil, Inc. Dba Gerges Chevron	Taft	0.51	Exempt/Low
C	1149	Get-N-Go	Fresno	0.84	Exempt/Low
C	3619	Get-N-Go #4	Fresno	0.51	Exempt/Low
S	3614	Gh Food Mart Inc./Complete Convenience Ct	Delano	1.02	Intermediate
C	3874	Ghs Brothers	Fresno	0.72	Exempt/Low
C	1296	Ghs Brothers Dba Xpress Food Mart	Fresno	1.00	Exempt/Low
C	165	Ghs Brothers Dba Xpress Food Mart 2	Fresno	0.51	Exempt/Low
S	965	Gifford's Market	Springville	0.51	Exempt/Low
S	666	Gil Duyst & Son Inc.	Visalia	8.34	Intermediate
N	5102	Gill Bros Inc.	Ceres	1.59	Intermediate
S	602	Gill Food Mart And Gas	Visalia	0.85	Exempt/Low
C	574	Gill's Texaco	Caruthers	0.67	Exempt/Low
C	4378	Gill's Truck Stop	Hanford	1.49	Intermediate
C	1754	Gmg Food Store #101	Madera	0.84	Exempt/Low
N	4293	Golden Bear Gas	Stockton	0.67	Exempt/Low
C	1541	Golden Boy Market	Fresno	0.51	Exempt/Low
C	3744	Golden Doaba Ent LLC Dba Am/Pm 82072	Fresno	2.77	Intermediate
C	8017	Golden Doaba Enterprises LLC	Fresno	0.48	Exempt/Low
S	1030	Golden Filling Station Dba Farmersville	Farmersville	0.51	Exempt/Low
S	592	Golden Rissco Inc. Dba Caldwell Chevron	Visalia	0.51	Exempt/Low
N	5073	Golden State Chevron	Turlock	0.37	Exempt/Low
S	1667	Golden State Mobil	Bakersfield	0.51	Exempt/Low
S	931	Goshen Travel Plaza	Goshen	0.51	Exempt/Low
N	639	Govinder S. Atwal	Lodi	0.51	Exempt/Low
N	5112	Granada Fuel & Food, Inc.	Santa Nella	1.14	Intermediate

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S	2064	Grand Avenue Coast Inc.	Bakersfield	1.55	Intermediate
C	1255	Grand Convenient Stores	Fresno	5.83	Intermediate
C	8735	Grand Petroleum Inc.	Firebaugh	0.45	Exempt/Low
N	1818	Grand Petroleum Inc.	Modesto	1.05	Intermediate
C	3613	Grangeville Market	Hanford	0.51	Exempt/Low
N	1228	Great America Gas & Food	Livingston	0.51	Exempt/Low
C	169	Greener Car Cleaner (Dba: Bubble Wash)	Selma	0.51	Exempt/Low
S	8067	Greg's Petroleum	Shafter	1.03	Intermediate
N	372	Grewal's Gas & Liquor	Stockton	0.70	Exempt/Low
S	324	Griffin Gas Liquor & Food	Tulare	0.51	Exempt/Low
N	9259	Grin Investments Inc.	Stockton	2.54	Intermediate
N	1792	Grip And Go	Modesto	0.67	Exempt/Low
N	1958	G's Food Mart	Patterson	0.67	Exempt/Low
N	454	Gsg Gas And Mart	Stockton	0.51	Exempt/Low
S	1934	Gun C Oh	Bakersfield	0.77	Exempt/Low
N	9466	Gurinder Singh	Modesto	5.83	Intermediate
N	9334	Gurpreet Sandhu	Manteca	1.85	Intermediate
C	3473	Guru Gas & Market Inc.	Huron	0.51	Exempt/Low
N	8851	Gustine Chevron	Gustine	0.64	Exempt/Low
C	9368	Gutherie's Cheveron Mini Mart	Madera	0.64	Exempt/Low
C	9374	H & S Business Center	Sanger	2.08	Intermediate
S	238	H & S Chevron Food Mart Inc.	Arvin	0.51	Exempt/Low
N	1106	H & S Energy Products #3038	Lockeford	0.93	Exempt/Low
N	859	H & S Energy Products, #3034	Manteca	0.51	Exempt/Low
N	3591	H & S Energy Products, #3035	Lathrop	1.94	Intermediate
C	1768	H&R Families Inc. Dba Chowchilla Chevron	Chowchilla	1.11	Intermediate
N	621	H&S Energy Products, LLC # 3081	Stockton	1.74	Intermediate
N	387	Hammer I-5 Am/Pm	Stockton	5.83	Intermediate
C	7716	Hanco77	Hanford	3.66	Intermediate
N	1209	Handi Stop	Merced	0.51	Exempt/Low
C	1085	Handi Stop #9	Fresno	0.76	Exempt/Low
C	613	Handi Stop Market	Fresno	0.51	Exempt/Low
C	2095	Handi Stop/Vinod Nijhawan	Clovis	0.51	Exempt/Low
C	9459	Handi-Stop	Caruthers	1.67	Intermediate
C	813	Hanford Liquor And Food Mart	Hanford	0.51	Exempt/Low
C	614	Hanford Tri Mart Inc.	Hanford	0.51	Exempt/Low
C	9056	Hanjrah Inc. Dba Arco Am Pm	Coalinga	1.25	Intermediate
S	2054	Happy Gas & Mini Mart	Bakersfield	0.51	Exempt/Low
S	911	Harbans Singh Grewal	Mcfarland	0.51	Exempt/Low

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N	9218	Harinder Singh Bhatia	Modesto	4.55	Intermediate
S	4547	Hari's Market	Porterville	0.51	Exempt/Low
C	90	Harjit Singh & Davinderpal Sangha	Fresno	1.38	Intermediate
C	2312	Harmon Star Mart #2 (Avtar Singh)	Fresno	0.51	Exempt/Low
N	3912	Harnam Corporation	Tracy	4.87	Intermediate
N	8692	Haroon Al Rashid, Rahman Gas & Market	Ceres	0.51	Exempt/Low
C	1733	Harpreet S Sidhu Dba Mexicali Market	Madera	0.67	Exempt/Low
C	617	Harris Ranch	Coalinga	2.79	Intermediate
C	1680	Harry's Liquor & Gas (Ravinder Kaur)	Madera	0.70	Exempt/Low
N	9188	Harsarb Inc.	Los Banos	0.64	Exempt/Low
S	455	Harvin Fuel Inc.	Terra Bella	0.51	Exempt/Low
N	771	Harvinder Pal Singh - Kettleman Chevron	Lodi	1.70	Intermediate
C	7954	Headlining Shopping Center LLC	Fresno	0.72	Exempt/Low
C	3544	Helm Liquor Market	Helm	0.67	Exempt/Low
S	3524	Henderson Ave Chevron (Taha Saleh)	Porterville	0.75	Exempt/Low
S	8816	Highland Manor	Oildale	0.51	Exempt/Low
N	2163	Hk 1313 Petroleum, Inc.	Modesto	1.76	Intermediate
N	8829	Hk 1313 Petroleum, Inc.	Modesto	2.73	Intermediate
C	2182	Home Away Inc. Dba The Pines Resort	Bass Lake	0.51	Exempt/Low
S	4674	Howards Mini Mart #6	Bakersfield	0.61	Exempt/Low
C	702	Hsg Farmers Inc. (Johnny Quik 149)	Clovis	1.00	Exempt/Low
S	7539	Hungry's Market	Bakersfield	0.67	Exempt/Low
N	2308	Hunt & Sons Inc.	Oakdale	1.98	Intermediate
N	2306	Hunt & Sons Inc.	Modesto	0.67	Exempt/Low
N	1089	Hunt & Sons Inc. - Arch Road Cardlock	Stockton	0.51	Exempt/Low
N	4198	Hunt & Sons Inc.- Service Road Cardlock	Ceres	0.67	Exempt/Low
S	112	Hwj Enterprizes Inc. Dba Samco Ca #4	Bakersfield	0.90	Exempt/Low
S	1865	Hwy 58 Fuel Stop	Bakersfield	0.51	Exempt/Low
C	2965	Ice Bucket	Coalinga	0.95	Exempt/Low
S	3509	In & Out Food Mart	Visalia	8.75	Intermediate
S	7522	Inderjit Inc.	Wasco	0.51	Exempt/Low
S	2023	Indie Co	Bakersfield	1.48	Intermediate
N	9348	Interstate A Enterprises Inc.	Lathrop	0.51	Exempt/Low

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S	822	Ivanhoe Mini Mart	Ivanhoe	0.51	Exempt/Low
S	976	Ivanhoe Speedy Mart	Ivanhoe	0.51	Exempt/Low
N	8854	Iyr Petroleum Inc.	Modesto	0.92	Exempt/Low
N	1156	J & B Body Shop	Stockton	0.05	Exempt/Low
C	762	J & T Junction Corp	Kingsburg	0.85	Exempt/Low
S	4148	J And J Liquor Stop Number 1	Bakersfield	0.51	Exempt/Low
S	3093	J And K Food Mart Inc.	Bakersfield	1.07	Intermediate
N	4975	J D Singh Service Stations, Inc.	Thornton	8.75	Intermediate
C	52	J L Gas And Food	Fresno	1.77	Intermediate
N	3978	J N S Market Liquor & Gas	Dos Palos	0.67	Exempt/Low
S	2348	J Street Mini Mart	Tulare	0.51	Exempt/Low
N	4291	J&D Property, LLC Dba Hughson Chevron	Hughson	0.89	Exempt/Low
N	1815	J&N Petroleum Inc.	Turlock	1.44	Intermediate
C	1011	J. Market And Gas	Reedley	0.51	Exempt/Low
S	330	Jack Griggs Inc.	Porterville	0.51	Exempt/Low
C	3373	Jack's Car Wash	Fresno	1.58	Intermediate
C	3293	Jack's Gas	Fresno	5.83	Intermediate
C	2306	Jack's Gas #2	Easton	0.78	Exempt/Low
C	734	Jacks Gas #4	Hanford	0.51	Exempt/Low
N	2059	Jacks Gas #5	Newman	1.10	Intermediate
S	818	Jack's Gas #7	Woodlake	0.51	Exempt/Low
S	3608	Jack's Git N Go	Tulare	0.56	Exempt/Low
S	8272	Jacks Liquor Store & Fueling	Visalia	0.67	Exempt/Low
C	674	Jacks Mart	Fresno	0.64	Exempt/Low
N	902	Jackson Energy	Stockton	1.65	Intermediate
S	2384	Jaco Hill	Bakersfield	1.27	Intermediate
S	2392	Jaco Hill	Bakersfield	2.01	Intermediate
S	2360	Jaco Hill	Wasco	2.23	Intermediate
S	2382	Jaco Hill	Bakersfield	2.33	Intermediate
S	2394	Jaco Hill	Bakersfield	2.65	Intermediate
S	2369	Jaco Hill	Shafter	3.07	Intermediate
S	2380	Jaco Hill	Bakersfield	3.33	Intermediate
S	2389	Jaco Hill	Bakersfield	4.19	Intermediate
S	2396	Jaco Hill	Bakersfield	6.20	Intermediate
S	2377	Jaco Hill Co	Bakersfield	0.51	Exempt/Low
S	2372	Jaco Hill Co	Lamont	0.57	Exempt/Low
S	2359	Jaco Hill Co	Arvin	0.82	Exempt/Low
S	2363	Jaco Hill Co	Taft	0.89	Exempt/Low
S	937	Jaco Hill Co	Tulare	1.14	Intermediate
S	2355	Jaco Hill Co	Wasco	1.38	Intermediate

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S	2390	Jaco Hill Co	Bakersfield	1.93	Intermediate
S	2371	Jaco Hill Co	Bakersfield	2.78	Intermediate
S	2370	Jaco Hill Co	Bakersfield	4.31	Intermediate
C	891	Jaco Hill Company	Orange Cove	0.89	Exempt/Low
C	670	Jaco Hill Company	Caruthers	0.92	Exempt/Low
S	636	Jaco Oil Co	Farmersville	7.77	Intermediate
S	2558	Jaco Oil Dba Fastrip Station	Bakersfield	5.11	Intermediate
N	4246	Jadwinder Singh	Patterson	8.75	Intermediate
C	1275	Jagtar Singh Brar Dba Hanford 76	Hanford	0.55	Exempt/Low
N	3406	Jahant Food & Fuel Stop	Acampo	1.15	Intermediate
S	2365	Jamieson Hill	Bakersfield	0.75	Exempt/Low
S	2387	Jamieson Hill	Bakersfield	1.69	Intermediate
S	2374	Jamieson Hill	Lamont	1.70	Intermediate
S	2393	Jamieson Hill	Taft	1.83	Intermediate
S	2399	Jamieson Hill	Lindsay	1.95	Intermediate
S	2361	Jamieson Hill	Bakersfield	2.43	Intermediate
S	2383	Jamieson Hill	Arvin	2.53	Intermediate
S	2373	Jamieson Hill	Bakersfield	2.68	Intermediate
S	2386	Jamieson Hill	Bakersfield	2.91	Intermediate
S	2397	Jamieson Hill	Bakersfield	3.00	Intermediate
S	2395	Jamieson Hill	Delano	3.16	Intermediate
S	2381	Jamieson Hill	Bakersfield	3.78	Intermediate
S	2375	Jamieson Hill	Bakersfield	4.64	Intermediate
N	3775	Jammu & Kashmir Inc./D&S Gas & Mini Mart	Legrand	0.51	Exempt/Low
N	66	Jass Enterprises Inc. - Am/Pm Woodbridge	Woodbridge	2.09	Intermediate
S	2457	Jasuir Singh Sohal-Kwik Korner	Dinuba	0.55	Exempt/Low
N	9650	Javier Galvan West Main Partners LLC	Turlock	8.75	Intermediate
N	535	Jay Mcillrath	Stockton	0.51	Exempt/Low
N	2658	Jbs Petro Inc.	Lodi	0.89	Exempt/Low
S	8259	Jeev Global Inc.	Tulare	1.44	Intermediate
S	3743	Jeffries Brothers	Bakersfield	1.14	Intermediate
S	3117	Jeffries Brothers	Bakersfield	1.32	Intermediate
S	3489	Jeffries Brothers Inc.	Wasco	0.51	Exempt/Low
S	2417	Jeffries Brothers Inc.	Shafter	0.51	Exempt/Low
S	2414	Jeffries Brothers Inc.	Taft	0.52	Exempt/Low
C	1053	Jensen Shell	Fresno	0.78	Exempt/Low
C	675	Jet Stop Inc.	Huron	0.67	Exempt/Low
C	3921	Jgss Food Service Inc.	Fowler	3.38	Intermediate

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S	1729	Jhaj & Brar Investment Inc.	Lost Hills	5.83	Intermediate
C	2825	Jiffy Food	Coalinga	0.51	Exempt/Low
C	475	Jiffy Food Stop	Easton	0.51	Exempt/Low
C	1752	Jiffy Market Food Store	Chowchilla	0.51	Exempt/Low
S	239	Jiffy's Store	Shafter	0.51	Exempt/Low
S	1277	Jkcm Corp Dba Jk Gas And Mart	Delano	0.51	Exempt/Low
C	3483	Jkr Ventures Inc. Dba R & S Mini Mart	Fresno	0.96	Exempt/Low
S	480	Jobrn Inc.	Bakersfield	0.55	Exempt/Low
C	1715	Joes Food Mart	Chowchilla	0.60	Exempt/Low
N	7849	Joes Food Mart	Modesto	0.82	Exempt/Low
N	435	Joe's Travel Plaza	Lathrop	0.67	Exempt/Low
N	4839	Joe's Travel Plaza - Westley	Westley	7.07	Intermediate
S	591	Joe's Westside Market	Porterville	0.62	Exempt/Low
S	8475	John & Suzie Cross Kennedy Meadows Gs	Inyokern	0.26	Exempt/Low
C	1185	Johnny Liquor Food Store	Sanger	0.51	Exempt/Low
C	9545	Johnny Quick #207	Fresno	0.97	Exempt/Low
C	3304	Johnny Quik 163	Fresno	5.83	Intermediate
C	7545	Johnny Quik Food Store	Clovis	1.86	Intermediate
C	695	Johnny Quik Food Store #109	Fresno	0.51	Exempt/Low
C	6986	Johnny Quik Food Store #189	Fowler	5.83	Intermediate
S	1289	Johnny's Foodmart	Bakersfield	1.16	Intermediate
C	3043	Josan & Josan Inc. Dba Selma Arco-Ampm	Selma	3.16	Intermediate
C	2324	Josan & Josan, Inc. Dba Hwy 41 Arco Ampm	Madera	2.47	Intermediate
C	9341	Josan Investment, Inc.	Lemoore	2.15	Intermediate
N	3828	Jsks Enterprises Inc. Dba Arco Am Pm	Manteca	3.07	Intermediate
C	1273	Jst LLC	Fresno	0.81	Exempt/Low
C	1297	Jst LLC	Fresno	1.20	Intermediate
N	757	Judge & Kap Petroleum Inc. Dba Gavinko Ga	Stockton	0.99	Exempt/Low
C	4884	K - C Market	Kettleman City	0.66	Exempt/Low
C	707	K & H Liquor And Food	Lemoore	0.51	Exempt/Low
S	744	K & K Mart	Mcfarland	0.51	Exempt/Low
S	1449	K & S Food Store	Bakersfield	0.60	Exempt/Low
N	1710	K S Chandi & Sons	Modesto	3.54	Intermediate
C	56	Kailey Fuels Inc. (Arco Am Pm)	Fresno	2.53	Intermediate
N	6572	Kamal Dhaliwal	Atwater	4.11	Intermediate
S	938	Kamlesh Rani	Pixley	0.51	Exempt/Low

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N	9026	Kaptan Gas & Food	Oakdale	0.85	Exempt/Low
S	975	Kdg Capital LLC Dba Sierra Sporting Goo	Exeter	0.51	Exempt/Low
S	1004	Ken's Chinowth Git & Go	Visalia	0.95	Exempt/Low
N	452	Kent's Oil Service Inc.	Stockton	4.42	Intermediate
C	716	Kerman Carwash Inc.	Kerman	0.77	Exempt/Low
N	5278	Kesar Petroleum Inc.	Stockton	0.28	Exempt/Low
C	55	Kettleman City Mobil Inc.	Kettleman City	1.05	Intermediate
S	6850	Kevin Stores Inc. Dba Hillside Liquor	Bakersfield	0.51	Exempt/Low
N	456	King Island Marina	Stockton	1.84	Intermediate
N	5100	Kingdon Airport LLC	Lodi	0.05	Exempt/Low
N	5126	Kings Market	Hilmar	0.51	Exempt/Low
C	1281	Kings River Sinclair	Reedley	2.09	Intermediate
C	3808	Kingsburg Food Mart	Kingsburg	0.57	Exempt/Low
N	1042	Kpmc Management Inc. Dba: Arco Cherokee	Lodi	0.66	Exempt/Low
S	3127	Kulwant Khaira Dba C&E Market	Tulare	0.51	Exempt/Low
C	1886	Kwik Korner	Reedley	0.51	Exempt/Low
S	1008	Kwik Korner Market	Orosi	0.67	Exempt/Low
C	92	Kwik Serv	Fresno	0.51	Exempt/Low
N	3277	Kwik Serv Lodi, B&W 113	Lodi	0.51	Exempt/Low
C	4225	Kwik Serve	Fresno	2.15	Intermediate
N	433	La Favorita, California Corporation	French Camp	0.51	Exempt/Low
C	6922	La Plaza 24, Inc.	Madera	0.51	Exempt/Low
S	2496	Lakhbir Singh Dba Cornerstone Market	Dinuba	0.70	Exempt/Low
S	1573	Larson Food Store	Bakersfield	0.00	Exempt/Low
N	3486	Lathrop Gas & Food Inc.	Lathrop	2.24	Intermediate
N	134	Lathrop Shell (Arbabian Family LLC)	Lathrop	1.38	Intermediate
S	3796	Lemon Cove Market	Lemon Cove	0.51	Exempt/Low
C	7380	Lemoore Crossing	Lemoore	0.51	Exempt/Low
C	1289	Lemoore Mobil (Foeng Yam)	Lemoore	0.51	Exempt/Low
N	1322	Lemos Entr. LLC/M&M Corner Mini Mart	Delhi	1.01	Intermediate
S	3562	Lerdo Chevron	Shafter	0.03	Exempt/Low
S	1513	Linder Equipment Co	Tulare	0.08	Exempt/Low
S	4188	Lindsay Chevron	Lindsay	5.83	Intermediate
S	3697	Lindsay Food Mart	Lindsay	0.82	Exempt/Low
S	9195	Lindsay Unified School District	Lindsay	0.51	Exempt/Low

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N	3273	Livingston Gas And Grocery	Livingston	0.54	Exempt/Low
S	9202	Lkmp Properties	Shafter	0.56	Exempt/Low
N	4773	Lodi Airport	Acampo	0.63	Exempt/Low
N	203	Lodi Food And Liquor	Lodi	0.51	Exempt/Low
N	5016	Lodi Valley Petroleum Inc.	Lodi	0.51	Exempt/Low
C	9402	Loma Vista Petroleum, Inc.	Clovis	2.95	Intermediate
N	1289	Los Banos Shell	Los Banos	1.18	Intermediate
N	1188	Los Camperos Inc. Dba Buy N Save	Los Banos	0.51	Exempt/Low
C	8054	Los Primos Market	Laton	0.51	Exempt/Low
S	1310	Lost Hills Travel Center Inc.	Lost Hills	1.79	Intermediate
S	767	Lovejot Singh & Jagjit Singh	Visalia	0.51	Exempt/Low
S	3957	Lovers Lane Food Mart	Visalia	0.59	Exempt/Low
N	4477	Love's Country Store Of California #223	Ripon	4.34	Intermediate
N	8912	Love's Country Stores Of Ca	Lodi	0.75	Exempt/Low
S	4025	Love's Country Stores Of Calif #230	Lost Hills	4.55	Intermediate
S	7567	Love's Travel Stop- #382	Tulare	2.06	Intermediate
C	9522	Love's Travel Stop #736	Madera	3.44	Intermediate
N	4378	Loves Travel Stops & Country Stores	Santa Nella	2.33	Intermediate
C	2394	Lucky 7	Madera	0.51	Exempt/Low
S	8632	Lucky 7	Bakersfield	0.51	Exempt/Low
S	2144	Lucky 7 #1	Delano	0.51	Exempt/Low
S	2958	Lucky 7 #2 Food Mart	Delano	0.51	Exempt/Low
C	991	Lucky Gas & Liquor	Fresno	0.61	Exempt/Low
S	1559	Lucky Seven #3	Bakersfield	0.51	Exempt/Low
N	1299	M & A Market	Merced	0.51	Exempt/Low
N	8199	M & B Petroleum	Modesto	2.93	Intermediate
N	1298	M.G. Santos, Inc., Texaco #2	Los Banos	0.88	Exempt/Low
C	3148	Madera Valero Gas & Food (Aahil Entrprs)	Madera	0.67	Exempt/Low
C	1726	Madtown Dino Mart	Madera	0.56	Exempt/Low
N	7715	Main St Chevron Turlock Project Inc.	Turlock	1.08	Intermediate
C	1035	Majha Business Solutions	Fresno	0.74	Exempt/Low
C	2888	Mallah Inc.	Fresno	0.63	Exempt/Low
N	8641	Mann Bros Truck Stop Inc.	Modesto	0.17	Exempt/Low
N	850	Manteca Liquor & Food	Manteca	0.64	Exempt/Low
N	9391	Manteca Petroleum, Inc.	Manteca	3.95	Intermediate
N	4339	Manu Deen Bani, Inc.	Snelling	0.51	Exempt/Low

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N	9302	March & March LLC	Stockton	0.67	Exempt/Low
S	2181	Market Express One Inc.	Bakersfield	0.51	Exempt/Low
N	4580	Marks Fuel & Food Inc. (Dba: Arco Victor)	Lodi	5.83	Intermediate
N	3956	Maxi Mart	Atwater	0.78	Exempt/Low
S	8951	Mcauliff Center Lp	Visalia	1.25	Intermediate
S	222	Mcfarland Chevron	Mcfarland	1.10	Intermediate
N	2281	Mchenry 76 & Food Mart	Modesto	0.66	Exempt/Low
N	4049	Mchenry Cruisers #10	Modesto	2.96	Intermediate
N	2263	Mchenry Shell	Modesto	0.51	Exempt/Low
N	86	Mcm14 Corp	Stockton	2.77	Intermediate
C	993	Meerpur Inc.	Fresno	0.51	Exempt/Low
C	3200	Mendota Food Mart	Mendota	0.67	Exempt/Low
N	1184	Merced Fuel & Food (Akshat Sharma)	Merced	5.83	Intermediate
N	1201	Merced Mall Chevron	Merced	1.59	Intermediate
N	7168	Merced River Development Inc.	Snelling	0.72	Exempt/Low
S	225	Mesa Marin Chevron	Bakersfield	0.19	Exempt/Low
S	2236	Metro Mart	Bakersfield	0.51	Exempt/Low
S	1448	Midway Market & Liquor	Lake Of The Wds	0.51	Exempt/Low
C	837	Mighty Mart	Sanger	2.82	Intermediate
S	8343	Mighty Mike's Gas, Inc.	Plainview	0.51	Exempt/Low
S	8989	Millbrook Gas Station	Bakersfield	8.75	Intermediate
C	2202	Millerton General Store	Clovis	0.51	Exempt/Low
S	2048	Ming Business Inc.	Bakersfield	1.53	Intermediate
N	549	Miracle Mile Market	Stockton	0.61	Exempt/Low
C	3611	Mission Gas N Go Inc.	Madera	3.05	Intermediate
C	843	Mission Plaza	Parlier	0.61	Exempt/Low
N	4569	Mitchell Gas & Lube	Ceres	5.83	Intermediate
S	8900	Mlh Enterprise	Bakersfield	1.80	Intermediate
N	9350	Mobil Exxon Gas And Mini Mart	Patterson	0.53	Exempt/Low
N	175	Mobil Stockton #1/Abdo Nashir	Stockton	0.88	Exempt/Low
S	1038	Moe's Quickstop	Orosi	0.51	Exempt/Low
N	1353	Mohamed M Obeid Dba Richard's Market & L	Gustine	0.51	Exempt/Low
N	1744	Monte Vista Petroleum Inc.	Turlock	5.83	Intermediate
C	1799	Monty's Liquor	Madera	0.51	Exempt/Low
S	1061	Mooney Shell	Visalia	0.51	Exempt/Low
N	2406	Morada Chevron Fast N Easy Go	Stockton	1.93	Intermediate
S	2304	Morton Express Mini Mart	Porterville	0.51	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	9562	Mo's Oasis Market	Hughson	1.00	Exempt/Low
N	125	Mossdale Chevron (Sksp Inc.)	Lathrop	1.46	Intermediate
S	589	Mota's Mini Mart	Ivanhoe	0.51	Exempt/Low
S	8913	Mountain View Inc.	Bakersfield	0.66	Exempt/Low
S	2776	Mountview Inc.	Bakersfield	0.98	Exempt/Low
S	3220	Mountview Inc.	Bakersfield	1.07	Intermediate
S	2230	Mpcn Corp Dba Super Food Mart	Bakersfield	0.51	Exempt/Low
N	334	Mss-Petro Inc. Dba Flames Liquor & Gas	Lodi	0.97	Exempt/Low
C	853	Mt Whitney Mini Mart	Riverdale	0.51	Exempt/Low
C	3479	Mtn View Gas & Mart (Bhandal Inc.)	Selma	1.15	Intermediate
S	747	Mueer M Saeed- Edison Mini Mart	Edison	0.51	Exempt/Low
S	2102	Munn Chau Dba Stockdale Food Mart	Bakersfield	0.73	Exempt/Low
S	4289	Munni Ji LLC Dba Tipton Shell	Tipton	0.52	Exempt/Low
S	8342	Murray Family Farms	Bakersfield	0.01	Exempt/Low
S	3267	Muthana Ii Corp Dba Obie's Downtown	Bakersfield	1.08	Intermediate
S	2492	N & S Mini Market	Porterville	0.67	Exempt/Low
S	9171	N Square	Goshen	5.71	Intermediate
C	3579	Nas Partnership Dba Six Star Food Mart	Madera	1.33	Intermediate
S	5420	Natalie Enterprises Inc. Dba Tadros Marke	Tulare	5.83	Intermediate
N	378	National Petroleum Manteca	Manteca	1.04	Intermediate
N	3957	National Petroleum Patterson	Patterson	8.75	Intermediate
C	3509	Navjeet Singh	Clovis	2.92	Intermediate
S	4293	Nelson's Corner LLC	Springville	0.51	Exempt/Low
N	4518	New Olive Market	Atwater	0.51	Exempt/Low
C	1290	Neya Inc.	Fresno	1.35	Intermediate
S	471	Niles Market	Bakersfield	0.51	Exempt/Low
N	2009	Nirmal Kaur Dba Waterford Market	Waterford	0.51	Exempt/Low
C	1141	Nirmal Singh Shop N Quick Inc.	Fresno	0.54	Exempt/Low
S	734	Nizar Karimi	Visalia	0.51	Exempt/Low
N	738	North Pole Gas & Food Inc.	Tracy	1.25	Intermediate
C	1128	Northgate Shell	Fresno	1.97	Intermediate
C	39	Nskb Investments Inc. Dba Sb Market	Fresno	1.92	Intermediate
C	2441	O C Citrus Mini Mart	Orange Cove	0.51	Exempt/Low
N	2072	Oakdale Municipal Airport	Oakdale	2.51	Intermediate

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N	9688	Oasis Fuels Inc. Dba Merced Truck & Auto	Le Grand	0.01	Exempt/Low
N	4196	Oasis Market	Crows Landing	0.69	Exempt/Low
S	7569	Oasis Market & Truck Stop	Ducor	0.67	Exempt/Low
N	8707	Oasis Market And Liquor	Turlock	1.89	Intermediate
N	1882	Oasis Mini Mart	Newman	0.72	Exempt/Low
C	1126	Old Town Shell	Clovis	0.51	Exempt/Low
S	9433	Olive Grove Foodmart	Bakersfield	2.39	Intermediate
S	2100	Olive Star Cc Inc.	Bakersfield	0.59	Exempt/Low
N	1849	Olsen Service Station/Nasser M Obaid	Modesto	0.51	Exempt/Low
S	3892	Omega Market	Porterville	0.51	Exempt/Low
S	6617	On The Go Food Store	Bakersfield	1.47	Intermediate
C	1250	On The Go Stores LLC Dba On The Go Fresn	Fresno	0.67	Exempt/Low
N	4176	One Stop Market	Patterson	0.67	Exempt/Low
N	1131	One Stop Market	Manteca	0.91	Exempt/Low
C	810	One Stop Market & Gas	Reedley	1.48	Intermediate
S	1454	One Stop Shell (Kulwant Singh)	Bakersfield	0.51	Exempt/Low
S	3725	Ooba Inc. Dba Samco Union #7	Bakersfield	1.32	Intermediate
S	2815	Orange Belt Grocery (Mohsen M Obad)	Lindsay	0.67	Exempt/Low
N	9230	Orange Market & Gas	Turlock	0.51	Exempt/Low
N	3939	Orlando's	Linden	0.64	Exempt/Low
S	811	Orosi Food Mart (Salah S Salah)	Orosi	0.51	Exempt/Low
S	1068	Orosi Mart & Deli (Salah Saleh Alisaleh)	Orosi	0.60	Exempt/Low
S	2436	Oswell Chevron, Inc.	Bakersfield	0.99	Exempt/Low
S	114	Outpost Food And Gas	Taft	0.51	Exempt/Low
C	2326	P J Express Mart	Madera	0.51	Exempt/Low
N	1202	Pacheco Chevron	Los Banos	1.79	Intermediate
N	8614	Pacific West Petroleum Inc.	Tracy	6.52	Intermediate
S	2555	Paige Ave Mini Mart	Tulare	1.13	Intermediate
C	1791	Pal Brothers, LLC	Madera	1.24	Intermediate
C	9342	Palm Bluff Carwash	Fresno	1.79	Intermediate
C	9440	Palm Plaza	Hanford	8.75	Intermediate
S	2219	Panama & Colony Gas	Bakersfield	0.51	Exempt/Low
S	7610	Panama Lane Shell	Bakersfield	1.09	Intermediate
S	2068	Pandher Mart - LLC	Bakersfield	1.73	Intermediate
C	4185	Panoche Mobil	Firebaugh	0.89	Exempt/Low
C	1892	Panoche Shell	Firebaugh	1.06	Intermediate

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N	4608	Paq Inc., Dba Gas-4-Less	Stockton	2.92	Intermediate
N	1749	Paradise Gasoline	Modesto	0.66	Exempt/Low
C	47	Pardeep Singh	Fresno	7.29	Intermediate
C	913	Parkway Mini Mart	Fresno	0.51	Exempt/Low
N	4067	Parkwood Gas & Food	Stockton	0.88	Exempt/Low
S	2954	Parmar Brothers Inc.	Tulare	0.57	Exempt/Low
C	1745	Parmar Petroleum Inc. Dba Gas N Stuff	North Fork	0.51	Exempt/Low
S	2499	Parshant Kumar/Madhu Bala (Pk 1 Stop)	Visalia	0.67	Exempt/Low
N	9546	Patterson Valero	Patterson	0.51	Exempt/Low
N	2098	Paul Oil Company Inc.	Oakdale	1.12	Intermediate
N	2099	Paul Oil Company, Inc.	Riverbank	0.91	Exempt/Low
N	5105	Pd Brothers/ G & B Liquor	Planada	0.51	Exempt/Low
N	8774	Pdi Dba Los Banos Valero	Los Banos	1.10	Intermediate
C	923	Penny Wise	Fresno	0.85	Exempt/Low
N	2105	Penny Wise Gas	Modesto	0.79	Exempt/Low
C	1977	Pennywise	Fresno	1.08	Intermediate
C	3918	Perjian Corporation	Fresno	0.51	Exempt/Low
N	633	Pershing Gas For Less	Stockton	2.53	Intermediate
N	9274	Pershing Holdings Inc.	Escalon	2.79	Intermediate
S	3576	Petro Travel Plaza	Wheeler Ridge	3.72	Intermediate
S	4161	Petro Travel Plaza Holdings LLC	Lebec	3.78	Intermediate
S	7238	Petro Travel Plaza LLC	Lebec	2.89	Intermediate
N	7988	Pg Trading Inc. Dba Grab And Go Plaza	Tracy	2.12	Intermediate
C	1184	Pic 'N' Go #2	Fresno	0.64	Exempt/Low
C	701	Pick Quick Food Store (Bladev S Padda)	Clovis	0.88	Exempt/Low
C	7163	Pilot Travel Centers #1277	Avenal	0.03	Exempt/Low
S	1456	Pilot Travel Centers #1302	Bakersfield	1.75	Intermediate
N	3363	Pilot Travel Centers LLC	Ripon	0.73	Exempt/Low
N	4547	Pilot Travel Centers LLC	Lodi	0.81	Exempt/Low
S	2012	Pilot Travel Centers LLC	Bakersfield	2.84	Intermediate
N	9260	Pilot Travel Centers LLC #1017-01	Lathrop	1.63	Intermediate
S	9102	Pilot Travel Centers LLC #1071-01	Tulare	0.47	Exempt/Low
N	9267	Pilot Travel Centers LLC #1080-01	Patterson	4.68	Intermediate
S	3806	Pilot Travel Centers LLC #154	Lost Hills	3.38	Intermediate

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C	2132	Pilot Travel Centers LLC #365	Madera	4.12	Intermediate
S	1439	Pine Mountain Service Center	Pine Mt Club	0.51	Exempt/Low
S	936	Pixley Handy Market Inc.	Pixley	0.52	Exempt/Low
S	2016	Pixley Mini Mart	Pixley	0.51	Exempt/Low
S	2649	Pj Express Mart	Farmersville	0.67	Exempt/Low
S	1041	Plano Handy Market (Hesham Makhlouf)	Porterville	0.67	Exempt/Low
N	1668	Platinum Gas & Market	Modesto	0.51	Exempt/Low
S	4154	Poplar Mini Mart	Porterville	0.51	Exempt/Low
S	574	Portavilla Market (Joseph Abdulla)	Porterville	0.67	Exempt/Low
S	8314	Porterville Arco	Porterville	4.19	Intermediate
S	2090	Porterville City Airport	Porterville	3.67	Intermediate
S	1027	Porterville Liquor	Porterville	0.53	Exempt/Low
S	1728	Pound's Grocery	Bakersfield	0.51	Exempt/Low
S	566	Preet Market	Tulare	0.51	Exempt/Low
S	1007	Prince Food & Gas	Visalia	0.65	Exempt/Low
S	633	Prince Mart (Harinderpal Kaur)	Lemon Cove	0.51	Exempt/Low
S	6859	Prince Palace	Bakersfield	1.06	Intermediate
S	4246	Prince Palace	Bakersfield	1.18	Intermediate
S	8341	Prince Palace Truck Stop Inc.	Bakersfield	1.08	Intermediate
S	604	Princess Superette	Visalia	0.51	Exempt/Low
C	3150	Pritam Singh Gill Dba Extra Mart	Madera	5.83	Intermediate
N	4351	Pritpal Singh - Pennywise Travel	Santa Nella	3.45	Intermediate
C	8518	Propel Fuels Inc.	Fresno	0.51	Exempt/Low
S	3790	Prosperity Food Land (Fawaz Alset)	Tulare	0.51	Exempt/Low
S	7005	Prosperity Mini Mart & Gas	Tulare	8.75	Intermediate
N	2097	Pushpinder Singh Dba Money Market	Oakdale	0.53	Exempt/Low
S	2621	Quality Market & Fuel	Lamont	0.61	Exempt/Low
S	311	Quality Mart	Lindsay	0.51	Exempt/Low
S	2283	Quic Shop Markets	Dinuba	1.14	Intermediate
N	2129	Quick & Save	Patterson	0.51	Exempt/Low
N	1349	Quick And Easy - Rai & Sons Corp.	Gustine	0.51	Exempt/Low
C	992	Quick Fill Inc.	Fresno	0.00	Exempt/Low
C	693	Quick Food Store	Fresno	0.51	Exempt/Low
C	7442	Quick N E-Z	Fresno	1.47	Intermediate
N	4234	Quick N Save	Hughson	0.51	Exempt/Low
N	4446	Quick N Save	Riverbank	0.51	Exempt/Low

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N	4610	Quick N Save	Merced	0.67	Exempt/Low
C	1139	Quick Pick & Deli	Fresno	0.51	Exempt/Low
N	141	Quick Serve	Manteca	1.66	Intermediate
N	4249	Quick Shop N Go	Modesto	0.51	Exempt/Low
C	3358	Quick Stop Mini Mart	Caruthers	0.51	Exempt/Low
S	221	Quick Trip Liquor	Tulare	0.58	Exempt/Low
S	1146	Quick-N-Handy Mart & Deli	Dinuba	0.80	Exempt/Low
S	2179	Quick-N-Handy Mart & Deli #2	Visalia	0.65	Exempt/Low
S	2665	Quick-N-Out	Bakersfield	0.51	Exempt/Low
S	603	Quik Jack's Inc.	Visalia	0.91	Exempt/Low
C	1730	Quik Serve Food Store	Coarsegold	5.83	Intermediate
N	2123	Quik Stop #142	Denair	1.50	Intermediate
N	2125	Quik Stop #45	Modesto	0.96	Exempt/Low
N	2114	Quik Stop #71	Modesto	0.99	Exempt/Low
N	2124	Quik Stop #73	Oakdale	0.96	Exempt/Low
N	2115	Quik Stop #79	Turlock	0.94	Exempt/Low
N	2118	Quik Stop #83	Modesto	1.70	Intermediate
N	2117	Quik Stop #87	Modesto	0.91	Exempt/Low
N	669	Quik Stop Market #120	Stockton	1.31	Intermediate
N	660	Quik Stop Market #121	Manteca	0.98	Exempt/Low
N	666	Quik Stop Market #124	Manteca	0.54	Exempt/Low
N	671	Quik Stop Market #138	Tracy	0.83	Exempt/Low
N	668	Quik Stop Market #144	Stockton	1.21	Intermediate
N	2121	Quik Stop Market #155	Turlock	1.01	Intermediate
N	2116	Quik Stop Market #156	Ceres	1.15	Intermediate
N	4362	Quik Stop Market #163	Livingston	3.22	Intermediate
N	663	Quik Stop Market #39	Stockton	0.62	Exempt/Low
N	659	Quik Stop Market #76	Stockton	0.97	Exempt/Low
N	662	Quik Stop Market Inc. #148	Lodi	0.77	Exempt/Low
N	661	Quik Stop Markets #125	Ripon	1.55	Intermediate
N	665	Quik Stop Markets #132	Stockton	1.07	Intermediate
N	670	Quik Stop Markets #152	Lodi	0.85	Exempt/Low
S	961	Qwik Stop	Porterville	0.63	Exempt/Low
C	6895	R & S Liquor	Corcoran	0.51	Exempt/Low
N	4559	R Abbate Enterprises	Gustine	0.61	Exempt/Low
S	1290	R J & Sons Inc.	Delano	0.67	Exempt/Low
N	2913	R K Service Station	Waterford	0.64	Exempt/Low
S	482	R Singh Enterprises Inc.	Exeter	0.62	Exempt/Low
N	1359	R St Chevron	Merced	0.53	Exempt/Low

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N	1094	Radc Enterprises Inc. - Grant Line Shell	Tracy	1.39	Intermediate
N	245	Radc Enterprises Inc. Dba Tracy Shell	Tracy	1.19	Intermediate
N	9597	Radc Enterprises, Inc.	Stockton	2.59	Intermediate
N	9596	Radc Enterprises, Inc.	Modesto	2.16	Intermediate
N	1737	Rai & Bath Petroleum Inc.	Modesto	3.19	Intermediate
N	1732	Rai & Sehaj Petroleum Inc.	Modesto	2.31	Intermediate
C	2364	Rai Food Mart Inc. Dba Oaks Mini Mart	Reedley	5.83	Intermediate
N	2127	Rai's Mart (Essam Alsumare)	Riverbank	0.67	Exempt/Low
S	2145	Ramco Express	Bakersfield	0.76	Exempt/Low
N	6060	Ramos Oil Inc.	Thornton	0.51	Exempt/Low
S	972	Ranch Market	Porterville	0.51	Exempt/Low
N	1169	Rancho Market And Gas Inc.	Winton	0.51	Exempt/Low
N	5015	Rancho San Miguel Market	Stockton	0.27	Exempt/Low
C	3076	Ranchos Valero	Madera	0.78	Exempt/Low
N	1053	Randhawa Fuel LLC Dba Dinomart	Manteca	1.09	Intermediate
N	983	Randhawa Petroleum LLC Dba El Dorado Gas	Stockton	0.65	Exempt/Low
C	2261	Rani Food & Liquor Inc.	Fresno	0.51	Exempt/Low
N	431	Rat Oil, Inc. Dba Gas And Shop	Ripon	0.51	Exempt/Low
N	282	Razi Petroleum Inc	Tracy	0.63	Exempt/Low
C	3083	Red Chillies LLC Dba Jackpot	Hanford	0.74	Exempt/Low
C	691	Red Rocket (Lakhbir Singh)	Clovis	0.51	Exempt/Low
C	3737	Red Top Gas	Chowchilla	0.51	Exempt/Low
C	1005	Red Triangle Oil Company	Fresno	0.51	Exempt/Low
S	111	Refaat Naiem Tayan	Bakersfield	0.97	Exempt/Low
N	1159	Refuel Petroleum, Inc.	Manteca	0.51	Exempt/Low
C	3819	Renna Ventures Inc.	Fresno	0.97	Exempt/Low
C	1016	Reno's Mega Mart	Firebaugh	1.38	Intermediate
N	208	Rg Gas Stations Inc. Dba Thornton Valero	Stockton	0.88	Exempt/Low
C	3300	Rhodes Inc.	Orange Cove	0.51	Exempt/Low
C	1021	Rhodes Texaco	Reedley	0.51	Exempt/Low
S	1287	Rio Bravo Market (Dipali Desai)	Bakersfield	0.51	Exempt/Low
N	459	Ripon Shell (Balaji Angle)	Ripon	0.91	Exempt/Low
N	3985	Riverbank Cruisers #34	Riverbank	2.30	Intermediate
C	8615	Riverside Golf Course	Fresno	0.36	Exempt/Low
C	9449	Riverside Valero	Fresno	1.28	Intermediate
S	825	Rj Food & Gas (Preetam Singh)	Dinuba	1.25	Intermediate

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S	6587	Rj's Travel Center	Traver	0.97	Exempt/Low
C	275	Robert V Jensen Inc.- Chevron	Hanford	0.93	Exempt/Low
C	1031	Robert V. Jensen, Inc.	Fresno	0.96	Exempt/Low
C	2423	Robert V. Jensen, Inc.	Reedley	0.94	Exempt/Low
N	1358	Robinson Oil Corp Dba Rotten Robbie #59	Santa Nella	2.54	Intermediate
C	1879	Roe Oil Company	Hanford	0.51	Exempt/Low
S	1663	Rosedale Station Inc.	Bakersfield	0.00	Exempt/Low
S	8831	Royal Express Delivery Inc.	Bakersfield	0.51	Exempt/Low
N	8695	Royal Gas And Food	Livingston	0.67	Exempt/Low
S	8898	Roy's Market	Bakersfield	0.51	Exempt/Low
S	803	Rozi's Liquor Store	Delano	0.51	Exempt/Low
S	596	Rozi's Market	Visalia	0.51	Exempt/Low
C	766	Rs Cheaper Co	Fresno	0.87	Exempt/Low
C	8997	Ryan Corner	Fresno	0.51	Exempt/Low
S	1732	S & A Market	Shafter	0.51	Exempt/Low
S	2104	S & H Fuel Stop 3 Inc.	Bakersfield	0.87	Exempt/Low
S	3955	S & H Fuel Stop Inc.	Bakersfield	0.51	Exempt/Low
S	1288	S & J Quick Stop	Shafter	0.53	Exempt/Low
C	2203	S & K Mini Market	Chowchilla	0.52	Exempt/Low
C	3424	S & K Mini Mart	Madera	0.55	Exempt/Low
C	1956	S & K Mini Mart	Sanger	0.68	Exempt/Low
N	2289	S & S Bal LLC	Turlock	0.97	Exempt/Low
S	679	S & S Mini Mart, Inc.	Lamont	0.51	Exempt/Low
N	2522	S&A Petro Inc.	Stockton	0.96	Exempt/Low
C	3111	S.B. Partners Inc. Dba Yosemite Gas	Oakhurst	8.75	Intermediate
N	4563	Safeway Inc.	Turlock	3.31	Intermediate
N	5020	Safeway Inc., Store #2707	Stockton	4.86	Intermediate
N	4490	Safeway, Inc.	Stockton	1.11	Intermediate
N	1260	Sagar's Gas N Save	Merced	0.67	Exempt/Low
S	2065	Saint Peter & Saint Paul LLC	Bakersfield	1.44	Intermediate
C	457	Saleh H. Alkobadi Dba East Reedley Store	Reedley	5.83	Intermediate
N	1769	Salida Cruisers #1	Salida	1.80	Intermediate
S	2014	Sal's E-Z Stop	Bakersfield	0.51	Exempt/Low
S	1348	Sam Khalil	Lebec	1.89	Intermediate
S	1066	Sam Qasem Alinagi Alqabeli	Farmersville	0.67	Exempt/Low
S	2287	Samco Food Store Inc.	Bakersfield	0.52	Exempt/Low
S	6555	Sam's Club # 4819	Bakersfield	9.59	Intermediate

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S	3734	Sam's Market	Bakersfield	0.51	Exempt/Low
S	6951	Sam's Market & Gas	Bakersfield	0.53	Exempt/Low
C	1222	Sam's Mini Mart	Coalinga	0.67	Exempt/Low
S	812	San Joaquin Helicopter	Delano	0.13	Exempt/Low
C	573	Sanger Automated Fuel Inc.	Sanger	0.58	Exempt/Low
C	134	Sanger Food Mart	Sanger	0.51	Exempt/Low
N	7987	Sanguinetti Investments, LLC	Farmington	2.34	Intermediate
S	2051	Sat Kaival Management LLC	Bakersfield	3.22	Intermediate
N	7310	Sat Kartar Blessings LLC	Stockton	0.76	Exempt/Low
C	404	Satinder Pal Singh	Sanger	0.51	Exempt/Low
C	7198	Satwant Mini Mart	Madera	1.08	Intermediate
S	819	Save Center Gas & Food (Gurdip S Sandhu)	Porterville	0.51	Exempt/Low
C	1137	Save-N-Go	Selma	0.73	Exempt/Low
N	2477	Sb Gas & Market	Tracy	0.51	Exempt/Low
N	3658	Sbd Oil Inc.	Westley	2.68	Intermediate
N	262	Sbr Petro Inc./Countryside Liquor & Gas	Lodi	0.51	Exempt/Low
N	3612	Sbsj Petro Inc. Dba Flag City Shell	Lodi	1.26	Intermediate
S	1083	Schwebel Petroleum	Bakersfield	0.51	Exempt/Low
S	1084	Schwebel Petroleum	Bakersfield	3.11	Intermediate
S	8562	Schwebel Petroleum Co Inc.		0.00	Exempt/Low
S	8198	Schwebel Petroleum Co Inc.	Fellows	0.00	Exempt/Low
S	8197	Schwebel Petroleum Co Inc.	Maricopa	0.61	Exempt/Low
C	3325	Second Generation LLC	Fresno	0.63	Exempt/Low
S	3909	Second Generation LLC	Farmersville	0.75	Exempt/Low
C	2832	Selma Chevron	Selma	0.68	Exempt/Low
C	455	Selma Exxon	Selma	1.18	Intermediate
C	763	Selma Quick Stop	Selma	0.51	Exempt/Low
C	8244	Selma Retail Prop Inc.-Dba Get N Go Selma	Selma	0.73	Exempt/Low
C	337	Sequoia Marketplace LLC	Squaw Valley	0.90	Exempt/Low
C	2196	Sequoia Marketplace LLC	Squaw Valley	1.18	Intermediate
N	8725	Seven-Eleven Delhi #Bp32	Delhi	2.84	Intermediate
S	2626	Seville Food Mart	Visalia	0.51	Exempt/Low
C	7819	Shah Chevron	Hanford	5.83	Intermediate
C	3365	Shah's Shell	Hanford	0.94	Exempt/Low
S	3626	Shakib Dashtipour	Bakersfield	1.87	Intermediate
S	8186	Shannon Village Mart	Visalia	2.37	Intermediate
N	8748	Shannon's Mini Mart	Merced	0.67	Exempt/Low

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C	2043	Shaver Lake Gas & Deli	Shaver Lake	0.51	Exempt/Low
C	3308	Shaver Lake Sports Inc.	Shaver Lake	0.46	Exempt/Low
S	4292	Shell	Visalia	0.51	Exempt/Low
S	3615	Shell "Barn" Mini Mart	Exeter	0.72	Exempt/Low
N	8736	Shell Station	Gustine	0.51	Exempt/Low
S	810	Shepherd's Market	Visalia	0.51	Exempt/Low
S	1031	Sherwood Handy Market	Porterville	0.63	Exempt/Low
S	2187	Shiralian Ent Inc.- Dba E-Z Trip-B/W	Buttonwillow	1.63	Intermediate
S	326	Shiralian Valero	Tulare	1.75	Intermediate
C	1800	Shirdhi Inc.	Chowchilla	1.32	Intermediate
N	1030	Shirdhi Inc.	Merced	1.55	Intermediate
C	8553	Shirdhi Inc. Dba Express Mart Valero	Lemoore	1.38	Intermediate
C	1228	Shirmiss Inc Dba Peach Shell	Clovis	1.39	Intermediate
C	1142	Shogy Market LLC	Firebaugh	0.51	Exempt/Low
S	2470	Shop & Go Market	Visalia	0.67	Exempt/Low
S	320	Shop & Save	Porterville	0.51	Exempt/Low
C	1145	Shop And Gas	Fresno	0.51	Exempt/Low
N	4044	Shop And Go	Merced	0.67	Exempt/Low
C	8516	Shop Kwik Market	Reedley	0.67	Exempt/Low
C	8751	Shop N Go #614	Clovis	1.98	Intermediate
C	88	Shop N Go #618	Lemoore	0.89	Exempt/Low
S	4036	Shop 'N Go Inc.	Tulare	0.98	Exempt/Low
C	136	Shop N Quick #2	Easton	0.79	Exempt/Low
C	2683	Shop N'go Inc.	Coalinga	0.89	Exempt/Low
C	1138	Shop-N-Go	Fresno	1.23	Intermediate
C	1140	Shop-N-Go	Fowler	1.92	Intermediate
C	4026	Shop-N-Go	Clovis	2.34	Intermediate
N	292	Short Stop Food Mart	Lodi	0.63	Exempt/Low
S	973	Shukri A Alrezaki	Lindsay	0.51	Exempt/Low
S	6930	Sidhu Estates Inc.	Dinuba	1.62	Intermediate
C	1152	Sierra Liquor & Deli	Hanford	0.51	Exempt/Low
S	2177	Sierra Minit Mart - Plano	Porterville	1.05	Intermediate
S	319	Sierra Minit Mart #1	Porterville	0.96	Exempt/Low
S	2546	Sierra Minit Mart #2	Porterville	1.55	Intermediate
S	2547	Sierra Minit Mart #4	Terra Bella	0.92	Exempt/Low
S	2086	Sierra Minit Mart #5	Tulare	1.20	Intermediate
S	2087	Sierra Minit Mart #7	Tulare	1.28	Intermediate
N	1724	Simlov Enterprise LLC	Turlock	2.08	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	3335	Simonyan Enterprises Ii Inc.	Lindsay	2.48	Intermediate
N	1381	Simple Simon Mini-Mart	Dos Palos	0.51	Exempt/Low
C	1746	Six Star Chevron (Tanver Ahmad)	Madera	1.31	Intermediate
N	674	Sjrj Investment Inc.	Manteca	0.51	Exempt/Low
N	2891	Sksp Inc. Dba Modesto Chevron	Modesto	5.83	Intermediate
C	9581	Skypark Arco	Fresno	2.11	Intermediate
C	1240	Smart Place Inc.	Fresno	0.51	Exempt/Low
N	2178	Smart Stop Food Mart	Modesto	0.51	Exempt/Low
N	1383	Smiley's Shell	Merced	0.51	Exempt/Low
N	1376	Smiley's Shell	Merced	0.74	Exempt/Low
N	353	Smk Chevron (Harvinder Pal Singh)	Acampo	1.58	Intermediate
C	8736	Snack Market & Tobacco	Fresno	1.01	Intermediate
C	3772	Snappy Food	Fresno	0.65	Exempt/Low
S	3716	Snappy Food Store	Bakersfield	0.66	Exempt/Low
N	9386	Sng Hotels Inc.	Manteca	8.75	Intermediate
C	3477	Snl Corp	Fresno	0.51	Exempt/Low
N	345	Sohal #3	Stockton	2.83	Intermediate
N	2034	Spa Food Liquor & Gas	Modesto	0.51	Exempt/Low
N	1258	Spa Petroleum Inc.	Merced	4.38	Intermediate
S	2061	Sparkling Image Corp	Bakersfield	1.49	Intermediate
C	159	Spl Lidder Enterprise Inc.	Hanford	0.51	Exempt/Low
N	2182	Sport Stop	Waterford	1.11	Intermediate
C	9088	Square Deal Market	Corcoran	0.74	Exempt/Low
N	258	Srh Food & Gas Market	Stockton	0.90	Exempt/Low
C	797	Srp Real Estate Inc. (Dba Belmont Fuel St	Fresno	0.61	Exempt/Low
S	3285	Ssg Bakersfield Group Inc.	Bakersfield	2.13	Intermediate
S	905	Sssb Corp, Inc. Dba Verdugo Market 2	Bakersfield	0.51	Exempt/Low
S	1453	Sssb1 Corp Inc. Dba 76 Food Mart	Bakersfield	0.64	Exempt/Low
S	2631	Sssb2 Corp (Wasco Market)	Wasco	0.67	Exempt/Low
C	1591	Star #1	Selma	1.22	Intermediate
C	1195	Star 1 Mart	Parlier	1.23	Intermediate
C	3692	Star 7 Market	Kerman	0.51	Exempt/Low
N	1779	Star Convenience Inc.	Modesto	0.51	Exempt/Low
N	7167	Star Convenience Inc. Dba Quik Shop & Gas	Modesto	0.51	Exempt/Low
N	2071	Star Gas	Oakdale	0.51	Exempt/Low
N	981	Statewide Petroleum Inc.	Manteca	0.51	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	700	Sterling Hartel Developments 1, Inc.	Fresno	0.57	Exempt/Low
C	3306	Sterling Hartel Developments 1, Inc.	Fresno	1.04	Intermediate
S	3420	Stine Road Chevron	Bakersfield	0.71	Exempt/Low
S	2072	Stockdale Mobil	Bakersfield	1.05	Intermediate
S	4129	Stockdale Mobil #2	Bakersfield	7.29	Intermediate
S	4127	Stony Creek Village	Stony Creek	0.51	Exempt/Low
C	5721	Stop And Shop #2	Fresno	0.51	Exempt/Low
C	1148	Stop N Go	Fresno	0.51	Exempt/Low
C	8350	Stop N Go Chevron	Madera	1.00	Exempt/Low
N	2209	Stop N Save Liquors #1	Modesto	0.51	Exempt/Low
N	2203	Stop N Save Liquors #10	Modesto	0.51	Exempt/Low
N	2201	Stop N Save Liquors #2	Modesto	0.51	Exempt/Low
N	2208	Stop N Save Liquors #4	Turlock	0.51	Exempt/Low
N	2206	Stop N Save Liquors #5	Riverbank	0.51	Exempt/Low
N	2202	Stop N Save Liquors #6	Modesto	0.51	Exempt/Low
N	2207	Stop N Save Liquors #7	Modesto	0.51	Exempt/Low
N	2204	Stop N Save Liquors #8	Modesto	0.51	Exempt/Low
C	994	Stop Zone Inc.	Hanford	0.51	Exempt/Low
S	1044	Strathmore Handy Market	Strathmore	0.51	Exempt/Low
S	1069	Strathmore Liquor	Strathmore	0.51	Exempt/Low
S	1722	Stuart's Petroleum	Bakersfield	1.03	Intermediate
S	2431	Stuart's Petroleum	Bakersfield	1.13	Intermediate
S	2078	Sub Station (Sukhdev Singh)	Woodlake	1.04	Intermediate
S	2638	Success Market	Porterville	0.15	Exempt/Low
S	1049	Suhovy's Market	Strathmore	0.51	Exempt/Low
S	806	Sukhsanam Market	Bakersfield	0.51	Exempt/Low
S	246	Sullivan Petroleum Corp LLC	Bakersfield	1.44	Intermediate
S	9173	Sullivan Petroleum LLC	Bakersfield	8.75	Intermediate
S	6678	Sullivan's Petroleum LLC	Bakersfield	1.66	Intermediate
S	1218	Sultana Food Mart	Sultana	0.51	Exempt/Low
N	2257	Sungold Ventures LLC Dba Sungold Petrole	Modesto	8.75	Intermediate
S	2706	Sunlines Handy Market	Porterville	0.51	Exempt/Low
C	1740	Sunny Market & Liquor	Madera	0.51	Exempt/Low
N	3280	Sunny's Food Mart	Modesto	0.51	Exempt/Low
S	2096	Sunnyside Handy Market	Porterville	0.51	Exempt/Low
C	9423	Sunnyside Market	Fresno	1.31	Intermediate
C	1129	Sunnyside Sinclair	Fresno	0.55	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	154	Sunrise Handy Market (Nezam Kasis)	Porterville	0.61	Exempt/Low
C	875	Sunrise Mini Mart	Reedley	0.51	Exempt/Low
N	1736	Sunrise Retail Enterprises Inc.	Riverbank	3.41	Intermediate
C	2050	Sunshine Food Mart	Fresno	0.53	Exempt/Low
S	1045	Sunshine Handy Market	Porterville	0.51	Exempt/Low
C	1201	Super 1 Food Store	Fresno	0.51	Exempt/Low
S	2031	Super 7 Beer & Food Inc.	Porterville	0.51	Exempt/Low
S	2656	Super 7 Food Store #2 (Paramjit Kaur)	Tulare	0.67	Exempt/Low
C	465	Super Express (Marinder Singh)	Clovis	0.81	Exempt/Low
N	8769	Super Mac Food & Gas #2	Modesto	0.51	Exempt/Low
N	4438	Super Mac Food & Gas (Paramjit Singh)	Hilmar	0.54	Exempt/Low
C	8807	Super Mart Chevron	Caruthers	0.51	Exempt/Low
S	618	Super Stop #2	Kingsburg	0.51	Exempt/Low
N	4142	Super Stop Gas & Liquor	Manteca	0.67	Exempt/Low
S	3578	Super Stop Shopping Center	Tulare	0.51	Exempt/Low
C	733	Super-7	Fresno	0.51	Exempt/Low
N	3414	Super-A Gas & Food	Winton	0.51	Exempt/Low
N	1388	Superway Market	Planada	0.67	Exempt/Low
S	1006	Sw Retail Group Dba Sal's Food Mart	Dinuba	0.63	Exempt/Low
C	8520	Sws Fuel Inc. Dba Johnny Quick 007	Madera	1.52	Intermediate
N	4419	Synergy Petroleum 332 Inc.	Stockton	0.89	Exempt/Low
C	1212	T & A Mobil Mini-Mart	Hanford	0.51	Exempt/Low
C	1209	T & J Arco Mini Mart	Parlier	1.04	Intermediate
S	2069	T S Gas Inc.	Bakersfield	0.00	Exempt/Low
N	3058	Ta Operating LLC	Santa Nella	1.31	Intermediate
S	8614	Ta Operating LLC	Arvin	2.22	Intermediate
C	1792	Tackle Box	Madera	1.09	Intermediate
S	8993	Taft Enterprises Inc.	Bakersfield	0.36	Exempt/Low
S	3648	Taft Hwy Chevron	Bakersfield	1.18	Intermediate
S	2379	Taing Horizon Inc.	Bakersfield	0.62	Exempt/Low
C	1210	Take 10	Corcoran	1.21	Intermediate
N	9330	Tera Investments	Lodi	2.04	Intermediate
S	1029	Terra Bella Handy Market	Terra Bella	0.51	Exempt/Low
S	2189	Terry M & Michael J Bennett	Visalia	0.61	Exempt/Low
S	3706	Tesoro West Coast Co LLC #68225	Tulare	1.71	Intermediate
S	900	Tesoro West Coast Co LLC #68124	Delano	0.51	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	3561	Tesoro West Coast Co LLC #68126	Earlimart	1.21	Intermediate
C	3548	Tesoro West Coast Company LLC #68139	Fresno	1.44	Intermediate
N	3384	Tesoro West Coast Company LLC #68166	Modesto	1.13	Intermediate
N	1928	Tesoro West Coast Company LLC #68226	Turlock	0.85	Exempt/Low
N	751	Tesoro West Coast Company LLC #68150	Lockeford	1.60	Intermediate
N	95	Tesoro West Coast Company LLC #68151	Lodi	1.14	Intermediate
N	104	Tesoro West Coast Company LLC #68152	Lodi	0.82	Exempt/Low
N	1039	Tesoro West Coast Company LLC #68153	Lodi	1.57	Intermediate
N	903	Tesoro West Coast Company LLC #68154	Lodi	1.62	Intermediate
N	2265	Tesoro West Coast Company LLC #68163	Modesto	0.90	Exempt/Low
N	1854	Tesoro West Coast Company LLC #68164	Modesto	1.55	Intermediate
N	1859	Tesoro West Coast Company LLC #68165	Modesto	1.45	Intermediate
N	1860	Tesoro West Coast Company LLC #68177	Oakdale	1.42	Intermediate
N	3564	Tesoro West Coast Company LLC #68221	Stockton	1.49	Intermediate
C	1225	Texaco	Huron	0.51	Exempt/Low
S	3224	Tfc88 Inc. Dba Stockdale West Texaco	Bakersfield	2.17	Intermediate
S	8605	The Barn Delano	Delano	1.35	Intermediate
S	9077	The Barn Demaree	Visalia	0.94	Exempt/Low
S	1452	The Barn Ii	Bakersfield	1.18	Intermediate
S	2095	The Barn Iii	Bakersfield	0.78	Exempt/Low
C	1742	The Forks Resort	Bass Lake	1.63	Intermediate
N	1847	The Grewal Family Trust	Turlock	1.06	Intermediate
C	3006	The Last Stop	Sanger	1.04	Intermediate
S	1638	The Spot Food Mart #4	Bakersfield	5.83	Intermediate
S	4168	The Spot Food Mart Inc.	Bakersfield	5.83	Intermediate
S	487	Three Rivers Chevron	Three Rivers	0.51	Exempt/Low
S	2215	Three Rivers Market	Three Rivers	0.51	Exempt/Low
N	856	Tiki Lagun Partners LLC	Stockton	1.80	Intermediate
S	904	Tip Top Liquors	Bakersfield	0.51	Exempt/Low
S	2260	Tipton Chevron	Tipton	0.67	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	2241	Tj Food N Liquor (Eric S. Tang)	Fresno	0.73	Exempt/Low
C	735	Tj Grangeville Corporation	Lemoore	1.00	Exempt/Low
S	1572	Tmp Corp Dba Freeway Gas & Liquor	Bakersfield	0.51	Exempt/Low
S	2434	Tmp Corp Dba Niles Chevron	Bakersfield	0.70	Exempt/Low
N	8867	Todd Energy Corporation	Los Banos	4.22	Intermediate
C	2232	Tollhouse Market & Grill	Tollhouse	0.51	Exempt/Low
S	2720	Tomer And Sons Inc.	Bakersfield	0.51	Exempt/Low
C	4217	Tony's 1 Stop Shop	Fresno	0.68	Exempt/Low
C	3689	Tony's One Stop Arco/Manjit Kaur	Fresno	1.22	Intermediate
C	1245	Tower Gas & Mini Mart	Fresno	0.51	Exempt/Low
S	3811	Town & Country Market	Porterville	1.63	Intermediate
N	638	Tr Petro Inc. Dba Plaza Liquor #2	Lodi	0.58	Exempt/Low
N	8746	Tracy 76 - Reliance Gas Investments Inc.	Tracy	0.75	Exempt/Low
N	849	Tracy Market Inc.	Tracy	0.97	Exempt/Low
N	3970	Tracy Truck & Auto Stop	Tracy	1.74	Intermediate
S	1733	Travel Centers Of America	Buttonwillow	2.58	Intermediate
N	1317	Travel Centers Of America	Santa Nella	3.71	Intermediate
S	2629	Traver Market	Traver	1.55	Intermediate
S	143	Traver Valley Farms	Traver	0.55	Exempt/Low
C	1151	Tri-Mart	Hanford	0.67	Exempt/Low
N	1905	Triple R Gas And Mart	Waterford	0.51	Exempt/Low
S	2055	Trmc Retail LLC - Speedway No 1477	Mettler	0.23	Exempt/Low
S	2056	Trmc Retail LLC-Speedway No 1474 (Mobil)	Frazier Park	1.43	Intermediate
S	2057	Trmc Retail LLC-Speedway No 1475 (Mobil)	Bakersfield	1.27	Intermediate
S	1048	Trmc Retail-Speedway No 3051	Visalia	1.68	Intermediate
C	3793	Tulare Arco (Sai Roja Inc.)	Fresno	3.29	Intermediate
S	588	Tulare Mini Mart	Tulare	0.51	Exempt/Low
S	7037	Tulare Petroleum Inc.	Tulare	3.40	Intermediate
C	8333	Tule River Tribal Council Dba Feather Tr	Avenal	0.00	Exempt/Low
N	3062	Turlock Petroleum Inc.	Ceres	3.77	Intermediate
S	2050	Turna & Sons Group Inc.	Bakersfield	1.63	Intermediate
N	887	Turner Cut Resort & Marina Inc.	Stockton	1.31	Intermediate
N	4765	Tvain Group Inc.	Turlock	4.79	Intermediate
N	8212	Tvain Investments Financial Inc.	Turlock	2.13	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	889	Two Guys Food & Fuel	Lathrop	1.12	Intermediate
S	1035	Two Village Market	Visalia	0.51	Exempt/Low
C	8032	U And A Mini Mart Ii	Sanger	0.82	Exempt/Low
S	852	U S Mini Mart	Earlimart	0.51	Exempt/Low
N	3592	Union Point Resort, Inc.	Stockton	0.00	Exempt/Low
S	8981	Union Village	Bakersfield	0.85	Exempt/Low
C	3241	United Park Inc.	Chowchilla	0.04	Exempt/Low
C	791	Us Gas And Food	Fresno	0.59	Exempt/Low
S	2020	Usa Food And Deli, Inc.	Exeter	0.51	Exempt/Low
C	989	U-Save Liquor Market Inc.	Fresno	0.78	Exempt/Low
S	3533	V G Mini Market	Bakersfield	0.52	Exempt/Low
N	3949	V K Chevron	Modesto	1.30	Intermediate
C	78	Valero Mini Mart (Sukhdev S. Brar)	Firebaugh	0.61	Exempt/Low
C	2166	Vallee Food Store #2	Coarsegold	0.59	Exempt/Low
C	2774	Vallee Foods #17	Fresno	0.93	Exempt/Low
S	571	Valley Convenience Stores Inc.	Exeter	0.51	Exempt/Low
S	2077	Valley Convenience Stores Inc.	Tulare	0.51	Exempt/Low
C	7138	Valley Food Mart	Coalinga	0.51	Exempt/Low
S	9356	Valley Fuel Goshen Inc.	Visalia	1.36	Intermediate
S	1883	Valley Fuel Tipton, Inc.	Tipton	0.74	Exempt/Low
S	813	Valley Fuel Visalia, Inc.	Visalia	0.51	Exempt/Low
C	94	Valley Gas	Fresno	0.51	Exempt/Low
C	1208	Valley Gas	Orange Cove	0.51	Exempt/Low
C	84	Valley Gas And Mini Mart (Ajitpal Singh)	Fresno	0.67	Exempt/Low
C	1813	Valley Gas Food Mart	Coalinga	0.51	Exempt/Low
N	3968	Valley Pacific Petroleum Services Inc.	Lodi	0.51	Exempt/Low
N	4158	Valley Pacific Petroleum Services Inc.	Stockton	0.51	Exempt/Low
N	1973	Valley Pacific Petroleum Services Inc.	Riverbank	0.51	Exempt/Low
N	3560	Valley Pacific Petroleum Services Inc.	Stockton	0.51	Exempt/Low
S	308	Valley Pacific Petroleum Services Inc.	Woodlake	0.51	Exempt/Low
S	2255	Valley Pacific Petroleum Services Inc.	Visalia	0.51	Exempt/Low
N	3138	Valley Pacific Petroleum Services Inc.	Tracy	1.48	Intermediate
C	1165	Valli Gas & Car Wash	Sanger	0.51	Exempt/Low
N	1988	Valtoha Inc. Dba Patterson Chevron	Patterson	0.87	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	999	Van De Pol Enterprises, Inc.	Lodi	0.51	Exempt/Low
N	4163	Van De Pol Enterprises, Inc. Dba Gustine	Gustine	0.51	Exempt/Low
C	1710	Van De Pol Enterprises, Inc. Dba Madera P	Madera	1.29	Intermediate
N	1290	Van De Pol Enterprises, Inc. Dba Merced C	Merced	0.60	Exempt/Low
N	1303	Van De Pol Enterprises, Inc. Dba R Street	Merced	0.51	Exempt/Low
C	3188	Van De Pol Enterprises, Inc. Dba:Chowchil	Chowchilla	1.23	Intermediate
N	156	Van De Pol Enterprises, Inc.	Ripon	0.13	Exempt/Low
N	921	Vanco Truck & Auto Plaza	Stockton	1.48	Intermediate
S	1585	Van's Deli Mart	Delano	0.51	Exempt/Low
N	1816	Verpal Investments Inc. Dba Eagle Chevron	Modesto	0.70	Exempt/Low
N	483	Village West Marina	Stockton	0.41	Exempt/Low
N	3627	Vine Fuels Inc.	Salida	1.47	Intermediate
N	2280	Vintage Car Wash Inc.	Modesto	0.51	Exempt/Low
S	2165	Virk Petroleum Corp/Akal Travel Plaza	Delano	0.13	Exempt/Low
C	2109	Virk Properties Inc. Dba Johnny Quik #157	Fresno	1.14	Intermediate
S	2703	Visalia Liquor Inc.	Visalia	0.63	Exempt/Low
C	3826	Vons - A Safeway Company	Oakhurst	3.05	Intermediate
C	3763	Vons - A Safeway Company	Clovis	4.35	Intermediate
C	7971	Vucovich Inc. Dba Fresno Equipment Co	Five Points	4.30	Intermediate
C	2918	Wagner's Mammoth Pool Resorts	Logan Meadow	0.00	Exempt/Low
S	8911	Wainright Oil Corp	Lebec	1.02	Intermediate
C	9777	Walmart Inc.	Kerman	3.06	Intermediate
S	1574	Wardaa 1 LLC Dba Samco Rosedale #13	Bakersfield	0.93	Exempt/Low
S	2013	Wardaa Inc. Dba Samco Norris #9	Bakersfield	0.51	Exempt/Low
S	1841	Wasco Chevron	Wasco	5.83	Intermediate
S	6830	Wasco Mini Mart (Ahmed Ghassan Nagi)	Wasco	0.91	Exempt/Low
N	890	Waterloo Liquors	Stockton	0.55	Exempt/Low
S	2440	Weedpatch Chevron	Bakersfield	0.83	Exempt/Low
C	48	West & Shaw Kwik Serv	Fresno	1.00	Exempt/Low
C	2866	West Hill Oil, Inc.	Coalinga	0.13	Exempt/Low
C	7275	West Hills Oil Inc.	San Joaquin	0.51	Exempt/Low
C	3593	West Hills Oil, Inc.	Kettleman City	0.61	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	945	West Lane Fuels	Stockton	0.51	Exempt/Low
S	2269	West Tulare Food Mart	Tulare	1.00	Exempt/Low
N	5049	West Valley Auto Service, LLC	Tracy	9.48	Intermediate
N	936	Western Food And Fuel	Stockton	0.51	Exempt/Low
N	1817	Westley Beacon	Westley	0.73	Exempt/Low
C	3401	Westside Stations, Inc.	Mendota	1.43	Intermediate
S	8338	Wheeler Ridge Shell Station	Bakersfield	0.51	Exempt/Low
S	4247	White Lane Mobil & Circle K	Bakersfield	0.51	Exempt/Low
S	1654	White Lane Shell (Jeffrey Yam)	Bakersfield	1.60	Intermediate
N	1983	Whitmore Stations Inc.	Ceres	1.16	Intermediate
S	2035	Willie's Market (Balwinder Mehat)	Lindsay	0.64	Exempt/Low
N	3135	Windecker Inc.	Los Banos	0.51	Exempt/Low
N	9339	Windecker Property Development LLC	Los Banos	2.04	Intermediate
N	3900	Wine Country Sta/Gill Pandher Invest Inc.	Lodi	0.87	Exempt/Low
N	1232	Winton Petroleum Inc.	Winton	0.51	Exempt/Low
C	287	WKM Associates Inc.	Fresno	1.26	Intermediate
C	469	Woodward Village 76	Fresno	0.77	Exempt/Low
S	745	Xpress Gas 76	Bakersfield	1.11	Intermediate
S	3143	Xpress Mart	Bakersfield	0.00	Exempt/Low
S	1887	Xtra Mart	Exeter	0.51	Exempt/Low
S	3961	Yahalla Inc. Dba Samco #2	Bakersfield	1.00	Exempt/Low
S	2613	Yakoob Mohamed Dba Jack's Gas & Deli	Orosi	0.65	Exempt/Low
S	3672	Yakoob Nagib Saleh Mohamed Dba Jacks Gas	Visalia	1.14	Intermediate
N	4172	Yosemite & Creekwood Inc.	Modesto	1.06	Intermediate
N	73	Yosemite Avenue Arco Am/Pm	Manteca	1.55	Intermediate
C	1797	Zippy Mart #3	Madera	0.67	Exempt/Low

Table A2. Other Types of Facilities Prioritized in 2022

Region	Facility ID	Facility Name	City/County	Prioritization Score	Prioritization Category
N	717	A. Sambado & Son, Inc.	Linden	4.81	Intermediate
N	7488	Aemetis Advanced Fuels Keyes Inc.	Ceres	5.87	Intermediate
C	8901	Agroplantae Inc.	Fresno	0.05	Exempt/Low
N	4399	All Foreign & Domestic Body Shop	Stockton	0.46	Exempt/Low
C	3115	American Avenue Landfill	Kerman	5.03	Intermediate
N	9476	American Bedliners & Truck Accessories	Stockton	2.87	Intermediate
C	6923	Ampersand Chowchilla Biomass LLC	Chowchilla	123.00	High Priority
N	3021	Anh Auto Body & Paint	Stockton	0.30	Exempt/Low
S	8416	Aptco LLC	Delano	0.36	Exempt/Low
S	3012	Aptco LLC	McFarland	1.96	Intermediate
S	2273	Bakersfield City Wastewater #2	Bakersfield	0.50	Exempt/Low
S	3103	Bakersfield City Wastewater #3	Bakersfield	2.16	Intermediate
S	1246	Berry Petroleum Company LLC	Kern County	6.73	Intermediate
S	1328	Berry Petroleum Company LLC	McKittrick	6.73	Intermediate
S	3585	Berry Petroleum Company LLC	Kern County	8.98	Intermediate
S	2265	Berry Petroleum Company LLC	Kern County	6.73	Intermediate
S	8591	Bethlehem Construction	Wasco	0.04	Exempt/Low
S	3984	Bowman Asphalt Inc.	Bakersfield	48.60	High Priority
C	150	Browning Ferris Industries	Fresno	0.13	Exempt/Low
C	146	Browning Ferris Industries	Fresno	0.19	Exempt/Low
S	4214	Calgren Renewable Fuels	Pixley	9.27	Intermediate
C	216	California Air National Guard	Fresno	28.00	High Priority
C	218	California Army National Guard	Fresno	3.43	Intermediate
C	402	California Dairies, Inc.	Fresno	1.43	Intermediate
S	382	California Resources Elk Hills LLC	Kern County	8.83	Intermediate
S	1738	California Resources Production Corp	Kern County	8.83	Intermediate
N	370	California Resources Production Corp	Stockton	1.13	Intermediate
S	8454	California Resources Production Corp	Kern County	8.83	Intermediate
S	8282	California Resources Production Corp	Kern County	8.83	Intermediate
C	652	Calmat Dba Vulcan Materials Company	Sanger	9.43	Intermediate
S	1538	Calmat Of Central California	Bakersfield	0.78	Exempt/Low
C	283	Chemical Waste Management, Inc.	Kettleman City	0.50	Exempt/Low
S	49	Chevron USA Inc.	McKittrick	0.05	Exempt/Low
S	1423	Chevron USA Inc.	Kern County	0.00	Exempt/Low
C	311	Chevron USA Inc.	Fresno County	0.17	Exempt/Low
S	2010	Chevron USA Inc.	Kern County	3.40	Intermediate
S	55	Chevron USA Inc. Lost Hills GP	Lost Hills	0.11	Exempt/Low
C	3074	City Of Clovis - Landfill	Clovis	0.73	Exempt/Low
N	2073	Covanta Stanislaus, Inc.	Crows Landing	3.59	Intermediate

Region	Facility ID	Facility Name	City/County	Prioritization Score	Prioritization Category
S	6971	Crimson Renewable Energy LP	Bakersfield	0.00	Exempt/Low
N	3715	Custom Marble & Onyx	Modesto	0.15	Exempt/Low
S	1385	Delta Trading L P	Bakersfield	0.02	Exempt/Low
N	558	Diamond Pet Foods-Lathrop	Lathrop	7.52	Intermediate
C	3801	E & B Trucking Inc.	Hanford	0.16	Exempt/Low
C	1830	Foster Commodities	Kingsburg	0.21	Exempt/Low
C	535	Fresno/Clovis Regional WWTP	Fresno	0.88	Exempt/Low
N	1660	Gallo Cattle Company	Atwater	31.90	High Priority
N	964	George Reed Inc.	Clements	3.79	Intermediate
S	7858	Grade 6 Oil, LLC - KRH	Bakersfield	5.94	Intermediate
S	724	Grade 6 Oil, LLC - Western Power & Steam	Bakersfield	5.94	Intermediate
N	2898	Graham Packaging Pet Technologies Inc.	Modesto	0.02	Exempt/Low
N	366	Granite Construction	French Camp	2.85	Intermediate
S	1610	Granite Construction Co	Bakersfield	7.78	Intermediate
S	8650	Granite Construction Co	Bakersfield	1.19	Intermediate
C	9867	Granite Construction Company	Kingsburg	0.00	Exempt/Low
N	7888	Granite Construction Company	Tracy	5.21	Intermediate
C	590	Granite Construction, Coalinga	Coalinga	5.46	Intermediate
C	8706	Greens Best Bark And Mulch, Inc.	Reedley	3.48	Intermediate
N	6082	Grower Direct Nut Company	Hughson	2.33	Intermediate
N	2403	Hamamoto's Body Shop	Stockton	0.00	Exempt/Low
N	8237	Hernandez Auto Body And Paint	Stockton	0.32	Exempt/Low
N	408	Holz Rubber Company Inc.	Lodi	50.00	High Priority
N	767	J R Simplot Company	Lathrop	3.63	Intermediate
C	142	J R Simplot Co/Simplot Grower Solutions	Five Points	0.15	Exempt/Low
C	144	J R Simplot Co/Simplot Grower Solutions	Firebaugh	2.68	Intermediate
S	37	Kern Oil & Refining Co.	Bakersfield	21.30	High Priority
S	1768	Kw Plastics Of California	Bakersfield	0.17	Exempt/Low
N	2000	Lakewood Memorial Park	Hughson	2.73	Intermediate
S	1703	Macpherson Oil Co	Bakersfield	0.81	Exempt/Low
N	2943	Main Body Shop	Stockton	0.19	Exempt/Low
N	4607	Merced Power, LLC	El Nido	5.08	Intermediate
C	3608	Nutrien Ag Solutions	Firebaugh	0.03	Exempt/Low
N	593	Owens-Brockway Glass Container	Tracy	0.94	Exempt/Low
S	1336	Pacific Pipeline System LLC	Lebec	0.51	Exempt/Low
S	3636	Pastoria Energy Facility LLC	Lebec	1.51	Intermediate
S	4056	Pena's Disposal	Cutler	1.68	Intermediate
S	8448	Pixley Biogas LLC	Pixley	9.27	Intermediate
S	6534	Pixley Cogen Partners	Pixley	9.27	Intermediate
S	3277	R & R Resources LLC	Kern County	0.28	Exempt/Low
N	8844	Rivermaid Trading, Co.	Lodi	4.22	Intermediate
S	1688	Ruben's Auto Body LLC	Lamont	0.56	Exempt/Low
N	3317	San Francisco Autobody Frame	Stockton	0.05	Exempt/Low
N	1643	Select Harvest USA	Turlock	0.08	Intermediate

Region	Facility ID	Facility Name	City/County	Prioritization Score	Prioritization Category
S	1372	Sentinel Peak Resources Ca LLC	Kern County	4.09	Intermediate
N	2382	Steven Stein Enterprises, Inc.	Stockton	0.01	Exempt/Low
N	2199	Stewart & Jasper	Newman	5.44	Intermediate
S	8310	Sturgeon Service International	Various Locations	0.00	Exempt/Low
S	360	Synagro WWT, Inc.	Lost Hills	0.05	Exempt/Low
C	1244	Toro Petroleum Corp	Firebaugh	0.43	Exempt/Low
S	2783	Tuboscope/Rodco A Nov LP Co Bakersfield	Bakersfield	3.84	Intermediate
S	548	Tulare City Wastewater Plant	Tulare	1.04	Intermediate
N	7617	USA Waste Of California, Inc.	Lathrop	18.60	High Priority
N	1291	Van De Pol Enterprises, Dba Merced Bulk	Merced	1.68	Intermediate
C	1714	Van De Pol Enterprises, Inc. Dba: Madera	Madera	2.43	Intermediate
S	1896	Ventura Coastal LLC	Visalia	0.49	Exempt/Low
S	2426	Visalia City Airport Aviation	Visalia	1.64	Intermediate
S	189	Voltage Multipliers Inc.	Visalia	0.59	Exempt/Low

Table A3. Facilities with Health Risk Assessments Performed in 2022

Region	Facility ID	Facility Name	City	Cancer Score	Acute Score	Chronic Score	Risk Category
N	5136	4283929 Delaware LLC; Dba West Coast Pet	Lodi	0.28	0.24	0.14	Intermediate Risk
S	890	Caballero Operations LLC	Bakersfield	9.40	0.83	0.05	Intermediate Risk
C	9450	Costco Gasoline Loc #1360	Clovis	0.00	0.50	0.20	Intermediate Risk
N	4669	Costco Gasoline LOC #658	Tracy	0.80	0.30	0.00	Intermediate Risk
N	7776	Costco Wholesale	Manteca	2.10	0.30	0.00	Intermediate Risk
S	7067	Costco Wholesale	Visalia	3.00	0.40	0.10	Intermediate Risk
S	6654	Costco Wholesale	Bakersfield	7.20	0.30	0.10	Intermediate Risk
N	4744	Costco Wholesale Loc #38	Stockton	6.70	0.50	0.20	Intermediate Risk
S	3930	Costco Wholesale Corp Loc #688	Bakersfield	3.50	0.30	0.10	Intermediate Risk
N	4153	Costco Wholesale Loc #142	Merced	2.20	0.20	0.10	Intermediate Risk
N	5127	Costco Wholesale Loc #782	Turlock	3.50	0.90	0.10	Intermediate Risk
S	3523	Elk Hills Power LLC	Tupman	0.04	0.00	0.00	Exempt/Low Risk
C	1406	Foster Farms, Belgravia Plant	Fresno	7.44	0.31	0.06	Intermediate Risk
N	8533	Highway 59 Composting Facility	Merced	3.19	0.07	0.00	Intermediate Risk
N	3696	Highway 59 Landfill Site	Merced	0.34	0.02	0.00	Exempt/Low Risk
C	2106	Nas Lemoore	Lemoore	8.09	0.45	0.01	Intermediate Risk
C	1820	Rio Bravo Fresno	Fresno	1.18	0.00	0.00	Intermediate Risk
S	4254	Salser & Dillard Funeral Chapel	Visalia	2.87	0.12	0.12	Intermediate Risk
C	7405	Triangle Rock Products, LLC	Madera	1.79	0.16	0.06	Intermediate Risk
S	3729	Visalia Landfill	Visalia	0.08	0.01	0.00	Exempt/Low Risk
C	8476	Vulcan Materials Co	Fresno	5.36	0.12	0.03	Intermediate Risk

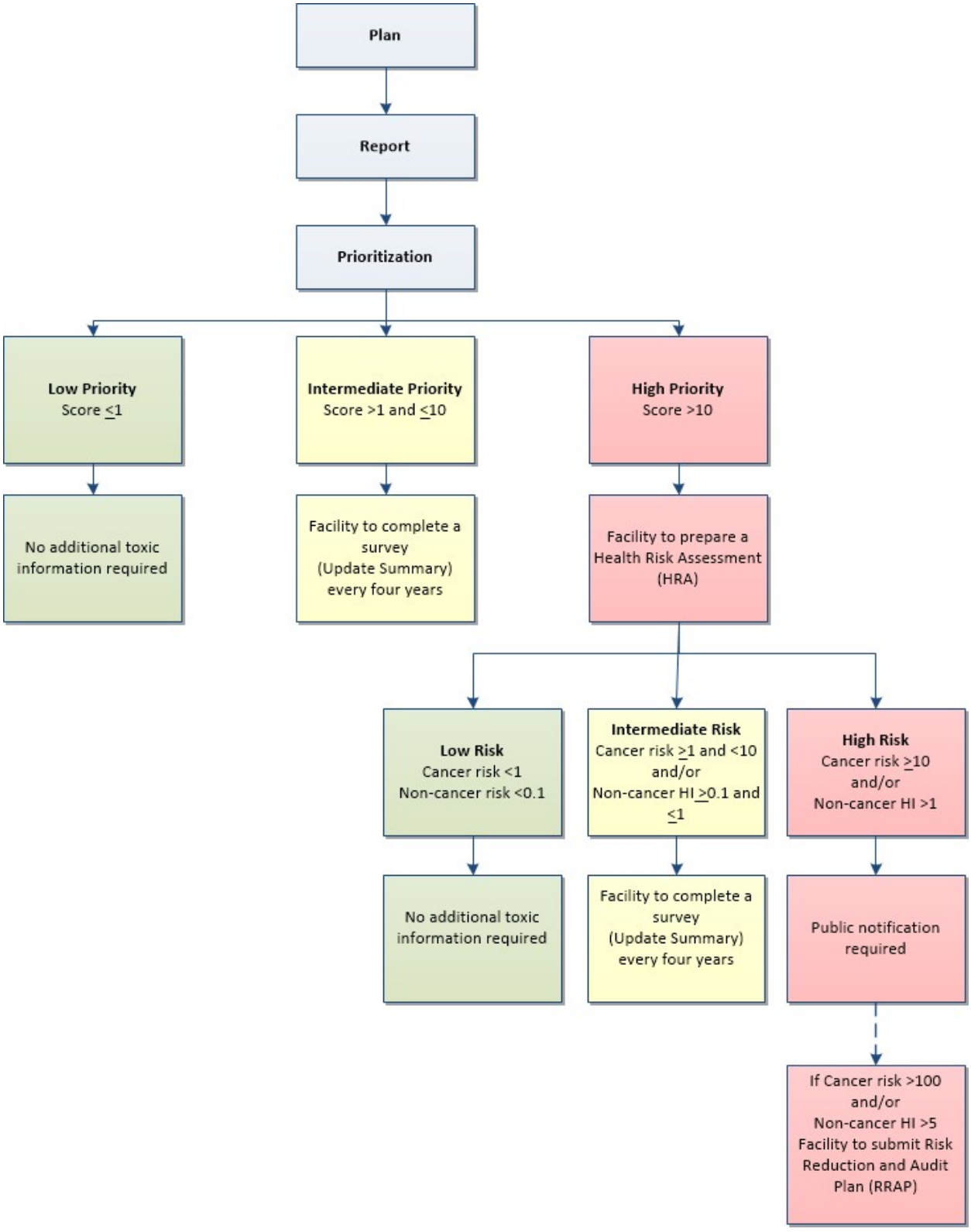
Appendix B. Toxics Emissions Summary

Emissions for eight counties of San Joaquin Valley from the latest California Air Resources Board California Toxics Inventory (CTI).

Table B1. Toxic Emissions Summary

Pollutant	CTI (tons/yr)
Acetaldehyde	3,512
Diesel Particulate Matter	2,520
Formaldehyde	2,318
Benzene	1,020
Perchloroethylene	448
1,3-Butadiene	269
Methylene Chloride	247
PAHs	238
Manganese	217
Acrolein	153
p-Dichlorobenzene	130
Styrene	96
Trichloroethylene	46
Chromium	34
Lead	28
Nickel	18
Acrylonitrile	7
Vinyl Chloride	7
Arsenic	5
Cadmium	3
Mercury	2
Chloroform	2
Ethylene Oxide	0
Ethylene Dichloride	0
Beryllium	0
Carbon Tetrachloride	0
Dioxins/Benzofurans	0
Chromium, Hexavalent	0

Appendix C. AB 2588 District Implementation Flow Chart



Appendix D. Current Status of NESHAP Delegation

National Emission Standards for Hazardous Air Pollutants (NESHAP) for which authority has been delegated to the District are included in District Rule 4002. This rule incorporates the NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (Table D.1), and the NESHAPs for Source Categories from Part 63, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (Table D.2).

Table D1. District Delegated NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, Code of Federal Regulations.

Subpart	Description
A	General Provisions
C	National Emission Standard for Beryllium
D	National Emission Standard for Beryllium Rocket Motor Firing
E	National Emission Standard for Mercury
F	National Emission Standard for Vinyl Chloride
J	National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene
L	National Emission Standard for Benzene Emissions from Coke By-Product Recovery Plants
M	National Emission Standard for Asbestos
N	National Emission Standard for Inorganic Arsenic Emissions from Glass Manufacturing Plants
O	National Emission Standard for Inorganic Arsenic Emissions from Primary Copper Smelters
P	National Emission Standard for Inorganic Arsenic Emissions from Arsenic Trioxide and Metallic Arsenic Production Facilities
V	National Emission Standard for Equipment Leaks (Fugitive Emission Sources)
Y	National Emission Standard for Benzene Emissions from Benzene Storage Vessels
BB	National Emission Standard for Benzene Emissions from Benzene Transfer Operations
FF	National Emission Standard for Benzene Waste Operations

Table D2. District Delegated NESHAPs from Part 63, Chapter I, Subchapter C, Title 40, Code of Federal Regulations.

Subpart	Description
A	General Provisions
F-I	National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry
J	National Emission Standards for Hazardous Air Pollutants from Polyvinyl Chloride and Copolymers Production
L	National Emission Standards for Coke Oven Batteries
R	National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)
S	National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry
T	National Emission Standards for Halogenated Solvent Cleaning (except §63.462 - Batch cold cleaning machine standards)
U	National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins
W	National Emission Standards for Hazardous Air Pollutants for Epoxy Resins Production and Non-Nylon Polyamides Production
X	National Emission Standards for Hazardous Air Pollutants from Secondary Lead Smelting
Y	National Emission Standards for Marine Tank Vessel Loading Operations AA National Emission Standards for Hazardous Air Pollutants From Phosphoric Acid Manufacturing Plants
BB	National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants
CC	National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries
DD	National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations
EE	National Emission Standards for Magnetic Tape Manufacturing Operations
GG	National Emission Standards for Aerospace Manufacturing and Rework Facilities
HH	National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities
II	National Emission Standards for Shipbuilding and Ship Repair (Surface Coating)
JJ	National Emission Standards for Wood Furniture Manufacturing Operations
KK	National Emission Standards for the Printing and Publishing Industry
LL	National Emission Standards for Hazardous Air Pollutants for Primary Aluminum Reduction Plants
MM	National Emission Standards for Hazardous Air Pollutants from Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills
YY	National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology (Generic MACT)
CCC	National Emission Standards for Hazardous Air Pollutants for Steel Pickling--HCl Process Facilities and Hydrochloric Acid Regeneration Plants
DDD	National Emission Standards for Hazardous Air Pollutants for Mineral Wool Production
GGG	National Emission Standards for Hazardous Air Pollutants from Pharmaceutical Production
HHH	National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities
III	National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production
JJJ	National Emission Standards for Hazardous Air Pollutant Emissions: Group IV Polymers and Resins
LLL	National Emission Standards for Hazardous Air Pollutants for Source Categories;

Subpart	Description
	Portland Cement Manufacturing Industry
MMM	National Emission Standards for Hazardous Air Pollutants: Pesticide Active Ingredient Production
NNN	National Emission Standards for Hazardous Air Pollutants for Source Categories; Wool Fiberglass Manufacturing
OOO	National Emission Standards for Hazardous Air Pollutant Emissions: Manufacture of Amino/Phenolic Resins
PPP	National Emission Standards for Hazardous Air Pollutants for Polyether Polyols Production
QQQ	National Emission Standards for Hazardous Air Pollutants from Primary Copper Smelting
RRR	National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production
TTT	National Emission Standards for Hazardous Air Pollutants for Primary Lead Smelting
UUU	National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
VVV	National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works
XXX	National Emission Standards for Hazardous Air Pollutants for Ferroalloys Production: Ferromanganese and Silicomanganese
AAAA	National Emission Standards for Hazardous Air Pollutants from Municipal Solid Waste Landfills
CCCC	National Emission Standards for Hazardous Air Pollutants from Manufacturing of Nutritional Yeast
EEEE	National Emission Standards for Hazardous Air Pollutants from Organic Liquids Distribution (Non-Gasoline)
FFFF	National Emission Standards for Hazardous Air Pollutants from Miscellaneous Organic Chemical Manufacturing
GGGG	National Emission Standards for Hazardous Air Pollutants from Solvent Extraction for Vegetable Oil Production
HHHH	National Emission Standards for Hazardous Air Pollutants from Wet- Formed Fiberglass Mat Production
JJJJ	National Emission Standards for Hazardous Air Pollutants from Paper and Other Web Coating
KKKK	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Metal Cans
MMMM	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Miscellaneous Metal Parts and Products
NNNN	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Large Appliances
OOOO	National Emission Standards for Hazardous Air Pollutants from Printing, Coating, and Dyeing of Fabrics and Other Textiles
PPPP	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Plastic Parts and Products
QQQQ	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Wood Building Products
RRRR	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Metal Furniture
SSSS	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Metal Coil
TTTT	National Emission Standards for Hazardous Air Pollutants from Leather Finishing Operations
UUUU	National Emission Standards for Hazardous Air Pollutants from Cellulose Products

Subpart	Description
	Manufacturing
VVVV	National Emission Standards for Hazardous Air Pollutants from Boat Manufacturing
WWWW	National Emission Standards for Hazardous Air Pollutants from Reinforced Plastic Composites Production
XXXX	National Emission Standards for Hazardous Air Pollutants from f Rubber Tire Manufacturing
YYYY	National Emission Standards for Hazardous Air Pollutants from Stationary Combustion Turbines
AAAAA	National Emission Standards for Hazardous Air Pollutants from Lime Manufacturing Plants
BBBBB	National Emission Standards for Hazardous Air Pollutants from Semiconductor Manufacturing
CCCCC	National Emission Standards for Hazardous Air Pollutants from Coke Ovens: Pushing, Quenching, and Battery Stacks
EEEEE	National Emission Standards for Hazardous Air Pollutants from Iron and Steel Foundries
FFFFF	National Emission Standards for Hazardous Air Pollutants from Integrated Iron and Steel Manufacturing
GGGGG	National Emission Standards for Hazardous Air Pollutants from Site Remediation
HHHHH	National Emission Standards for Hazardous Air Pollutants from Miscellaneous Coating Manufacturing
IIIII	National Emission Standards for Hazardous Air Pollutants from Mercury Emissions from Mercury Cell Chlor-Alkali Plants
JJJJJ	National Emission Standards for Hazardous Air Pollutants from Brick and Structural Clay Products Manufacturing
KKKKK	National Emission Standards for Hazardous Air Pollutants from Clay Ceramics Manufacturing
LLLLL	National Emission Standards for Hazardous Air Pollutants from Asphalt Processing and Asphalt Roofing Manufacturing
MMMM M	National Emission Standards for Hazardous Air Pollutants from Flexible Polyurethane Foam Fabrication Operations
PPPPP	National Emission Standards for Hazardous Air Pollutants from Engine Test Cells/Stands
QQQQQ	National Emission Standards for Hazardous Air Pollutants from Friction Materials Manufacturing Facilities
RRRRR	National Emission Standards for Hazardous Air Pollutants from Taconite Iron Ore Processing
SSSSS	National Emission Standards for Hazardous Air Pollutants from Refractory Products Manufacturing
TTTTT	National Emission Standards for Hazardous Air Pollutants from Primary Magnesium Refining

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

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Vacant
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Air Pollution Control Officer

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Bakersfield, CA 93301-2373
(661) 326-6900 • FAX (661) 326-6985

www.valleyair.org

DATE: June 19, 2008

TO: SJVUAPCD Governing Board

FROM: Seyed Sadredin, Executive Director/APCO
Project Coordinator: Arnaud Marjollet

RE: RECEIVE AND FILE THE "2008 ANNUAL REPORT ON THE DISTRICT'S INDIRECT SOURCE REVIEW PROGRAM"

RECOMMENDATION:

Receive and file the "2008 Annual Report on the District's Indirect Source Review Program" (see attachment A).

BACKGROUND:

District Rule 9510, Indirect Source Review (ISR), was adopted by the District's Board to reduce the impacts of growth in emissions resulting from new land development in the San Joaquin Valley. The rule's intent, requirements, and administrative procedures are generally described in this report, which was prepared pursuant to Rule 9510 to describe emission reductions achieved and mitigation fees received through implementation of the ISR program.

DISCUSSION:

District Rule 9510 applies to new development projects that emit emissions of at least two tons of nitrogen oxides (NOx) or two tons of particulate matter smaller than ten microns in aerodynamic diameter (PM10) per year.

Developers of projects subject to Rule 9510 must reduce emissions occurring during construction and operational phases, or pay specified mitigation fees. To minimize emissions and to minimize the applicable mitigation fee, developers have begun voluntarily incorporating many air-friendly design changes into their proposals.

For instance, significant reductions in emissions have been generated via the use of cleaner construction equipment. For large distribution centers, proponents have voluntarily proposed to use cleaner truck fleets. In addition, many lesser but still cumulatively significant reductions in emissions have been garnered by a whole range of effective design principles, like installation of solar power, integrated mixed-use development design, bike lanes, high-efficiency housing design, and many others.

If a developer does not achieve the sufficient emission reductions through onsite measures, the rule provides a mechanism by which the developer can pay an offsite mitigation fee to the District. One hundred percent of all offsite mitigation fees received by the District are to be used by the District's existing Emission Reduction Incentive Program (ERIP) to fund emission reduction projects, achieving emission reductions in behalf of the project. Additionally, if a project is subject to off-site emission reduction fees, the developer is required to pay an administrative fee equal to four percent (4%) of the required off-site fees. This fee is to cover the District's cost of administering the off-site emission reduction program.

Section III of this year's report summarizes District Implementation of Rule 9510 and Section IV summarizes funds received and expended, emission reductions realized, and overall cost-effectiveness of funded projects. Appendix A of the report provides a list of all emission reduction projects funded by the ISR program.

Attachment
2008 Annual Report on the District's Indirect Source Review Program (13 pages)

San Joaquin Valley Air Pollution Control District
Meeting of the Governing Board
June 19, 2008

RECEIVE AND FILE THE "2008 ANNUAL REPORT ON THE DISTRICT'S INDIRECT SOURCE REVIEW PROGRAM"

Attachment:
2008 Annual Report on the District's Indirect Source Review Program
(12 pages)

The above attachment has been included with the agenda packets distributed to members of the Governing Board. It has not been included with other agenda packets. A copy of this document is available for review and/or purchase from the San Joaquin Valley Unified Air Pollution Control District.



San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

2008 Annual Report on the District's Indirect Source Review Program

Reporting Period: March 1, 2007 to February 29, 2008

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT GOVERNING BOARD
2008 Annual Report on the District's Indirect Source Review Program

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Supervisor, Tulare County

EXECUTIVE DIRECTOR / AIR POLLUTION CONTROL OFFICER

SEYED SADREDIN

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I. EXECUTIVE SUMMARY

This *"2008 Annual Report on the District's Indirect Source Review Program"* was prepared by the San Joaquin Valley Unified Air Pollution Control District. District Rule 9510, Indirect Source Review (ISR), was adopted by the District's Governing Board to reduce the impacts of growth in emissions resulting from new land development in the San Joaquin Valley. The rule's intent, requirements, and administrative procedures are described in this report, as are the emission reductions achieved and mitigation fees received during 2007-2008 through implementation of the ISR program.

District Rule 9510 applies to new development projects that emit emissions of at least two tons of nitrogen oxides (NOx) or two tons of particulate matter smaller than ten microns in aerodynamic diameter (PM10) per year. The rule contains provisions exempting traditional stationary source projects that are subject to the District's stationary source permitting requirements.

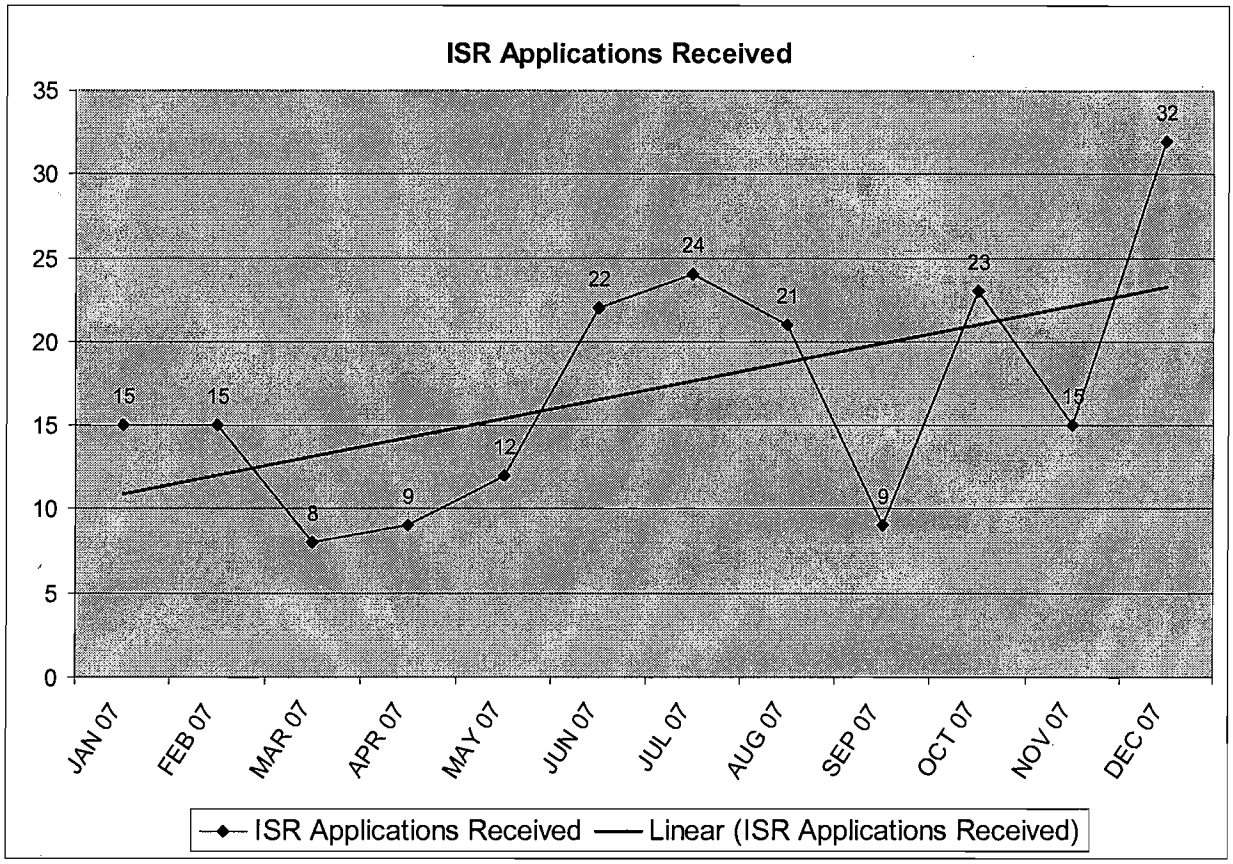
Developers of projects subject to Rule 9510 must reduce emissions occurring during construction and operational phases, or pay specified mitigation fees. To minimize emissions and to minimize the applicable mitigation fee, developers have begun voluntarily incorporating many air-friendly design changes into their proposals. For instance, significant reductions in emissions have been generated via the use of cleaner construction equipment. For large distribution centers, proponents have voluntarily proposed to use cleaner truck fleets. In addition, many lesser but still cumulatively significant reductions in emissions have been garnered by a whole range of effective design principles, like installation of solar power, integrated mixed-use development design, bike lanes, high-efficiency housing design, and many others.

If a developer cannot achieve the required emission reductions through onsite measures, the rule provides a mechanism by which the developer can pay an offsite mitigation fee to the District. One hundred percent of all offsite mitigation fees received by the District are to be used by the District's existing Emission Reduction Incentive Program (ERIP) to fund emission reduction projects, achieving emission reductions in behalf of the project. Additionally, if a project is subject to off-site emission reduction fees, the developer is required to pay an administrative fee equal to four percent (4%) of the required off-site fees. This fee is to cover the District's cost of administering the off-site emission reduction program.

Despite legal challenges[1] and slowed growth in the building industry, especially in the residential development sector, the ISR program had considerable success during this reporting period. As compared with the 2006-2007 reporting period, the ISR program experienced a 46% increase in Air Impact Assessment (AIA) applications received (194 applications received this year versus 133 last year) and a 244% increase in payment of

[1] On June 27, 2006 a lawsuit was filed by various building industries challenging the validity of District Rule 9510. On March 25, 2008 the Fresno County Superior Court ruled in favor of the District on all accounts. An appeal of that decision was filed May 22, 2008. There is a companion case pending in Federal Court which claims District Rule 9510 is preempted by federal tailpipe control standards. Initial indications of the outcome of this case may become apparent in the fall of 2008.

off-site mitigation fees ($5,716,032 received this year compared to $1,660,072 last year).



This increase continued throughout the year, as seen by the graph above, and is attributable to major efforts in District outreach and implementation of measures to improve linkages between the ISR program and District Compliance functions. Outreach included coordinating and holding multiple meetings with key planning agency staff throughout the San Joaquin Valley, conducting public workshops on how to comply with ISR and providing land use agencies training on the use of URBEMIS.

For the 2007-2008 ISR annual reporting period, the District's ISR accounts held a beginning balance of $5,090,869. During this reporting period, the District received off-site mitigation fees totaling $5,392,453 resulting in a grand total of $10,483,322 in off-site mitigation fees. The District funded off-site emission reduction projects totaling $3,125,191, leaving an unexpended balance of $7,358,131.

Implementation of District Rule 9510 resulted in projected combined on-site and off-site emission reductions totaling 2,078 tons of nitrogen oxides (NOx) and 1,087 tons of fine particulate matter (PM10). Off-site emission reduction projects funded by the ISR program achieved emission reductions representing 252 of NOx and 9 tons of PM10, with an average cost effectiveness of $11,928 per ton of reduced emissions.

II. INTRODUCTION

The District's population increased by 22% between 1990 and 2000, and California's Department of Finance has projected that the San Joaquin Valley Air Basin (SJVAB) will experience an overall increase in population of 24% between 2000 and 2010, and an additional 26% increase between 2010 and 2020. Population growth results in increased area source emissions from activities such as increased consumer product use, fuel combustion, and landscape maintenance. Additionally, the total number of vehicle miles traveled (VMT) increases at an even faster rate than the population growth rate. The District experienced a 9% increase in VMT in just three years, between 1999 and 2002, and we expect to see an additional 27% increase in VMT from 2002 to 2010.

The projected growth in these so called "indirect source" emissions erodes the benefits of emission reductions achieved through the District's stationary source program and the state and federal mobile source controls. The District has longstanding statutory authority to regulate indirect sources of air pollution. Pursuant to this authority, the District made a federally enforceable commitment to regulate indirect sources when it adopted its PM10 Attainment Plan in June 2003. Subsequently, the California State Legislature passed Senate Bill 709, Florez, in the fall of 2003, which Governor Gray Davis subsequently signed and codified into the Health and Safety Code in §40604. This additional legislation required the District to adopt, by regulation, a schedule of fees to be assessed on area wide or indirect sources of emissions that are regulated by the District.

District Rule 9510 (Indirect Source Review) was adopted by the District's Board on December 15, 2005, and became effective March 1, 2006. Rule 9510 was adopted by the District's Board to reduce the impacts of growth in emissions resulting from new land development in the San Joaquin Valley. Although the rule does not directly regulate VMT, it is designed to regulate the air impacts associated with new development. Rule 9510 applies to residential and non-residential development projects, including transportation and transit projects, which equal or exceed established applicability thresholds. Rule 9510 establishes emission reduction requirements for NOx and PM10 pollutants. Emission reductions required by the rule that are not achieved through on-site emission reduction measures are subject to off-site emission reduction fees. These fees are used by the District to fund emission reduction projects, mitigating the project's potential impact on air quality in the SJVAB.

This report was prepared pursuant to provisions of Rule 9510 that require the District to prepare an annual report regarding expenditure of received funds and achieved emission reductions. Pursuant to Rule 9520, Section 10.4, the annual report should include the following:

- Total amount of Off-Site Fees received;
- Total monies spent;
- Total monies remaining;
- Any refunds distributed;
- A list of all projects funded;

- Total emissions reductions realized; and
- The overall cost-effectiveness factor for the projects funded.

III. IMPLEMENTATION

District Rule 9510 (Indirect Source Review)

District Rule 9510 applies to new development projects that emit emissions of at least two tons of NOx or two tons of PM10 per year. Developers of projects subject to Rule 9510 are required to reduce emissions occurring during construction and operational phases. During construction, exhaust emissions of NOx and PM10 are to be reduced by 20% and 45% respectively, compared to the statewide average for construction equipment. Construction exhaust emissions can be reduced through installation and use of aftermarket devices, and through use of construction equipment that is newer than the statewide average. Operational emissions of NOx and PM10 are to be reduced by 33.3% and 50%, respectively, of the project's baseline for 10 years.

Operational emissions can be reduced by incorporating design elements that reduce onsite emissions, and the District has seen some very positive clean-air technologies and techniques employed by developers to reduce indirect emissions. For instance, significant reductions in emissions have been generated via the use of cleaner construction equipment. For large distribution centers, proponents have voluntarily proposed to use cleaner truck fleets. In addition, many lesser but still cumulatively significant reductions in emissions have been garnered by a whole range of effective design principles, like installation of solar power, integrated mixed-use development design, bike lanes, high-efficiency housing design, and many others.

If, after implementing such onsite measures, a developer cannot achieve the required emission reductions, the rule provides a mechanism by which the developer can pay an offsite mitigation fee to the District. One hundred percent of all offsite mitigation fees received by the District are to be used by the District's existing Emission Reduction Incentive Program (ERIP) to fund emission reduction projects, achieving emission reductions on behalf of the project. To recover the District's costs for administering the requirements of Rule 9510, the District's Board adopted Rule 3180 (Administrative Fees for Indirect Source Review). Provisions of Rule 3180 establish an application filing fee structure of $432 for residential and $648 for non-residential projects. Additionally, if a project is subject to off-site emission reduction fees, the developer is required to pay an administrative fee equal to four percent (4%) of the required off-site fees. This fee is to cover the District's cost of administering the off-site emission reduction program.

Development Mitigation Contracts

A Development Mitigation Contract (DMC) is an air quality mitigation measure by which a developer voluntarily enters into a contractual agreement with the District to reduce a development project's impact on air quality beyond that achieved by compliance with District Rule 9510. By fully mitigating the project's impact on air quality, a developer

can address one of the issues that have led to California Environmental Quality Act (CEQA) legal challenges to development projects within the SJVAB.

Implementation of a DMC is complementary to ISR; project emissions are characterized, mitigation funds are paid to the District, the District administers the funds to secure the required emission reduction projects. A prerequisite for the District to enter into a DMC is that the DMC will exceed the air quality benefits achieved by compliance with Rule 9510. Therefore, developers who enter into a DMC are considered in compliance with District Rule 9510. This report therefore includes revenues and emission reductions resulting from DMCs. During this reporting period, the District received no new off-site mitigation fees from development mitigation contracts. However, DMC funds carried forward from the previous reporting period were used to fund off-site emission reduction projects.

IV. 2007–2008 ANALYSIS

Table -1: Summary of ISR Program for 2007 to 2008

		Total ISR Program
Beginning Balance	**$**	**5,090,869**
Total Application Fees Received	$	115,869
Total Administrative Fees Received	$	207,710
Total Amount Off-Site Fees Received	$	5,392,453
Total Fees Received	$	5,716,032
Grand Total of Available Off-Site Fees	**$**	**10,483,322**
Total Amount Spent (Contracted)	**$**	**3,125,191**
Total Balance of Available Off-Site Fees	$	7,358,131
Total Amount Refunded	$	0
Grant Total Balance of Available Off-Site Fees	**$**	**7,358,131**

		NOx	*PM10*	*Total*
Total Off-Site Achieved Emission Reductions	***Tons***	251.56	9.09	**260.65**
Emission Reductions Cost Effectiveness *(average based on projects funded)*	*$/Ton*			**11,928**
Total ON-SITE Projected Emission Reductions	*Tons*	1,009.61	305.20	**1,314.81**
Total OFF-SITE Projected Emission Reductions	*Tons*	1,067.91	781.78	**1,849.69**
Total Projected Emission Reductions	***Tons***	2,077.52	1,086.78	**3,164.50**

Total Application Fees Received

District Rule 3180 (Administrative Fees for Indirect Source Review) establishes application fees of $432 and $648 respectively for non-residential ISR applications. The District may also charge for additional staff time required to process an application. As presented in Table-1, the District received application fees totaling $115,869.

Total Administrative Fees Received

District Rule 3180 (Administrative Fees for Indirect Source Review) establishes a four percent (4%) administrative fee to cover the District's costs of operating an off-site emissions reduction program. As presented in Table-1, the District received administrative fees totaling $207,710.

Total Amount of Off-site Fees Received

Provisions within Rule 9510 allow applicants to defer payment of off-site mitigation fees. The payment schedule must provide assurance that reductions from off-site emission reduction projects can be obtained reasonably contemporaneous with emission increases associated with the project. As presented in Table-1, the District received off-site fees totaling $5,392,453. This total does not include fees that have been deferred, nor does it include payments that have been invoiced, but not yet received. As compared to $1,543,697 presented in last year's annual report, this represents a 249% increase in off-site fees received by the District.

A balance of $5,090,869 in off-site mitigation fees was carried forward from the previous reporting period, resulting in $10,483,322 available to fund off-site mitigation projects. Please note that last year's annual report showed a remaining off-site mitigation fee balance of $3,368,308. This amount included $1,722,561 representing funds which had been committed to projects, but not contracted at the time of the annual report.

Total Expenditure of Off-site Fees Received

The District uses off-site fees to fund quantifiable and enforceable off-site emission reduction projects, reducing surplus emissions of NOx and PM10. With the exception of $131,000 voluntarily released by a developer, expenditure of off-site mitigation fees has been limited to fees collected through Development Mitigation Contracts. Of the $131,000 that was available to the District, an emissions reduction project representing $31,000 was funded, and the balance of $100,000 is currently contracted and will be reported in the next year ISR Annual Report.

As presented in Table-1, funds totaling of $3,125,191 were dispersed during this reporting period, leaving a balance of $7,358,131.

Total Emission Reductions Realized

The District funded 25 emission reduction projects for a total of 81 emission sources. These projects consisted primarily of re-powering various type of diesel powered industrial portable equipment such as top grinder, oil drill rig, plastic granulator and agricultural irrigation pumps, with either cleaner diesel engines or by conversion to electric motors. The projects funded achieved total emission reductions of 252 tons of NOx and 9 tons of PM10, with a total of 261 tons combined. The same projects also reduced emissions of Reactive Organic Gases (ROG) by 31 tons. A complete list of all projects funded is presented in Appendix B.

Projected Emission Reductions

Projected emission reductions are a combination of emission reductions to be achieved in the future through implementation of design elements at full project build out and through funding off-site emission reductions projects, using off-site mitigation fees.

For this reporting period, implementation of District Rule 9510 resulted in combined projected on-site and off-site emission reductions totaling 2,078 tons of NOx and 1,087 tons of PM10.

Overall Cost-effectiveness of Funded Projects

Average overall cost-effectiveness is calculated based on total tons of emissions reduced, NOx plus PM10, divided by total funds spent. During this reporting period, the District achieved emission reductions totaling 261 tons and expended funds totaling $3,125,191. As presented in Table-1, average cost-effectiveness is calculated to be $11,928 dollars per ton. This represents a 7% increase, as compared to last year's cost-effectiveness of $11,133 dollars per ton. The District anticipates that cost effectiveness will continue to increase as the most cost-effective projects are funded first.

Appendix A - List of all emission reduction projects funded by the ISR program

APPENDIX A

List of all emission reduction projects funded by the ISR program

EMISSION REDUCTIONS PROJECTS
ISR Annual Report / March 2007 – Feb 2008

Project Name	Date Rec'd	Date Executed	Executed Contract Amount	Amount Paid	Amount UnPaid	Balance	Status	Count Installed	Count Projected	Project Type	Nox Tons	PM10 Tons	ROG Tons
VERA													
Old River Ranch		18-May-07	$25,000	$21,992	$0	$3,008	Closed	1		AG Engine	1.70	0.06	0.21
Old River Ranch		10-Apr-07	$115,567	$0	$115,567	$0	Outstanding		6	AG Engine	1.98	-0.06	0
Old River Ranch		21-Mar-07	$90,000	$90,000	$0	$0	Closed	3		AG Engine	3.15	0.07	0.31
Old River Ranch		30-Apr-07	$22,278	$19,789	$0	$2,489	Closed	1		AG Engine	1.91	0.07	0.26
Old River Ranch		23-Apr-07	$82,719	$82,719	$0	$0	Closed	3		AG Engine	8.52	0.33	1.08
Old River Ranch		23-Apr-07	$20,000	$20,000	$0	$0	Closed	1		AG Engine	1.19	0.01	0.09
Old River Ranch		16-Apr-07	$30,000	$30,000	$0	$0	Closed	2		AG Engine	1.48	0.08	0.26
	Dec-08		**$385,564**	**$264,500**	**$115,567**	**$5,497**		**11**	**6**		**19.93**	**0.56**	**2.21**
Lennar Communities	Feb-08	26-Sep-07	**$16,496**	**$14,920**	**$0**	**$1,576**	**Closed**	**1**		Ag Engine	**1.07**	**0**	**0.18**
Castle & Cooke/ West Ming	May-08	14-Nov-07	**$131,128**	**$131,128**	**$0**	**$0**	**Closed**	**3**		Off Road - Portable Grain Grinders, Pellet Mill Equipment	**36.34**	**1.3**	**4.37**
Castle & Cooke/ Gateway Village		31-May-07	$1,232,390	$484,073			Closed	12		Ag Engine	41.84	1.46	5.42
Castle & Cooke/ Gateway Village					$748,317		Outstanding		8		18.84	0.65	2.39
	Oct-08		**$1,232,390**	**$484,073**	**$748,317**	**$0**		**12**	**8**		**60.68**	**2.11**	**7.81**
Panama 99 Prop. LLC/HWY 99		04-Apr-07	$151,421	$79,985			Closed	2		Off Road - Air Compressors, Drill Units Hydraulic Drill Equipment	4.35	0.16	0.54
Panama 99 Prop. LLC/HWY 99					$71,436		Outstanding		2		6.25	0.26	0.83
Panama 99 Prop. LLC/HWY 99		25-Jun-07	$103,274		$103,274		Outstanding		3	Off Road - Drill Service Pumps	8.26	0.35	1.07
Panama 99 Prop. LLC/HWY 99		19-Jun-07	$41,192	$39,368	$0		Closed	1		Ag Engine	4.48	0.15	0.51
Panama 99 Prop. LLC/HWY 99		14-Nov-07	$47,705	$47,705	$0		Closed	1		Off-Road - Portable Grain Equipment	12.29	0.41	1.42
	Oct-08		**$343,592**	**$167,058**	**$174,710**	**$1,824**		**4**	**5**		**35.63**	**1.33**	**4.37**
Castle & Cooke /Stockdale Ranch		11-Jun-07	$49,428	$49,428	$0	$0	Closed	1		Off Road - Plastic Granulator	4.70	0.17	0.52
Castle & Cooke /Stockdale Ranch		31-May-07	$100,987	$100,987	$0	$0	Closed	3		Off Road - Sprayer	5.22	0.18	0.6
Castle & Cooke /Stockdale Ranch		19-Jun-07	$67,025	$67,025	$0	$0	Closed	3		Off Road - Hydraulic Power Pack	6.38	0.27	0.94
Castle & Cooke /Stockdale Ranch		31-May-07	$48,394	$48,394	$0	$0	Closed	1		Off Road - Pump Engine	3.00	0.10	0.34
Castle & Cooke /Stockdale Ranch		20-Aug-07	$27,910	$0	$27,910	$0	Outstanding		1	Off Road - Drill Rig	1.10	0.05	0.15
Castle & Cooke /Stockdale Ranch		31-May-07	$275,651	$217,842	$0	$57,809	Closed	7		Off Road - Generator, Mud Pump, Drill Rig, Draw Work	24.28	0.91	2.96
Castle & Cooke /Stockdale Ranch				$0	$57,809	($57,809)	Outstanding		1		15.88	0.53	1.82
Castle & Cooke /Stockdale Ranch		31-May-07	$140,916	$0	$140,916	$0	Outstanding		4	Ag Engine	12.51	0.43	1.48
Castle & Cooke /Stockdale Ranch		02-May-07	$25,857	$25,857	$0	$0	Closed	1		Ag Engine	1.60	0.06	0.21
Castle & Cooke /Stockdale Ranch		06-Jun-07	$171,600	$0	$171,600	$0	Outstanding		5	AG Engine	17.17	0.59	2.12
Castle & Cooke /Stockdale Ranch		31-May-07	$77,253	$77,253	$0	$0	Closed	3		AG Engine	5.01	0.21	0.69
	Oct-08		**$985,021**	**$586,786**	**$398,235**	**$0**		**19**	**11**		**96.85**	**3.50**	**11.8**
ISR													
ISR Mitigation		02-Oct-07	$31,000	$0	$31,000	$0	Outstanding		1	Park and Ride Subsidy	1.06	0.29	0.34
	Sep-08		**$31,000**	**$0**	**$31,000**	**$0**			**1**		**1.06**	**0.29**	**0.34**
		Totals	**$3,125,191**	**$1,648,465**	**$1,467,829**	**$8,897**		50	Projects	Achieved	**168.51**	**6.00**	**20.91**
								31	Projects	Projected	**83.05**	**3.09**	**10.20**
											251.56	**9.09**	**31.1**

AIR QUALITY EMISSION REDUCTION AGREEMENT

This Air Quality Emission Reduction Agreement ("Agreement") is entered into as of _____, 2007 by and between Developer Name ("Developer") and the SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq. ("District").

RECITALS

WHEREAS, Developer is presently seeking governmental approval of land use entitlements ("Entitlements") which will permit the development of a Project located in the City/County, California, as more particularly described on Exhibit A attached hereto (the "Project"); and

WHEREAS, the Project incorporates the design features specified on Exhibit B attached hereto ("Emission Reduction Design Features"), in order to significantly reduce the air quality impacts associated with the Project; and

WHEREAS, despite incorporation of the Emission Reduction Design Features, without additional emission reductions, the Project would cause impacts on air quality within the geographical boundaries of the San Joaquin Valley Unified Air Pollution Control District, as depicted on Exhibit C attached hereto (the "District Boundaries"); and

WHEREAS, Developer anticipates that mitigation of impacts on air quality resulting from the Project will be either required as a condition to the approval of Developer's Entitlements, or voluntarily imposed by Developer as a means of reducing such impacts; and

WHEREAS, Developer desires to fully comply with all requirements of the California Environmental Quality Act codified at California Public Resources Code section 21000, et seq. ("CEQA"), including all requirements relating to the mitigation of air quality impacts arising from or in connection with the Project; and

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WHEREAS, District is an air pollution control district formed by the counties of Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare, pursuant to California Health and Safety Code section 40150, et seq.; and

WHEREAS, District is responsible for developing and implementing air quality control measures within the District Boundaries, including air quality control measures for stationary sources, transportation sources, and indirect sources; and

WHEREAS, District has determined that with appropriate funding, District can bring about a reduction of emissions from certain projects in types and in sufficient quantities to fully mitigate the net air quality criteria pollutant impacts of the Project as quantified in the Verified Air Quality Assessment (as defined in Section 2.2 below) ("Project's Air Impact"); and

WHEREAS, Developer and District desire to enter into this Agreement in order to develop and implement air quality control measures which will fully mitigate the Project's Air Impact to the extent that the development of such Project will result in no net increase in criteria pollutant emissions over the criteria pollutant emissions which would otherwise exist without the development thereof.

AGREEMENT

NOW THEREFORE, in exchange of the mutual covenants herein contained, Developer and District hereby agree as follows:

1. **Emission Reduction by Developer and District.**

1.1. **Emission Reduction Proposals**. Developer shall identify and propose to District opportunities to reduce emissions to fully mitigate Project's Air Impact, including but not limited to opportunities for removal or retrofitting of stationary, transportation, indirect, and/or mobile pollution source equipment, and/or other opportunities therefore (each, an "**Emission Reduction Proposal**"). Each Emission Reduction Proposal shall be submitted in writing to District, using District approved forms, and shall contain a representation by Developer that the owner/operator of the identified Pollution Source Equipment has expressed interest in entering into a written funding agreement with

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District in District's then standard form ("**Funding Agreement**") requiring removal or replacement of the identified equipment with new equipment under District's "Heavy Duty Engine Emission Reduction Incentive Program", or another emission reduction program adopted by District ("**District Emission Reduction Program**"). Developer shall submit Emission Reduction Proposals to District in sufficient amounts to fully mitigate emissions from each distinct phase of the project. For each phase of the project, Developer shall submit Emission Reduction Proposals to District no later than application for grading permits for, and before generating emissions from, that phase. Any Emission Reduction Shortfall for a given phase shall be addressed according to Section 1.7.2 of this Agreement.

1.2. **District's Verification of Emission Reduction.** As quickly as practicable upon Developer's submission to District of an Emission Reduction Proposal, District shall determine the types and quantities of permanent reduction in emissions which would be realized by the proposed removal or retrofit and shall advise Developer of such determination in writing ("**Emission Reduction Verification**") thereby verifying that in District's considered opinion the removal or retrofit proposed in the Emission Reduction Proposal would result in permanent emission reduction in the locality of the Project in the types and quantities so determined by District.

1.3. **Emission Reduction Proposal Advance.** Developer shall advance to District, on the date of submittal of each Developer's Emission Reduction Proposal, a monetary sum equal to the total estimated cost (as specified in each Developer's Emission Reduction Proposal), until sufficient advance is received by District to fully mitigate the Project's Air Impact ("**Emission Reduction Proposal Advance**").

1.4. **Funding Agreements.** As soon as practicable after District's receipt of Developer's Emission Reduction Proposal Advance, District shall use diligent efforts to enter into Funding Agreements with the owners and/or operators of the pollution source equipment identified in Developer's Emission Reduction Proposal, thereby providing for the removal and/or retrofit of all of such Pollution Source Equipment, and

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providing for District's payment (from the Emission Reduction Proposal Advance) to such owner or operator, of an amount equal to the estimated cost of such opportunity, as specified in Developer's Emission Reduction Proposals. District shall use diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals within one hundred eighty (180) days following District's receipt of a complete Emission Reduction Proposal and the Emission Reduction Proposal Advance from Developer.

1.5. **Use of Emission Reduction Proposal Advance**. District shall use the Emission Reduction Proposal Advance to meet its monetary obligations under the Funding Agreements that District shall enter into with the owners of the Pollution Source Equipment identified in Developer's Emission Reduction Proposals.

1.6. **Use of Unused Portions of Emission Reduction Proposal Advance.** In the event Developer is unable to submit to District Emission Reduction Proposals providing for emission reduction in the types and quantities necessary to fully mitigate the Project's Air Impact, or in the event District is unable to enter into Funding Agreements with any of the owners or operators identified in Developer's Emission Reduction Proposals, District shall notify Developer in writing of the additional emission reductions needed to fully mitigate the Project's Air Impact, and Developer shall have a reasonable time, not to exceed one hundred eighty (180) days within which to submit to District additional or supplemental Emission Reduction Proposals in order to provide the necessary additional emission reduction.

1.7. **Unused Advance / Emission Reduction Shortfall / Additional Payment.**

1.7.1. **Unused Advance.** If, despite District's diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable, supplemental Emission Reduction Proposals submitted by Developer), District is unable to enter into Funding Agreements sufficient to fully mitigate the Project's Air Impact, then District shall use any unused portion of Developer's Emission Reduction Proposal Advance to fund emission

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reduction opportunities to mitigate the balance of the Project's Air Impact at District's actual cost of doing so, provided that such actual costs shall not exceed the costs set forth in the following Emission Reduction Cost Schedule:

Emission Reduction Cost Schedule		
Year Paid	NOx or ROG ($/ton)	PM10 ($/ton)
2007	$49,700	$55,940
2008	$65,450	$90,110
Beyond	Prevailing Costs	Prevailing Costs

District is of the considered opinion that the emission reductions listed in the above schedule can be achieved at the corresponding times and costs shown in said schedule. If, at the time of invoicing, the District has not identified Prevailing Costs for post-2008 payments, 2008 costs shall apply.

1.7.2. **Emission Reduction Shortfall/Additional Payment.** In the event the emission reduction brought about by the Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable supplemental Emission Reduction Proposals), and that brought about pursuant to Section 1.7.1 above, are not sufficient to fully mitigate the Project's Air Impact ("**Emission Reduction Shortfall**"), then Developer shall be credited for the emission reduction brought about as a result of Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals and for the emission reduction brought about pursuant to Section 1.7.1 above, and Developer thereafter shall deposit with District, within 30 days of receiving notice of the Emission Reduction Shortfall from District, an additional amount equal to the product of (i) District's cost per ton of emission reduction as shown in the Emission Reduction Cost Schedule set forth in Section 1.7.1 above, multiplied by (ii) the total number of tons of emission reduction necessary to fully mitigate the Project's Air Impact less the total number of tons of emission reduction so credited to Developer. However, in no case shall the amount paid to District and the

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amount of emission reductions achieved per this agreement be less than the amount that would be paid to District or the amount of emission reductions that would be required for this Project according to District Rule 9510 (Indirect Source Review). To allow verification of equivalency of emission reductions and off-site mitigation fee amounts, according to District Rule 9510, Developer shall submit to District an ISR Air Impact Assessment Application, using District forms, no later than concurrent with the Developer's submission of the air quality assessment, as set forth in Section 2.2.

1.8. **Surplus Mitigation.** In addition to the amounts payable under paragraph 1.3, Developer shall deliver to District an additional sum equal to five percent (5%) of the Emission Reduction Proposal Advance. Said additional sum shall be paid under the same schedule as set forth in paragraph 1.3. District shall utilize such additional sum to fund further localized emission reduction opportunities in quantities consistent with the schedule set forth in paragraph 1.7.1.

1.9 **Time of Use**. Any emission reductions brought about by this Agreement prior to the date Developer receives final approval of the Project from all applicable Governmental Authorities shall be credited to the total amount of emission reductions achieved per this agreement.

1.10. **District's Obligation**. The monies paid by Developer under this Agreement shall be used by District to obtain localized emission reductions in the types and quantities necessary to fully mitigate the Project's Air Impact as quantified in the Verified Air Quality Assessment. If necessary, District shall assist Developer in securing emission reductions, consistent with the provisions established in Section 1.7.2.

1.11. **Developer's Obligation**. District acknowledges that, if the Project is not finally approved so that such development is allowed to proceed, Developer has no obligations under this Agreement relative to the respective Project. Developer acknowledges that it must satisfy the terms of this Agreement in order to develop the Project.

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2. **CEQA Compliance/Full Mitigation.** For and in exchange of Developer's payment of funds pursuant to Section 1 above, District shall ensure, by way of entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, that the Project's Air Impact is fully mitigated, such that the Project, combined with the emission reductions brought about in accordance with Section 1 above, shall result in no net increase in air quality impacts over those air quality impacts which would otherwise exist without the development of such Project. For the purpose of this agreement, full mitigation means the sum of all NOx, ROG, and PM10 emission reductions achieved by the Emission Reductions Proposals equals, or is greater than, the sum of all NOx, ROG, and PM10 emissions increases calculated as the average annual construction and the peak annual area source and mobile source emissions of NOx, ROG, and PM10 less the average annual emissions that have occurred at the project site during the three years prior to release of the Notice of Preparation. In addition to entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, District shall do all of the following:

2.1. **District's Verification of Air Assessment Protocol.** Within ten (10) business days following the date of this Agreement, Developer shall submit to District an air assessment protocol prepared by Developer's air quality consultant reflecting the methodology, including air quality impact modeling, to be utilized in the preparation of the air quality assessment for the Project. Within twenty-one (21) business days following District's receipt of Developer's air assessment protocol, District shall review and comment upon such air assessment protocol, and, after Developer's incorporation of any revisions suggested by District, District shall verify in writing to Developer the correctness of the air assessment protocol which will be utilized in the preparation of the air quality assessment for the Project.

2.2 **District's Verification of Air Quality Assessment.** Following District's Verification of Air Assessment Protocol, Developer shall submit to District an air quality

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assessment prepared by Developer's air quality consultant assessing the air quality impacts of the Project. District shall use its best efforts to review and comment upon Developer's air quality assessment within thirty (30) days following District's receipt of Developer's complete air quality assessment, and, after Developer's incorporation of any and all revisions suggested by District, District shall verify in writing to Developer the correctness of the air quality assessment to be utilized in connection with the CEQA documents for the Project, including (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein (the "**Verified Air Quality Assessment**").

2.3. **District's Verification of Administrative Draft Environmental Impact Report**. Upon request by Developer, and submission by Developer to District of any administrative Draft Environmental Impact Report, or other applicable CEQA documents for the Project, District shall review, comment upon and, after incorporation of any and all revisions made by District, verify in writing to Developer the correctness of all portions thereof which pertain to air quality impacts, including, (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein.

2.4 **District's Acknowledgment Regarding Full Mitigation**. At such time as District is provided an opportunity as a commenting agency to comment upon the Draft Environmental Impact Report and Final Environmental Impact Report for the Project, District shall comment in writing as to the correctness of all portions thereof which pertain to air quality impacts, including (i) the methodology utilized in the

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preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein. District shall at all times fully perform its duties and obligations as a commenting agency, and the provisions of this Section 2.4 shall not be interpreted to the contrary. At such time as District has entered into Funding Agreements pursuant to Section 1.4 above and the owners/operators of equipment to be removed and/or replaced under such agreements have removed and replaced such equipment in accordance with the provisions thereof, District shall verify in writing to Developer and to the lead agency that full mitigation of the Project's Air Impact has been achieved, upon successful fulfillment of all Funding Agreements. District shall ensure that the owners/operators of equipment to be removed and/or replaced pursuant to such Funding Agreements perform all obligations to be performed on the part of such parties under said Funding Agreements. District acknowledges that the Verified Air Quality Assessment and its quantification of the Project's Air Impact will be based on the pending applications for development of the Project and that actual approvals may be for a lesser amount of development. District agrees that Developer's obligations under this Agreement shall be based on the amount of development actually approved, and the final quantification of the Project's Air Impact will be revised accordingly.

2.5. **District's Oversight of Air Quality Mitigation Monitoring Plan.** Upon request of the lead agency having jurisdiction over the Project, District shall oversee that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1 of this Agreement. Alternatively, upon request of that lead agency, District shall cooperate with the lead agency in the oversight of that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1

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of this Agreement.

2.6. **District's Documentation, Record Keeping and Monitoring**. District shall document, keep adequate records on and monitor the emission reduction brought about as a result of this Agreement, and shall from time to time, upon written request by Developer or by the lead agency for the Project, provide to Developer or to the lead agency written reports verifying that emission reduction has been and/or is being brought about so as to fully mitigate the Project's Air Impact.

3. **Subsequent Litigation, Legislation and/or Administrative Action / Credit to Developer**.

3.1. **Subsequent Litigation**. In the event that despite this Agreement, Developer is required as a result of a final judgment or District Approved Settlement (as defined below) in any subsequent third party litigation, to pay monies in addition to the monies to be paid by Developer pursuant to Section 1 above, then, provided that the project total emissions are the same as quantified in the Verified Air Quality Assessment, District shall acknowledge and credit Developer with mitigation of the air quality impacts of the Project in such types and quantities that Developer can establish, to the reasonable satisfaction of District, will result from Developer's payment of such additional monies, and shall reduce any amounts thereafter payable by Developer under this Agreement by an amount equal to the additional monies so paid by Developer. This requirement shall not apply if the additional monies are required to mitigate emissions that exceed those set forth in the Verified Air Quality Assessment. For purposes of this Section 3.1.1, a "**District Approved Settlement**" shall mean a settlement of a lawsuit filed pursuant to CEQA, the National Environmental Protection Act or other applicable environmental law which (i) provides for Developer's payment of monies in exchange for a dismissal of such lawsuit, (ii) provides for the use of such monies by the petitioner in such lawsuit in such a manner as to mitigate adverse air quality impacts of the Project, and (iii) is approved in writing by District.

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3.2. **District Rule 9510.** The performance of Developer's and District's obligations under this Agreement will fully mitigate the Project's Air Impact. Inasmuch as the mitigation provided under this Agreement exceeds the mitigation which would otherwise have been provided under Sections 6.0 and 7.0 of District's Rule 9510, and the Project's mitigated baseline (being zero emissions) is less than the threshold stated in Section 4.3 of said Rule 9510, the Project is exempt from Sections 6.0 and 7.0 of District's Rule 9510. Accordingly, no off-site Emission Reduction Fee will be required in connection with the approval or development of the Project. For each individual project developed at the project site requiring a discretionary approval by the lead agency, Developer shall provide District with a map or diagram indicating its location within the area covered by this Agreement.

4. **Term of Agreement.** This Agreement shall be effective upon the date first written above, and shall terminate upon District's meeting its obligation to implement projects that provide necessary emissions reductions to fully mitigate the Project's Air Impact (the "**Term**"). Developer may, at any time by written notice to District, terminate this Agreement, whereupon, (i) District shall acknowledge in writing to the lead agency that Developer has mitigated air quality impacts of the Project to the extent and in the types and quantities brought about by Funding Agreements theretofore funded by Developer's Emission Reduction Proposal Advance (and if applicable pursuant to Section 1.7.1 above), (ii) District shall refund to Developer any unused portion of Developer's Emission Reduction Proposal Advance less any unpaid administrative fees incurred; and (iii) neither Developer nor District shall have any further rights or obligations under this Agreement. Developer acknowledges that in the absence of this Agreement, the project is subject to all applicable provisions of District Rule 9510 (Indirect Source Review).

5. **Payment of Administrative Fees to District.** Developer agrees to pay to District, in order to reimburse District for its general overhead required for the administration of this Agreement, an administrative fee ("***ERIP Fee***") in an amount

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equal to four percent (4%) of the Emission Reduction Proposal Advance. Such ERIP Fee shall be due and payable upon Developer's delivery of the Emission Reduction Proposal Advance pursuant to Section 1.3 above. In addition to the ERIP Fee, Developer agrees to pay to District, within thirty (30) days following Developer's receipt of District's invoice, administrative fees to reimburse District for staff time spent and materials used by District in the administration of this Agreement, other than that time associated with the ERIP program covered by the ERIP Fee above, including review, verification and preparation of documents, and staff time relating to the performance of District's obligations hereunder, based on a time and materials basis at District's average weighted labor rates.

6. **Representations, Covenants and Warranties.**

6.1. **Developer's Representations, Covenants and Warranties.** Developer represents, covenants and warrants to District, as of the date of this Agreement, and as of the date of Developer's submission to District of any documents contemplated hereunder, as follows:

6.1.1. The undersigned representatives of Developer are duly authorized to execute, deliver and perform this Agreement, and upon Developer's execution and delivery of this Agreement, this Agreement will have been duly authorized by Developer.

6.1.2. Upon execution and delivery of this Agreement by Developer, Developer's obligations under this Agreement shall be legal, valid and binding obligations of Developer, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.1.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

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6.1.4. Other than the execution and delivery of this Agreement by the undersigned representatives of Developer, there are no approvals, consents, confirmations, proceedings, or other actions required by Developer or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2. **District's Representations, Covenants and Warranties.** District represents, covenants and warrants to Developer, as of the date of this Agreement, and as of the date of District's delivery to Developer of any documents contemplated hereunder, as follows:

6.2.1. The undersigned representatives of District are duly authorized to execute, deliver and perform this Agreement, and upon District's execution and delivery of this Agreement, this Agreement will have been duly authorized by District.

6.2.2. Upon execution and delivery of this Agreement by District, District's obligations under this Agreement shall be legal, valid and binding obligations of District, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.2.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative, quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

6.2.4. Other than the execution and delivery of this Agreement by the undersigned representatives of District, there are no approvals, consents, confirmations, proceedings, or other actions required by District or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2.5. No lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or

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anticipated will render invalid, void or unenforceable any right or benefit Developer is to receive under the terms and conditions of this Agreement.

6.2.6. The monies paid by Developer under this Agreement shall be sufficient to ensure that the emission reduction contemplated by this Agreement shall occur, and District shall utilize such monies in such a manner as to ensure that such emission reduction shall occur.

6.2.7. Upon the approval of this Agreement by the governing board of District, the Air Pollution Control Officer of District, or equivalent representative, or a delegee of such officer, shall have the authority to approve, deliver, verify, enter into, acknowledge and/or accept any communication, notice, notification, verification, agreement and/or other document to be issued or entered into by District under the terms and conditions of this Agreement, without further approval of the governing board of District.

7. **Indemnification**. Developer agrees to indemnify, defend and hold harmless District for, from and in connection with any third party claims, losses and/or liabilities arising from or in connection with District's performance of this Agreement, excluding only such claims, losses and/or liabilities which result from or in connection with District's sole negligence, act or omission.

8. **Inurnment**. Developer's rights and obligations under this Agreement, or applicable portions thereof, shall run with the land encompassed by the Project, and shall inure to the benefit of and be binding upon the heirs, successors and assigns of Developer who take title to such lands or applicable portions thereof. Upon Developer's conveyance of all or any portion of the lands encompassed by the Project, the rights and obligations of Developer under this Agreement shall, to the extent applicable to the lands so conveyed, be transferred to the transferee thereof, and Developer shall thereupon be released by District from, all obligations and liabilities so assigned, except for such obligations and liabilities arising prior to such transfer.

9. **Assignment**. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement. Upon any such assignment, Developer shall

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deliver to District a written assignment and assumption agreement specifying the fact and extent of the assignment, the name and address of the assignee, and the assignee's assumption of all obligations of Developer thereby assigned. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement to a third party for use in connection with the mitigation of air quality impacts resulting from one or more projects other than the Project, so long as (i) the project is located within the District Boundaries, (ii) the air quality impacts of such project(s) will in fact be mitigated, as verified by District, by the emission reductions brought about by this Agreement, and (iii) the project(s) consist of residential, commercial, industrial and/or mixed use real estate projects which incorporate the Emission Reduction Design Features. Upon any such assignment by Developer, District shall enter into an amendment of this Agreement which acknowledges the assignment and conforms the various provisions of this Agreement as may be required to be conformed in order to provide to the assignee the rights and benefits of this Agreement as if such assignee and its project were the original party and project contemplated in this Agreement.

10. **Recitals Incorporated**. The recitals set forth hereinabove are hereby incorporated into this Agreement and acknowledged, agreed to and adopted by the parties to this Agreement.

11. **Further Assurances**. Developer and District agree to execute and deliver any documents and/or perform any acts, which are reasonably necessary in order to carry out the intent of the parties with respect to this Agreement.

12. **No Joint Venture or Partnership**. District and Developer agree that nothing contained in this Agreement or in any document executed in connection with this Agreement shall be construed as making District and Developer joint ventures or partners.

13. **Notices**. Any notices or communications relating to this Agreement shall be given in writing and shall be deemed sufficiently given and served for all purposes

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when delivered, if (a) in person, (b) by facsimile (with the original delivered by other means set forth in this Section 13), (c) by generally recognized overnight courier or (d) by United States Mail, certified or registered mail, return receipt requested, postage prepaid, to the respective addresses set forth below, or to such other addresses as the parties may designate from time to time by providing written notice of the change to the other party.

To Developer: Address & Contact Name	To District: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Seyed Sadredin Executive Director/APCO
With a copy to: Address & Contact Name	with a copy to:San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Dave Warner Director of Permit Services with a copy to: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Philip M. Jay District Counsel

14. **Entire Agreement.** The terms of this Agreement, together with all attached exhibits, are intended by the parties as the complete and final expression of their agreement with respect to such terms and exhibits and may not be contradicted by evidence of any prior or contemporaneous agreement. This Agreement specifically supersedes any prior written or oral agreements between the parties with respect to

the subject matter of this Agreement.

15. **Amendments and Waivers.** No addition to or modification of this Agreement shall be effective unless set forth in writing and signed by the party against whom the addition or modification is sought to be enforced. The party benefited by any condition or obligation may waive the same, but such waiver shall not be enforceable by another party unless made in writing and signed by the waiving party.

16. **Invalidity of Provisions.** If any provision of this Agreement as applied to either party or to any circumstance shall be adjudged by a court of competent jurisdiction to be void or unenforceable for any reason, the same shall in no way affect (to the maximum extent permissible by law) any other provision of this Agreement, the application of any such provision under circumstances different from those adjudicated by the court, or the validity or enforceability of this Agreement as a whole. The parties further agree to replace any such invalid, illegal or unenforceable portion with a valid and enforceable provision which will achieve, to the maximum extent legally possible, the economic, business or other purposes of the invalid, illegal or unenforceable portion.

17. **Construction.** Unless otherwise indicated, all Section references are to the sections of this Agreement and all references to days are to calendar days. Whenever, under the terms of this Agreement the time for performance of a covenant or condition falls upon a Saturday, Sunday or California state holiday, the time for performance shall be extended to the next business day. The headings used in this Agreement are provided for convenience only and this Agreement shall be interpreted without reference to any headings. Wherever required by the context, the singular shall include the plural and vice versa, and the masculine gender shall include the feminine or neuter genders, or vice versa. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. The language in all parts of this Agreement shall be construed as a whole in accordance with its fair meaning, and shall not be

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construed against any party solely by virtue of the fact that such party or its counsel was primarily responsible for its preparation.

18. **Governing Law**. This Agreement shall be governed by the laws of the State of California applicable to contracts made and to be performed in California.

19. **No Third-party Beneficiaries**. Nothing in this Agreement, express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person other than the parties to it and their respective permitted successors and assigns, nor is anything in this Agreement intended to relieve or discharge any obligation of any third person to any party hereto or give any third person any right of subrogation or action over or against any party to this Agreement.

20. **Exhibits**. The exhibits attached to this Agreement shall be deemed to be a part of this Agreement and are fully incorporated herein by reference.

21. **Force Majeure**. The time within which any party shall be required to perform under this Agreement shall be extended on a day-per-day basis for each day during which such performance is prevented or delayed by reason of events reasonably outside of the control of the performing party, including, without limitation, acts of God, events of destruction, acts of war, civil insurrection, strikes, shortages, governmental delays, moratoria, civil litigation and the like, and/or delays caused by the non-performing party's act or omission.

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IN WITNESS WHEREOF, Developer and District have executed this Agreement and agree that it shall be effective as of the date first written above.

DEVELOPER: Developer Name,

a California limited liability company

By:_____

Name:_____

Title:_____

DISTRICT: **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT**, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq.

///

DISTRICT

San Joaquin Valley Unified Air Pollution Control District

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By:_____

Councilmember J. Steven Worthley, Chair

Governing Board

///

Recommended for approval:

San Joaquin Valley Unified Air Pollution Control District

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_____

Seyed Sadredin

Executive Director/APCO

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Approved as to legal form:

San Joaquin Valley Unified Air Pollution Control District

_____

Philip M. Jay

District Counsel

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Approved as to accounting form:

San Joaquin Valley Unified Air

Pollution Control District

///

_____

Roger W. McCoy

Director of Administrative Service

For accounting use only:

Program:_____

Account No.:_____

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EXHIBIT A

DESCRIPTION OF THE PROJECT

[INSERT MAP.]

EXHIBIT B

EMISSION REDUCTION DESIGN FEATURES

The project shall incorporate the following Emission Reduction Design Features:

The project will incorporate the following on-site features:

1. Utilization of land use designs which create walkable communities and encourage pedestrian travel.
2. Utilization of interconnecting sidewalks, walking paths and/or bike paths in order to encourage travel by means other than motor vehicle.
3. Utilization of appropriate landscaping to create reasonable shade canopies for streets, parkways and parking areas.
4. Utilization of roadway designs, which enhance pedestrian safety by appropriate signaling, signage and separation from traffic.
5. Design requirements, which incorporate natural gas hookups and electrical outlets on patios.
6. Design requirements, which prohibit the installation and use of wood burning stoves and wood burning fireplaces.

Prior to issuance of grading permits for the Project, Developer shall prepare and submit to District dust control plans for the areas to be graded, in accordance with District Regulation VIII. The plan shall be prepared consistent with District Regulation VIII and must be reviewed and approved by the District prior to commencement of grading activities. Each contractor working on the Project site shall implement the dust control measures outlined in the approved dust control plan. The dust control measures selected shall be incorporated as a note on each grading plan.

District maintains New Source Review requirements that direct owners/operators of certain types of stationary equipment to obtain an Authority to Construct ("ATC") and Permits to Operate ("PTO") from the District. As part of this process, the need for emission control equipment is assessed and the District determines whether a Health Risk Assessment ("HRA") must be prepared.

Owners/operators of all stationary sources for which such approvals are required should show proof of compliance with District Rules and Regulations prior to issuance of certificates of occupancy.

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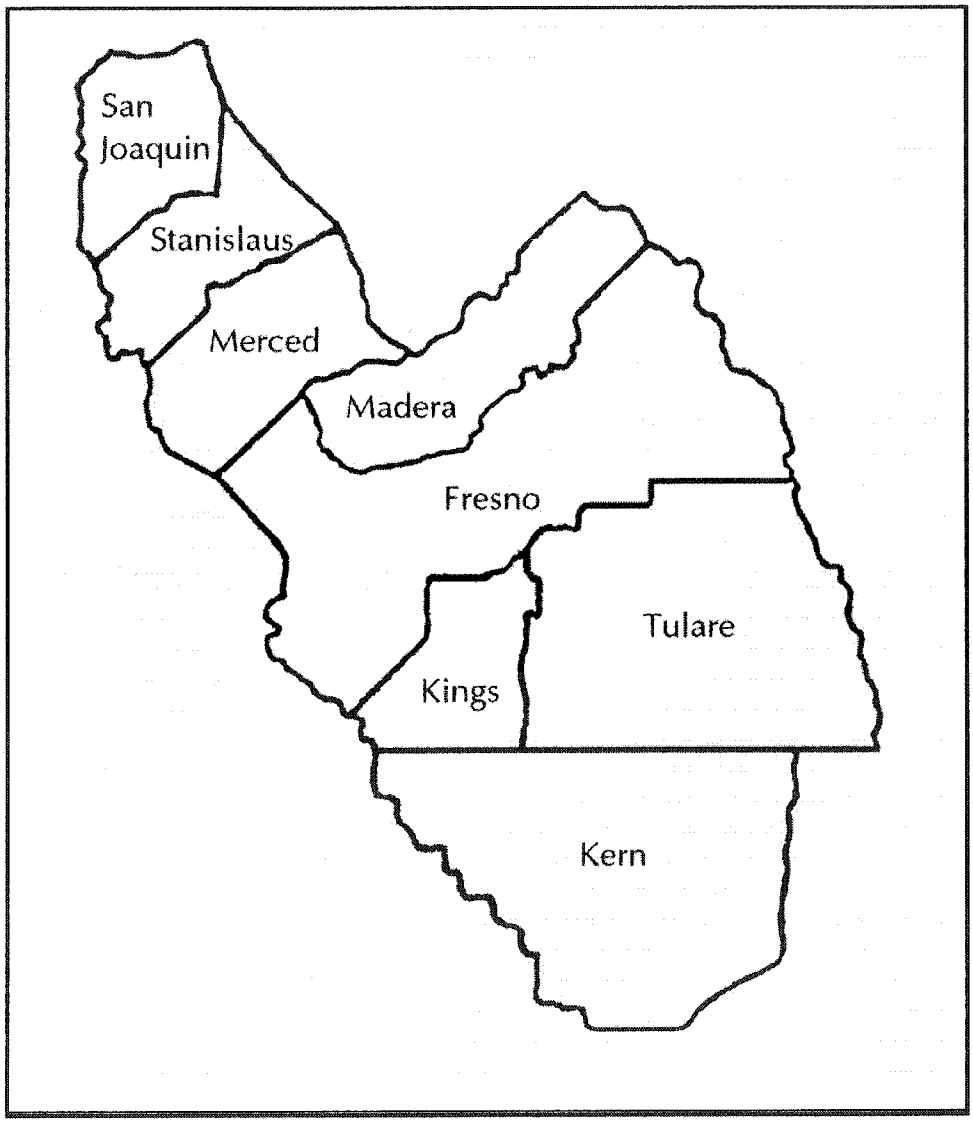
EXHIBIT C

DISTRICT BOUNDARIES



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SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

FINAL DRAFT STAFF REPORT

December 15, 2005

Rule 9510 – Indirect Source Review (ISR)
Rule 3180 – Administrative Fees for Indirect Source Review

Prepared by: Chrystal Meier, Air Quality Specialist
Jennifer Barba, Senior Air Quality Specialist
Dave Mitchell, Planning Manager
Tom Jordan, Special Projects Administrator
Scott Nester, Planning Director

I. SUMMARY

A. Reasons for Rule Development and Implementation

The San Joaquin Valley Air Basin (SJVAB) is classified as a nonattainment area for the state and federal health based ambient ozone and PM10 standards by the California Air Resources Board (ARB) and the U.S. Environmental Protection Agency (EPA). The SJVAB is currently classified as serious nonattainment for the 24-hour and annual National Ambient Air Quality Standards (NAAQS) for particulate matter 10 microns in size and smaller (PM10), serious nonattainment for the new federal 8-hour ozone standard, non-attainment for the new federal PM2.5 standard, and severe nonattainment for the 1-hour state ozone standard.

Legislation

SB 709, Florez, was passed by the state legislature, was signed by Governor Gray Davis, and codified into the Health and Safety Code in §40604 in 2003. This requires the San Joaquin Valley Air Pollution Control District to adopt, by regulation, a schedule of fees to be assessed on areawide or indirect sources of emissions.

PM10 Plan Commitment.

The San Joaquin Valley Unified Air Pollution Control District (District) adopted its 2003 PM10 Plan on June 19, 2003, which projects attainment of the NAAQS for PM10 at the earliest practicable date of December 31, 2010. As part of its PM10 attainment strategy, the District is required to reduce directly emitted PM10 and the PM10 precursor oxides of nitrogen (NOx). The 2003 PM10 Plan commits the District to develop new rules or amend existing rules to achieve these emission reductions. The Indirect Source Rule (ISR) is one of the commitments contained in the 2003 PM10 Plan

to meet these requirements. The ISR commitment will be implemented through Rule 3180 and Rule 9510. Indirect sources are land uses that attract or generate motor vehicle trips.

Ozone Plan Commitment.

Emission reductions from Rule 9510 are also important for attaining state and federal ozone standards. As an extreme nonattainment area, the SJVAB was required by the Federal Clean Air Act (CAA) to attain the NAAQS for ozone by November 15, 2010. In order to achieve attainment by 2010, the Extreme Ozone Attainment Demonstration Plan contained commitments to reduce a precursor of ozone, NOx and volatile organic compounds (VOC). These commitments included NOx reductions from indirect sources. Although the federal one-hour standard has been revoked, the plan commitments must still be implemented to ensure progress is made toward attaining the new more stringent 8-hour ozone standard. By 2007, the District will be required to prepare a plan to comply with the federal 8-hour ozone standard that is expected to require additional reductions. Additionally, the California Clean Air Act (CCAA) requires the District to adopt all feasible control measures to attain the standards.

Health Impacts of Non-Attainment

Since 1996 there have been more than 800 new scientific studies published that associate the effects of airborne particulates on human health. Overall the studies validate earlier research and confirm the relationship between particulate air pollution, illness, hospitalization and premature death. Infants and children, particularly asthmatic children, are especially sensitive to the effects of fine particulate pollutions. For additional information on particulate health impacts see the 2003 PM10 Plan, Chapter 1.

Ozone research has produced strong evidence that correlates exposure to ozone and adverse health effects. In humans, ozone can irritate and inflame the respiratory tract, particularly during heavy physical activity, which results in heavy coughing, throat irritation, and breathing difficulties. For additional information on ozone health impacts see the District's Extreme Ozone Attainment Demonstration Plan, Section 2.3.

B. District Authority and Limitations

Authority

The primary provision of state law giving the District authority to regulate indirect source emissions is part of the California Clean Air Act legislation adopted in 1988. The provision, incorporated into Health and Safety Code, Section 40716, states that "a district may adopt and implement regulations to … reduce or mitigate emissions from indirect and areawide sources of air pollution." To further clarify, a California Attorney General opinion issued in 1993 states that

> *"a district's regulations may require the developer of an indirect source to submit the plans to the district for review and comment prior to the issuance of a permit for construction by a city or county. A district may also require the owner of an indirect source to adopt reasonable post-construction measures to mitigate particular indirect effects of the facility's operation. Such regulations could be enforced through an action for civil penalties…"*

Indirect source mitigation programs are also consistent with ARB's interpretation of the CCAA all feasible measures requirement:

> *"every feasible measure to mean that, at a minimum, a district consider regulations that have been successfully implemented elsewhere. They should also consider going beyond what has already been accomplished by evaluating new technologies and innovative approaches that may offer potential emission reductions. Further, districts should consider not only technological factors, but also social, environmental, economic (e.g., cost-effectiveness), and energy factors which prevail in the district, along with the resources realistically available to the district to adopt, implement, and enforce the measures."*

Health and Safety Code 42311(g) allows districts to adopt a schedule of fees on areawide or indirect sources which are regulated, but for which permits are not issued, to cover the costs of District programs related to this source. SB 709, Florez, was passed by the state legislature, was signed by Governor Gray Davis, and codified into the Health and Safety Code in §40604 in 2003. This requires the San Joaquin Valley Air Pollution Control District to adopt, by regulation, a schedule of fees to be assessed on areawide or indirect sources of emissions.

Finally, the District has the authority to control indirect sources, defined in the Clean Air Act (CAA §110(a)(5)(C)) as, "… a facility, building, structure, installation, real property, road, or highway which attracts, or may attract, mobile sources of pollution"(emphasis added). This authority comes from the CAA §110(a)(5)(A)(i):

> *"Any State may include in a State implementation plan … any indirect source review program."*

Analysis of Nexus Applicability

The District analyzed the applicability of Nexus requirements for Rule 9510 and 3180. The District's legal council's analysis found that the Rule and supporting documentation likely meets the federal 'reasonable relationship test'. In addition, the analysis found that the California Mitigation Fee Act (CGC §66000 et seq.) does not apply to Rule 9510 and 3180. The analysis similarly found that California Proposition 13 and 218 do not apply to Rules 9510 and 3180.

California's Mitigation Fee Act (CGC §66000 et seq.) establishes authority and limitations on fees or taxes charged, "by a local agency to the applicant in connection *with approval of a development project*." CGC §66001 (a) states, "In any action establishing, increasing, or imposing a fee *as a condition of approval* of a development project by a local agency on or after January 1, 1989, the local agency shall do all of the following," and §66001 (b), "In any action imposing a fee *as condition of approval* of a development project. (Italics added)." The District cannot impose on the local land-use authority and will not be approving or disapproving development projects. As such, the District cannot place 'conditions of approval' on a project. Therefore, the Mitigation Fee Act does not apply to the ISR Rule. The District does not consider the action of approving or disapproving an air quality analysis and assessment of fees as a discretionary action.

Limitations

The District will not be approving development projects, but the air impact assessments associated with development projects. In this approval, the District will assess air impacts, the amount of reduction required by the rule, the amount of applicant-specified on-site emission reductions, and the amount of off-site emissions reductions needed, if any. The District recognizes the land-use authority of SJVAB Cities and Counties and does not have land-use authority itself.

II. RULE DEVELOPMENT PROCESS

As part of the rule development process for this project, District staff held public scoping meetings in Fresno, Modesto, and Bakersfield in October 2003. At the scoping meetings, District staff presented the objectives of the proposed rulemaking project, collected information, and received comments from interested parties, local agencies, the building industry, real estate associations, consultants, and trade associations. The comments received were incorporated into the draft rules and staff report. In March of 2004, the District presented a draft Rule 9510, and several other documents. In June of 2005, the District presented draft Rule 9510 and draft Rule 3180, as well as associated appendices. The comments received were incorporated into the draft rules and staff report. In addition, District staff held a public workshop September 1, 2005 and solicited input on the draft rule and associated documents. The District received comments from interested parties and affected entities. Information obtained throughout this workshop process was used to develop and modify the draft rules and staff report.

Pursuant to state law, District staff is required to perform an assessment of the socioeconomic impacts prior to the adoption, amendment, or repeal of a rule that will have significant air quality benefits or that will strengthen emission limitations. As a part of the District's socioeconomic analysis process, District staff held a Focus Group meeting on August 11, 2005 to assist in the collection of socioeconomic data for the

implementation of the new proposed program. The Focus Group consisted of a limited number of representatives from interested groups.

Final drafts of the proposed rules, staff report, emission reductions analysis, cost effectiveness analysis, on-site emission reduction checklist, socioeconomic analysis, and rule consistency analysis, will be published prior to a public hearing by the Governing Board to consider the adoption of proposed Rules 3180 and 9510. The tentative schedule for the public hearing to consider the adoption of the newly proposed rules by the District Governing Board is for December 15, 2005.

III. BACKGROUND

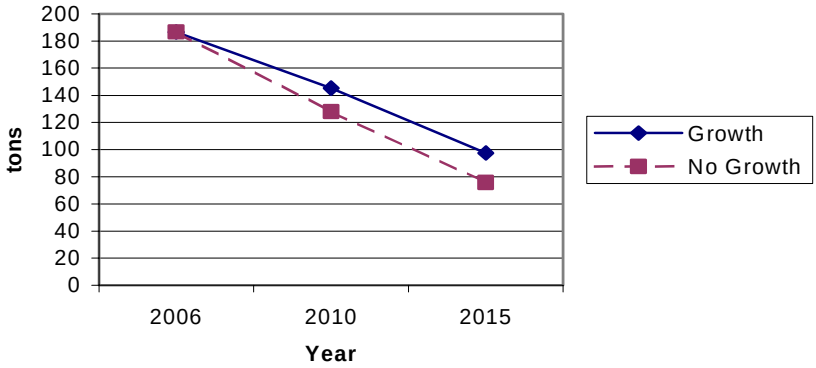
A. Growth and Emissions

The District exceeds state and federal air quality standards for ozone and PM10, despite significant reduction of air pollution from both mobile and stationary sources, primarily because of increases in population and vehicle miles traveled (VMT) in the SJVAB.

Reductions

Federal, state and local efforts have led to approximately 30 percent reduction in smog precursors and a ten percent reduction in PM10 (overall) in the SJVAB since 1990[1]. Significant reductions from stationary sources have been achieved, so that mobile sources now produce 69 percent of all NOx emissions in the District. Today's new cars pollute about 90 percent less than models produced 25 years ago due to California's strict vehicle emissions standards. By 2003, the average new car in California will pollute 75 percent less than 1994 models[2]. Although these standards will continue to greatly improve air quality, large increases in population and driving partially reduce the benefits of cleaner motor vehicles. The following chart shows how much lower the emissions from motor vehicles would be if growth were not to occur.

Figure 1
Difference in NOx Emissions for All Vehicle Types



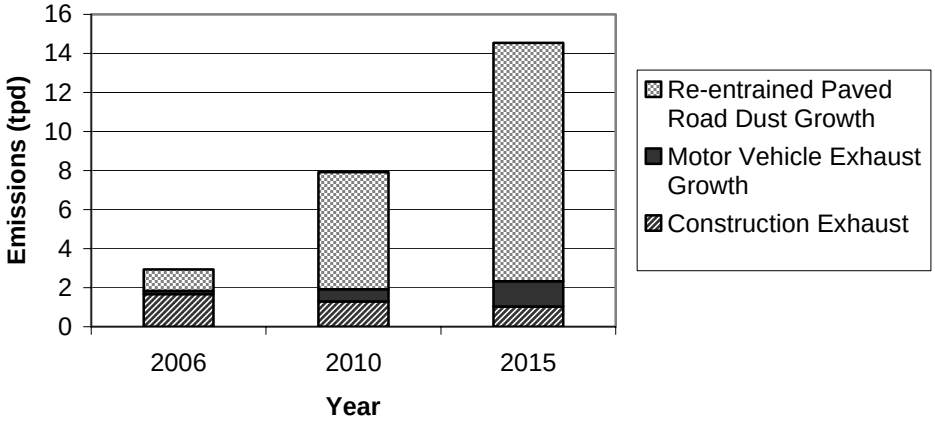
Population Growth

The SJVAB has experienced a large increase in population in the past several decades. The total population in the District increased by 22% between 1990 and 2000, and California's Department of Finance is projecting that the SJVAB will see an overall increase in population of 24% between 2000 and 2010. Each county varies, with the highest expected growth in terms of percentage increase in Madera, and the lowest expected growth in Fresno, but in terms of numbers of people, Fresno is expected to see the largest increase[3]. With increased population there is an increase in emissions from area sources, such as consumer products, fuel combustion, landscape maintenance equipment, etc.

VMT Growth

The total number of vehicle miles traveled (VMT) in the District has increased at a faster rate than population growth. The District witnessed a nine percent increase between 1999 and 2002, and is expecting a 27 percent increase from 2002 to 2010[4]. Entrained and re-entrained paved road dust and corresponding PM10 emissions, increase as VMT increases. The ozone and PM10 precursor NOx, also increases as VMT increases.

Figure 2
PM10 Emissions from Development



Increased Emissions From Growth

The past and projected increases in population, associated development and construction emissions and vehicle miles traveled, and the slower than expected introduction of technological advances in automobile and truck emission controls, have significantly slowed progress toward attainment. The ISR program can reduce and offset some of the growth in emissions and is required for attainment of the federal ozone and PM10 standards by the dates required in ozone and PM10 attainment plans.

B. Existing Indirect Source Programs

The District identified several examples of air pollution agencies in California that are currently reviewing land use projects for indirect source impacts and/or collecting mitigation fees in their districts. Five air pollution agencies have adopted and implemented an indirect source rule or policy. The methods and authority over development projects vary from air district to air district. Brief descriptions of these programs are provided below.

Mendocino County Air Quality Management District (AQMD) outlines their permitting process for indirect sources in Rule 1-200. The rule requires any indirect source to obtain an Authority to Construct (ATC) prior to starting construction. When Mendocino AQMD receives an application, they perform a California Environmental Quality Act (CEQA) determination. The ATC is not issued until a Notice of Determination is completed and filed.

Great Basin Unified Air Pollution Control District (APCD) also has an indirect source permit rule in place, Rule 216. This rule defines indirect sources as a secondary source, which is any structure, building, facility, equipment, installation, operation, or aggregation thereof. The application and associated informational documents are reviewed, and an analysis on expected emissions and air quality impact is performed. Public notice is published, and the general public is allowed to review and comment. The District then considers comments and imposes conditions on the approval of the permit or denies a permit if it is determined that the secondary source will contribute to a violation of any air quality standard. The fees imposed on secondary sources in Great Basin are outlined in Rule 301. Those fees are based on the size of the commercial unit and the number of parking spaces, or the number of residential dwelling units.

Colusa County APCD has an indirect source fee rule, Rule 4.8. The fees are assessed for building permit applicants during the city or county's permit process. The fees are based on the square footage of commercial or industrial projects, or by residential unit. The city or county may retain an administrative fee of ten percent. The fees are used to offset the District's costs, and any excess is used to mitigate air quality impacts.

Placer County APCD has instituted a "Policy Regarding Land Use Air Quality Mitigation Funds." During CEQA review, the APCD assesses total emissions that are estimated to occur during the ozone season from a particular project. The emissions are estimated by utilizing URBEMIS, which will be mentioned later in this staff report. After estimating emissions during the ozone season from URBEMIS, Placer County APCD requires 40% mitigation of a project's impact or to below a significance threshold, either on-site, off-site, by paying a fee, or a combination of those options.

Shasta County AQMD has adopted Rule 3:16, which allows Shasta County to place reasonable conditions on any fugitive, indirect or non-traditional source. At the current time, Shasta County utilizes the rule to mitigate the impact of new residential dirt roads by requiring paving or paying a fee. Their Resolution 84-2 authorizes an in-lieu buy out schedule for road paving, which is currently set at $800 per parcel below 1,000 feet in elevation.

In addition to the above examples, numerous government agencies in the SJVAB have created impact fee programs that have proved useful in drafting this program. The most common are transportation/transit impact fees for cities such as Bakersfield, Lathrop, and Visalia. The City of Stockton and the City of Turlock also have air quality impact fee programs in place.

C. Program Options

The District considered several options for the initial approach to the ISR program. The options were developed to coincide with the normal development process as a condition of application completeness during the environmental review with a city/county, or while compiling conditions of permit approval as part of the cities/counties development processes.

District Permit Program: This option would require permit applicants to obtain a permit from the District prior to paying the city/county's building permit fees. The District could require applicants to provide specific documents needed to determine the emissions from the project using URBEMIS. The District could then require on-site emission reduction measures as conditions of approval of the permit and/or calculate a fee. Under this option, the District could collect the off-site fee prior to issuing the District permit or defer the fee until the city/county issued the building permit.

City/County Review & Administration: This option would allow the city/county to review the emissions generation of an applicant's project, likely using URBEMIS. Under this option, the city/county would collect the off-site fee, if any, and transfer the fee to the District's off-site fund account(s). The city/county could also operate the entire program including expenditure of funds on emission reduction projects if the city/county adopted a program at least as effective at reducing emissions as the District's rule.

District Review & City/County Administration: Under this option, the District would require the applicant to provide documents necessary to perform an emissions generation analysis, likely using URBEMIS. The District would calculate the off-site fee amount based on total emissions and identify credits for specific on-site emission reduction measures included in the project. Prior to authorization of a building permit, the city/county would review the list, check which on-site measures have been incorporated into the project, and collect the fee, if any.

Simple Fee: This option would allow cities/counties to charge an off-site fee based on certain criteria, such as size or number of units. If this option was pursued, most likely the per unit fee would be based on the Institute of Transportation Engineers (ITE) trip generation rates for the different land uses and emissions calculated by URBEMIS. Under this option, the city or county would assess and collect the fee. An appeal program or a rebate program would be a possibility to give credit for any on-site measures that were performed or incorporated into the design of the project.

District Review & Administration: Under this option, the District would require the applicant to provide documents necessary to perform an emissions generation analysis, likely using URBEMIS. The District would calculate a required reduction amount based on total emissions and identify credits for specific on-site emission reduction measures included in the project. Required reductions not achieved by voluntary on-site measures would be achieved off-site through an offset fee. Offsite reductions would be subject to criteria including (but not limited to) being quantifiable and surplus. The District would conduct annual reporting to analyze the effectiveness of the off-site emission reduction program.

The District chose to pursue the 'District Review & Administration' option for several factors. Primarily, the District chose to craft the ISR rules to be compatible with local land-use authorities decision-making processes, and to have the ability to be worked into CEQA documents at the Lead Agencies' discretion. The District includes the options for voluntary on-site emission reduction measures that would allow a reduction in off-site fees.

IV. PROPOSED REGULATIONS

A. Proposed Rule 9510

The purpose of proposed Rule 9510 is to reduce emissions of NOx and PM10 from new development projects. The rule applies to development projects that will seek to gain a discretionary approval for projects that, upon full build-out will include any one of the following: 50 residential units, 2,000 square feet of commercial space, 25,000 square feet of industrial space, 20,000 square feet of medical office space, 39,000 square feet of general office space, 9,000 square feet of educational space, 10,000 square feet of government space, 20,000 square feet of recreational space, or 9,000 square feet of uncategorized space. The rule also applies to transportation projects whose construction exhaust emissions will result in a total of two tons per year of NOx and PM10 combined. However, there are several sources that are exempt. These include transportation projects that meet certain conditions, reconstruction projects that result from a natural disaster, development project's whose primary functions are from District permitted stationary sources. Also, development projects that have a mitigated baseline below two tons per year for NOx and PM10 shall be exempt from the

mitigation requirements of the rule. Anti-circumvention language was added to prevent piecemealing of development projects.

Applicability

Rule 9510 applies to any applicant that applies for a final discretionary approval for a development project which will include any of the following: 50 residential units; 2,000 square feet (sf) of commercial space; 25,000 sf of light industrial space; 100,000 sf of heavy industrial space; 20,000 sf of medical office space; 39,000 sf of general office space; 9,000 sf of educational space; 10,000 sf of government space; 20,000 sf of recreational space; 9,000 sf of space not identified, and; transportation and transit projects where construction exhaust emissions results in a total of 2 tons of NOx and PM10 combined.

Exemptions

Transportation and Transit projects are only subject to the construction emission reduction requirements of the rule. Development projects subject to the rule that reduce their operational emissions to less than 2 tons per year of NOx and PM10 each not subject to the rule's operational or construction emission reductions requirements.

Reconstruction of a development that was damaged or destroyed that is rebuilt to essentially the same use and intensity is similarly not subject the rule's requirements. In addition, development projects whose primary functions are regulated by District permits are exempt. Those stationary source projects are exempted because the projects' primary emissions are from stationary sources that are currently regulated by District rules and permitting requirements.

Application

Rule 9510 requires applicants of new development projects to submit an Air Impact Assessment (AIA) application to the District prior to or at the project's application for a final discretionary approval with a public agency. The application would include the information necessary for the District to perform an assessment, project location and description, an on-site emission reduction checklist, and an assessment by the applicant (if desired). An AIA would consist of inputting project data into an APCO-approved model to estimate emissions, and inputting on-site emission reduction measures that are components of the project design and/or other project specifics to calculate emissions reductions. This will be performed by the District and may be performed by the applicant. The emissions and emissions reduction outputs will be used to calculate the amount of on-site emission reduction is achieved, and what the off-site emission reduction fee would be, if any. Proposed Rule 9510 specifies the use of an APCO-approved model (Draft Rule 9510 Section 3.2), which in most cases will be URBEMIS. In the event that URBEMIS is not suitable for the proposed land use (i.e. does not have ITE trip rate), the District may approve another model, or review and approve off-line with project-specific calculations. If project-specific data is entered into

the APCO-approved model and overrides defaults, the applicant shall document and justify those project-specific inputs.

On-Site Emission Reduction Checklist
The measures listed in the checklist have a known quantification methodology in URBEMIS 8.7. The methodologies can be found in the URBEMIS User's Guide, available at South Coast AQMD's website http://www.aqmd.gov/ceqa/urbemis.html. The on-site emission reduction checklist shall identify which measures have been voluntarily selected by the applicant, the enforcement mechanisms available for those measures, and the reasons for not selecting the remaining measures. All measures selected that are above District or State requirements, regardless of enforcement mechanism, will count towards emission reductions for the project, in accordance with the methodologies in URBEMIS. The measures for the On-Site Emission Reduction Checklist can be found in Appendix C.

On-Site Enhancing Measures
The District has identified several measures that are known to have an air quality benefit. However, at this time they do not have a quantification methodology for project-level emission reductions. These measures still have a beneficial air quality impact. For this reason, the District will maintain a list of 'On-Site Enhancing Measures' and make it available to applicants. There are no requirements on selection of measures from the On-Site Enhancing Measures list. As emission reduction methodologies are determined for these and other new measures, they can be incorporated into URBEMIS. The list is available in Appendix C.

Monitoring and Reporting Schedule
For projects that select on-site measures that do not already have an enforcement mechanism, a proposed SJVAPCD On-Site Monitoring and Reporting Schedule (MRS) will be completed. The District will provide a standard form for the MRS, and the applicant is responsible for completing the MRS. The District will then work with the applicant to finalize the MRS. Draft Rule 9510 §5.4 discusses the components of a MRS.

Fee Deferral Schedule
In addition to the AIA application, the applicant may propose a Fee Deferral Schedule at the time of application or during application review in anticipation of a possible off-site fee, or within 15 days of receiving an off-site fee invoice. The District will provide the Fee Deferral Schedule format. The applicant can choose the schedule of payments, but all fees for a development or phase thereof must be received *prior* to construction of that development or phase thereof. Draft Rule 9510 §5.5 discusses the components of a FDS.

Completeness Finding
The District will have 10 days to determine whether or not the application is complete. After the District deems the application complete, the District has 30 days to approve

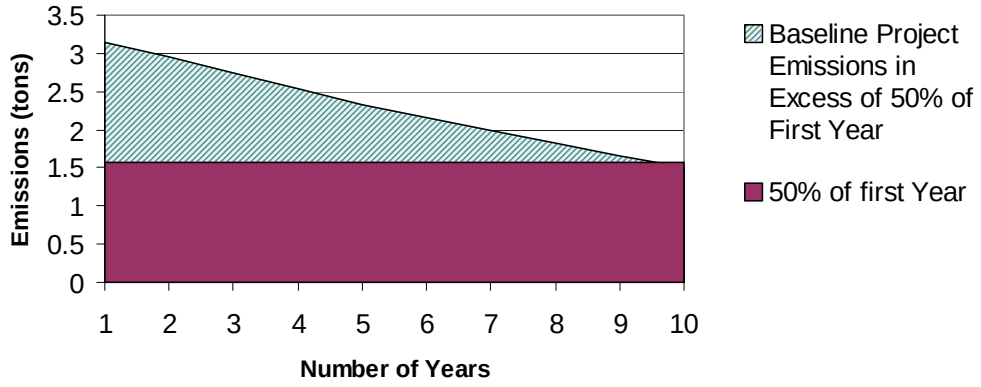
the application and notify the applicant of the estimated fee amounts. In addition, the application and MRS will be submitted to the applicable public agency for voluntary review. The public agency may provide comment at their discretion. The applicant may have the assessment modified to incorporate more on-site measures, if desired. Once the proposed MRS is approved, the District and the applicant shall finalize the MRS. If there are changes to the project that will impact the emissions total or schedule of build-out, the applicant shall notify the District of that change within 60 days of said changes, or prior to the start of project construction, whichever is first. As stated above, if a project mitigates to less than two tons of operational NOx and PM10, it will not be subject to the required emission reductions stated in the draft Rule 9510 §4.3.

Required Emission Reductions

Proposed Rule 9510 would require applicants to reduce NOx and PM10 emissions. The rule is designed to reduce the impact of the development projects to the extent needed for the District to reach attainment of ozone and PM10 standards. The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. Draft Rule 9510 Section 6.0, et seq., describes the required emission reductions.

Although the majority of the NOx emissions associated with a project are due to motor vehicles, there is a decline in NOx emissions over time due to ARB's tailpipe controls. The NOx mitigation fee is structured to account for a 50% decline in annual NOx emissions from motor vehicles over ten years. Thus, the rule requires mitigation of the cumulative NOx emissions in excess of 50% of the project's operational baseline emissions (the emissions at the first year of buildout) until the project's emissions reach half of the project's first-year baseline emissions, which is approximately 10 years. This method ensures that a project does not over-mitigate its emissions. Draft Rule 9510 Sections 3.8 defines baseline emissions. Rule 9510 Sections 3.10 and 3.27 define construction baseline and operational baseline, respectively. Rule 9510 Section 3.20 defines 'mitigated baseline'. Project emissions and the required mitigation can be visually represented as follows:

Figure 3
NOx Project Emissions and Reductions Compared to 50% of the First Year Emissions



In essence, the NOx mitigation required for Rule 9510 is represented above by the triangle, which is equal to one third of total project emissions during the first ten years. The applicant can reduce the emissions represented by that triangle by using on-site mitigation measures, by paying the District a fee to fund emission reduction projects off-site, or through a combination of the two. The fee amount would decrease or be eliminated depending on the amount of on-site mitigation incorporated by the applicant into the design of the project.

The PM10 mitigation requirement is different from NOx. Operational PM10 emissions from a project do not decline over time – they remain constant. Accordingly, Rule 9510 will require mitigation equal to half of the emissions for the first year after build-out for 10 years (the same period of time required for NOx mitigation).

Proposed Rule 9510 would also require applicants to reduce NOx and PM10 construction equipment emissions. The rule requirement is to reduce construction NOx emissions by 20% and PM10 emissions by 45% beyond the statewide average. In determining the level of reduction for construction emissions, the District researched what other air districts had set, and found those targets are achievable. There are several options available for controlling NOx and PM10 emissions from equipment used for construction on-site. Options can include, utilizing newer equipment, altering fuel type, modifying an engine, or using exhaust after-treatment devices, to meet the rule requirements. New equipment can provide a high percentage of emissions reductions, depending on the horsepower and the year of the equipment. The reductions are achievable with existing technology with a mix of newer equipment and retrofit devices, and will allow applicants applying moderate effort to pay no fee on construction.

Achieving Emission Reductions

If on-site mitigation measures are chosen by the applicant, the applicant shall submit a MRS to the District for the those on-site mitigation measures that do not have built in enforcement mechanisms. All on-site emission reductions measures that are above District and State requirements will be credited to emission reductions for the project. The MRS will identify enforcement mechanisms, which may include identifying specific funding mechanisms, as well as monitoring, recordkeeping and reporting. The Proposed MRS shall be forwarded by the District to the public agency for review. It is important to note that the percent reduction achieved onsite results in a greater reduction of the NOx fee. While on-site mitigation is not required, the "bigger bang for the buck" is achieved with as much on-site mitigation as possible. For example, when onsite NOx reductions exceed the excess emissions above 50% of the first year's baseline, the NOx fee becomes zero. Additionally, if the onsite measures reduce the NOx and PM10 to less than 2 tons per year each at buildout (baseline), no additional reductions are required. See Table 1 for examples of on-site emission reductions and the associated off-site fee reduction. See Table 2 for a list of simple measures that small projects can achieve, and a list for larger projects. If the emission reductions required by the rule are not fully achieved on-site, off-site fees would be required.

The use of off-site fees is strictly limited to procurement of off-site emission reductions. Absolutely no off-site funds may be used for District staffing or budget. The District shall provide annual reporting per draft Rule 9510 Section 10.4. Annual reports shall include, at a minimum: the total amount of off-site fees received; the total monies spent; total monies remaining; any refunds distributed; a list of all projects funded; the total emission reductions realized, and; the overall cost-effectiveness factor for the projects funded.

Off-site mitigation would consist of paying a fee to fund emission reduction projects for required emission reductions that are not reduced on-site. Rule 9510 contains pollutant-specific fee formulas in Section 7.0, et seq. Appendix B shows how those formulas were developed. The off-site fees are strictly tonnage based. This means that all projects are treated equally, and assessed on the amount of emissions associated with the project. The fee formula applies equally to all applicable projects, accounts for the amount of on-site emission reductions. The fee would be payable in 60 days upon notification of fee amount, unless the applicant has arranged a FDS with the District.

Both the NOx and the PM10 fee formulas include a Cost of Reductions for one ton of that pollutant. These values were determined based on historical grant programs with the district and project fund use, and represents an average value for a range. Appendix E contains a greater description of how those values were derived.

Rule 9510 directs the District to administer the fee use to achieve emissions reductions that the fees were based on, in a cost-effective manner. There are numerous emissions

reduction projects available. Potential projects are as follows: projects currently qualifying for the District's Heavy-Duty Engine Incentive Program including, alternative fuel low-emission school buses, transit buses, and other vehicles, diesel engine retrofits and repowers for trucks, PM efficient street sweepers powered by natural gas, agricultural water pumping engine replacements, locomotive repower/retrofits, electric forklifts, etc. Other potential projects include gross polluter replacement, biomass subsidies, electric vehicle or lawn equipment rebates, truck refrigeration unit plug-ins at distribution centers, woodstove replacement/retirement, video-teleconferencing systems, and telecommuting start-up costs. Potential PM10 reduction programs include paving or treating unpaved traffic surfaces and shoulders and PM10 efficient street sweeper purchases. Some projects will achieve reductions of NOx and PM10. The funds will be managed by a grant-like program and allocated as applications are received. If a sufficient amount of applications to fund projects are not received, the District will consider a directive program that would be approved by the Governing Board. The District recognizes the sensitivity of the geographic distribution of the funds. Any emissions reduction project will provide a localized benefit to the area of fee origin.

Table 1
On-Site Reductions and Associated Operational Off-Site Fee Reductions.

Example Project 150 Single-Family Units in 2006 <u>On-Site Package</u> - Increased Density (from 50 to 30 acres) - No Wood Stoves - Increased Energy Efficiency by 10% - Located near local-Serving Retail - Bus Service Nearby - Traditional Street Design - Sidewalks on Both Sides of Street - Bikelanes on 20% of streets - 10% of units Deed-Restricted Below Market Rate	On-Site Emission Reduction (%)		Operational Off-Site Fee Reduction (%)	
	NOx 12%	PM10 36%	NOx 36%	PM10 72%
Example Project 200 Multi-Family Units 40,000 sf Strip Mall 60,000 sf General Office <u>On-Site Package</u> - No Wood Stoves - Increased Energy Efficiency by 10% - Located near local-Serving Retail - Bus Service Nearby - Traditional Street Design - Sidewalks on Both Sides of Street - Bikelanes on 20% of streets - 5% of units Deed-Restricted Below Market Rate - Commercial and Retail implement Transportation Demand Measures - Commercial and Retail Reduce Parking Supply	On-Site Emission Reduction (%)		Operational Off-Site Fee Reduction (%)	
	NOx 23%	PM10 29%	NOx 68%	PM10 59%

Table 2
Basic On-Site Measures for Small and Large Projects.

Small Projects	Large Projects
All Land Uses: Traditional Street Design Increased Energy Efficiency Include Sidewalks on all streets Locate near mass transit stops Locate near a mix of uses Residential: No Fireplaces or Woodstoves Locate near local serving retail Locate near jobs Non Residential: Reduce parking supply Locate near residences Implement Transportation Demand Measures Include Bike Racks	Same as Small Projects, Plus: All Land Uses: Include a mix of uses Install Bike Paths or Bike Lanes and/or Pedestrian paths

AIA Approval

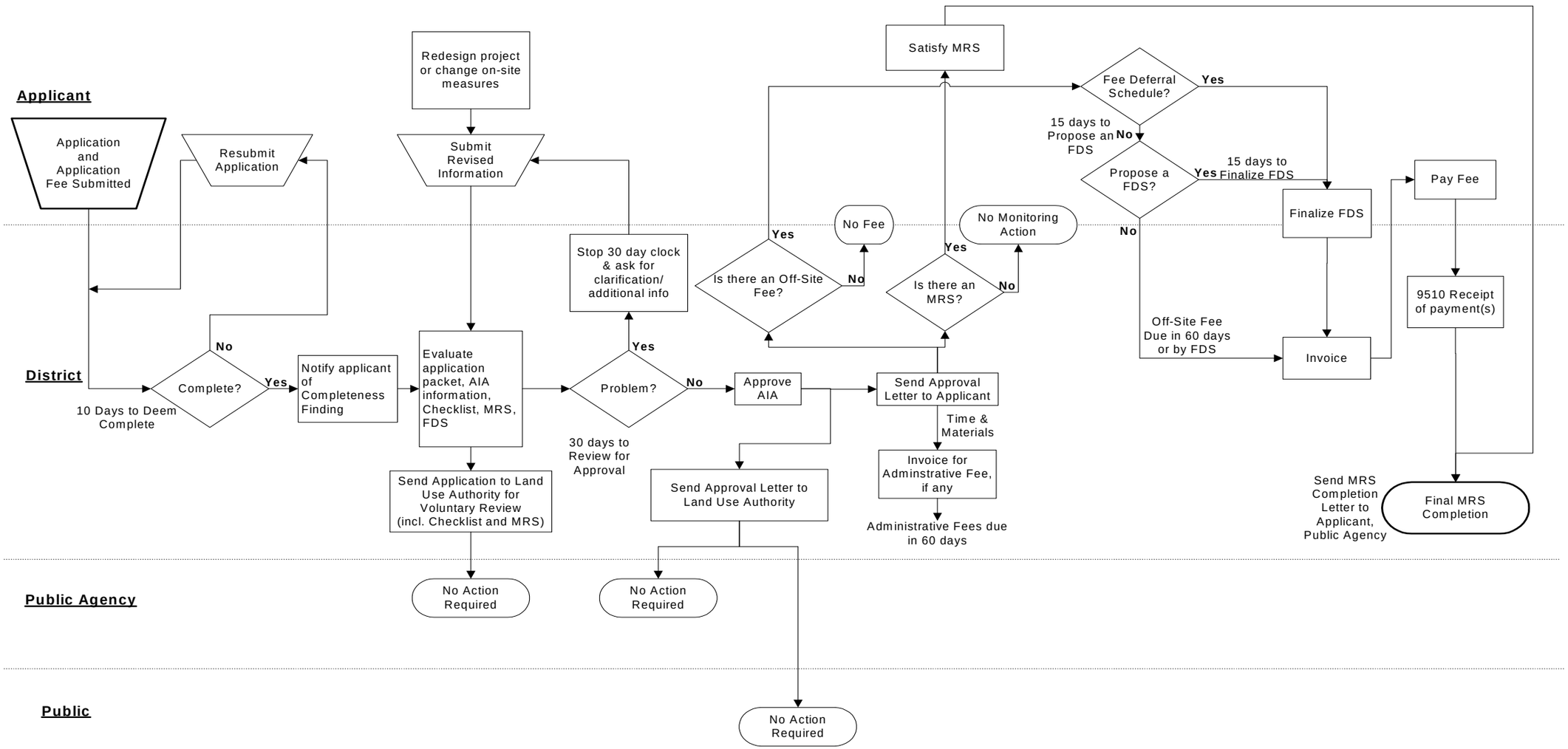
The District will provide a decision on the AIA application within 30 days of finding the application complete. The District will approve the AIA application or disapprove the AIA application. It is important to note that the District will not be approving a permit or other discretionary action as a result of Rule 9510. In addition, the District will not be approving or disapproving the development project itself, but the Air Impact Assessment application for that project. The authority for land-use decisions lies with the local land-use agency. The AIA application approval is ministerial and will not involve conditions of approval.

MRS Maintenance

For those projects that have a MRS with the District, the applicant is responsible for implementing those measures identified. The District is responsible for monitoring and receiving reports for on-site emission reduction measures. The District shall provide a tentative compliance letter to the applicant, public agency and public upon request. Upon completion of the last MRS requirement, the District shall provide a letter of MRS completion to the public agency and applicant. The District shall also make the letter available to the public.

If the applicant committed to on-site construction emission reductions, the applicant is responsible for submitting the construction equipment schedule to the District prior to applying to the public agency for a grading permit. At that time, the District will verify construction emissions for the project. If the on-site emission reductions specified by the applicant are not achieved, the District shall assess and invoice for off-site fees required by the rule.

ISR Application Flow Chart



B. Proposed Rule 3180

The purpose of proposed Rule 3180 is to recover the costs of administering Rule 9510. The proposed rule includes a non-refundable application-filing fee to be paid when an application is submitted to the District. Once an application and the application fee are received, district staff will log the total staff hours spent on the project using the District's automated Labor Information System. The application evaluation fee will comprise those hours at a weighted average labor rate, minus the application-filing fee, so that only the cost of the actual hours spent on the project will be recovered.

Rule 3180 also contains a fee equal to 4% of the offsite emission reduction fees to recover the cost of administering off-site emission reduction projects. The 4% would be payable when the offsite emission reduction fees are collected.

C. Program Implementation - Streamlining

The process identified in Rule 9510 may be completed prior to or concurrent with the City/County permit review process. Specifically, Rule 9510 has been designed for non-interference with the City/County land-use and California Environmental Quality Act (CEQA) processes. However, information from the ISR process may be used by a Lead Agency in environmental documents, at their discretion. Currently, air quality impact assessments are usually required for projects with potentially significant air impacts. Since the NOx and PM10 pollutants will be addressed through ISR, it will not place an added burden to the applicant, and should provide a foundation for or replace the ozone precursor and PM10 emission analysis included in that environmental document. The On-Site Emission Reduction Checklist will help applicants identify quantifiable mitigation alternatives and provide justification for feasibility or infeasibility. The MRS will identify enforcement mechanisms for on-site emission reduction measures that were selected by the applicant.

The District will provide information on the District's website, such as application forms and guidance documents. The District will revise its Guidelines for Assessing and Mitigating the Air Quality Impacts (GAMAQI) document as needed. In addition, the District will work with Cities and Counties on additional measures to facilitate communication and streamlining of the application and review process.

Finally, the ISR program is set up to allow the applicant to provide the AIA. However, the applicant is not required to provide modeling or emissions calculations. The District will prepare the AIA based on the project-specific information provided in the AIA application. The District will not charge a specific fee for modeling, but will invoice for any time and materials beyond that covered by the application filing fee. The application filing fee was estimated based on the average time expected to review and AIA application and conduct emissions calculations/modeling for the project.

D. Use for Environmental Review – CEQA

The ISR program operation is not subject to CEQA requirements. The review conducted on applications for the program is a ministerial action not subject to CEQA, per PRC §21080 *Division Application to Discretionary Projects; Nonapplication; Negative Declarations; Environmental Impact Report Preparation* (b)(1):

> *(b) This division does not apply to any of the following activities:*
> *(1)Ministerial projects proposed to be carried out or approved by public agencies.*

The ISR Program will require an amount of emission reductions from certain development projects subject to the rule. Implementation and compliance with the rule will reduce the cumulative NOx and PM10 impacts of anticipated growth to less than significant because the reductions attributed to this program were identified in two attainment plans as necessary to achieve the applicable standards. CEQA Guidance document § 15064 (h)(3) states-

> A lead agency may determine that a project's incremental contribution to a cumulative effect is not cumulatively considerable if the project will comply with requirements in a previously approved plan … which provides specific requirements that will avoid or substantially lessen the cumulative problem (e.g. … air quality plan).

The GAMAQI will be updated with any necessary changes to District CEQA policy and provides a suitable location for changes to defaults and guidance on model usage.

E. APCO- Approved Models

Proposed Rule 9510 specifies the use of an APCO-approved model, which in most cases will be URBEMIS. URBEMIS stands for "Urban Emissions Model." URBEMIS was originally developed by the California Air Resources Board (ARB) as a modeling tool to assist local public agencies with estimating air quality impacts from land use projects when preparing a CEQA environmental analysis. The model was developed to estimate construction, area source, and operational air pollution emissions from vehicles from a wide variety of land use development projects in California, such as residential neighborhoods, shopping centers, office buildings, etc. Originally designed as a 'sketch planning' tool for CEQA project review, it has been continuously enhanced with each new version to provide greater capability and accuracy. URBEMIS is used statewide by air agencies and public agencies and contains air basin-specific information. URBEMIS has substantial flexibility to accommodate project specific travel and vehicle information when available. The model also includes a mitigation component that allows the user to select specific measures and quantify emission reductions associated with the selected measures[5].

The District undertook an extensive effort to ensure that URBEMIS is the right tool for this program. The District hired a consultant, TY Lin International/CCS, to review

available land use emissions models, recommend which model is most suitable for this program, and identify areas of improvement. The consultant recommended URBEMIS as the best tool for ISR for several reasons, including:

- URBEMIS contains the latest California-specific emission factors with motor vehicle emission factors based on EMFAC2002,
- URBEMIS is the only model that contains emissions calculations for PM10
- URBEMIS contains emissions calculations for area sources
- URBEMIS contains motor vehicle activity based on trip rates from the Institute of Transportation Engineers (ITE)
  ITE rates are nationally accepted, are widely used and have withstood legal challenges.
- URBEMIS does not require large amounts of input for an emissions estimate (it is easy to use)
- URBEMIS inputs are objective and quantifiable.
  For Example- For sidewalk coverage, the input fields include percent of streets with sidewalks on both sides and the percent of streets with sidewalks on one side.
- URBEMIS contains the flexibility to modify defaults if project-specific information is known.
- URBEMIS is free.

TY Lin International/CCS made recommendations on the improvements to the area-wide mitigation component and hired a sub consultant, Nelson/Nygaard, to make detailed recommendations for improvements to the operational mitigation component. Nelson/Nygaard researched the latest studies on land use, what design features consistently reduced vehicle activity (and consequently emissions) in the real world and by how much. Nelson/Nygaard then created emissions reduction calculation methodologies based on those studies and submitted a report to the District. The District then initiated an extensive statewide effort to update the URBEMIS model with the resulting recommendations. The District, TY Lin International/CCS, and Nelson/Nygaard met with the URBEMIS working group, which is a group of representatives from air districts throughout the state of California, as well as the California Department of Transportation (CalTrans), and presented the recommended changes to URBEMIS. Once the URBEMIS Working Group made recommendations that were incorporated into the report, the report was then peer reviewed by several well respected researchers in the field of land use and travel activity. The peer review comments were incorporated into the report and approved. The final report was incorporated into URBEMIS 8.7, released to the public, and is included in this document as Appendix D.

The URBEMIS model would require, at minimum, the following inputs: type of land use, number of units, and any mitigation measures selected. However, there are numerous defaults that can be modified if more precise information on the project is available.

These can include: trip rate(s), emission factors and usage rates for specified area source emissions, year of project use, fleet characteristics in terms of percentage of and fuel use of vehicle types, trip speeds, trip lengths, trip percentages, ambient seasonal temperatures, variable start percentages, and emission reduction inputs. Emission reduction inputs can include increased density, zero hearth options, percent energy efficiency beyond Title 24, percent of landscape equipment electrically powered, number of housing units and study area employment (job to housing ratio), the presence of local serving retail, the number of transit stops, intersections per square mile, percentage of streets with sidewalks, percentage of bike lane coverage, percentage of housing units below market rate, numerous transportation demand management measures, number of actual parking spaces, and controls on fleets. Based on those inputs, the model calculates total area source emissions, total vehicle emissions, total overall emissions and total reduced emissions in terms of lbs/summer day, lbs/winter day, or tons/year.

In addition to the benefits of URBEMIS, this model was chosen over other potential models for various reasons. A different option was to use transportation models used by the COGs for conformity purposes. Transportation models, while appropriate for their current use, are not appropriate for ISR for the following reasons:

- There is not one model used valley-wide.
    - *There are eight different models. Some cover only one county, others cover multiple counties.*
- The eight models do not use the same modeling basis, making for inconsistencies of software if multiple models are used.
- The analysis requires subjective inputs.
- Certain trips are not accounted for in the transportation model.
  For example- While URBEMIS will account for the very-short trips associated with new gas stations (passby trips), transportation models do not include the short drives into gas stations.
- The transportation models include deviations from known trips.
    - *They do not account for 10-15% of trips on Arterial Streets*
    - *They do not account for 15-35% of trips on Collector Streets*
    - *Trips on local streets are not included*
- The trip types come from old, 1970's data that is only periodically updated.
- Does not include new area emissions, which are wholly attributable to new developments.
- Transportation modeling requires many inputs, and is not easily used by an average applicant.
- Transportation modeling is not free

It is the view of the District that URBEMIS is the best tool available. As stated above, URBEMIS has a solid, proven basis (EMFAC2002, ITE, peer-reviewed quantification), is flexible and allows changes to various calculation inputs when project-specific information is known. Comments received by the District pointed out that URBEMIS

contains some information that may need refinement. Particularly, the fleet mix and the on-road silt-loading factor. The District agrees that new, more accurate information should be incorporated into URBEMIS when that information becomes available Concerning the on-road silt-loading factor, the District concurs with the air basin specific factor received in comments and will be recommending using the factor of .031 for analyses prepared for the rule and will incorporate that factor into the San Joaquin Valley portion of URBEMIS. To remedy the fleet-mix issue, the District has hired a consultant (VRPA) to investigate and recommend new land-use specific fleet mixes. In addition, the District is participating in a statewide effort to improve the construction portion of URBEMIS. In the interim detailed guidance and sample construction inputs will be provided by the District to assist applicants.

F. Other Issues

The 2003 PM10 Plan also included a one-ton per day PM10 emission reduction commitment for Metropolitan Bakersfield by 2010. That commitment is being addressed through a "task force" composed of staff from the City of Bakersfield, Kern County, and the District. The task force is identifying the projects that would provide the greatest impact on ambient PM10 levels in the area.

Input from the public during the scoping meetings and from written comments suggested that the proposed indirect source rules should include existing sources as well. There are several types of land uses that generate significant trips that could be considered: event centers, distribution centers, and regional shopping centers. The District has performed some preliminary research on distribution centers and warehouses. There are well over 2600 distribution facilities in the SJVAB, with an average size of 800,000 sq ft, according to District estimates. The District will continue to consider regulations on these types of sources for some time in the near future.

The District will work to coordinate the ISR program with the public agency land-use approval process. The District will be coordinating review with the public agency through-

1. Making the ISR process concurrent with or prior to the public agency process;
2. Forwarding a copy of the AIA application (upon determination of completeness), a copy of the AIA approval package (upon approval), and a letter of Final Compliance to the public agency for voluntary review and commenting;
3. Communicating with the public agency when necessary during the application review process; and
4. Incorporating ISR AIA data into the District's CEQA commenting process.
5. Providing a letter of project status to the public agency upon request.

In addition, the application and approval will be made available to the public.

V. EMISSIONS AND EMISSIONS REDUCTIONS

The District committed to reduce the PM10 and NOx emissions from indirect sources in the 2003 PM10 Plan and the Extreme Ozone Attainment Demonstration Plan, which could be achieved by on-site emission reduction and/or emission based fees that would be used to fund off-site emissions reduction projects. Both plans contained emissions reduction commitments from growth that were necessary to demonstrate attainment. Appendix B contains an estimate of total emissions and emissions reductions expected from new development projects by 2010, which are 5.4 tons per day of NOx and 5.8 tons per day of PM10.

The ISR program is expected to achieve the emission reductions committed to in the PM10 and ozone plans. However, the District realizes that those emission reductions may not be achieved for a variety of reasons. If the emission reductions are not achieved because growth becomes less than that forecast in the emission inventories, the District will not need to adjust the program to make up the reductions. This is because the need for emission reductions was based on the projected growth. If growth occurs at a level less than that predicted, then the level of emission reductions needed will similarly be reduced. However, if other circumstances are encountered and the emission reductions are not achieved, the District will have to make a SIP revision, possibly substituting another measure for the remainder of emission reductions required or adjusting the off-site mitigation fee program to obtain greater reductions.

The District based its estimate of emission reductions achievable by the ISR program on total growth in the emission inventory that is subject to the rule accounting for rule mitigation requirements, exemptions and applicability thresholds. The District considered using a bottoms-up estimate of emissions based on the number of projects and units expected each year. Statistics on residential development were available for this type of analysis; however, due to the wide variety of uses and limited data on the numbers and sizes of non-residential uses, a comprehensive bottom-up analysis was not feasible.

VI. COST EFFECTIVENESS – OFF-SITE EMISSION REDUCTION PROJECTS

District staff has prepared a draft cost effectiveness analysis of the estimated costs of emission reductions required in the proposed Draft Rule 9510. The cost effectiveness analysis is attached to this staff report and labeled Appendix E. This analysis details the types, quantities and costs of projects available for funding from the off-site fees collected by the District, and provides an example mix of projects to demonstrate how the fees may be used. The District shall use 100% of the off-site funds received for

emission reduction projects. No off-site funds may be used for the District's budget, staffing or other administration.

Off-Site fund use accountability is written into the Draft Rule 9510. The District shall provide annual reporting per draft Rule 9510 Section 10.4. Annual reports shall include, at a minimum: the total amount of off-site fees received; the total monies spent; total monies remaining; any refunds distributed; a list of all projects funded; the total emission reductions realized, and; the overall cost-effectiveness factor for the projects funded. Annual reports shall be made available to the public.

For off-site emission reduction projects, the duration of the contract will vary depending on the project. Some contracts will be completed upon installation, while others may require reporting for 5 years or longer. For example, a road-paving project would have a contract that is completed upon installation, whereas an engine contract typically contains a 5-year reporting requirement.

VII. SOCIOECONOMIC IMPACT ANALYSIS

Pursuant to state law, the District is required to analyze the socioeconomic impacts of any proposed rule or rule amendment that significantly affects air quality or strengthens an emission limitation. The provisions of Draft Rules 9510 and 3180 will reduce PM10 and NOx, emissions by requiring pollutant specific mitigation through measures incorporated in to the design of a new project, and/or paying a fee to fund emissions reduction projects; therefore, District staff solicited volunteers from affected entities to participate as members of the socioeconomic focus group for these rules. District staff held a focus group meeting, to identify the socioeconomic impacts of the draft rules. District staff will use the socioeconomic analysis to further refine the draft rules. The socioeconomic report was released to the public for comment and review and was presented at the final workshop. The report was incorporated into this staff report as Appendix F. The final socioeconomic report will be presented to the District Governing Board at the public hearing for adopting the proposed rules.

The implementation of ISR fees may have socioeconomic impacts on certain development types that are summarized below and described in the socioeconomic impact analysis. Although impacts may occur, the program has been designed to minimize economic impacts and to allow options to developers that minimize their fees. However, the District recognizes that some businesses and individuals will be impacted, but believes that the impact is justified by the benefits of the rule to the Valley. The rule is designed to reduce emissions of pollutants contributing to poor air quality in the entire air basin and will provide a health benefit through its implementation. The District is required to attain federal air quality standards by specific dates with reductions contained in District attainment plans. These plans rely on reductions from ISR that if not achieved will result in sanctions that would cause a far greater impact to the Valley's economy than

implementing the rule. If ISR were not adopted, rules on other industries with as great or greater economic impacts would still be required.

A. RESULTS

SINGLE-FAMILY RESIDENTIAL. The Socio found a less-than-significant impact on Single-Family Residential project applicants for 2006, 2007 and 2008. The Socio found a minor increase in the price Single-Family Residential buyers would find in the average Valley City for 2006, 2007 and 2008. See Appendix F Tables 19-21 and associated text.

MULTI-FAMILY RESIDENTIAL. The Socio found a less-than-significant impact on Multi-Family Residential project applicants for the average Valley city for 2006, 2007 and 2008. The Socio found a minor increase in the price Multi-Family Residential buyers and renters would find in the average Valley City for 2006, 2007 and 2008. Multi-family residential development in small and medium sized bedroom communities is projected to experience a significant impact in 2007 and 2008. Small rural/farming communities could have a significant impact in 2008. The reason for the greater impact in these particular areas is the lower overall cost of housing in those areas making the fee a higher percentage of the housing cost. This impact is mitigated to some extent by the rule threshold of 50 units and 2 tons per year of emissions. Many projects in those areas are small. Some locations qualifying as bedroom communities are seeing very rapid growth in housing stock that is as expensive or more expensive than in the large urban areas. This trend may also limit the areas of impact. Due to the ability of the developer to pass on or absorb at least part of the cost and for consumers to amortize the cost in a mortgage or through rents, the District believes that this impact is not significant. See Appendix F Tables 23-25 and associated text.

INDUSTRIAL. The Socio found a less-than-significant impact on industrial project applicants for 2006 and 2008. The Socio found a less-than-significant impact on industrial renters in 2006 and 2008. See Appendix F Tables 28 and 29 and associated text.

OFFICE. The Socio found a less-than-significant impact on office project applicants for 2006 and 2008. The Socio found a less-than-significant impact on office renters in 2006 and 2008. See Appendix F Tables 28 and 29 and associated text.

COMMERCIAL. The Socio found a less-than-significant impact on industrial project applicants for 2006, but a significant impact in 2008. The Socio found a less-than-significant impact on commercial renters in 2006, but a significant impact in 2008. Commercial uses with a small footprint but high trips due to customer turnover experience the greatest impact. Commercial and other development types may reduce their fees with on-site measures. Many measures are available that may be required for other purposes and add no cost to the development, but can add amenities and value to the project. This would provide a mechanism to reduce the impact of the fee. Overall, the District concludes that with mitigation options and the ability to pass costs

on to project tenants, this impact should not be considered significant. See Appendix F Tables 28 and 29 and associated text.

PROSPECTIVE HOME-BUYERS AND SMALL BUSINESSES. Socio Section 6.4 addresses the impact on small business and includes a discussion of potential disproportionate impact on home-buyers and small business. The socio concludes that the increased costs due to the fees would have a temporary impact while the consumer responds to the costs with changes in purchasing decisions or increases income.

VIII. ENVIRONMENTAL IMPACTS

Pursuant to state law, District staff has conducted an initial study to identify any possible environmental impacts of this program and prepared a proposed negative declaration for draft Rules 9510 and 3180. The 30-day comment period for the proposed negative declaration ends on December 5, 2005. The District Governing Board will consider approving the negative declaration at the December 15, 2005 public hearing for the rules.

IX. RULE CONSISTENCY ANALYSIS

Pursuant to the California Health and Safety Code, Section 40727.2, District staff has prepared a rule consistency analysis of the program and is included in this staff report as Appendix G. The Rule consistency analysis shows the rule is non-duplicative, and consistent with existing District, state and federal rules.

X. REFERENCES

1. California Air Resources Board, Emissions Inventory, www.arb.ca.gov.

2. California Air Resources Board, *Status Report,* 1994

3. California Department of Finance, Population Projections, www.dof.ca.gov/HTML/DEMOGRAP/projco.pdf

4. 2003 PM10 Plan, Appendix B

5. South Coast AQMD website, Frequently Asked CEQA Questions, http://www.aqmd.gov/ceqa/faq.html

APPENDIX A

Responses to Comments on Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Indirect Source Review)

December 15, 2005

SUMMARY OF COMMENTS AND RESPONSES ON THE RECEIVE AND FILE OF DRAFT RULE NOVEMBER 17, 2005

Public Comment
Date November 5, 2005
Multiple Letters- Signed by

Kaaren Page	Betty Sanderson	Theresa Stump
Stephen Page	J Wesley Sanderson	Bill Moffit
Warren A. Minna	Georgette Theotig	Deb See
Nancy Faisselman	Isabel Stierle	Rosmarie Grabski
Nany Bacon	Li?? Wa???	Monte Harper
		Emid Harper

As a resident of the San Joaquin Valley, I am very well aware that the Valley is rated as '*extreme non-attainment*' when it comes to meeting federal air quality standards. We must take bold steps to clean up our air while allowing reasonable housing growth.

The best way to reach this goal is through your proposed Indirect Source Rule Package (Rules 9510 and 3180) that the District is sponsoring. This is accomplished two ways: allowing housing and commercial developments to be designed to reduce air pollution and to charge a fee for that air pollution that cannot be eliminated, with the fees being used to fund other projects that reduce air pollution.

1. **COMMENT:** I support a strong version of the rule that offers a real chance to improve the air in the valley and at the same time allow developers to use innovative design features to reduce our dependency on automobile transportation.

Our lungs, our health, and our children deserve no less.

RESPONSE: Comment Noted

California State Department of Housing and Community Development:
Date: November 29, 2005

Thank you for the continued opportunity to comment on the San Joaquin Valley Air Pollution Control District's (District) proposed Draft Rules 9510 and 3180 (Rules). The Department has reviewed the draft Rules as revised November 17, 2005 and the District's "Response to Comments" found in Appendix A of the draft Rules. The Department appreciates the District addressing some of the issues raised in the

comment letters of July 25, 2005 and September 15, 2005. However, as discussed below, the Department continues to have a number of concerns with the revised draft of the Rules.

Proposed Rule 9510 does not comply with the "clarity," "consistency," and "nonduplication" requirements set forth in Health and Safety Code Section 40727, and an adequate nexus has not been established to support these rules. In addition,

2. **COMMENT: The proposed inclusion, followed by the deletion of, an exemption for housing directly assisted by federal, State, or local government is of particular concern.** The District's response to comment #92 indicated the government supported housing exemption (affordable housing) was removed "based on the District's internal analysis of applicability and impacts….". Although affordable housing qualifies as a mitigation measure, it is unclear how the URBEMIS model assesses and credits affordable housing. Affordable housing is often a catalyst for the type of transit-oriented development that is encouraged by the District's policy recommendations as described in District's *Air Quality Guidelines for General Plans*. According to the Air Resources Board's study, *The Land Use – Air Quality Linkage*, densities found in affordable housing developments are generally high enough to provide the ridership needed to support transit service (page 15).

RESPONSE: As stated in the November 17th Staff Report (p. 11) and in the September 1, 2005 Response to Comments, the methodology for emission reduction is detailed in the URBEMIS User's Guide (http://www.aqmd.gov/ceqa/urbemis.html). Basically, the trip reduction benefit of below-market-rate housing will be credited to a development that includes this feature. In addition, Appendix D- Recommended Changes to URBEMIS details the research supporting the emission reduction and the methodology for the reduction on pages D-38 through 39 and includes the following statement:

> *… Thus, the total reduction is as follows:*
>
> *Trip reduction = % units that are BMR * 0.04*
>
> *A development with 20% BMR units would thus gain a 0.8% reduction. A development with 100% BMR units would gain a 4% reduction.*

3. **COMMENT:** There is also insufficient information in the draft Rule analyses to discern whether and to what extent affordable housing developments, despite qualifying for some mitigation credits, might be subject to fees for off-site emissions reductions. This has the potential to render projected affordability levels or the projects themselves, infeasible as proposed. Affordable housing development proposals, are already subject to significant development constraints despite their acknowledged benefit potential relative to air quality.

Applying Rule 9510 to these projects would subject them to an additional and ambiguous permit requirement. This effect would be inconsistent with State laws which require affirmative actions to promote affordable housing opportunities. Accordingly, the Department urges the District to reinstate the exemption for housing projects in which at least 49 percent of the units are reserved for lower-income households and which are directly assisted by federal, State, or local government.

RESPONSE: The staff report and socio-economic impact analysis recognize that any fee would increase costs, but that market forces so far outweigh the effect of the fee that they render it insignificant. The District disagrees that the rule is contrary to state law promoting affordable housing. Rule 9510 is being adopted to reduce the air quality impacts of new development, including housing projects serving all market segments. Since the rule contains provisions to reduce potential fees for developments that contain affordable housing, it encourages affordable housing to be included in more projects.

4. **COMMENT:** Having deleted the exemption, the District must now amend those documents that were based on the exemption being part of the project. This includes the CEQA initial study which describes the project as exempting some sources including “certain low-income housing projects” (page 4). By removing the exemption, the District has redefined the project.

RESPONSE: The District does not concur that removing the low-income housing exemption substantially changes the project analyzed in the CEQA initial study. First, the socioeconomic impact analysis that is the basis of the initial study discussion on impacts on housing and population indicated that low-income households were already unable to afford new homes and rental units affected by the rule. The revised socioeconomic impact analysis was based on the latest rule version and arrived at the same conclusions regarding impacts with and without the exemption. Therefore, the impacts examined in the initial study are also the same. Second, by removing the exemption for "certain low-income housing projects", the language of the Rule would result in a slight reduction in air quality impacts, as some additional housing projects would now be subject to the Rule. The change in language does not substantively affect the analysis of environmental impacts. On the contrary, the language change would result in an environmental benefit.

5. **COMMENT: Although the District does have the authority to implement regulations to accomplish the reduction or mitigation of emission from indirect sources, it does not have the authority to operate a permitting system for the operation or construction of these sources and has failed to show the required nexus.** The proposed Rules would impose an (off-site) fee

on development projects which are unable to incorporate on-site measures adequate to reduce indirect emissions to a specified level. The fee is determined via an application (Air Impact Assessment Application (AIA)) which is required to be approved by the District before a final discretionary permit is issued for the construction of the development project. Unless the AIA application is submitted, the project cannot go forward without the developer incurring civil penalties. In such circumstances, contrary to the assertions of the staff analyses, a fee is being imposed as a condition of approval of a development project. A 1993 Attorney General Opinion explained that "the Legislature has recognized indirect sources as essentially different from other sources of pollution and consequently has made them exempt from ordinary permitting requirements" (Ops. Cal. Atty. Gen. 92-519). The opinion goes on to clarify that "permits may not be required of indirect sources under either the general permitting authority (Government Code Section 42300) or the special permitting authority provision relating to the attainment of State ambient air quality standards (Government Code Sections 40910-40926). Further, the imposition of fees as a condition of permit approval is subject to the nexus requirements of Government Code Section 66000 et. seq. and the District has failed to show the "reasonable relationship" nexus as required.

RESPONSE: The author is mistaken about the nature of the ISR program and how the rule is designed to be implemented. The rule is consistent with the Attorney General opinion cited in that it does not require permits. Under the commenters theory, any fee is a de facto permit. Developers are subject to civil penalties if they fail to follow any District regulation. For example, failure to comply with Regulation VIII – Fugitive Dust Rules during construction or Rule 4901 – Residential Wood Combustion fireplace installation limitations may result in civil penalties. Similarly, failure to comply with the mitigation requirements of Rule 9510 may result in civil penalties, but cannot stop a development from being constructed. The District will not be implementing a permitting system for the operation or construction of projects. The ISR program will not be a permitting system, have discretionary actions, or have any land-use authority. The author states:

> The fee is determined via an application (Air Impact Assessment Application (AIA)) which is required to be approved by the District before a final discretionary permit is issued for the construction of the development project.

However, this is not the case. The application is required, but is not tied to the *issuance* of a discretionary permit. The purpose of the application is to provide information necessary to determine if a fee must be paid and the amount of the payment if one is required. The application must be submitted concurrent with the *application* to the local land use authority for a final discretionary permit. This timing is to allow the applicant to take credit for reducing project air impacts during the local agencies approval process. The District does not require completion *prior to* issuance of a permit by the local agency, nor does the District

have the authority to stop the project from being issued a final discretionary permit by the local agency.

The District's action is ministerial, and does not involve conditions of approval. All projects are subject to the same requirements, and must fulfill the requirements. The District does have the authority to enact penalties for non-compliance; however, this does not make the actions of the District discretionary or make the program a permitting program. Further, the fee is only enacted if a project is, "unable to incorporate on-site measures adequate to reduce indirect emissions to a specified level". The required emission reduction applies to all applicable projects equally, and must be satisfied. The project applicant has the *option* to reduce the fee through on-site measures. There is no discretion on the part of the District. The author's statements on applicability of laws regulating permitting actions do not apply to the ISR program, as it is not a permitting program.

The District continues to assert that Rule 9510 is not subject to Government Code Section 66000 et. Seq. Regarding the reasonable relationship requirement, the District has clearly made this demonstration. The air quality impacts of construction, area source and indirect source emissions from development projects and the methods used to quantify these impacts are clearly identified in the staff report and are undeniably contributing to the air basin's serious air quality problems. The emission reduction projects that will be utilized to mitigate a portion of these impacts are also clearly identified. Sufficient checks and balances are in place in the rule through an elected Governing Board and EPA oversight of this state implementation commitment to ensure that the mitigation funds will be used effectively on the impacts created by the development projects.

6. COMMENT: The consistency analysis (Appendix G) fails to include analysis and findings relative to other State laws and regulations, including directly related provisions of the California Environmental Quality Act (CEQA). The District already has existing procedures for permit review pursuant to CEQA, which are put forth in its "Guide for Assessing and Mitigating Air Quality Impacts". Proposed Rule 9510 should be subjected to a rule consistency analysis with this guide, as well as requirements for air quality analysis and mitigation pursuant to CEQA which is undertaken in the permitting process of local governments. The Department remains concerned about the duplication of assessment and potential duplication of mitigations pursuant to CEQA and the proposed Rule 9510. The District's decision to modify its CEQA handbook *after* the adoption of the proposed rules (G-2) is inconsistent with the requirement of Health and Safety Code 40727.

RESPONSE: The Guide for Assessing and Mitigating Air Quality Impacts (GAMAQI) identified by the author is a voluntary guidance document for use by lead agencies addressing air quality in CEQA documents and is in no way regulatory. Under CEQA, for most development projects the District is a commenting agency. As a commenting agency the District provides comments to the Lead Agency to the following aspects: the potential significance of air quality impacts of a project; applicable District Rules; potential mitigation measures; and if an analysis is provided to the District, the adequacy and accuracy of that analysis. Requesting comments from the District is voluntary by the Lead Agency, and comments and mitigation measures suggested by the District are non-binding. CEQA requires *disclosure* of environmental effects for discretionary actions by a public agency, and requires reasonable and feasible mitigation of effects that are determined to be significant. Nowhere within CEQA can the District require a reduction in emissions from a development project. Voluntary CEQA commenting is not parallel to an ISR program. Mitigation required by CEQA is not the same in intent, requirements, or in practice with the emission reduction requirements of the ISR program. ISR is not duplicative of any mitigation required by the lead agency since the rule provides for credit for all measures and features included in the project that reduce emissions when project emissions are calculated. The District disagrees that modifying the District's GAMAQI after adoption is inconsistent with the California Health and Safety Code (CH&SC) Section 40272 for all the reasons stated above.

CH&SC Section 40272(b)(4) states:

> **"Consistency" means that the regulation is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.**

CH&SC Section 40272(b)(5) states:

> "Nonduplication" means that a regulation **does not impose the same requirements** as an existing state or federal regulation unless a district finds that the requirements are necessary or proper to execute the powers and duties granted to, and imposed upon, a district.

CH&SC Section 40727.2(a) states:

> **…** the district shall identify all existing **federal air pollution control requirements,** including, but not limited to, emission control standards constituting best available control technology for new or modified equipment, **that apply to the same equipment or source type as the rule or regulation proposed for adoption or modification by the district…**
>
> ***And***
>
> **…**The analysis shall also identify **any of that district's existing or proposed rules and regulations that apply to the same equipment or source type, and all air pollution control requirements and guidelines that apply to the same**

equipment or source type and of which the district has been informed pursuant to subdivision (b)

CH&SC Section 40727.2(h) states:

Nothing in this section limits the existing authority of districts to determine the form, content, and stringency of their rules and regulations. In implementing this section, it is the intent of the Legislature that the districts retain their existing authority and flexibility to tailor their air pollution emission control requirements to local circumstances.

The District has performed the analysis required by CH&SC 40727 et. seq, in Appendix G: Rule Consistency Analysis. First, no person has identified any existing federal or state requirement or guideline that applies to the same type of source that the District is proposing to regulate per CH&SC Section 40272(b). Second, the District identified few District rules for consistency analysis, and no US EPA rules or guidelines that apply to development projects in terms of New Source Performance Standards, Control Technique Guidelines, Maximum Achievable Control Technology or National Emission Standards for Hazardous Pollutants.

The District has found that the proposed ISR program is consistent with existing District rules, and has determined that there is no conflict or duplication with existing state law and CEQA.

7. COMMENT: The direct and indirect costs imposed by the Rules on the residential development process will result in increased housing costs. The preparation of the AIA (which not only calls for a detailed Urban Emissions analysis (URBEMIS)), but also for ongoing monitoring of selected mitigation measures), is likely to result in increased costs. In some instances, despite the assessment of the socio-economic analysis, the mitigation fees could have a detrimental impact on the economic feasibility of developers of market-rate mixed-use and workforce housing. These types of developments are already financially burdened since they typically have a more difficult time obtaining financing and quickly bringing a project into the market place.

RESPONSE: The cost of the preparation of a typical AIA is included in the application-filing fee— $400 for residential projects and $600 for non-residential projects, regardless of number of units. Worst case for a 50 unit residential subdivision would be $80 per housing unit. The modeling required for an AIA will be done by the District if not provided by the applicant. Monitoring of mitigation measures selected will only occur for measures that are not already required by another public agency, and the costs will be born out of the administrative fees from the rule (assessed at 4% of the off-site fee amount). Therefore, there are no costs additional to those discussed in the Socioeconomic Analysis.

8. COMMENT: By proposing to control emissions through fees that will be used to fund other projects, the District would be treating housing developments as direct sources when they are in fact indirect sources. The CEQA initial study for the proposed rules describes the project's purpose as being to "reduce emissions of NOx and PM 10 from new development projects" (page 4). If the fees collected under the Rules are a mechanism to control emissions from new development projects, then the District is adopting a market-based incentive program and is subject to the Economic Incentive Program (EIP) requirements, as was asserted by the Environmental Protection Agency (EPA) in their comments. Market-based programs may only be used for direct sources. "An EIP is a regulatory program that achieves an air quality objective by providing market-based incentives or information to ***emission sources*** (emphasis in original). By providing information or flexibility in how sources meet an emission reduction target, an EIP empowers sources to find the means that are most suitable and most cost-effective for their particular circumstances. By setting a price on pollution and pollution reductions through a fee-based approach or a trading program, some sources can realize an economic reductions for less than the cost imposed by a fee (*Improving Air Quality with EIP, EPA-452/R-01-001, January 2001 at 23)*. The proposed Rules allow a developer to either use the on-site emissions controls or to pay a fee and thus "realize an economic gain or avoid additional costs by making the reductions for less than the cost imposed by a fee." The District has failed to show the proposed Rules are consistent with EPA's EIP guidance and is treating new developments as direct sources.

RESPONSE: The District disagrees that EIP guidance applies. Although there are similar elements in EIPs, Rule 9510 contains both voluntary elements (onsite mitigation) and mandatory elements (mitigation fees) that preclude the use of the EIP guidance in its entirety. Still, the rule meets the SIP submittal criteria that apply to all rules of being surplus, enforceable, quantifiable, and permanent for the time required in the SIP and meets the fundamental EIP principles of integrity, equity, and environmental benefit.

9. COMMENT: It is impractical, and an excessive and unnecessary burden for applicants to be required to include justification of mitigation measures not selected, as is proposed by Section. 5.3.2. The on-site checklist contains a number of emission reduction measures, which will often be inapplicable. As a result, Section 5.3.2 should be deleted. As proposed, the provision implies, for example, that all 18 of the on-site measures listed in Appendix C for residential projects (or 39 if the "on-site enhancing measures" also required justification) could be applicable for all projects. Measures which would not be routinely feasible or applicable, include but are not limited to:

- An on-site bike lane would not likely be warranted or feasible on the site of a 50-unit apartment building (R-7) nor would an apartment building involve the design of street patterns (R-10).

- "Reduce Wood Fireplaces and/or Woodstove above that required by District Rule 4901" would not be applicable to most new apartment buildings (R-14).

- All new subdivisions cannot be sited within half a mile of an existing transit stop, and it is beyond the ability of applicants to have a transit stop added within a half a mile of a new subdivision (R-2), independent of where the project is located.

RESPONSE: The District does not agree with the author's statement that it is impractical, excessive and/or an unnecessary burden to include justification. The purpose of the justification is to encourage developers to examine the potential measures more closely and not immediately reject a measure without considering its feasibility. Onsite measures have permanent air quality benefits and typically create value and provide other benefits to the development. Measures included as mitigation measures in the lead agencies CEQA document, as most are expected to be, will not require District long term monitoring. If a measure is impractical or not applicable to a project, the applicant needs only to state that in the justification. The District does not see how this is an undue burden. Finally, onsite measures are implemented voluntarily by the developer and are not required by Rule 9510.

10. **COMMENT:** As a result of these concerns, the Department respectfully requests that the District not adopt the Draft Rules as proposed and continue to work with all interested parties on needed revisions. Thank you for your consideration of these concerns. For further discussion or to set-up a meeting, please contact Linda Wheaton, Assistant Deputy Director, at (916) 327-2642.

RESPONSE: Comment Noted.

City of Porterville
Date: November 29, 2005

11. **COMMENT:** The City of Porterville appreciates and encourages the District's efforts to improve air quality in our Valley, however, the District staff report does not clearly define how the additional fees acquired through adoption of the DESIGN program would result in a quantifiable improvement to air quality in the San Joaquin Valley air basin beyond the measures already in place. Further, neither rule dictates a funding source to compensate local jurisdictions for the

additional efforts resulting from approval. Please provide clarification of these points in the final rules. Thank you for the opportunity to comment.

RESPONSE: First, Appendix B – Emission Reduction Analysis, Attachments 2 and 3 show the tonnage of offsite reductions that are estimated to occur as a result of the adoption of the ISR rules. By 2010, it is estimated that the ISR will achieve 5.4 tons per day (tpd) reduction of NOx, and 5.8 tpd reduction of PM10 from growth. The amount of off-site reductions (from the fees) are 4.7 tpd and 4 tpd of NOx and PM10, respectively. These estimates are based on the amount of reduction required by the rule, and assume an amount of that reduction is achieved on-site. The off-site fees will be used to achieve this reduction, as specified in Appendix E: Cost Effectiveness Analysis, which states how much in off-site fees is expected and how that money will be spent to achieve quantifiable reductions. Specifically, Appendix E: Cost Effectiveness Analysis, Attachment 1 (p. E-13 through E-33) details potential projects, the amount of reduction achievable, the cost of those reductions and a potential spending plan.

Second, the rule does not dictate a funding source to compensate local jurisdictions because there are no requirements placed on local jurisdictions. The local jurisdiction is not required to review, assess or otherwise act on ISR projects. The District is committed to including local jurisdictions in the process through informing them of projects and project-specific information received by the District, and District actions on those projects just as it does now when it provides comments on local agency CEQA referrals. However, neither the ISR rules nor the administrative process require 'additional efforts' from local agencies.

Visalia Unified School District
Date: October 25, 2005

On behalf of the Visalia Unified School District ("the School District"), I respectfully submit the following comments and questions to Draft Rules 9510 and 3180 of the San Joaquin Valley Air Pollution Control District ("the Valley Air District"). I am unclear about several items in the Valley Air District's proposed fee and plan to decrease emissions' impact from new development in the area. The School District's main concern is that the Draft Rules lack sufficient clarity to allow the School District to analyze what the potential impact of the new fees may be and whether the fees would actually be applicable to our projects. The School District is particularly concerned because any fees that must be paid as a result of the enactment of the Draft Rules will reduce the School District's financial ability to provide classrooms to students in these newly developed areas.

12. COMMENT: Applicability of Draft Rules to the School District

It is unclear whether the Draft Rules apply to the School District's construction of new schools. Section 2.1 of Draft Rule 9510 states that the rule applies "to any developer that seeks to gain a final discretionary approval for a development project… of … 9,0000 square feet of educational space." The Draft Rules define "developer" as any person or entity that undertakes a development project. Also, the definition of a "development project" includes any project that it "subject to a discretionary approval by a public agency" where the discretionary approval "requires the exercise of judgment or deliberation."

The school District takes the position that the Draft Rules do not apply to it because it does not operate as a "developer" and the School District school construction projects are not development projects since they are not "subject to the discretionary approval by a public agency." However, according to the Draft Rules, if a developer is constructing a school facility on behalf of the School District, then due to the definitions in the Draft Rules, the fee may be applicable.

RESPONSE: If the approval to site and construct a new school is not subject to a discretionary permit, then the author is correct that the ISR rules would not apply. Otherwise, schools have many options available in onsite measures that would substantial reduce any potential fee.

13. COMMENT: Fee Calculation

In addition to the question of the fee's applicability, the formula to be used in calculating the air impact mitigation fee is extremely confusing. A more straightforward formula from which the estimates of fees can be made would prove beneficial to those impacted by the Draft Rules. If these Draft Rules are intended to apply to the School District's development of new schools, a more concise formula would help us in the planning and estimating process.

RESPONSE: Although the fee formula is somewhat complex, it is the most accurate and equitable way to assess fees based on emissions to achieve the emission reduction committed to in the District's SIP. The District has found that using an excel file to calculate fees is easy and accurate. The District will make a calculator with the formula built in available to the public prior to implementation. Prior to that, the District is willing help applicants and agencies create an excel file that calculates emission reductions required and fees required.

14. COMMENT: Requirement of Nexus

The School District has reviewed comments to the Draft Rules submitted by other associations that are impacted by these rules. One major problem noted by many of the commentators related to the fact that the Draft Rules fail to comply with the nexus test required by AB 1600, enacted as Government Code

Sections 66000 et seq, and as required by case law such as in *Ehrlich v. City of Culver City* (1996) 12 Cal4th 854.

Similarly, we would like to express our concerns that the fees proposed do not appear to demonstrate a reasonable relationship to the cost of implementing the air pollution mitigation program. It appears to us that there is a huge disparity between the cost of implementing the mitigation program and the fees to be collected. Further, the Draft Rules and supporting analyses are largely silent on the actual mitigation measures to be funded that will reduce emissions' impact resulting from a given project. It would be helpful if the Valley Air District provided details of the actual measures and projects that will be undertaken to reduce emissions' impact as well as the benefits accruing to the public as a result of these measures.

RESPONSE: Please refer to the September 1, 2005 Response to Comment #125 about the analysis of nexus applicability that the District performed. The District disagrees that there is a disparity between the fees to be collected, estimated as up to $103 million between 2006 and 2008, and the cost of achieving off-site reductions. In Appendix E: Cost Effectiveness Analysis, Attachment 1 (p. E-13 through E-33) details potential projects, the amount of reduction achievable, the cost of those reductions and a potential spending plan.

15. COMMENT: Notice to Those Impacted by Draft Rules

Although the School District is within the San Joaquin Valley Air Basin and is subject to the jurisdiction of the Valley Air District, we feel we were not provided with adequate notice of the Draft Rules. If the Draft Rules are held to apply to the School District, the fees imposed will greatly impact our ability to plan for the development of new classrooms and educational facilities. Therefore, in the future, we request written notice of proposed rules and regulations that are intended to apply to the School District.

RESPONSE: The District regrets that the School District did not receive notice of the proposed rules; however, this rule was noticed in accordance with all legal requirements. The District will add the School District to the ISR mailing list. In addition, the District suggests that the School District visit the District website at http://www.valleyair.org/lists/list.htm. The School District can receive District news, workshop notices, and other important information for this or other plans via e-mail by subscribing to one of the District's e-mail notification lists. The e-mail notification lists are setup and maintained by the end user and not by District staff. Individuals may add or delete their names from these lists at anytime.

California League of Food Processors (CLFP)
Date: November 22, 2005

16. **COMMENT:** First, CLFP supports the amendments proposed by the District that would exempt canning and food processing from Rule 9510. Most of the primary activities performed by food processors are already regulated by the District and are subject to Rule 2201 (New and Modified Stationary Source Review Rule) and Rule 2010 (Permit Rule), so the proposed exemption will avoid redundant or confusing new regulations.

RESPONSE: Comment Noted

17. **COMMENT:** Second, CLFP and other organizations have expressed concern to the District regarding the cumulative cost of complying with the various new air pollution control requirements imposed on manufacturers in recent years. The food processing industry is one of the major sources of employment in the San Joaquin Valley and the firms operate in a very competitive economic environment. The financial resources available for complying with new regulations are very limited. CLFP appreciates that the District has responded to industry concerns by recognizing the cumulative impact of air regulations and the major investments made in stationary source emission controls.

RESPONSE: Comment Noted

California Building Industry Association
Date: November 29, 2005

On behalf of the California Building Industry Association (CBIA) and its Affiliate Associations located in the San Joaquin Valley, I am entering into the formal record comments on the proposed Draft Rules 9510 and 3180 (the "ISR"). CBIA member companies provide housing that is the cornerstone of quality of life in the San Joaquin Valley.

18. **COMMENT:** The Federal Clean Air Act, 42 U.S.C. Section 7410 (a)(2)(F), requires that approvable control measures provide quantifiable, surplus, enforceable, permanent, and adequately supported reductions in air emissions. The proposed Draft ISR does not provide sufficient analysis or findings to establish that the proposed Indirect Source Mitigation Program meets these criteria. Indeed, the document barely addresses these fundamental topics. Because these criteria have not been met, the Indirect Source Mitigation Program does not meet the Federal Clean Air Act test for full approval and inclusion in the State Implementation Plan ("SIP").

Indirect Source programs, on the scale proposed by the San Joaquin Valley Air District, have not been adopted or implemented successfully anywhere in the United States. We note that USEPA has never approved a proposed indirect source rule for emission reduction credit.

RESPONSE: The District has complied with the cited Clean Air Act section. EPA has recognized that areas with a long history of air regulation must pursue new and innovative ways to reach emission reduction requirements since the stationary sources in many cases are already in their second or third retrofit requirement with rapidly diminishing air quality returns. This had led EPA to produce guidance on voluntary and emerging measures and for taking SIP credit for mobile source incentive programs. Although Rule 9510 is unique, it still meets all control measure approvability criteria. See also the District's response to EPA's comment letter on the September 1, 2005 draft.

19. COMMENT: The expected emissions benefits are not properly quantified. The URBEMIS model-based approach proposed to calculate project travel and emission impacts is inconsistent with the SIP inventory methodology. The SIP emissions inventory used the California Air Resources Board's EMFAC-2002 model to establish the NOX and PM10 emission reductions targeted by the ISR rules. One of the key components of EMFAC is a regional travel demand model ("TDM"). The TDM is used to calculate regional travel impacts such as vehicle miles traveled ("VMTs") and trips within the SIP inventory. The SIP calculations that identify further emission reductions needed for the San Joaquin Valley to attain federal ambient air quality standards are, in turn, based on vehicle travel activity forecasts from TDMs.

New project impacts determined under the ISR rules should be calculated in a manner consistent with the SIP targets to ensure no over- or under-compliance. There is an inconsistency between the way URBEMIS and TDMs calculate new or net added vehicle miles traveled (VMT) and vehicle trips. The fundamental difference between TDMs and URBEMIS is that TDMs robustly account for the interaction effects between multiple land uses, while URBEMIS does not.

Interaction effects refer to the fact that when considered together, each individual land use (or project) "competes" with others for vehicle trips. Where these land uses are located within a metropolitan area or county and how well the regional roadway network provides access to each land use affects the number of trips taken and their length (and thus VMT). For example, locating a new shopping center near an existing residential area would likely shorten the length of existing shopping trips taken from the residential area (and thus reduce VMT). It may also increase the number of shopping trips from the residential area due to its proximity compared to the location of existing shopping centers.

The Draft ISR relies primarily on URBEMIS to calculate project level impacts, even though the District's own modeling consultant has stated that this model was designed to be a "sketch planning" tool, and was never intended to provide a detailed numerical analysis of project level air quality impacts. If the travel activity (VMT and trips) of all the URBEMIS-based individual ISR project analyses were added together, they would overstate the net travel impacts determined when jointly simulating the same new projects using a TDM. This conclusion is based on a side-by-side comparison of impacts of a hypothetical but typical new residential project performed by Sierra/Dowling using URBEMIS and the Fresno County TDM. Correcting the existing biases in the URBEMIS default assumptions does not change this result because URBEMIS treats each new project and its interaction with existing land uses and other new projects separately.

The District has attempted to account for this fundamental difference between TDMs and URBEMIS by applying a 50% discount factor in the NOx and PM10 fee formulas to require mitigation of only half or one direction of two way trips between a new project and existing land uses. While in concept this approach could eliminate the double counting problem, simply slicing URBEMIS impacts in half does not demonstrate SIP consistency.

On top of this fundamental discrepancy with the SIP methodology, URBEMIS overstates residential project emissions by over 70% as a result of multiple technical shortcomings. On this basis alone, URBEMIS cannot be considered a reliable and accurate gauge of project emissions. URBEMIS' technical problems as an emission estimation tool are documented in detail in Sierra Research's comment letter of July 22, 2005.

RESPONSE: The author states that the "emission reduction benefits are not properly quantified". The District assumes the author is discussing the emission reduction benefits from implementation of the rule, which were properly quantified in Appendix B: Emission Reduction Analysis, using the known growth data (provided to the state by the COGs), and applying a standard rule penetration, estimated on-site emission reduction achievement, and applying the emission reduction requirements to the growth emissions. This analysis is considered 'top-down' and is standard practice. The analysis did not rely on URBEMIS, a project-level model or 'bottom-up' analysis, for valley-wide emissions estimates from valley-wide growth.

The District has repeatedly addressed the "70%" overestimation cited by the author as a distortion of fact. The District has stated that project-specific data is acceptable when available and has committed to addressing the few issues that have been raised concerning URBEMIS default values, and will provide guidance on those items prior to ISR implementation.

The District could not find any reference in the Clean Air Act or in EPA guidance that prescribes implementation to use the same methodology as the SIP. Indeed, the District did not find any reference prescribing a model or methodology to assess mobile and area emissions from development projects. The author's assertion that the methodology itself must be the same for the SIP and implementation is not based on any statute, guidance, or on historical methods of rule implementation. What is important is that the rule achieves the amount of reduction committed to in the SIP, and that the model produce consistent and repeatable results and be based on widely accepted inputs and methods, all of which apply to URBEMIS.

The author mischaracterizes the fee formula's use of a 50 percent baseline as a discount factor used to correct a deficiency in URBEMIS. URBEMIS correctly uses ITE trip generation rates to show the impact of all trips associated with a development project including those generated and those attracted to the site. The purpose of the 50% of the baseline in the fee formula is to meet the nexus requirements and to meet the intent of Health and Safety Code 40717.5(a)(1) for Districts to… "make reasonable and feasible efforts to assign responsibility for existing and new vehicle trips in a manner that equitably distributes responsibility among indirect sources." By basing the fee on half the emissions, the District is ensuring that only trips from the project site are assigned responsibility. Furthermore, URBEMIS has the capability to account for reductions for passby trips where someone stops on their way to their primary destination and diverted linked trips where the trip length is shortened to account for trips that although not directly on the route to the primary destination, still result in a shorter trip length than would occur if someone went there directly. Finally, URBEMIS can accept project specific trip generation information based on market studies and local traffic studies when a proposed project may produce different results than would be expected using default trip information. We believe this a reasonable and feasible effort to meet the Health and Safety Code requirements.

The District believes the best model should be used based on the needs and parameters of the project. For SIP inventory purposes, regional TDMs are the most appropriate model for estimating emissions. However, as admitted by Sierra Research (letter November 29, 2005, Comment #29 below), TDMs are regional models that are inappropriate for project-level analysis and TDMs contain their own flaws. These flaws are ignored in the author's 'URBEMIS vs. TDM' discussion. For instance, TDMs do not account for some trips on arterial and collector streets. TDMs require a large amount of data input, are not easily used, were not developed to estimate land-use impacts, and are not available to the public. Simply, TDMs are too broad of tools to accurately estimate the emissions from individual projects. A side-by-side comparison of a project-level analysis using URBEMIS and a TDM would be misleading, as a regional TDM was never meant to be, nor should be, used to estimate and individual project's emissions.

URBEMIS uses emissions factors derived from EMFAC2002, the same model used in the SIP. Several issues raised with URBEMIS (silt loading, fleet mix) will be remedied prior to implementation. URBEMIS is maintained by a statewide working group of technical experts and air districts. URBEMIS is used in CEQA analysis across the state, and is commonly used for Environmental Impact Reports (EIRs) to assess project-specific air quality impacts. URBEMIS has been used by the District and applicants in assessing air emissions for Mitigation Agreements, as well as other agencies to assess air impacts for mitigation settlements. The District has more than adequately shown URBEMIS to be the best model for the job.

The 'fundamental flaw' raised by the author simply does not exist. It has been well demonstrated that URBEMIS is the best program for ISR's needs, and it is widely recognized across the state by other air districts, local land use agencies, and other agencies as an appropriate tool for assessing specific project-level air impacts. It is the District's assessment that the author compares TDMs to URBEMIS in raising 'SIP methodology consistency' as a 'fundamental flaw' to discredit URBEMIS; and, since TDM's are inappropriate for project-level analysis, leave the District with no available model to use.

20. COMMENT: There is no discussion of whether the emissions are surplus. New development is already controlled by existing and proposed District rules, some of which overlap the ISR proposal. Dozens of cities and counties with the San Joaquin Air Basin have adopted ordnances creating local traffic mitigation and congestion relief programs, funded by fees on new development and, in the case of several counties, increased sales taxes. In addition, large scale developments, such as planned communities, are increasingly entering into air quality mitigation agreements within the context of the environmental review process mandated by the California Environmental Quality Act ("CEQA"). All of these measures address the same concerns as the Draft ISR, improved traffic flow and reduction of tail pipe emissions.

The failure of the Draft ISR and the supporting documentation to discuss or quantify the emissions reductions attributable to these other programs undercut the ability of the measure to provide surplus and quantifiable emission reductions as required by statute.

RESPONSE: The emissions growth estimates used to develop the rule are from the District's emission inventory that includes the benefit of all adopted local, state, and federal regulations and so are surplus to adopted control programs and regulations. Local regulations that have been adopted as transportation control measures currently have no emission reductions claimed in the District's SIP. Congestion relief measures and other transportation impact fees are

required just to keep emissions from exceeding emission budgets and do not provide additional SIP creditable reductions. Local programs and ordinances that do provide a surplus benefit will now be able to provide credit to their communities through the onsite mitigation component of the rule and will reduce the fees paid by developments contributing to those programs. In addition, reductions obtained through CEQA measures and Development Mitigation Agreements will be credited toward the emission reduction requirements of the rule.

There are no existing or proposed District rules that overlap the proposed ISR program. Appendix G: Rule Consistency Analysis describes other District rules and analyzes potential for inconsistency—none were found.

21. COMMENT: The proposed Indirect Source Mitigation Program does not contain an enforceable commitment. The permitting process in the Draft ISR operates independently of any other relevant regulatory process. Numerous parties have commented that the air quality impacts attributable to new development are also subject to CEQA. Early attempts by the Air District to reconcile or streamline the ISR with the normal environmental review process have been abandoned for the time being, replaced with a statement that the Air District will revise its existing Air Quality CEQA Guidelines at some future date to minimize conflicts between the two processes. By separating the Air District permit process from CEQA, the Air District has removed any responsibility for enforcement from local agencies with the land use authority necessary to enforce on-site mitigation measures.

RESPONSE: First, the ISR program is not a permitting program. Second, the ISR program is enforceable, the same as all other District Rules, and does not need to rely on 'other relevant regulatory process' and does not conflict with other regulatory processes. This enforcement authority comes from state law. In fact, most of the District's rules "operate independently of any other relevant regulatory process" as they are stand-alone rules not dependant on other regulations. Please see District Rule 1040 (Enforcement).

The District does not need to revise the Guide for Assessing and Mitigating Air Quality Impacts (GAMAQI) in order to make the rule enforceable. The District will be revising the GAMAQI in order to clarify for those undergoing the CEQA process how ISR will affect their projects. This is no different than how the GAMAQI currently addresses other applicable rules. For instance, Regulation VIII (Fugitive PM10 Prohibitions) is discussed in the text of the GAMAQI. However, the GAMAQI discussion does *create* the enforcement of Regulation VIII, but acts to inform lead agencies, consultants, project applicants, and the public.

22. **COMMENT:** In addition, no legal nexus between the proposed mitigation program and the fees imposed on individual development projects has been established. The cost and ultimate success of the mitigation measures are speculative. The Air District's proposed mitigation program, based upon after-the-fact grant applications and the funding of primarily off-site mitigation, has not worked well in other situations, such as the South Coast Air Quality Management District's Mobile Source Reduction Commitment program. Until nexus can be demonstrated, no enforceable commitment is possible. The language of SB 709 did not repeal the independent, Constitutionally-based requirement that that "rough proportionality" between the impact created and the cost of its mitigation be established. This comment has been made several times, both in writing and testimony, and the Air District has never fully responded to this issue.

The Air District cites the USEPA approved PM10 and Ozone Attainment Plans along with SB 709 as authority that it must impose ISR. In doing so, the District is arguing backward from a conclusion, sidestepping the fundamental issue of whether an enforceable commitment exists. Such backstops are not a substitute for establishing whether an enforceable commitment exists for purposes of the Federal Clean Air Act.

RESPONSE: Although the District believes it has adequately responded to each comment regarding nexus 'rough proportionality', here is a synopsis of how the District makes this demonstration:

> The District developed an estimate of growth in mobile source emissions from new development by using the SIP emission inventory growth-only projections. This allows us to estimate the amount future emissions will increase only accounting for growth. This information was used as the basis for the ISR control measure in the 2003 PM10 Plan. Construction and area source emissions are entirely the responsibility of the development project. The emissions attributable to growth were then reduced to account for projects that will be exempt from the rule. The mitigation requirements were then applied to the emissions subject to the rule to determine the potential emission reductions. The emission reductions are cumulative since each year additional mitigation is accomplished and the benefits from prior years continue to provide a benefit. This information is provided in Appendix B of the staff report.
>
> Once the overall emission reduction target for the ISR control measure was identified, the next step was to determine the method to calculate the fair share of the emissions attributable to individual projects. As has been thoroughly discussed elsewhere, it is not appropriate to use the SIP inventory method to calculate emissions from individual projects. URBEMIS was identified as the best tool for conducting project level estimates. See Appendix D of the staff report.

With the emission estimation tool selected, the District then used URBEMIS to estimate emissions from a variety of different land use projects using basic default inputs. The basic factors used to estimate project mobile emissions are the number of vehicle trips, the length of the trips, and the average vehicle fleet emission rates. Based on comments received on early drafts, the District replaced default values for PM10 silt loading values, and activated the commercial passby trips component. The purpose of this analysis was to estimate the potential emissions and fees from an individual development. The results were then used in socioeconomic impact analysis to determine the potential impacts of worst-case fee amounts.

The next step in determining rough proportionality is to verify that the individual project impact is roughly proportional to the mitigation achieved with the fees that are collected. This is accomplished by using an emission based fee formula to determine the amount of funds collected and a fixed cost of reductions for the emission reductions to be purchased by the District. The cost of reductions was developed for future years based on recent cost-effectiveness history with District grant programs, a determination that the reductions will be continue to surplus to any adopted regulations, the emission inventory for the sources, and the technical and economic feasibility of the projects. This analysis is adequate to confirm that the District will be able to maintain rough proportionality between the emissions generated and the emissions reduced through the fees.

The District has several options for corrective actions should the average cost of reductions achieved by the ISR Program be significantly higher or lower than predicted. Since staff will be continuously monitoring the projects funded, we will be able to identify early if costs are on target. If costs of reductions are coming in high, the first option would be to focus the project mix on more cost-effective projects until the average approaches the target amount. If insufficient low cost off-site projects are available, the cost of reductions could be increased by amending the rule. If costs of reductions are coming in low and it appears that the lower-than-expected cost-effectiveness can be sustained, the fee amount may be lowered. The District may also modify the incentive amounts offered to attract preferred, highly cost-effective projects where potential applicants may be reluctant to participate when the incentive amount offered may be inadequate to cover costs of implementing the project. Modified incentive amounts could also be used if the District has difficulty attracting sufficient projects.

The comparison to mobile source emission reduction credit programs is not valid. The reason those programs have not been highly successful is because stationary sources needing ERCs have been able to obtain those reductions at lower costs using traditional banked ERCs than could be achieved by mobile source reductions. Grant programs throughout the state have been extremely successful in obtaining emission reductions from a wide variety of sources. Since ISR reductions can be obtained from any source of surplus, quantifiable, and enforceable reductions, it can be expected to do even better than the existing grant programs in attracting projects.

23. COMMENT: There is no finding that the benefits of the proposed measures will be permanent.

The Draft ISR assumes that the measures will be in effect for ten years. Because of the passive nature of many of the on-site mitigation measures, there is no guarantee that purchasers of newly developed property will leave those mitigation measures in place. Likewise, there is no documentation that the emission reductions associated with the proposed control measures will persist throughout the life of the SIP. As discussed previously, the benefits are speculative, have not been quantified and documented, and as a result the longevity of the benefits are equally speculative.

RESPONSE: The ISR program differentiates between onsite and off-site measures when demonstrating the permanence of the reductions for SIP purposes. The onsite measures are most closely related to measures covered by EPA's Voluntary and Emerging Measures Policy. This policy recognizes that land use measures are highly desirable, but more difficult to quantify than traditional measures. Once the project is constructed with the onsite features in place, the benefits continue indefinitely into the future. Measures like density, mix of uses, and pedestrian infrastructure are not likely to be eliminated after development. All on-site measures that are not required by the lead agency will be enforced by the District to ensure that the emission reduction benefits will occur for the full duration of ten years. Offsite projects funded with mitigation fees only take credit for SIP reductions during the life of the project. This is accounted for in the emission reduction spreadsheet in Appendix B. Offsite projects meet EPA SIP criteria for permanence. Applicants are under contract to utilize the cleaner equipment through the term of the contract. When the new equipment, device, or paved road reaches the end of its useful life, the new purchase must comply with regulations in place at that time and will use cleaner technology in many cases.

As the District has repeatedly demonstrated, the benefits are not speculative, have been quantified and documented. Please refer to the *entire* Staff Report, Appendix B: Emission Reduction Analysis, Appendix D: Recommended Changes to URBEMIS, and Appendix E: Cost Effectiveness Analysis.

24. COMMENT: The proposed Indirect Source Mitigation Program is not adequately supported. The Air District's socio-economic analysis focused on the narrowest viewpoint available, the impact on residential builders, and did not even attempt to analyze the larger impacts on other business sectors, employment, public services, etc. The proposed rulemaking provides no information on the commitments from other agencies that are necessary to implement the various measures. Finally, there is no indication that the proposed requirements have been integrated into local development plans.

RESPONSE: First, there are no "commitments from other agencies that are necessary" to implement ISR. Therefore, the District did not include "commitments from other agencies" as there are none.

The author mistakenly states that the socioeconomic analysis, "focused on the narrowest viewpoint available." The author is posing that the District did not thoroughly or adequately address the socioeconomic impacts of the ISR program, which is untrue. The socioeconomic analysis included analysis on the impacts to homebuilders, homebuyers, renters, low-income housing and housing affordability. In addition it analyzed the impacts to commercial, office and industrial builders, buyers and renters, and small businesses. The mitigation fees are spent on projects in the San Joaquin Valley that provide benefits to the Valley's economy as described in the revised socioeconomic impacts report.

ISR has been designed to work synergistically with the local development approval process. Developers may use mitigation measures and local requirements of the local development process to reduce their Rule 9510 fees, but are not required to do so. The proposed requirements of ISR, a prescribed amount of emission reduction for particular development projects, do not need to be integrated into local development plans, but may be used to demonstrate that air quality impacts of the project have been reduced. Developers wanting to use Rule 9510 as support for their air quality impact study for the local development approval process can time their application to the District such that it will fit seamlessly with the normal CEQA timelines. For the 'mitigation program', there are no up-front requirements for all projects. Applicants that voluntarily commit to certain measures that are not already requirements by other agencies must enter into an agreement with the District that details the schedule of monitoring and reporting for the District to enforce implementation of those measures. The 'mitigation program' requirements are to implement those measures the applicant has voluntarily committed to. The only possible conflict with local development plans is if a measure is not allowed by the local agency: in that instance, the District would remove that measure from the ISR project, and reassess emissions. Thereby avoiding conflicts with the local agency.

25. COMMENT: In summary, for the reasons stated above, the Draft ISR continues to be fundamentally flawed, and is unlikely to satisfy the requirements of the Federal Clean Air Act. As a result, the Air District will have a difficult time convincing USEPA that the ISR control measure will contribute to the emission reduction goals set forth in the SIP and the District should look to other measures to obtain PM10 and NOx reductions.

RESPONSE: As stated in Response to Comment #18, the EPA is supportive of the rule, and has not raised the 'flaws' that the author claims are present. The emission reduction goals in the SIP will primarily be achieved through grant and incentive programs that have been in operation for over a decade and that meet all SIP submittal criteria. Credit for new grant and incentive programs will follow the same SIP criteria and will comply with the same standards for quantification and verification as the existing programs. Each new program will go through a public review process and be approved by the District's Governing Board. The voluntary onsite measures will only be credited to the extent that they meet the criteria of EPA's Voluntary and Emerging Measures Policy.

Sierra Research – On Behalf of CBIA

Date: November 29, 2005

On behalf of the California Building Industry Association (CBIA), Sierra Research (Sierra) is pleased to submit the following comments on the revised draft Indirect Source Rules (ISR) 9510 and 3180 released by the San Joaquin Valley Unified Air Pollution Control District (District) earlier in November.

Our comments in this letter rebut District responses to earlier comments submitted by Sierra in September. As directed by CBIA, our comments focus on technical and modeling issues related to the use of the URBEMIS model under the proposed rules based on our independent review of the model and its underlying assumptions. In this review we were assisted by Dowling Associates, Inc. (Dowling), a transportation planning firm with extensive travel demand modeling experience supporting a number of the San Joaquin Valley Transportation Planning Agencies (TPAs).

Our rebuttal covers the following two issues:

1. URBEMIS modeling assumptions substantially overestimate residential project emissions. A combination of unresolved technical problems result in overstating both residential PM10 and NOx project emissions, and therefore ISR fees, by over 70%.

2. Rule 9510 consistency with SIP emissions inventory has not been demonstrated. The SIP travel model projects a different amount of travel (and therefore emissions and fees) from each project than URBEMIS calculates. Our Fresno County test case shows that URBEMIS produces higher project emissions than does the SIP methodology.

A detailed discussion of each of these unresolved issues is provided in Attachment A.

26. COMMENT: Summary

The following table summarizes each of the technical modeling issues identified by Sierra/Dowling during the ISR rulemaking process, their impacts, and the District's response to each issue.

Status of District Responses to Sierra/Dowling ISR Comments		
Issue	Emissions Bias	District Response
Residential Fleet Mix	NOx high by **20%**	Will fix, revised fleet mix to be determined
Silt Loading Factors	PM_{10} high by **50%**	Will fix
Average Vehicle Trip Lengths	NOx and PM_{10} high by **20-30%**	Will fix, unsure of approach
Residential Fleet Age Distribution	Exhaust NOx and PM_{10} high by over **20%**	Not convinced data provided warrant a revision
SIP Consistency	NOx and PM_{10} likely **high by unknown amount**	Handled by 50% fee discount?

Although the District has indicated a willingness to address some of the modeling issues we have identified, we believe the responses to our earlier comments on URBEMIS model issues are incomplete (in that corrections will not be made until after ISR adoption) or mildly dismissive (e.g., not willing to consider how revised residential age distribution impacts will be addressed). Some of the unresolved issues are fundamental and still need to be addressed before these rules can go forward

Furthermore, the District has not proven that the URBEMIS-based ISR approach will result in emission reductions that match SIP targets. From a policy standpoint, we believe this burden-of-proof lies with the District and that SIP consistency cannot simply be asserted.

These technical problems result in major discrepancies in estimating emissions and corresponding fees under Rule 9510. Thus, we respectfully recommend that the District delay its scheduled December 15 hearing on ISR adoption until these issues are fully resolved.

If you have any questions about the information presented above or in Attachment A, please feel free to contact Bob Dulla or me at (916) 444-6666.

RESPONSE: The District has determined that all items that the author raises have been adequately addressed. See the following Comments and Response to Comments #27 through #29.

ATTACHMENT A
UNRESOLVED RULE 9510 TECHNICAL ISSUES
THAT RESULT IN OVERSTATED EMISSIONS

27. COMMENT: URBEMIS Modeling Assumptions Substantially Overestimate Residential Project Emissions - In responses to our comments, the District acknowledged that many of the default modeling assumptions in the URBEMIS model do not accurately represent conditions in the San Joaquin Valley when applied to residential projects. These incorrect model defaults identified by Sierra and Dowling substantially overestimate residential project emissions by a minimum of 70% for both pollutants targeted under the ISR rules, oxides of nitrogen (NOx) and "fine" particulate matter (PM10).

The District's response to these URBEMIS model default issues is incomplete. In acknowledging these problems, the District responds only that these faulty model assumptions will be corrected in a future version of URBEMIS that will be released (presumably without opportunity for public review) after the ISR rules are adopted.

Although the District has indicated that a small part of these model corrections will be made prior to rule implementation, no timetable has been provided for revising URBEMIS, nor has it been made clear that these revisions will be publicly reviewed. The District has been aware of these modeling issues since July, yet no further action has been taken. The District's approach does not guarantee the release of a revised and fully reviewed model before implementation.

RESPONSE: The District does not "acknowledge that ***many*** (emphasis added) of the defaults… do not accurately represent conditions in the San Joaquin Valley". The District does acknowledge that a there are a few items that need refinement, specifically the on-road silt loading factor (easily adjusted by a known amount) and the fleet mix (less easily adjusted). The District had already hired a consultant to analyze and recommend a revised fleet mix, and results are expected prior to rule implementation. The author's assertion that "no further action has been taken" is misinformed and false. In addition to researching the fleet mix, the District is participating in the URBEMIS statewide working group (see paragraph below for more information). The model defaults ***do not*** overestimate residential project emissions "by a minimum of 70% for both pollutants". This claim is false, and the District has repeatedly addressed this claim.

The author is incorrect in his assertion that the District will make changes to URBEMIS "without opportunity for public review" and therefore without any review or safeguards. Changes to URBEMIS are made through a statewide working group that includes other air districts, model experts, technical experts and other public agencies such as CalTrans. As consultants such as Sierra Research use URBEMIS, they often find areas for improvement and correction. Any proposed changes impacting the statewide use of the model must be vetted through this group. The District cannot, nor does it propose to, make 'closed door', questionable changes to the URBEMIS model. If an applicant or a consultant can find better input data or another model that more accurately characterizes the emissions from their project, the District will consider them. If they apply broadly, the District is committed to make those changes available to all users. Sierra should recognize that all modeling is based on incremental improvement. The District will use the best information currently available and commits to continuous improvement in its emission estimating techniques and models.

The author states that a "small part" of issues will be addressed. The District finds only three items raised that are legitimate and only two that are substantial, one of which (silt loading) has been resolved, and the other (fleet mix) is currently being researched. As for a "guaranteed release" of a revised program prior to implementation, these *two* issues can be addressed through guidance. A revised program is not necessary to account for the refined default changes. As stated above, the District is participating in the URBEMIS statewide working group, which is currently expecting to release a revised program in more than one year. The District is committed to making URBEMIS as accurate as possible, and is working towards that goal. Any change that can be made through District guidance will be implemented quickly.

In addition, the silt loading factor issue was raised by Sierra Research, which proposed a new factor, and the District agreed that the proposed factor was more accurate. This revised factor has been publicly discussed, and has been included in ISR documentation.

28. **COMMENT:** In addition, the District did not act on the evidence presented by Sierra/Dowling based on U.S. Census and Caltrans Travel Survey data—that new residential developments exhibit newer vehicle fleet age distributions (and therefore have lower average emissions). The District's response indicates a need for further survey data to warrant revising the URBEMIS default vehicle age distribution when applied to new residential projects.

Would data from a third-party survey that gathered information on vehicles per household and age from a random sample of "new" residential households in the

San Joaquin Valley be sufficient to warrant a revision if it showed a similar shift toward newer vehicles in the existing Sierra/Dowling analysis? And if so, how will this be accomplished? The District suggests the possibility of an age correction factor to address the fact that the EMFAC model emission factors used by URBEMIS cannot easily be modified to account for a revised age distribution. Who would develop this age correction factor and how would it be developed?

RESPONSE: The District did not act on the survey data because we are not yet convinced that it is more accurate than the information currently used in URBEMIS, which is an age distribution from EMFAC2002 (See September 1, 2005 Response to Comments #121 through #153). As pointed out in your previous comment letter, providing a project-specific fleet-mix age for each land use type would not be easy and would not be possible to automate in the current models used to quantify project emissions. We are not sure if the survey data described is adequate for this purpose. Since Sierra previously stated that it wants any changes vetted through a public process, the District will first pass this information to the URBEMIS Working Group for assessment. If consensus is reached that a major overhaul to URBEMIS is needed to account for fleet age differences, then the District will work to raise the necessary resources to develop the model. The new model would need to be submitted to EPA for approval. The fleet age distribution currently in use is adequate for the ISR program until such a time as a model capable of using this information becomes available.

29. COMMENT: Rule 9510 Consistency with SIP Emissions Inventory Has Not Been Demonstrated We continue to disagree with the District's assertion that the URBEMIS model-based approach proposed to calculate project travel and emission impacts is consistent with the Statewide Implementation Plan (SIP) inventory methodology. This SIP emissions inventory and its underlying methodology were used to establish the NOx and PM10 emission reductions targeted by the ISR rules. Thus, it is critically important to ensure that new project impacts determined under the ISR rules are calculated in a manner consistent with the SIP targets to ensure no over- or under-compliance.

Our disagreement centers on the inconsistency between URBEMIS and regional travel demand models (TDMs) in calculating new or net added vehicle miles traveled (VMT) and vehicle trips. The TDM models are used to calculate regional travel impacts (i.e., VMT and trips) within the SIP inventory. The fundamental difference between TDMs and URBEMIS is that TDMs robustly account for the interaction effects[1] between multiple land uses; URBEMIS does not.

1 Interaction effects refer to the fact that when considered together, each individual land use (or project) "competes" with others for vehicle trips. Where these land uses are located within a metropolitan area or county and how well the regional roadway network provides access to each land use affects the number of trips taken and their length (and thus VMT). For example, locating a new shopping center near an existing

If travel activity (VMT and trips) were totaled across all the URBEMIS-based individual ISR project applications, we believe they would overstate the net travel impacts determined when jointly simulating the same new projects using a TDM. This conclusion is based on a side-by-side comparison of impacts of a hypothetical but typical new residential project performed by Sierra/Dowling using URBEMIS and the Fresno County TDM. Further, we believe this conclusion remains valid even after correcting existing bias in URBEMIS default assumptions. This is because URBEMIS treats each new project and its interaction with existing land uses and other new projects separately.

We understand and agree with the District that it is not practical to make developers run TDM simulations under each ISR application, and readily acknowledge that TDMs are not without flaws of their own. However, calculations performed within the SIP that identify further emission reductions needed for the San Joaquin Valley to attain federal ambient air quality standards (a portion of which are targeted by the ISR rules) are based on vehicle travel activity forecasts from TDMs.

The District suggests that this fundamental difference between TDMs and URBEMIS is accounted for by applying a 50% discount factor in the NOx and PM10 fee formulas to require mitigation of only half or one direction of two-way trips between a new project and existing land uses. We understand the concept in principle, but strongly believe that by simply slicing URBEMIS impacts in half, SIP consistency has not been demonstrated. We believe the acid test of SIP consistency consists of an analysis that compares summed URBEMIS vs. TDM simulated travel impacts for a package of specific projects that have been developed in recent years. We are not aware that this type of URBEMIS analysis has ever been done and is likely one of the key reasons why ISR rules have never been successfully adopted and implemented on this scale.

RESPONSE: Please see Response to Comment #19 above. The District agrees that the model used for the ISR program should be carefully chosen as to not over- or under-comply with the SIP reduction targets. However, the District maintains that the methodology for implementation does not need to be identical to the SIP methodology to achieve this. The author states that for the Valley, if URBEMIS is compared side by side to a TDM, URBEMIS over-estimates net travel impacts. However, a regional TDM was never meant to be, nor should it be, used to estimate emissions from an individual project. To take a project-level model and try to compare it 'side-by-side' to a regional model is inappropriate and misleading.

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residential area would likely shorten the length of existing shopping trips taken from the residential area (and thus reduce VMT). It may also increase the number of shopping trips from the residential area due to its proximity compared to the location of existing shopping centers.

Stop the Air Board Tax *We'll All Pay!*
Date: November 16, 2005
Signed by
City of Clovis – Mayor Nathan Magsig
San Joaquin Busniess Council – President Ron Addington
Visalia Chamber of Commerce – President and CEO Mike Cully
Kern County Taxpayers Association – Executive Director Michael Turnipseed
Greater Merced Chamber of Commerce – CEO Will Lee

30. **COMMENT:** A broad-based coalition of local chambers of commerce, local government officials, homebuilders, taxpayer organizations, agricultural groups, ethnic and community groups are formally opposing Rules 9510 and 3180 proposed by the San Joaquin Valley Air Pollution Control District (the District). These Rules will collect hundreds of million of dollars by imposing fees on every new home, small and large business, public facilities and other new construction projects within the Central Valley, with questionable air quality benefit.

Indeed, as Rules 9510 and 3180 are currently proposed, the District is proposing to collect more than $670 million in fees over the next five years- taken right out of the regional economy.

RESPONSE: First, the proposed rule does not apply to all new development nor does it impose fees on all new development. For instance, the following projects are exempt from the rule or the fees:

- Projects below the applicable size thresholds in the rule (e.g., 50 residential homes)
- Projects at stationary source businesses already regulated by the District
- New projects and expansions that do not require a new discretionary approval by the local land-use agency
- Projects that employ enough control features to reduce emissions to less than 2 tons per year

The District's most up to date estimate of the offsite mitigation fees is $103 million over the next 3 years. The authors' estimate of $670 million in five years is erroneous. The authors' estimate is based on incorrect use of the fee formulas and emissions estimates and record setting development rates. The District believes that it is not prudent to base revenue estimates on record development rates that would result in SIP commitments that fall short if not realized. Although the authors' estimates are overstated, it should be recognized that solving the Valley's air pollution problems is very costly as can confirmed by industrial sources that have invested billions of dollars on pollution control in the last three decades. The funds will not be taken out of the regional economy. All offsite mitigation fees will be used to purchase emission reductions here and will

result in the funds being reinvested in the Valley. The cost of administering the program is assessed at only four percent of the offsite emission fees.

Finally, the District has thoroughly documented, described and demonstrated that the proposed rules will have a real and substantial beneficial impact on air quality. For more information on the emission reduction analysis or spending plan, please see Staff Report Appendix B: Emissions Reduction Analysis (which used a standard, accepted emission reduction methodology) and Appendix E: Cost Effectiveness Analysis (which thoroughly demonstrates the availability of off-site reductions and a plan for off-site fee use).

31. **COMMENT:** As you are probably aware, the Air District recently released a revised version of these Rules and accompanying documents. In our opinion, the changes have failed to address some of the fundamental concerns of our coalition. Namely, the Rules continue to unfairly target new homeowners and businesses to disproportionately fund air emissions cleanup; the methodology and science remain flawed and they still significantly overestimate emissions and result in inflated fees; the fees still seek to impose enormous and unjustified new costs on businesses, new homeowners, public entities and ultimately all Valley consumers and our economy; and the rules still fail to provide for full accountability.

We all support the goal of cleaner air, but there are better and more effective ways to reduce air pollution in a manner that is balanced and less costly for residents and our economy.

As representatives of the coalition, we feel compelled to share the following key reasons we are respectfully urging you and other Governing Board members to oppose Rules 9510 and 3180 when they come up for a vote on December 15, 2005.

RESPONSE: Please see Response to Comments #32 through #42 below.

32. **COMMENT:** ISSUE #1 – LACK OF FAIRNESS, EFFECTIVENESS OR EFFICIENCY
Indirect source rules place a disproportionate burden on new housing, new businesses and new public facilities to pay for a regional problem that is the responsibility of ALL residents. Indirect source rules are just that – *indirect, unproven* and *inefficient* ways to go about calculating and mitigating air quality emissions. For this reason, no other air district in the nation has adopted this type of indirect source rule. The District should be pursuing more balanced solutions that equally apply to all residents and rules that more directly go after

the true source of emission – namely tail pipe emissions and the dirtiest pollution sources like diesel.

RESPONSE: The authors claim that new homeowners and businesses are being singled out unfairly for controls by this rule. This rule would be only one of many measures that the District has implemented and proposes to implement to control emissions from nearly every possible source category. The District has produced two comprehensive plans, one for ozone and one for PM10, that analyze current and future emissions, and lay out a strategy for emission reductions by a variety of controls and actions. For example, the ISR program is one of more than 20 rules identified in the 2004 Extreme Ozone Attainment Demonstration Plan.

The authors indicate that the ISR program attempts to 'burden' new development to pay for a regional problem. The ISR program only assesses and places requirements on the fair share of the emissions from new development to solve regional ozone and PM10 problems. Each project that would go through the ISR program would be responsible *only* for their own emissions.

In addition, the District has successfully and aggressively regulated existing sources of air pollution. Existing homeowners have contributed in the form of DMV surcharges to the tune $7 per year per vehicle, compliance with fireplace regulations, low-VOC architectural coatings, and smog check programs. New stationary sources must employ Best Available Control Technology and mitigate their new emissions with offsets.

33. COMMENT: ISSUE #2 – THE COST OF THE PROPOSED RULES
Two years into the rule-making process, the District still has failed to provide the public with a comprehensive estimate of the cost of the proposed Rules. Specifically, the socioeconomic analysis fails to address the cumulative impact on housing costs, on business costs, and on economic growth and job creating. The analysis discusses impact on only select segments of the business community, ignoring the full economic impacts of the rule. Our coalition has reviewed what information is available in the District's socioeconomic analysis and we were able to determine that the District will collect as much as $670 million in fees over the next five years.

RESPONSE: Concerning the adequacy of the District's analysis of economic impacts, please refer to Response to Comment #24 above. Concerning the '$670 million' in purported fees, please refer to Response to Comments #30 and #34.

34. COMMENT: Housing:

The District's analysis shows the fees will average more than $1,700 on every home by 2008. Cumulatively, we estimated that the cost on all new housing projects in the eight county region will exceed $225 million over the next 5 years, assuming the current pace of housing permits. That's why the State Department of Housing and Community Development warned that these Rules will negatively impact housing affordability in our region.

RESPONSE: The author has misstated the facts provided in the District's analysis and in the Socioeconomic Analysis. The fee estimates of $1,700 per home and the various numbers sited for industrial and commercial projects represent maximum worst-case fees that may apply if the developers choose to employ no on-site controls. Even so, this amount was found to not have a significant impact on the housing market in the socioeconomic impact analysis. If the high rates of development continue, the air impacts from housing will also be greater than predicted, and so those funds will be needed to offset some of that increase. The District believes that nearly all projects will be able to reduce their fees with on-site-measures since local land use agencies currently require some of the measures and many developers incorporate them as standard practice. The District has published an extensive list of control measures that would reduce the applicable fees. The authors' estimate assumes that all homes and industrial and projects will be built with no control features and is not realistic. In addition, the authors apply the worst-case fee to a higher, possibly unsustainable, rate of housing construction. The author then used this inflated fee amount and based the $670 million on a rough assumption of the ratio between housing and commercial/industrial development. The District finds this methodology of fee estimation to be inappropriate and inflated.

The District hired an independent consultant to perform a comprehensive socioeconomic analysis that assesses the economic impact of the proposed rule including any significant impact on housing affordability. This report concluded that rule would have a negligible impact on housing affordability.

35. COMMENT: New Business Developments:

The District's own assessment estimates the level of likely fees on selected properties to be significant. By 2008 it will cost $397,483 in new fees to build a local community shopping center and $131,000 in new fees to build a neighborhood shopping center. These developments are typically home to mom and pop businesses, restaurants and small retail shops and these fees will be directly passed along to these small business owners (and ultimately their consumers and employees). The District also reports that as much as 2/3 of the total fees they plan to collect will come from non-residential projects. Since the District's figures show that the total fees on housing may exceed $225 million, it

is conceivable that the cost to businesses and non-residential developments will exceed $400 million.

RESPONSE: The fees are based on emissions generated by each project. If a commercial development generated emissions that resulted in a fee of $397,483, it would be a very large development or one composed of many small retail establishments. If it were comprised of many small businesses, each one would be responsible for a fair share of the impact and the fee.

The author falsely states that, "the District's figures show …fees on housing may exceed $225 million." The District's figures ***do not*** show that housing fees will be that high. See Response to Comment #34 above, which illustrates how the authors distorted facts to generate an inflated number. In fact, the District's analysis shows that the District may receive up to $103 million from *all* types of development subject to the rule between 2006 and 2008. The 2/3 ratio cited by the author was provided by the District as a rough estimate arrived at by subtracting residential development emissions from all development related emissions. The District used the emission reduction analysis (Appendix B) for fee income analysis since the emissions growth data from the state is well accepted for this purpose. See also Response to Comment #30 and #34.

36. COMMENT: Public Facilities:

The Rules also apply to public and government facilities such as new schools, transit projects, government office buildings, fire houses, police stations and more – driving up the cost of public works projects and ultimately further burdening taxpayers with higher costs. The District's analysis is silent on these costs and their impact on local finances and fees.

RESPONSE: The District has drafted the rule to fairly allocate emissions among all indirect sources. Public uses are a substantial part of the growth in emissions that if not addressed here, would need to be addressed through other means. We agree that the cost of achieving air quality mandates could increase the cost of these facilities; however, we would expect most transit projects, fire houses, and police stations to be exempt since they would produce emissions below the two ton per year level. In addition, schools and government offices are well suited in many cases to incorporate features that enhance walking, bicycling and transit use and use low emission vehicles and equipment that could reduce the fees, possibly to zero.

37. COMMENT: ISSUE #3 – FLAWED SCIENCE

Members of our coalition and others have repeatedly demonstrated that the methodology and modeling that the District staff is using to calculate indirect sources of emissions – and resulting fees and mitigations – are fundamentally

flawed. These flaws result in grossly inflated fees and mitigation requirements. For instance, the URBEMIS model being used by the District (a computer program used to estimated emissions associated with land development projects), overstates vehicle emissions by over 70% (see public comments filed Sierra Research, July 22, 2005). No other air district in the nation uses URBEMIS to determine fees for vehicle emissions because, as the District's modeling consultant said, it's a "sketch planning" tool, not an accurate gauge of the specific emissions resulting from an individual project.

RESPONSE: In context, the term sketch-planning tool did not imply that it is not an accurate gauge of specific emissions resulting from an individual project. In fact, URBEMIS is a proven statewide model used by other air districts, including South Coast and Sacramento Metro Air Districts, in assessing emissions from project-level developments. URBEMIS is commonly used for CEQA analysis, and is also used by other air districts to determine off-site mitigation fees. In addition, the Development Agreements entered into by the District and applicants relied on URBEMIS for emissions estimates. See Staff Report pages 19 through 22 for a detailed discussion on why URBEMIS is the best model for the purposes of the rule. See also Response to Comment #19 above.

The CBIA and its consultant, Sierra Research, have provided comments (See September 1, 2005 Comments #123 through #162 and above comments #18 through #29) about the adequacy or implied lack thereof of the URBEMIS model. However, the District has shown that the 'flaws' stated by the author are not valid.

For example, the authors assert that the model overstates vehicle emissions by over 70%. The comments received by the District compared the URBEMIS model, which counts both ends of trips, to a regional impact model (admittedly inappropriate for project-level analysis- See Comment #19 above) that only accounts for one end of trips. The URBEMIS program does not overstate emissions, as asserted by the author, but accounts for emissions differently than a regional model. It should also be understood how the fee formulas work. Please see Figure 3 and 4 in Appendix B- Emission Reduction Analysis, which clearly show that half of the estimated baseline emissions are not assessed fees.

URBEMIS reflects the state of art in quantifying emissions from development projects. In fact, developers and local land use agencies routinely use URBEMIS to quantify project impacts during the CEQA process. The proposed rule allows for the use of other models that can better quantify emissions from various types of projects. The accuracy of URBEMIS will be further refined through the use of project-specific information in lieu of the otherwise applicable defaults. The authors' claim may have merit if the District rule only allowed for the use of URBEMIS defaults and disallowed the use of project-specific information such as proper traffic counts and vehicle mix. This is not case.

The District is part of a statewide working group that will continually work on refining and enhancing the accuracy of the URBEMIS model.

38. COMMENT: ISSUE #4 – DISTRICT'S OWN DOCUMENTS DEMONSTRATE THAT FEES CANNOT BE AVOIDED THROUGH ON-SITE MITIGATION.

District staff has continually and erroneously stated that if sponsors of new development satisfy the District's list of on-site mitigation measures, they won't have to pay any fees. According to the Air District's own documents and comments by their own staff, this is simply not true.

Even the District's newly revised staff report demonstrates that new homebuilders and businesses likely cannot completely mitigate indirect source emissions on-site (see Draft staff report page 15, 11/17/05). Perhaps this is why, at a recent meeting before the Bakersfield Chamber of Commerce, District Deputy Executive Officer Seyed Sadredin admitted most projects will not be able to mitigate their estimated air impact on site and will likely have to pay all or most of the fees.

Neither the text of the Rules nor the staff report provide useful guidance on how doing one or all of the proposed on-site mitigations will score against the proposed fees and it has provided no detail about the air quality benefits of each of the proposed mitigation measures. Accordingly, applicants have no way of determining how much on-site mitigation will reduce emissions or how it will reduce the fee they're obligated to pay.

Second, the District's proposed on-site mitigation checklist relies heavily on the existence of mass transit and other forms of transportation that don't exist to achieve emission reductions. Further, since there is no plan or realistic prospect of these necessary transportation projects being built in the near future, it is impossible for sponsors of development to comply with these types of on-site mitigations to avoid fees.

RESPONSE: The authors' comments are incorrect. The District has *not* stated that simply enacting the measures on the on-site list would result in no fees. The District has stated, and has conducted internal analysis that verifies, that it is possible to incorporate enough measures to result in no fees. The page referenced to from Staff Report *does not* assert or state that homebuilders and businesses cannot completely mitigate emissions on-site. The Staff Report does demonstrate how a certain percentage of on-site reduction achieves a larger percentage of fee reduction. District staff is unsure how the author misinterpreted the Staff Report, as the text states, "… the "bigger bang for the buck" is achieved with as much on-site mitigation as possible…..See Table 1 for ***examples*** (emphasis added) of on-site emission reductions and the associated off-site fee reduction".

Concerning guidance on how the measures "score" against the fees, and the air quality benefit associated with the measures, the authors should read page 11 of the Staff Report, which states,

> *The measures listed in the checklist have a known quantification methodology in URBEMIS 8.7. The methodologies can be found in the URBEMIS User's Guide, available at South Coast AQMD's website http://www.aqmd.gov/cega/urbemis.html.*

URBEMIS is a free, easy to use program that can be downloaded and used by the public, project applicants, public agency staff, and anyone else. See also September 1, 2005 Response to Comments #7 and #9. Applicants can easily see on their own how incorporation of measures reduces emissions through using the model (most simple projects take less than ½ hour), and can see how that reduces the fees by running the numbers through the fee formulas.

Finally, the checklist does not 'rely' on mass transit and other transportation for emission reductions, but provides a venue to credit emission reductions from those items. Project applicants are not required to 'comply' with the list, but fill in which measures apply to their project, and which measures do not.

The fees can be reduced significantly by employing the reasonable number of measures suggested by the District. We agree that it will be difficult to total eliminate the fees initially with the type of development that has historically occurred in the Valley.

On how to 'score' the emission reduction from the measures suggested by the District, all measures in the on-site lists have a quantification methodology in the URBEMIS model. These methodologies may be read in the URBEMIS User's Guide. The measures do not have a straight "credit" associated with implementation, but a calculated reduction based on various parameters, which may include interaction with other selected measures, amount input, and other parameters. The District will provide a great deal of assistance to the applicants to properly quantify the emissions and the applicable credits for measures employed.

ISSUE 5 – DISTRICT HAS FAILED TO ADDRESS SOME BASIC – BUT IMPORTANT – POLICY QUESTIONS RAISED THROUGHOUT THIS PROCESS

The following represent just a few of the many very important policy concerns that the Air District has failed to address or respond to, despites these questions being raised for many months. Governing Board members should take great pause before voting on Rules without getting answers to these very serious questions and concerns.

39. COMMENT: District has not quantified fees for the full 5-year rule period: The socio-economic and cost/effectiveness analyses provide an incomplete

accounting of fees that the District expects to assess over the 5-year rule period. No information has been provided in either appendix on the cost to public facilities including schools, parks, and roads. No information has been provided in any appendix on the overall economic impact to the Central Valley.

RESPONSE: The fee schedule holds fees past 2008 at the 2008 level. The socioeconomic impact analysis and cost-effectiveness analysis only assess 2006-2008 because those are the amounts being proposed in the rule. If the rule is amended to change the fee amounts by a significant amount, it would result in the preparation of new analyses. If fees are held to the 2008 level, socio impacts would be the same as the 2008 level. For cost effectiveness, the District is confident that targets are feasible through 2008, but past 2008 would be too speculative.

The District disagrees that overall impact on the economy in the Central Valley is not adequately addressed. Since the impact on the development industry was not significant and fees will be recirculated into the regional economy, it is logical to conclude that the rule would not have a significant adverse impact on the regional economy. See also Response to Comment #24 above.

See Response to Comment #36 regarding public facilities.

40. COMMENT: Incomplete Spending Plan: Although Appendix E offers a spending program for the fees collected by Rule 9510, it falls short of what is acceptable. First, it covers only three of the five years of the rule period. Second, the revenue projects cover roughly one-sixth of the Rule's potential revenue: $102 million vs. the potential $670 million in total fees that could be collected.

RESPONSE: As stated above, the first three years have enough information to be adequately assessed.. Second, the $670 million stated by the authors is based on incorrect information and misinterpretations of rule requirements (see above Response to Comments #30 and #34). District analysis, using factual data, shows that the District may receive up to $103 million between 2005 and 2008 based on the availability of the fee deferral option and historic development rates. The cost of reductions is more uncertain farther into the future. The District will reassess the cost of reductions prior to 2009 so that changes in regulations and the availability of new technologies can be taken into account.

The District has proposed a detailed plan in the staff report that will be considered by the Board at the December hearing. Additionally, as a part of the District's annual budget process, the plan will be reviewed and amended as necessary. The District will also provide routine reports on the quantity fees collected, projects funded, and emission reductions achieved per Rule 9510 Section 10.4.

41. COMMENT: Unresolved fee estimation issues: As noted above, the URBEMIS model overstates project emissions by over 70%. The District has not committed to fix URBEMIS prior to Rule adoption and implementation. Unless resolved, Governing Board adoption will result in projects paying fees that are exaggerated by as much or more than 70% due to improper default values that do not reflect actual conditions in the Central Valley.

RESPONSE: As stated previously (Response to Comment #19), the "70%" overestimation is simply not valid. Previous comments have pointed out refinements that should occur to some URBEMIS default values, such as the silt loading factor, and the District has committed to providing guidance prior to implementation and to update URBEMIS as soon as possible with the revised factors (see Response to Comments #19-22, #27-29, #37, and Staff Report pages 21-22). However, the statement that the model grossly overstates vehicle emissions is not valid.

42. COMMENT: Unresolved CEQA conflicts: CEQA already requires mitigation of air quality impacts associated with new development, yet the District states that Rule 9510 is not duplicative and is completely independent of the CEQA process. However, the District's response to EPA concerns is that it is counting on local agency CEQA requirements to make on-site mitigation measures enforceable. The District has not explained how its Rule will interact with local agency CEQA actions to achieve this result.

RESPONSE: Currently, for measures that are required by a local agency, that agency includes them in CEQA documentation and is required to enforce those measures. The District recognizes this enforcement mechanism through CEQA for those measures that are required by the local agency. Therefore, although the project applicant is taking credit for emission reductions from measures required by lead agencies, the District will not have to enforce those measures independently. For measures that are not required by the local agency, the District will be responsible for enforcement. There are no new requirements on local agencies, and no additional 'interaction' is required by the rules.

43. COMMENT: In closing, members of our coalition agree that improving the region's air quality is an important goal and one that demands that everyone in the Central Valley play a role. Accordingly, the District has a duty to convince the public of the value of its new policy and to win their trust in carrying it out. Regrettably, the District has failed to demonstrate the value or benefit of the proposed Rules.

Members of our coalition stand ready to work with the District on an alternative to proposed Rules 9510 and 3180 and towards achieving a more equitable, efficient and cost effective plan to reduce emissions.

In the meantime, we urge you to reject Rules 9510 and 3180 when they're brought before a vote of the Governing Board on December 15, 2005.

RESPONSE: Comment Noted.

SUMMARY OF COMMENTS AND RESPONSES ON THE SEPTEMBER DRAFT RULE SEPTEMBER 1, 2005

EPA:
Date: September 20, 2005

1. **COMMENT:** We are providing comments based on our preliminary review of the draft rule identified above. In general, we are very supportive of the District's effort to reduce emissions from new development projects and we recognize that this effort raises unique challenges. Please direct any questions about our comments to me at (415) 947-4115 or to Lily Wong at (415) 947-4114.

RESPONSE: Comment Noted.

2. **COMMENT:** 1. Program Evaluations and the EIP
This rule relies on market-based strategies to reduce emissions and, as a result, is subject to national guidance entitled, "Improving Air Quality with Economic Incentive Programs" (EIP), EPA-452/R-01-001, January 2001. Specifically, the DESIGN program has elements similar to Clean Air Investment Funds as described in chapter 9 of the guidance. As a result, the District's staff report should demonstrate that the program is consistent with the EIP guidance including, for example, provisions regarding environmental benefit, consistency with attainment/progress plans and automatic suspensions. Generally, we do not believe these demonstrations will be difficult to make. However, we believe the District should expand the scope of the annual program evaluation requirement (rule provision 10.4) to address elements identified in the EIP (sections 5.3(b) and (c)), including evaluation of the overall effects of the program, whether the Air Impact Mitigation Fees are appropriate based on the cost of reductions, and whether the program is achieving the projected emission reductions. The rule should also describe the procedures and criteria for the evaluations. Lastly, since the District will be responsible for obtaining emission reductions for off-site mitigation projects, the SIP submittal should include the District's commitment to rectify in a timely manner any shortfall in emission reductions.

RESPONSE: The District disagrees that the rule is a market based strategy subject to EIP guidance. Indirect sources are not seeking to use incentive funding as a substitute for controlling emissions directly. Although it is not an EIP, the District intends to demonstrate that the program will provide environmental benefit and is consistent with all plans and rules. The appropriate

mechanism to ensure program performance is with annual reporting and corrective action to make up any shortfall. This can be accomplished by focusing funding on more cost-effective projects and would not require any special rule provision to accomplish. In the event that the rule did not achieve a milestone and altering the project mix was not successful, contingency measures are in place in the SIP to make up the shortfall while revisions to the rule are made or new rule(s) are adopted to correct the situation.

3. **COMMENT:** 2. Mitigation
The District should ensure that on-site mitigation of emissions and off-site emission reductions are enforceable.

RESPONSE: The on-site measures are voluntarily chosen by the developer and, when included as a mitigation measure in the local agency environmental document, are enforceable under the California Environmental Quality Act (CEQA). These types of measures have a relatively large amount of uncertainty, but are highly desirable due to their ability to permanently change trip generation and miles traveled. Therefore the District proposes to account for emission reductions accomplished onsite under Voluntary and Emerging Measures guidance. Projects funded with off-site fees will be under contract with the District enforceable under contract law.

4. **COMMENT:** 3. Director's Discretion
The rule (provisions 3.2, 3.5, 5.3) allows the use of an "APCO-approved model" to calculate emissions and emission reductions from development projects. To avoid inappropriate director's discretion, the rule should identify, by name and version, all models that may be used under this rule, or require that the model or model revisions be approved by the District and EPA.

RESPONSE: The rule has been revised to reflect that the District and EPA will approve models and model revisions used under the rule. Since all emission reduction calculations are accomplished using emission factors approved by the ARB and EPA and are consistent with the emission inventory factors, this should allow for quick implementation of model improvements that will be developed over time.

5. **COMMENT:** 4. Surplus
The rule should include provisions and mechanisms to ensure that emission reductions from on-site and off-site mitigation projects will be surplus to the requirements of the plan (e.g., reductions required by Rule 8061), and are not otherwise relied upon in the plan (e.g., part of the planning or growth assumptions in the plan). At a minimum, the rule should define "surplus" to include consideration of rule requirements and planning assumptions, and include provisions to prevent the double counting of emission reductions. We note, for example, that the May 19, 2005 PM-10 Plan (p. 4-45) lists a few specific

activities expected to provide emission reductions for this rule. However, the URBEMIS model allows credit for on-site mitigation measures not included on this list such as fewer wood burning stoves, energy efficiency projects and off-road maintenance equipment. While the Plan may include assumptions regarding these emissions, the District should ensure that the rule achieves the emissions reductions that the Plan predicts for the rule and that mitigation measures do not result in double counting of emission reductions assumed elsewhere in the plan.

RESPONSE: The District will demonstrate that all offsite emission reduction projects submitted for credit are surplus in the documentation for each program developed to utilize the off-site funds. The District's Heavy Duty Engine Incentive Program is the prototype for how it will manage funding received from Rule 9510. This program has stringent criteria for determining if reductions remain surplus for the wide variety of projects. The District works closely with ARB in developing guidelines such as those adopted for the Carl Moyer Program. These guidelines pay particular attention to the issue of surplus reductions. New project types will undergo a similar rigorous process.

ARB: No comment received.

California State Department of Transportation:
Date: September 8, 2005

6. **COMMENT:** The purpose of this letter is to comment on the proposed San Joaquin Valley Unified Air Pollution Control District (District) Rule 9510 (Decreasing Emissions' Significant Impact from Growth and New Development) and the associated fees as stated in proposed rule 3180 (Administrative Fees for Air Impact Assessment Applications). When applied to the California Department of Transportation's (Department) construction sites, these rules attempt to regulate vehicular (mobile) emissions regardless of the District's lack of specific authority to regulate these emissions.

Both statutory and case law clearly establishes that "local and regional authorities have the primary responsibility for control of air pollution other than vehicular sources." (See *California Health and Safety Code* sections 39002, 40000, 43000 and 43013). The responsibility for regulating vehicle emissions belongs to the California Air Resources Board. The proposed District rules attempt to regulate mobile emissions from vehicles without statutory authority and therefore, it is our position that the proposed rules do not apply to vehicular emissions on Caltrans projects.

RESPONSE: Rule 9510 does not attempt to regulate emissions from vehicles. The rule would regulate the emissions resulting from the act of construction and

the emissions resulting from the act of operation. The distinction lies in the following:

- The rule does not set emission reduction requirements for individual engines or pieces of equipment
- The rule does not require retrofits, the use or purchase of certain pieces of equipment or prescribe any specific use of emission reduction technology
- The rule does not limit emissions through hours of operation or prescribe certain activities that reduce emissions
- The rule does not require emission reductions to be achieved through the equipment or engines used.

Simply, an amount of reduction is required by the rule, which can be achieved through any on-site or off-site means that are quantifiable and meet the requirements of the rule. The rule does not set a fleet average, regulate engines or vehicles or otherwise delve into the realm of mobile emissions, which the District does not have authority to regulate. The District does, however, have the authority to regulate indirect sources per Health and Safety Code, Section 40716:

> *"(a) district may adopt and implement regulations to … reduce or mitigate emissions from indirect and areawide sources of air pollution."*

The District has the authority to control indirect sources, defined in the Clean Air Act (CAA §110(a)(5)(C)) as, "… a facility, building, structure, installation, real property, road, or highway which attracts, or may attract, mobile sources of pollution"(emphasis added). This authority comes from the CAA §110(a)(5)(A)(i):

> *Any State may include in a State implementation plan … any indirect source review program.*

The Indirect Source Review Program that the District is proposing would review the emissions from that indirect source (the facility, building , installation, real property, *road*, etc.) that occur from the installation of that source (i.e. construction) and the operation of that source (i.e. area and mobile). For transportation projects, essentially road construction, the District would review only the construction emissions associated with that indirect source.

It is the District's position that the proposed rule is within the authority granted to the District by the federal Clean Air Act and the California Health and Safety Code.

California State Department of Housing and Community Development
Date: September 15, 2005

The Department of Housing and Community Development (Department) has reviewed the Draft Rules as revised September 1, 2005 and continues to have significant concerns about their impact on housing development and costs in the San Joaquin Valley. Many of the concerns expressed in the Department's July 25, 2005 letter have not been addressed by subsequent revisions or by the District's responses to our comments, and are reiterated below.

7. **COMMENT:** 1. The on-site mitigation measures for residential development proposed by the Draft Rule 9510 duplicate the type of mitigation measures already required by the environmental review and mitigation process pursuant to CEQA or the local land-use permitting process. For example, requirements for transit measures, tree canopies, bike trails, etc., are already imposed by local governments during the existing local permitting process. This duplication is of particular concern if the projects cannot receive credit for such measures already incorporated in the project, or if the duplication were to result in most projects being charged fees for off-site mitigation programs. It is not evident that imposing the same type of mitigation requirements as those already imposed by State law (or sometimes federal as well) is necessary for the District to execute its powers as required by Health and Safety Code Section 70727 (b)(5).

Recommendation: Clarify that projects will receive mitigation credits for on-site mitigation measures approved or required by the local government's permitting process.

RESPONSE: It is the District's intent that all quantifiable on-site measures that reduce a project's emissions be given credit in the ISR program. The District does not require the applicant to implement any of the measure listed, but requires the applicant to identify which measures will and won't be implemented. The applicant is required to identify measures that are a requirement of another agency so that the District can identify which selected measures will need District enforcement, and which measures will be enforced by another public agency. The measures listed in Appendix C have a known quantification within the URBEMIS model. Measures selected will be credited to the project. The District will amend the rule language and staff report to reflect this.

8. **COMMENT:** 2. Draft Rule 9510 will lengthen and complicate permit-processing times for new homes in a manner inconsistent with the Permit Streamlining Act, which is applicable to all public agencies (*Chapter 4.5 of the Government Code, commencing with Section 65920)*. Draft Rule 9510 does not meet the consistency standard of Health and Safety Code Section 40727 (b)(4)).

- Section 8.1 of Draft Rule 9510 has been revised to require the District to determine the completeness of Air Impact Assessment (AIA) applications in ten days instead of thirty. It is unclear whether this changes will result in a practical benefit, however, as the Draft Rule does not include a mechanism for facilitating concurrent review between the District and local planning agencies. Sections 5.0 and 8.2 suggest the District is cognizant of the need to coordinate with local agencies, but does not specify the timing and nature of the coordination. Without concurrent review, developers who are required to, or elect to, alter a project may be required to resubmit plans to the local planning agency for additional discretionary review. Such outcomes would have additional and redundant cost implications for permit processing. Further, projects which would otherwise be subject to ministerial permit processing only, should not be subjected to discretionary review because of the Draft Rules.

- Draft rule 9510, Section 8.8, proposes the District should have 90 days to take final action on an AIA application. Consequently, absent a concurrent review, process time could now take an additional 90 days. In some cases, Draft Rule 9510 thus has the potential to double existing processing times.

Recommendation: Revise draft Rule to include a mechanism or process for concurrent review by the District and local planning agencies to avoid impacts on local government. The Rule should not directly, or indirectly, prompt local governments to assess yet additional fees for responsibilities which may fall on them in implementing the District's Rule.

RESPONSE: Draft Rule language will be revised to make application submittal for ISR concurrent with local agency processes. Specifically, applications must not be submitted after application for a final *discretionary* permit in the San Joaquin Valley Air Basin, and may be submitted prior to that time. The rule will not place requirements upon the public agency for review or implementation of the ISR process. The public agency review (§ 8.2) has been revised to a voluntary review. The District will be coordinating review with the public agency through:

1. Making the ISR process concurrent with or prior to the public agency process;
2. Forwarding a copy of the AIA application (upon determination of completeness), a copy of the AIA approval package (upon approval), and a letter of Final Compliance to the public agency for voluntary review and commenting;
3. Communicating with the public agency when necessary during the application review process; and
4. Providing a letter of project status to the public agency upon request.

It should be noted that this rule will not apply to ministerial projects, nor will it prompt ministerial projects into becoming discretionary projects. That determination is made by the local land use authority.

9. **COMMENT:** 3. There is insufficient information or clarity in the Draft Rules regarding not only permit processing coordination, but also quantification and cost of mitigation measures. According to Health and Safety Code Section 40727 (b)(3), a rule or regulation adopted by a District board should be "…easily understood by the persons directly affected by it." Neither the Draft Rules, the Appendices, nor the Draft Staff Report describes the methodology the District will use to determine the number or value of mitigation credits to be associated with the various mitigation measures. Other aspects of the Draft Rules warranting clarification include, but are not limited to: ….*(District - see Comments 10 through 13 below)*

Recommendation: Revise Draft Rule 9510 to include a detailed description and analysis of the methodology the District will use to determine the number or value of mitigation credits to be associated with various mitigation measures. Clarify the items noted above in Draft Rules 9510 and 3180.

RESPONSE: The District will clarify the staff report to address how emission reductions from measures will be assessed. All measures within Appendix C have a quantification methodology in the URBEMIS model. These methodologies may be read in the URBEMIS User's Guide, available at South Coast Air Quality Management District's website http://www.aqmd.gov/ceqa/urbemis.html, and will be made available at the District's website. The measures do not have a straight "credit" associated with implementation, but a calculated reduction based on various parameters, which may include interaction with other selected measures, amount input, and other parameters.

10. **COMMENT:** Draft Rule 9510, Section 5.5 – Mitigation and Monitoring Report Program: The Draft Rule should specify if the applicant or the District is responsible for preparing this document.

RESPONSE: The rule language will be revised to reflect the following: The applicant is responsible for preparing a proposed document. The District will provide the format and recommended keys for the document. The District will then work with the applicant to finalize the document prior to approval. It should be noted that this will only apply to measures selected by the applicant that do not have another enforcement mechanism, such as being a requirement by another public agency.

11. **COMMENT:** Draft Rule 9510, Section 8.5 – Air Impact Mitigation Fee Estimate Acceptance: What amount of time does the developer have to respond to the estimate provided by the District?

RESPONSE: The draft Rule will be revised to reflect the following Unless the applicant has proposed a Fee Deferral Schedule (FDS) prior to AIA approval, the applicant must pay the fee within 60 days, or may propose a FDS within 15 days of receiving the fee invoice. If the applicant proposes a FDS within the allowed timeframe, the District then has up to 15 days to finalize the FDS with the applicant.

12. **COMMENT:** Draft Rule 9510, Section 10.2.3 – Administration of the Mitigation Funds: what, if any, limits are there on the duration of the contract between the developer and the District?

RESPONSE: A distinction must be drawn between the ISR applicant, and an applicant for the funds. Section 10.2.3 discusses the process between the District and the applicant for funds. The duration of the contract will vary depending on the project. Some contracts will be completed upon installation, while others may require reporting for 5 years. For example, a road-paving project would have a contract that is completed upon installation, whereas an engine contract typically contains a 5-year reporting requirement. The staff report will be amended to include this information.

13. **COMMENT:** Draft Rule 3180, Section 4.2 – Application Processing Time Log: How long does the District have to respond to a developer's request for a copy of the Log?

RESPONSE: The District uses an automated Labor Information System (LIS) to track project time by all staff working on a project. This allows the District to easily prepare the time log within a short timeframe. The District standard for this type of request is 10 days. The District will amend Draft Rule 3180, Section 4.2 to state the District has up to 10 days to provide the information.

14. **COMMENT:** 4. The direct and indirect costs imposed by the Draft Rule on the residential development process will result increased housing costs. The rationale for these increased costs as required by the Health and Safety Code Section 40728.5 are not adequately identified nor justified by the complete analysis.

The Department commends the District's decision to reinstate the exemption for housing projects directly assisted by federal, State, or local housing funds. Assisted projects, however, only account for a small percentage of the San Joaquin Valley's workforce housing stock. The majority of new lower- and moderate-income residents will occupy market-rate units. Increases in

construction costs resulting from the Draft Rules will ultimately be passed on to these residents in the form of higher rents and home prices.

Yet, as indicated below, the Executive Summary of the socioeconomic assessment the District prepared pursuant to the Health and Safety Code Section 40728.5 concludes that increases in the construction and housing costs are irrelevant because lower-income residents are already overpaying for housing and are thus dependent on public subsidies:

The analysis demonstrates that, even before the imposition of an air quality fee(s), most low-income (and) households in the Central Valley are priced out of newly constructed multifamily unit market, the rents for which need to be at levels that account for the price of land, development cost, developer fees, and an adequate level of profit, among other things. The analysis discusses how public subsidies can assist in enhancing the financial feasibility of a real estate project in which a certain portion of units are set-aside as below-market rental units (San Joaquin Valley Unified Air Pollution Control District. Socioeconomic Analysis Proposed Indirect Source Rule: Draft Rules 9510 and 3180. 24 August 2005.p.1.)

The demand for assisted housing far exceeds available resources of all levels of government. The District should not assume that higher rents and home prices can be solely addressed by government subsidies. Furthermore, higher housing prices are problematic because the affordability gap widens, forcing more San Joaquin Valley residents to overpay for housing and/or live in overcrowded conditions. Additional regulatory barriers that increase the cost of housing supply must be restructured and their benefit should exceed their cost impacts.

The Department also notes that the socioeconomic assessment does not address the impact of the Draft Rules on small business or analyze the availability or cost-effectiveness of alternatives, as required by Health and Safety Code Section 40728.5(b)(1), (b)(3), and (b)(4). For example, Part 6 (p. 26-32) includes generic information about impacts on single-family and multifamily homebuilders, but does not specify impacts on small homebuilders.

Recommendation: Revise the socioeconomic assessment to include: 1) a more thorough analysis of the impact of the Draft Rules on the economy of the San Joaquin Valley, including the number of consumers who will be overpaying for housing; 2) the impact of the Draft Rules on small residential developers; and 3) alternatives to the Draft Rules.

RESPONSE: The Socioeconomic Analysis will be amended to include analysis on the rule's impact on small businesses. In addition, the analysis does not discuss alternatives because there are no identified alternatives to adoption of the ISR rules.

Although the Socioeconomic Analysis does discuss the role of public subsidies, the District's conclusion is not that low-income housing impacts are irrelevant due to public subsidies. The Socioeconomic Analysis discusses public subsidies to show the options and availability of what subsidies exist. The conclusion of the Socioeconomic Analysis is that the impacts on housing costs (both to the developer and the buyer/renter) are less than significant. The District's conclusion is similar to how some pollutant thresholds of significance are set. For example, the District is in non-attainment for ozone and PM10. It could be argued that because the air is bad already, *any* increase is contributing to non-attainment and therefore is significant. However, the District finds it impractical and unwarranted to force every project that emits *any amount* of the applicable pollutants into the 'significant' category. Therefore, the District determines significance for PM10 and ozone precursors against a threshold that aims to truly differentiate between less-than-significant and significant impacts. Similarly, the Socioeconomic Analysis states on page 37:

For the most part, rents that low-income households should pay are substantially below the rents that the typical new multi-family units construction in the region should command, even before the imposition of the air fee.

That is to say, the market is such that low-income households are already priced out of most new dwelling units. Any increase in housing costs, regardless of origin, will exacerbate this disparity. However, the analysis shows that the potential increase in mortgage is, "*a small fraction of the original household income required to finance a new home in the event no air quality fees were in place*," and the potential increase in rents are, "*similarly small*." (p.1)

15. **COMMENT:** 5. Draft Rule 9510 would impose mitigation fees without adequately establishing a nexus. The Draft Staff Report and Summary of Comments and Responses from the June 30, 2005 public workshop do not adequately support the nexus between the expenditure of mitigation fees and the location of indirect sources. For example, while NOx occurs throughout the District, the impact of other pollutants, such as PM10, is more localized.

Recommendation: Clarify the nexus between PM10 and the expenditure of mitigation fees.

RESPONSE: The District has prepared documentation included in the staff report for the rule that provides the information necessary to demonstrate a nexus between project impacts and the off-site fee. See Response to Comment #125 for the findings of the District's legal counsel's analysis of nexus requirements.

16. **COMMENT:** In summary, the Draft Rules do not appear to comply with the "clarity", "consistency," and "nonduplication" requirements set forth in Health and Safety Code Section 40727(b). Than you for the opportunity to submit additional comments. Given the magnitude of the concerns identified in this letter, the Department recommends that the District not adopt Draft Rules 9510 and 3180 as drafted and continue to work with all interested parties on needed revision.

RESPONSE: The District disagrees that Rule 9510 conflicts with H&S 40727(b). The District prepared a consistency analysis that is provided as Appendix G to the Staff Report. The rule is being revised to improve clarity of the requirements and will provide detailed rule implementation guidance prior to implementation and typically uses compliance assistance bulletins when issues arise after implementation. The rule does not duplicate other requirements on indirect and areawide sources. Emissions estimates used in the rule account for existing controls on vehicles and equipment. The rule requires a reduction of a portion of the remaining emissions after control. Because of the Valley's rapid growth, a substantial portion of benefit of the controls is offset; hence the need for additional emission reductions to reach attainment by deadlines mandated for the District's PM10 and ozone plans.

Local Public Agencies:

City of Hanford
Date: September 23, 2005

17. **COMMENT:** I applaud your efforts to continue to evaluate methods to improve the air quality in the valley. However, I would request that the San Joaquin Valley Unified Air Pollution Control District take the time to further study Draft Rule 9510 and Draft Rule 3180.

RESPONSE: This rule has been under development for more than two years. The District has had three rounds of workshops, focus groups, stakeholder meetings and other outreach. We believe that the rule development process has been adequate.

18. **COMMENT:** On behalf of the City of Hanford, I would ask that you slow down the process and identify specific steps and programs that will be implemented to reduce air pollution; include additional input from representative agencies and clearly identify how the funds collected will actually improve air quality in the valley.

RESPONSE: See the Staff Report for more information on how the rule works to reduce emissions through on and off-site measures and how the District will use funds received as a result of Rule 9510 and Rule 3180. In addition,

Appendix E (Cost Effectiveness Analysis for Rule 9510) for details on the exercise that the District has completed to ensure that:

1. The emission reduction projects exist in a quantity to provide the reductions necessary, and
2. Those projects exist at a cost-effectiveness that can achieve the schedule listed in the rule in Section 7.2.1 and 7.2.2.

19. **COMMENT:** The incompatibility of the proposed regulations regarding the CEQA requirements poses additional concerns.

RESPONSE: The District believes that Rule 9510 is fully compatible with CEQA requirements. The rule provides a new opportunity to provide consistent air quality analysis and emission reductions on a Valley-wide basis. See Response to Comments #8.

20. **COMMENT:** Restraint must be used in determining actions that would have a significant impact on our residents, the business community and our local governments. Specifically, there must be a nexus for the fee's charged and the specific identification on how the generated funds would be used to remedy the problem which exists.

RESPONSE: The District has designed the rule to address only a fair share of the impacts caused by new development. We are confident that the rule will mitigate emissions in direct proportion to the impact caused by the project in keeping with nexus standards. The key to meeting the nexus is that impact will be estimated with best available tools and emission reductions obtained to offset the impact will be quantified with best available factors and methods. See also Response to Comment #125.

Council of Fresno County Governments (Fresno COG)
Date: September 9, 2005

At the request of our Transportation Technical Committee (TTC), the Council of Fresno County Government (Fresno COG) is submitting this letter regarding the Air District's DESIGN (Decreasing Emissions' Significant Impact from Growth and New development) program. The most recent draft of the DESIGN program was discussed by Fresno COG staff and TTC members at the September 7, 2005 meeting. Many of our member jurisdictions have significant concerns over the proposed rule and requested that we submit the following comments.

21. **COMMENT:** Inadequate Notice and Review Time
In some cases, Fresno COG and our member agencies received only a one-day notice for the September 1, 2005 workshop. This late notice prevented several agencies from attending on that day. On several calls with the Air District last month, Fresno COG staff indicated the need for improved communication and

coordination. This continues to be a concern, as the current rule development schedule allows only two weeks to review and comment on the draft rule.

RESPONSE: The District has a list serve for the rule that enables all interested parties to receive immediate notice of workshops and document availability. The District accepts comments up to and including the Governing Board hearing, allowing for more than a month of additional review time should it be needed.

22. COMMENT: Transportation Projects Subject to the Rule
The short review time is especially troubling given the recent addition of transportation projects (with construction emissions greater than 2 tons per year) as subject to the DESIGN rule. Fresno COG and our local agencies are unclear how this will impact the project approval process and need additional time and information to assess the impacts.

RESPONSE: The rule does not impact the project approval process since the District has no discretion over those projects. The rule just provides a mechanism to enable the agencies to reduce the impacts of project construction. See also the Staff report.

23 COMMENT: Demonstrate the Air Quality Benefits
Fresno COG requests that the Air District clarify how this rule will improve air quality. Please provide additional analysis of the air quality improvements and examples of how the revenue will be used.

RESPONSE: The Staff Report contains analysis that quantifies the projected air quality benefits of the rule. Additional details regarding the potential projects funded by the rule are included in the revised Appendix E. See also Response to Comment #18 on the use of off-site funds.

24. COMMENT: Improve Response to Comments
As noted by several commenters at the September 1st workshop and by our member agencies at our committee meeting, Fresno COG also requests that the District develop and adequate process to address comments received. The "Response to Comments" distributed at the workshop was organized by category, rather than submitting agency; this made it time-consuming to locate and review specific Reponses. In several cases, our local jurisdictions indicated that comments were not addressed and needed to be given sufficient consideration by Air District staff.

RESPONSE: The District has modified the Response to Comment format to address this concern. The District feels that the current format will allow commenters to find their specific comments and the associated responses.

25. **COMMENT:** Identify Rule Changes
Please provide a document on the Air District website that identifies and tracks changes made from previous drafts of the rule. This has been the practice with other rule modifications and is essential to reviewing and commenting on this document.

RESPONSE: The changes to the draft from this round of comments will be made in strikeout/underline format.

Fresno County, Department of Public Works and Planning
Date: September 15, 2005

26. **COMMENT:** We are concerned with the language of the rules as it relates to transportation projects. Should 2.2 say "two (2.0) tons" **per year** "of NOx and PM10 combined.", based on similar language in 2.3.4 and 4.2

However, looking more closely, these three are *not* identical in that:
- 2.2 says "NOx and PM10 combined"
- 2.3.3 says "NOx and PM10"
- 4.2 says "NOx and PM10 each"

If there is a specific reason for the differences, can you explain?

RESPONSE: Since construction emissions occur during a specific period, the emissions are based on the total during the construction period. For example, if a project emits 3 tons of combined emissions during a six month construction period, that amount is subject to the 20% NOx and 45% PM10 emission reduction requirement. If a project emits the same 3 tons of emissions over two years, the calculation is also based on the entire construction project.

Section 2.2 refers to construction NOx and PM10, which is based off of 2 tons of NOx and PM10 total tons combined. The District will revise the rule language to clarify that construction pollutants are total tons combined, and operational pollutants are tons per year non-combined. Section 2.3.2 will be revised to state "NOx *or* PM10" and be specific to operational emissions.

27. **COMMENT:** Also, please look at 8.8. Under it you have 8.7.3, but should that actually be 8.8.4?

RESPONSE: The section will be renumbered as noted.

Kern County Planning Department
Date: July 22, 2005

The Kern County Planning Department appreciates the opportunity to comment on Draft Rule 9510 and Rule 3180 which are being implemented to assist the District's attainment goals for State and Federal standards for ozone and PM10. The stated purpose of Rule 9510 is to provide a mechanism for development to mitigate construction, direct and indirect emissions from their projects through design features, on-site and off-site measures. Rule 3180 will provide for payment of the District's staff cost to implement the new rule.

As our comments have consistently stated, the DESIGN Rule, while using the language of CEQA (Significant Impact) avoids all relationship to CEQA and simply defers any questions to a later time after Rule Development is complete. The following is a preliminary list of questions, comments and concerns regarding this matter.

28. **COMMENT:** What is the basis for the exemption of projects that have mitigated baseline below two tons per year for each pollutant from the Rule? Is this basis evidence that 10 projects in the same area producing less then two tons per year each are not cumulatively considerable under CEQA?

RESPONSE: The District has made changes to the project submittal timing in the rule to ensure that the air analysis conducted can also be used to support the CEQA process for the local agencies discretionary approval.

The rule is designed to reduce the impact of the project to the extent needed for the District to reach attainment of ozone and PM10 standards. The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. The rule sets levels that are in compliance with state law regarding indirect source regulations and are feasible to achieve. Based on the District's analysis, project's with emissions below two tons per year of operational NOx and PM10 were not required to reduce emissions to achieve the emission reduction required by the District's plans for attainment.

29. **COMMENT:** Why are only NOx and PM10 being addressed when CEQA requires all pollutants to be quantified and mitigated to the extent they exceed thresholds?

RESPONSE: The ISR program's primary purpose is to meet attainment plan requirements *not* as a CEQA compliance method; however, we believe that reducing one precursor, NOx, will reduce the cumulative impact on ozone from new development to less than significant levels.

It is not the District's intent to reduce the impacts of all pollutants in the valley through this rule. The rules are the result of the District's PM10 and Ozone Attainment Plans, as they identified the need to reduce directly emitted PM10 and NOx in order to reach the standards on schedule. Sufficient ROG was obtained from other control measures to enable the District to predict attainment without additional ROG control. Therefore, the rule was able to focus on those two pollutants and can make the case that ROG from predicted growth from new development will not impact the attainment strategy.

30. **COMMENT:** The District has an established threshold in the GAMAQI of 10 tons of ROG yet no provision for mitigation in the DESIGN rule. Why?

RESPONSE: See Response to Comment #29 above. The GAMAQI is the District's Guide for Assessing and Mitigating Air Quality Impacts, specifically written to help lead agencies, as identified in CEQA, address CEQA for air quality impacts and may be revised to reflect changes that are appropriate.

31. **COMMENT:** Section 6.2 requires mitigation of only apportion of the project's emissions (1/3 of the project's first-year area source and operational baseline NOx emissions over a period of ten years) and then states that it "represents cumulative emissions…". The use of the term "cumulative" should be deleted and replaced by another term to explain the Districts intention. An interpretation of the phrase "cumulative emissions" in a CEQA document, under current case law interpretation, does not include such a reduction as proposed by the District. This disconnect will lead to confusion and legal challenges of CEQA documents.

RESPONSE: The District believes that the term "cumulative" best describes the emissions being reduced by the rule. The NOx emissions are declining over time, so a project that reduces emissions to the extent described by the fee formula will be mitigating its cumulative impact. See also Response to Comment #28.

32. **COMMENT:** The District is the authority that provides guidance and direction for local government on air assessments for CEQA and has been recognized as such by the Courts. If the District has sufficient basis for establishment of this Rule with reductions in required emissions to be mitigated on " the concept that annual NOx emission from motor vehicles declines 50% over ten years.", then the District should include in this Rule making, clear direction from the Governing Board to amend the GAMAQI, through a Public Hearing process, to formally adopt this approach in Air Quality Assessment methodology for CEQA documents. This process, which would necessarily include the fact basis for the adoption of this standard, would provide clear direction for the connection of this Rule to CEQA and provide support of the Lead Agency in current challenges to Air Assessment methodology in CEQA documents.

RESPONSE: The primary purpose of the rule is to help the District meet its attainment plan commitments. The rule provides for emission reductions in a framework that provides strong assurance that reductions will be real, surplus, quantifiable, and permanent and therefore should strengthen environmental documents that rely on reductions to reduce significant air impacts. The District's GAMAQI is formally adopted by the Governing Board at a public hearing. Any revisions will also go through a public review process with a workshop and Governing Board hearing. See also Response to Comment #28.

33. COMMENT: The staff report states on Page 11 that "The current concept is that Rule 9510 will mitigate the cumulative impacts of anticipated growth since the reductions attributed to this program was identified in two attainment plans as necessary to achieve the applicable standards." Yet the next sentence weakly states that "The District may (emphasis added) revise the GAMAQI to define the exact role that Rule 9510 will have in the CEQA process, prior to adoption of this program." Please clarify why the District is not committed to amending the GAMAQI to clearly provide relief for local government in CEQA litigation in a matter, air impacts, for which the District is the recognized expert.

RESPONSE: The District is committed to providing guidance through the GAMAQI that accurately reflects the impacts of all adopted District rules and regulations on air quality.See also Response to Comment #28 and #31.

September 1, 2005 Workshop – Verbal Comments

Bakersfield

Dr. Adrian Moore – Reason Foundation

34. COMMENT: There is a lack of a causal link between new uses and an increase in emissions from new trips. If it is automobiles that are causing the pollution that the rule is targeting, then the District should be going after automobiles.

RESPONSE: There are more than twenty years of CEQA documents that have consistently found that new development has a significant impact on air quality. New development is constructed to accommodate growth. Prior to development of green field areas there are no trips and no construction emissions at the project site. The argument that some trips are displaced from another existing use are not valid except in the short term. When people move to a new house, someone can be expected to move into the existing home and replace the trips the old homeowner was making. When commercial uses open in a new growth area, they may temporarily divert trips from existing commercial uses, but in a growing area the most important factor is an expanding market area. When the community adds enough residents to support another like commercial use, the

trips will be drawn from the area farthest from the existing use to the new use, and overall the number of trips is increasing.

35. **COMMENT:** The sources listed in the District's staff report are not published or peer-reviewed. Specifically, Dr. Holtzclaw's study is not published.

RESPONSE: The Holtzclaw study provides analysis of VMT differences in areas with different levels of pedestrian and transit accessibility in California. The study has been available for all who wish to review it. In addition, the study has been referenced by other researches numerous times in peer-reviewed journals.

36. **COMMENT:** Additionally, the benefits from design identified in the staff report are likely the result of self-selection and not an actual shift in modal choices based on design. Therefore the reductions from the increase in the on-site measures implemented will not materialize from implementation of this rule.

RESPONSE: The author's comment is based on a false assumption that there are no people in the San Joaquin Valley that would choose different development designs if they were available. The District maintains that trip making behavior would change if onsite design measures were widely implemented. The causal link between new development and vehicle emissions has been well documented and is generally accepted. The issue of self-selection v. modal shift in development with 'smart growth', 'transit-oriented' or 'pedestrian-oriented' design has not been resolved. It is known that there is a real, verifiable correlation between land use design and vehicle use. Studies show that well-designed development that considers pedestrian, bicycling and transit generates less emissions than totally automobile oriented design.

The District recognizes that there is always uncertainty when predicting individual travel behavior. For this reason, the District proposes to submit reductions claimed for onsite measures as a voluntary and emerging measure that allows for this type of uncertainty in order to promote innovation.

37. **COMMENT:** If it is automobiles that are causing the pollution that the rule is targeting, then the District should be going after automobiles.

RESPONSE: State and federal controls on motor vehicles are not sufficient for the District to attain federal air quality standards within mandated timeframes. The District has authority to seek additional reduction from indirect and areawide sources to close the gap. Stationary sources must provide offsets to further reduce emissions beyond what is feasible onsite. Indirect source rules operate under a similar concept. See also Response to Comment #6.

38. **COMMENT:** Reducing trips doesn't create large reductions relative to increasingly clean vehicles, regardless of increasing VMT

RESPONSE: The heart of the problem is that although vehicles are increasingly clean, increases in travel and VMT are offsetting a substantial portion of the benefit, hence the need for an indirect source review rule.

39. COMMENT: The housing impact is not near accurate because the market could be in a bubble right now. The Socioeconomic Impact Analysis should use quintiles instead of an average; you would find a huge impact on low incomes with that methodology.

RESPONSE: First, the impact on housing stated in the Socioeconomic Analysis was based on the number of housing units used by the District, which were based on the state population forecasts. If the growth rate exceeds the projection, the impacts will be greater and so will the need for emission reductions. Also, a greater number of units subject to the rule would have no added impact on individual development projects. Second, the use of an average is appropriate because the impact of the fee filters out over time, so the effect, such as an increase in rent, isn't immediate. See also Response to Comment #49.

Arthur Unger – Kern-Kaweah Chapter of the Sierra Club

40. COMMENT: The studies in the District's materials regarding differences in trip generation from different types of development are published.

RESPONSE: Comment Noted.

41. COMMENT: Concerning the information provided in the Socioeconomic Impact Report – the prices of housing in the Valley are a result of supply and demand, not necessarily resultant from fees that are assessed.

RESPONSE: The Socioeconomic Analysis supports the author's comment. The report states, "it is apparent that larger market forces are the primary culprit behind the increases in housing prices…"

Carla Waleka – Construction Industry Air Quality Coalition

42. COMMENT: The Construction Industry Air Quality Coalition would like to see the construction calculator and know the assumptions and inputs.

RESPONSE: The calculations used in the rule were done using URBEMIS construction module. The construction calculator used by SMAQMD is proposed as a model for development of a San Joaquin Valley version. We are now proposing to continue using URBEMIS with the option for developers to use a construction calculator if approved by the APCO.

Renee Nelson – Clean Water and Air Matter, Bakersfield

43. **COMMENT:** The process laid out by the District does not comply with CEQA. The process will allow for negotiations with applicants behind closed doors with no option for public input, which is required under CEQA. In addition, CEQA states that mitigation can't be differed until later. The District also put forth a comment that CEQA timelines vary with jurisdiction, which is untrue.

RESPONSE: The ISR program does not involve discretionary approval of development projects, and therefore is not subject to CEQA. We expect local agencies to use the air analysis accomplished for the rule and o-site emission reduction measures agreed to by the applicant *and the local agency* to reduce air impacts in their CEQA process. If a citizen has an issue with the approval of a project due to air quality impacts they will have the same options that are currently available to them to challenge the project and the validity of the analysis used to support the decision made by the local council or board. See also Response to Comments #8 and #28.

44. **COMMENT:** This program must be aligned with CEQA and should not allow changes to a project behind closed doors.

RESPONSE: The rule is being revised to change the application timeframe to be concurrent with the local agency CEQA process. District has no authority to require applicants to include on-site emission reduction measures. We have traditionally worked with applicants to help them identify changes to the project that would reduce air impacts as early in the development process as possible and will continue this effort. The rule requirement is for the applicant to fill out the on-site emission reduction checklist; however, it does not prescribe a minimum or maximum number of measures that should be checked. The responses on the checklist are solely up to the applicant. The land-use decision making authority is with the local land use authority, not the District. The AIA information will be made available to the public. See also Response to Comments #8 and #29.

45. **COMMENT:** Does the ISR program apply to agricultural projects?

RESPONSE: The District believes the applicability section and the definition of a development project effectively exclude agricultural projects.

46. **COMMENT:** Will the ISR apply to waste-hauling projects?

RESPONSE: Hauling projects are not specifically stated as a project in the rule. ISR projects are land-use based, triggered by a discretionary permit in combination with new construction or increased use that generates construction and/or area and mobile emissions that exceed the ISR threshold. If a land use requires a discretionary permit, and meets or exceeds the applicability threshold, then the emissions from hauling would be subject to the rule. However, if the project is hauling operations alone then it would not be subject to the rule.

47. COMMENT: Where will mitigation funds be used in relation to the project assessed the fees?

RESPONSE: The funds will be spent within an area based on the type of pollutant. NOx is a regional pollutant, but every attempt will be made to fund projects in the vicinity of the project site. PM10 is a more localized pollutant, and PM10 funds would be spent closer to the project assessed the fees.

Brian Todd, BIA and Business, Industry and Government (BIG)

48. COMMENT: The District needs to tell the public about how much more fees will be in the Bakersfield area due to the need for additional PM10 reductions.

RESPONSE: The additional PM10 reductions cited by the commenter is the 1-ton per day by 2010 needed in the Bakersfield Metropolitan area. This rule does not address that reduction. ISR program fees are tonnage based and do not adjust by location. The 1-ton needed in Bakersfield is being addressed through a PM10 task force. Voluntary mitigation agreements in the area may be used to the extent that they mitigate beyond the requirements of Rule 9510.

49. COMMENT: The dynamic driving prices for housing in small and medium cities stated in the presentation is due to school fees. The ISR fees will exacerbate this problem. In addition, the housing market may be a bubble. Basing the fee on housing bubble numbers is a flawed methodology because the market is unstable, and the fee revenue depends on the number of houses.

RESPONSE: The District fees were not based on the number of housing units going in. The fees were based on the amount required to offset emissions, and is purely emission based. The expected *fee revenue* and *future impacts* are estimated from the forecasted population data from the state and the emissions from growth in residential and non-residential development.

It is important to note that the District will only be collecting fees to reduce as in there is development creating emissions to reduce. If the number of houses decrease (bubble burst), the District would have fewer emissions to reduce; therefore, the same fee brings the appropriate amount to reduce those emissions (less revenue). If the number of houses increases, the District would

have more emissions to reduce; therefore, the same fee brings the appropriate amount to reduce those emissions (more revenue).

Heather Ellison

50. COMMENT: What is the meaning of 'recreational space' and 'unidentified space' in the rule?

RESPONSE: Rule 9510 §13.7 defines recreational space for recreational uses such as soccer fields. Unidentified is a catchall category to indicate that other land use categories not listed are still subject to the rule if they generate emissions and are not otherwise exempt.

Mike Kelly – Western State Petroleum, Vector Environmental

51. COMMENT: Previous comments to the District were not adequately addressed in the previous response to comments. The law states that the District can regulate the increase in emissions. There is a concern that the Rule will trigger review of those discretionary permits that don't result in an increase in vehicle traffic, such as certain Conditional Use Permits (CUPs).

RESPONSE: The District typically consolidates similar comments and provides a single response. The District will consider providing individualized responses on a case-by-case basis.

The Rule applies to the *increase* in emissions resulting from land-uses changes that require a discretionary permit. Therefore, if project requires a discretionary permit, but does not result in an increase in emissions that meet the applicability threshold, then it would not be subject to the Rule. However, if the CUP allows for an increase in indirect or area source emissions or new construction activity that generates emissions, it would be subject to the rule if not specifically exempt.

Fresno

Bob Keenan – BIA, BIG

52. COMMENT: Fee collection and use is governed by the Health and Safety Code, §6600 subsection G. The rule does not meet those requirements.

RESPONSE: The author cites Government Code Section 66000 (The Mitigation Fee Act) as the impetus for promulgating a nexus document. The legislation clearly states that it is applicable to fees (§66000(b)), "in connection with approval of a development project." Section 66000(a) defines a development project as including, "a project involving the issuance of a permit for construction

or reconstruction, but not a permit to operate." In addition, Section 66001(a) states:

> *In any action establishing, increasing, or imposing a fee* ***as a condition of approval*** *of a development project by a local agency on or after January 1, 1989, the local agency shall do all of the following:*
> (Emphasis added)

Section 66005(a) also ties the legislation with 'condition of approval of a development project'.

1. The District will not approve or disapprove a development project, but will approve or disapprove the project's analysis to determine the quantity of emission reductions required to comply with the rule. The authority to approve or disapprove the development itself is the local land-use agency, not the District.
2. The District will not be issuing a permit, nor will the District give a discretionary approval of the project.
3. The District's ISR action is ministerial, and therefore will not include conditions of approval.

The District stands by its previous assessment. The Mitigation Fee Act does not apply to the ISR rules. However, the District has analyzed the applicability of nexus requirements to this rule. See Response to Comment #125 for the findings of the analysis.

53. **COMMENT:** Fees paid at the permit doubles to the buyer and prices people out of the market.

RESPONSE: Fee prices may price some people out of a particular house, but not necessarily out of the entire market. Currently, market forces are increasing the price of housing to a much greater extent than the fee would. In addition, the difference between paying prior to building permit issuance and at certificate of occupancy can't possibly double the cost unless the loan was at an astronomical interest rate. If the fee were financed in a mortgage at 30 years it may double, but it also doubles the amount they are paying for anything.

54. **COMMENT:** The fees from the program will drive up the costs of existing housing.

RESPONSE: Existing housing is not subject to the rule. Although the District realizes that sellers of existing housing may take advantage of a potential increase in new housing prices by artificially inflating the price of existing housing, the District does not have control over existing housing prices.

Increases in existing housing prices 'attributable' to the rule would be resultant of the seller, not of the District.

55. COMMENT: The impact of the fees resulting from implementation of the ISR program would ruin the Valley's economy.

RESPONSE: The commenter's position that ISR fees would ruin the economy is not supported by factual evidence. The Socioeconomic Analysis found the worst-case scenario of fees to be within the margin that can be absorbed by the economy. This is not to say that there is no impact, but that the impact is less than significant. In addition, the residential scenario in 2008 resulted in a fee of about $1,800 per house. This scenario had no emission reduction measures included; it had a density of 3 unit per acre (increased density decreases emissions), no sidewalks, or any other measure that reduces emissions (and thus fees). See also response to comment #56 and #14. Finally, housing prices have steadily increased in over the last ten years. This increase is far more than $1,800 *every year*. The District does not state this to justify the potential fee, but to illustrate what has occurred in housing prices and that the Valley's economy has not crashed as a result. It is illogical to suggest that a potential $800 per residential unit in 2006 to $1,800 in 2008 would ruin the Valley's economy. As stated in Response to Comment #14, the fee amount listed in the Socioeconomic report is likely much more than will actually occur.

56. COMMENT: The cost of on-site mitigation is not included in the socioeconomic impact report. Therefore, the report does not accurately reflect the impact of the rule.

RESPONSE: The Socioeconomic Analysis does not include the price of on-site emission reduction measures for a specific reason. That is, it is reasonable to expect that an applicant would not choose a more expensive option over a cheaper option. The 'worst-case', no on-site-measure fees are therefore the most that an applicant would pay. It is also important to note that on-site measures are entirely voluntary.

Also of note, many of the on-site measures that count towards reduced emissions are *already* requirements by local land use agencies. For example, most agencies require some amount of sidewalks or bicycle improvements with development that is adjacent to a street. URBEMIS calculates an emission reduction from the amount of sidewalks and bicycle infrastructure built in the project. Therefore, crediting certain on-site measures are of no additional cost to an applicant because they had already incorporated the measures into the project as a result of the public agency requirements.

Mark Stout - Fresno Metro Ministries

57. **COMMENT:** The proposed rule only mitigates a portion of the emissions. Why does the rule only reduce a portion of the emissions, and why the particular level- for example the 33% for operational NOx.

RESPONSE: The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. The rule sets levels that are in compliance with state law regarding indirect source regulations and are feasible to achieve. The 33% is based on the area under the triangle that accounts for declining mobile emissions over time – see the fee formula.

58. **COMMENT:** A slide of the presentation showed huge NOx emissions increase from 2006 to 2010 from development. The number listed for reduction attributable to the rule seems rather small in comparison.

RESPONSE: The slide incorrectly showed the reductions attributable to construction as cumulative instead of temporary during the construction phase of development.

59. **COMMENT:** The District would benefit from making the URBEMIS runs available to the community groups. The community groups should be able to review what developers are inputting, and verify the modeling.

RESPONSE: The runs will typically be used in the CEQA process and included with negative declarations and EIRs. The files will be available with a public information request. The District will make this information public. See also Response to Comment #8.

Colby Morrow – Southern California Gas Company

60. **COMMENT:** Appendix C should be amended. PUC Energy Efficiency programs can be administered by energy companies and municipalities.

RESPONSE: Appendix C, page C-5 will be amended.

Cathy Crosby, Fresno County Public Works, Transportation and Planning

61. **COMMENT:** The response to comment format from the previous workshop made it difficult to find one's comments and the associated responses. The preferred format would be the EIR format, where the original comment letter is retained.

RESPONSE: The District has revised the response to comment format to address this issue. The format is a hybrid, retaining the original comment but not in the original letterform.

62. COMMENT: Several of the Fresno County July 22nd comments weren't addressed in the response to comments. Specifically:

- Transportation projects should be re-written to include non-vehicle projects, such as pedestrian projects.

RESPONSE: The definition of Transportation projects does not include non-vehicle projects because of the definition of an indirect source. The Clean Air Act (CAA §110(a)(5)(C)) defines and indirect source as, "… a facility, building, structure, installation, real property, road, or highway which attracts, or may attract, mobile sources of pollution". Pedestrian projects do not attract mobile sources of pollution, but pedestrians. It would be inappropriate to include non-indirect sources in with transportation projects to be subject to the requirements of the rule.

63. COMMENT: §7.2.2.2 of their letter describers the dissolution of community service districts.

Previous Comment
7.2.2.2- Community Service Districts (as a means to insure perpetual funding for operational mitigation): The Air District may want to evaluate under what conditions a Community Service District that funds any mitigation activity not directly related to health & safety may, after formation, discontinue assessment or dissolve the Community Service District by vote of property owners making up the District.

RESPONSE: All measures within the on-site checklist have an emission reduction benefit associated with their implementation. The District identified those on-site measures that reduce emissions from development projects, and help reduce the air impact of development projects. The goal of the rule is to reduce emissions from development project to achieve the emission reduction committed to by the PM10 and ozone attainment plans. Although each measure is indirectly associated with an air benefit (reduced emissions and attainment of the PM10 and ozone standards), the District considers the measures to be health-related. Therefore, funding of these measures constitutes a health-related activity.

64. COMMENT: Maintenance concern. Where will the funds for County enforcement of the rule come from?

RESPONSE: The County will not be required to enforce the rule. See Response to Comment #8.

Ray Leon – Latino Issues Forum

65. **COMMENT:** The District should clarify the PM2.5 and toxics issue. Suggests that the District break PM10 down further to strengthen the rule.

RESPONSE: This rule is a result of the PM10 and ozone attainment plan commitments. The rule controls NOx and PM10. Some fraction of PM10 is PM2.5 and will be reduced as a result of the rule. NOx reduces ozone during the warm months and reduces ammonium nitrate, most of which is PM2.5, during the cold months of the year.

The District recognizes the issue of toxic emissions from diesel engines, and the particular hazards of PM2.5. However, toxics are addressed through the District's permitting program, state regulation, and through CEQA commenting. District thresholds of significance for these pollutants are contained in the Guide for Assessing and Mitigating Air Quality Impacts (GAMAQI). In addition, PM2.5 will be addressed in the federal PM2.5 Attainment Plan due in 2005.

Mike Sanchez – City of Fresno

66. **COMMENT:** The city's July 22nd comments need to be addressed; they weren't addressed in the previous response to comments.

Previous Comments (paraphrased)

Nexus and Proportionality

- **A.** What is the Nexus determination for the project
- **B.** ISR rules address emissions from existing development; so, placing requirements on new development to remedy problems from existing development would be inappropriate.

Relationship of SJVAPCD and Rules 9510 and 3180 to CEQA and Planning Law

- **C.** Rule appears to defer or circumvent CEQA analysis because analysis and mitigation would be prepared after CEQA analysis. Also, it appears that the District would be issuing a construction permit, making the District a responsible or trustee agency.
- **D.** There may be differences in interpretation of mitigation measures and the reductions associated with them.
- **E.** Because the District is the appropriate agency to make a detailed determination of air quality impacts and appropriate mitigations, the District should fulfill its CEQA responsibilities by providing analysis and recommendations to the local land use jurisdictions so that the CEQA analysis work can be completed with this information.
- **F.** The District should not determine locations or patterns for development, this is the local jurisdiction's authority.

G. "Analysis and conclusions regarding land use and its vehicular emissions need to be rooted in data… recommend objective criteria"

Applicability of the Rules 9510 and 3180

H. It is not addressed if the rule applies to general, regional, community or specific plan adoptions. At that level, project specific information may not be known, and analysis may not be accurate. Therefore, they should be exempted from the rule**.**

I. Each public agency defines 'discretionary' and there is variability as to what each public agency considers discretionary. Therefore, the ISR rules will be applied inconsistently.

J. Language should be included in the rules to prevent piecemealing.

Timing and Project Tracking

K. Request ISR review to be shortened from 30 to 10 days to , "remain within the statutory CEQA timelines for responding to initial study requests" because URBEMIS runs are quick. The District should send the ISR project information to the public agency for incorporation into CEQA documents.

L. How will timing of construction be controlled for mixed use projects, since commercial often lags behind residential development?

M. How will the District track projects, such as multi-phase tract maps or shell buildings, for review and analysis.

Interagency Cooperation

N. "The ISR Rules propose that cities and counties withhold building permits pending satisfaction of SJVUAPCD requirements." There should be an agreement between the public agencies and the District that includes indemnification of the city.

O. "Local land use jurisdictions should be made a party to any mitigation agreements entered with the developer…(and) it would be ideal if such agreements were recorded as covenants running with the land…for which the … analysis was done."

Use of Mitigation Fees Collected Through ISR Rules

P. It appears that the ISR funds will be used to fund existing programs. New programs that expand mass transit and similar systems should be considered. "… the majority of the funding generated through the ISR rule should address vehicular pollution through measures to reduce traffic volume and relieve traffic congestion in the vicinity of the land use projects paying the ISR Rule-related fee."

RESPONSE:

A. See Response to Comment #125

B. ISR rules address emissions from *growth*, not from existing emissions. See Response to Comment #170. See also, Response to Comments #34 and #39.

C. Rule has been revised to be concurrent with CEQA analysis and Public Agency approval process. See Response to Comments #8 and #44. Also,

the District would not become a Responsible agency as a result of ISR implementation (See Response to Comment #52 and #187)

D. The measures listed in the On-Site Emission Reduction Checklists have a known quantification method associated with them. Applicants will identify the *specific* implementation of each measure, so there will not be interpretation of the amount of reduction. See also Response to Comments #7 and #9.

E. Although the ISR rules were not written to address CEQA, the reductions committed to in the PM10 and ozone attainment plans from this rule and individual project compliance can be used in CEQA documents at the public agency's discretion. See Response C above for timing of ISR implementation. See Response to Comment #8 for information on communications between the District and the land-use authority.

F. The District will not be making land-use decisions, and recognizes that that is the authority of the local land use agency. The land-use design considerations discussed by the District are discussed because they are known to reduce air quality impacts. The District provides these types of measures to encourage applicants to design projects submitted for city/county approval in ways that improve air quality and reduce potential ISR fees. The District has no authority over implementing land-use changes. Please note, the District will not require a minimum selection for the on-site checklist, measures selected are voluntarily identified by the applicant and are likely already part of the project. See also Response to Comment #43 and #44.

G. The measures listed on the on-site checklist have objective criteria, based on extensive research within URBEMIS. Please refer to Appendix D (Recommended Changes to URBEMIS for Rule 9510 and 3180) and the URBEMIS User's Guide (available at URBEMIS User's Guide, available at South Coast Air Quality Management District's website http://www.aqmd.gov/ceqa/urbemis.html). See also Response to Comments #7 and #9.

H. The ISR rules are applied to the last discretionary approval of a development project per Rule 9510 Section 2.1. The adoption of a general plan or specific plan is not usually the last discretionary approval a project will go through. Residential development may be rezoned, and must get a subdivision or tract map. Conditional Use Permits and Site Plan Reviews often apply to commercial and office development. However, the District recognizes that some projects may not require additional discretionary approval after the zoning is approved. Specifically, industrial development may not require additional approval. Therefore, the last discretionary approval will vary depending on the project. The District will provide outreach to developers and the public to ensure awareness of the rule; however, it is the responsibility of the applicant to be aware of the need, or lack thereof, for additional discretionary approval by the local land-use agency, and to apply at

the appropriate time. Additionally, applicants are encouraged to apply *prior* to the application for last discretionary approval with the land-use agency.

I. The District recognizes the variability of the application of 'discretion' in the Valley. As stated in H above, the last discretionary action is the trigger for the rule. This may cause inconsistency early in ISR implementation; however,

J. Language has been included. See Rule 9510 Section 2.3

K. First, the ISR program is not a CEQA compliance program (See Comments above). Analysis of the AIA application involves more than opening and running URBEMIS. The District will be analyzing the documentation for projects, running modeling program, finalizing MRS's, finalizing FDS's, etc. See the Draft Staff Report for additional information. The District will be sending information to the public agency. See Response to Comment #8.

L. The District does not have the authority to control construction timing. See Comments F, G and H above.

M. The District will be tracking projects through a database, and will be tracking project location primarily through APN. Multi-phase projects will be entered as such, with the applicable expected build-out dates. The applicant is responsible for identifying the use and build out of the projects. Should the project change, the applicant is responsible for notifying the District. If the project changes such that there is an increase in air emission and the applicant does not notify the District, they will be in violation of the rule and subject to District enforcement action. The District will share project information with public agencies to coordinate project tracking.

N. The District will not require or request that public agencies withhold building permits for ISR enforcement. However, the District may enter into an agreement with a public agency for information sharing that would facilitate District enforcement of the rules.

O. The District will be sending the public the on-site emission reduction checklist, as well as other information (see Response to Comment #8) during the review process. The District will consider the use of covenants for MRS compliance enforcement.

P. The District will not be using the ISR funds solely for existing emission reduction programs. The District has conducted an analysis of emission reduction projects available, and the cost effectiveness associated with them. This analysis can be found in Appendix E. See Response to Comments #18 for the use of funds, and #47 and #188 on the location of funding projects.

Modesto

Sally Rodeman – CalTrans, District 10

67. COMMENT: District 10 did not receive the notice for the meeting.

RESPONSE: You will be added to the rule mailing list. Other Caltrans staff received notice.

CalTrans District 10 is on the District's mailing list as a street address, to which the District has been mailing notices. District staff looked into the issue, and found that the CalTrans website lists a PO Box for District 10. The District will work to resolve this issue.

68. COMMENT: Is CalTrans a developer as defined by the rule?

RESPONSE: CalTrans would be a developer in those instances where the project meets the applicability of the rule.

69. COMMENT: Can the District put that in writing in the rule?

RESPONSE: The District does not specify or write out *who* a rule applies to, but write *what* a rule applies to. The rule is written so that all entities and individuals conducting activities subject to the rule must comply, so there is no need to list every possible agency or entity subject to the rule.

70. COMMENT: Does the Socioeconomic Impact Report account for impacts on the State of California, considering that the state is broke?

RESPONSE: The socioeconomic analysis provides the overall impact to the economy but does not specifically separate out impact to individual government agencies.

71. COMMENT: Does the District have a list of mitigation measures for construction?

RESPONSE: The Staff Report contains a discussion of measures that reduce emissions from construction activities.

Tom Carlson – Sierra Research

Thanks for addressing Sierra Research's comments from the last draft of the rule. Particularly, for Sierra Research's comments on silt loading, trip links and fleet mix.

72. COMMENT: How will the District be addressing the needed changes to the URBEMIS model?

RESPONSE: Updated default values will be provided as rule guidance. This information may be contained in the next update to the GAMAQI. The next upgrade to URBEMIS, beginning next year will include many of the new defaults and an improved construction module. The upgrade may take as much as a

year to complete, so in the interim, the guidance documents will be provided as needed.

73. **COMMENT:** What is the basis for the targets on PM and NOx reductions from construction?

RESPONSE: The District researched what other air districts had set for reductions, and found that those targets are achieved in practice. The reductions (20% NOx and 45% PM10) are achievable with existing technology with a mix of newer equipment and retrofit devices, and will allow applicants applying moderate effort to pay no fee on construction.

74. **COMMENT:** What is the District's response to the vehicle age distribution by age of project that Sierra Research had provided? Is the information provided by Sierra Research not adequate or substantial enough to change the modeling?

RESPONSE: The District is not currently convinced that the data cited would be valid in all circumstances, but will consider projects that provide evidence supporting a reduction for fleet age. There may be other factors that offset the possible benefit from newer vehicles such as higher rates of vehicle ownership (more vehicles per household).

75. **COMMENT:** URBEMIS is a sketch planning tool. Sierra Research believes the District should use a travel model. Sierra Research believes that a travel model is more accurate than URBEMIS, and found that URBEMIS estimates are 60% higher than the travel model estimates for the same project. In addition, as a sketch tool, URBEMIS is inconsistent with SIP methodology.

RESPONSE: The District believes that URBEMIS has been improved beyond its characterization as a sketch planning tool. Very few of the modules of the program are overly conservative. Most modules rely on statewide averages extracted from the emission inventory which should not be considered conservative estimates. The most important module is the mobile source module that includes the same emission factors used to build the emission inventory. It does a good job of arriving at a composite emission rate needed for a project level analysis. Models can always be made more accurate by individualizing more and more input factors. The District believes that URBEMIS balances data requirements with reasonable output accuracy and ease of use. The travel demand models described by Sierra Research are extremely data intense and would be very costly to run for the approximately 1,000 projects that will be submitted to the District each year. It is uncertain whether the demand models are more accurate for project level analyses than URBEMIS with local information**.**

Jan Ennenga – Manufacturing Council

76. **COMMENT:** There is a concern that the ISR program would apply to CEQA processes and permits for existing facilities that make modifications.

RESPONSE: ISR projects are land-use based, triggered by a discretionary permit in combination with new construction or increased use that generates construction and/or area and mobile emissions that exceed the ISR threshold. If a land use requires a discretionary permit, and meets or exceeds the applicability threshold, then the emissions from hauling would be subject to the rule.

77. **COMMENT:** What exactly does "primary source of emissions" mean for the exemptions section?

RESPONSE: The District had originally include an exemption for "A development project, whose primary source of emissions are from stationary sources…" However, the District is revising exemption to make specific land uses exempt. The District has completed a review of industries permitted by the District. This analysis details the amount of rules that apply to each industry and the amount of pollutants regulated by these rules. The intent is to remove the ambiguity of "primary" emissions and detail which industries will be exempt from the rule. In addition, industries with stationary sources may petition the APCO for ISR exemption.

Bill Zelocci – BIA CC, PSSP, StanCo (Affordable Housing)

78. **COMMENT:** The bill targets housing only. The fees, at least the biggest fees are from housing. The Rule doesn't affect other land uses that produce vehicle trips.

RESPONSE: The rule targets new development that results in area and/or mobile emissions. The rule contains an applicability section and an exemptions section. The rule *does not* target housing exclusively or charge higher fees for residential development. Housing constitutes about 1/3 of the development related emissions and therefore 1/3 of the potential for fees under the rule. Other land uses such as commercial office and retail generate more emissions and potential fees. Housing is used extensively in discussing socio-economic impacts because that is what concerns most people. Fees are emission based, not land-use specific. Fees apply to the broad categories of land uses specified in the rule. Certain land uses are exempted from the rule because their emissions are primarily from stationary sources, and they have been subject to extensive controls and requirements already. The sector targeted by the rule are those land uses without the majority of emissions from controlled stationary sources, which haven't been subject to rules or emission controls.

All fees are tonnage based, and the required reduction formula applies equally to all applicable projects. This means that a particular project only pays the off-site emission reduction fee for the required reductions that are not achieved on-site.

The Socioeconomic Analysis discusses the potential impacts to housing more extensively than the impacts to commercial or industrial, because the impact on housing affordability is of a greater concern to the affected industries and the general public than the impacts on commercial or industrial.

Certain land uses are exempted from the rule because their emissions are primarily from permitted stationary sources (the rule only covers area and mobile emissions), and they are and have been subject to extensive controls and requirements.

79. COMMENT: The rule should also address existing housing.

RESPONSE: The goal of the rule is to achieve an emission reduction from *growth* that was identified in the PM10 and ozone plans. Although VMT is increasing valley wide, the majority of new emissions are attributable to new development. It would be inequitable to assess fees on existing uses with the purpose of mitigating emissions from growth.

80. COMMENT: Part of the presentation used small, unreadable font. Please use a reasonably large font for presentations, so that people may be able to read what is on the screens.

RESPONSE: Comment Noted. The District apologizes for the illegible font-size, and will attempt to make future presentations clear and readable.

Randy Hatch – Planning Director, City of Ceres

81. COMMENT: There is a concern that the ISR program will cause changes to a project after a local agency has granted approval to the project.

RESPONSE: The rule has been changed to make the process concurrent or prior to the approval process by the public agency. The District defers land-use choices to the public agency and the applicant. See Response to Comment #8 for more information.

The District does not place requirements for land-use measures on the project. The on-site emission reduction checklist must be filled out by the applicant, but the District does not have a minimum or maximum requirement for the number or type of measures to be selected. Inclusion of measures is voluntary by the applicant (see Response to Comments #56). The District will not engage in negotiations to include on-site measures (See Response to Comment#44).

Therefore, the District will not be imposing measures that conflict with the local land use agency. It is the applicant's responsibility to make sure that those measures they have voluntarily selected are consistent and approvable by the local land use agency. In the instance that the identified measure is not acceptable by the local land use agency, the applicant is responsible for notifying the District and the on-site emission reduction checklist and emissions modeling will be revised to reflect the project at that time.

In addition, the rule and staff report will be revised to provide more interaction with the public agency and the District. See Response to Comment #8 for more information.

82. **COMMENT:** How do public agencies determine compliance with the rule, especially if the District's approval can occur after the approval by the public agency?

RESPONSE: The District will revise the ISR process to be concurrent with or prior to the approval process at the public agency. See Response to Comment #8 for more information. Specifically, the District will provide letters notifying the public agency of the Determination of Completeness, AIA Approval and Final Compliance, as well as providing a letter of compliance status to the public agency upon request.

83. **COMMENT:** What exactly is meant by 'parks' in the applicability section?

RESPONSE: Active recreation parks – parks that attract motor vehicles. It is not the intent of the rule to assess passive recreation parks. Parks will be assessed based on emissions the same as other land uses,

84. **COMMENT:** The City of Ceres suggests the District alter the application process to make it prior to the final public agency approval, perhaps by tying it to the application to the public agency. In addition, the City suggests the District include a predevelopment process. The City of Ceres has a predevelopment process that aids in the application process.

RESPONSE: The District will amend the rule language and the staff report to make the application to the ISR program concurrent with or prior to the final discretionary approval application to the public agency See Response to Comment #8 for more information. The District does not currently have a plan for formal pre-application consultations. However, the District will be available for consultations any time prior to actual application and encourages applicants to meet with District staff to clarify issues when needed.

Fresno

Kathryn Phillips – Environmental Defense

85. **COMMENT:** Concerning the view that land use does not have an impact on air quality (see comment #34) – that is a minority view. Most have realized that land use does have an impact on air quality.

RESPONSE: Comment Noted.

86. **COMMENT:** Concerning the issue of self-selection (see comment #36), the choice of good design should be available.

RESPONSE: Comment Noted.

87. **COMMENT:** The URBEMIS model is imperfect, but it is appropriate for this rule.

RESPONSE: The District concurs. The District is aware that there is not a 'perfect' model available, nor is there likely to be one in the future. However, the URBEMIS model is best available method for quantifying project emissions and benefits from on-site measures.

88. **COMMENT:** Rule 9510 section 2.1.8 has one threshold for recreation, but the definition includes movies. 'Movie theaters' are more commercial in nature, and should be moved to commercial. In addition, 'parks' should be defined.

RESPONSE: Comment Noted. 'Movie theaters' will be removed from recreation to commercial.

89. **COMMENT:** A 2-ton exclusion level (Rule 9510 section 4.2) is too generous. This level should be reduced.

RESPONSE: See Response to Comment #180.

90. **COMMENT:** Rule 9510 section 2.2 discusses transportation projects that have two tons or more of NOx and PM10 combined. How large of a project would fit this description? How large would a project be to be subject to the rule – a pothole or an interstate exchange?

RESPONSE: Small maintenance projects would not exceed the threshold. Construction of a one-half mile arterial road segment would exceed the threshold. The road project must also be subject to a discretionary approval to be brought into the ISR process.

91. **COMMENT:** Rule 9510 section 3.5 defines 'Baseline Emissions'. This section should be clarified. Where exactly is the baseline?

RESPONSE: The definition will be changed to the following:
Baseline Emissions: the unmitigated estimated NOx and PM10 emissions, output calculated by the APCO-approved model, in the units of tons per year.

In addition, the following will be added to the definition section of the rule to clarify the issue of baseline:

Construction Baseline: the sum of unmitigated NOx or exhaust PM10 for the duration of construction activities for a project or any phase thereof.

Operational Baseline: the entirety of NOx or PM10 emissions, including area source and mobile emissions, calculated by the APCO-approved model, for the first year of buildout for that project, or any phase thereof.

A development would have two construction baselines (one NOx, one PM10) and two operational baselines (one NOx and one PM10), if it does not have phase. For the purposes of this discussion, the four baselines will be referred to as a 'baseline set'. For projects with phases, each phase will have one baseline set. According to the off-site fee formulas, the equations are used for each baseline set.

As and example, one project has three phases. The rule contains four fee formulas: an operational NOx, an operational PM10, a construction NOx, and a construction PM10. Each of the four calculations are performed three times, once for each phase or 'baseline set'.

The operational baseline is calculated at the date of expected buildout, the construction baseline is calculated at the date(s) of expected construction.

92. **COMMENT:** Rule 9510 section 4.1.5 needs clarification of what federal, state and local funds for low income housing are applicable.

RESPONSE: Based on the District's internal analysis of applicability and impacts, the exemption for low-income housing has been removed. It has been determined that the Rule should apply to all new residential development that meets the applicability section of the Rule.

93. **COMMENT:** Rule 9510 section 5.3.2 discusses the application for the AIA. The District should list out what information will be in the application.

RESPONSE: The District will expand that section to include more specific information of what will, at a minimum, be included in the AIA application.

94. **COMMENT:** Environmental Defense recommends including ROG in the rule for emissions reductions.

RESPONSE: See Response to Comment #57 and #65.

95. **COMMENT:** Rule 9510 section 6.1.1.1 and 6.1.1.2 discusses the reductions required from construction emissions. The 45% reduction requirement for PM10 is too low. Applicants can get much higher results with existing technology. The 20% NOx reduction requirement may similarly be too low. In addition, Environmental Defense recommends requiring emission reductions by vehicle and suggests that the District talk to CARB about their in-use construction equipment regulations.

RESPONSE: See Response to Comment #57 and #65.

96. **COMMENT:** Rule 9510 section 10.2 (APCO administration of funds) does not contain the term 'permanent'. The District should aim for permanent reductions.

RESPONSE: Many of the projects funded by the District will meet the strict interpretation of permanent reductions. In some cases, the projects are expected to be permanent but the user of the clean equipment is only obligated to operate it during the contract period. After the contract period ends, it is highly likely that any replacement equipment will be as clean or cleaner than that funded by the District due to lower emission standards and improving technology over time for nearly all source categories.

97. **COMMENT:** The funding of projects with fees received from this rule is implied to be application-based. The rule should state if it is application based.

RESPONSE: Although current District programs are primarily open application based for as long as funding is available, for some source categories it may be more appropriate to have requests for proposals with deadlines and project ranking. Therefore, the rule language should remain the same.

98. **COMMENT:** The economic analysis and other supporting documents don't include health impacts and those costs. This information should be included to keep the purpose and goals of these actions in perspective.

RESPONSE: It is not feasible to assign a dollar amount to the health effects that will be avoided or lessened by the implementation of this rule. However, the District will include health-impacts information from the PM10 and ozone attainment plans in the staff report.

Kristine Foster – Asthma Coalition, Respiratory Therapist, Asthma Educator and CAC member.

99. COMMENT: Land use planning is important and the District needs to include education for the public.

RESPONSE: The District concurs with both of the commenter's points. The District currently believes that Rule 9510 will provide incentives for development that creates fewer impacts and will bring greater awareness of this issue to the public.

Bakersfield

Mike Kelley – Vector Environmental

100. COMMENT: Does the rule apply to the fraction of PM greater than 10 microns?

RESPONSE: No. The rule applies to PM10, the fraction of PM 10 microns or less in diameter.

Chambers of Commerce – Public/Private Organizations

The Greater Merced Chamber of Commerce

Date: September 14, 2005

101. **COMMENT:** The Greater Merced Chamber of Commerce urges the district to reevaluate the impacts of rules 9510 and 3180 will cause to the Central Valley. The District has no organized plan for the fees that will be charged and when asked, the district indicates grant money for clean air vehicles and other measures to reduce the pollution. Before these rules should be brought to the board for approval, a complete plan should be developed.

RESPONSE: The District has a history of funding more than $100 million in emission reduction projects. These existing programs are underway and the system is in place for processing projects funded by Rule 9510. The District has provided additional information on the types of projects available for the program in Appendix E. The District has identified more than $400 million in projects available at a cost-effectiveness that will allow the District to achieve plan commitments. As technology advances, even more opportunities for retrofit and replacement programs are expected.

102. **COMMENT:** These rules will make the housing costs rise to a level that will make housing in Merced more unaffordable and will hamper industrial and commercial development in the greater Merced area. A comprehensive study needs to be completed on the effect the rules will have on economic development and jobs in the valley. The valley leads the nation in unemployment figures and the need for jobs through out the Valley is extremely important. These rules ill affect new job creation.

The costs of these new rules will slow down growth that will be coming to the Valley. Without a clear economic study, these rules should not be approved. Growth will happen and proper planning is needed to make sure the growth is well-planned and well-implemented. These rules will create more problems than they will solve.

The Greater Merced Chamber requests more studies and a better economic plan be developed before the rules go forward to the board for approval. Thank you for your consideration of our concerns.

RESPONSE: According the Merced County Association of Realtors, the median home price in Merced County is $330,000. The proposed fee amounts not considering the potential for reductions due to project design are between $800 and $1800 per unit in the first 3 years of program operation. In percentage terms this ranges from .24% to .54% added cost to the median home. The funds

collected from the developers are used for air pollution projects in the area that will benefit the local economy.

Stanislaus Economic Development and Workforce Alliance (Alliance)
Date: September 13, 2005

I am the CEO of the Stanislaus Economic Development and Workforce Alliance. The Alliance is a public private organization comprised of representatives of Stanislaus County, all cities in the county and dozens of private business investors. It is the designated agency for all economic development and workforce activities in the county.

I attended the video conference of an APCD staff presentation at a public \meeting on September 1 in Modesto. I am very concerned about several aspects of that presentation and therefore the consequences of Rule 9510 and Rule 3180 proposed for implementation by the APCD.

My concerns are as follows:

103. **COMMENT:** Regarding the exemption for projects whose primary source of emissions that come from stationary sources, how is **primary** determined?

RESPONSE: The District has completed a review of industries permitted by the District. This analysis details the amount of rules that apply to each industry and the amount of pollutants regulated by these rules. The intent is to remove the ambiguity of "primary" emissions and detail which industries will be exempt from the rule. In addition, industries with stationary sources may petition the APCO for ISR exemption.

104. **COMMENT:** Regarding the submittal of applications no later than 30 days **after** last discretionary approval, what kinds of delays to projects will be experienced while APCD reviews the mitigation plans and does their calculations and assessments. My experience tells me the current workload precludes timely processing or even a return of phone calls regarding ATC requests and other permitting. Staffing is either insufficient or incompetent or both. What steps are contemplated to alleviate the existing gridlock and avoid additional bottlenecks in the future?

RESPONSE: See Response to Comment #8 for the ISR application changes. It should be noted that the ISR process is not a permit, nor is it a discretionary action (See Response to Comment #187). The District is working on producing a streamlined approval process that has clear information requirements and timelines (as listed in the rule). The Planning Department will be responsible for ISR project review and approval. The Planning Department, as well as all affected departments (Compliance, Emission Reduction Incentive Program – ERIP, and Administration), has produced a staffing analysis for implementation

of the ISR program. The Planning Department identified the steps in review and approval, the time associated with those steps, and in this process identified steps that could be merged or simplified. The staffing requests are listed in the Board Memo, and the District will provide a more detailed staffing request before the Board adoption hearing. However, the staffing analysis is for ISR adoption only, and does not address staffing for existing programs.

105. COMMENT: The APCD has not yet created an emissions calculator.

RESPONSE: URBEMIS will be used for Operations, District is working to determine if a modification to URBEMIS or a separate calculator will be needed for construction. However, methodology for construction is known. Take vehicle type, hours of operation and compare to emissions from the state-wide average. URBEMIS can come up with default fleet numbers, we are working about refining them.

106. COMMENT: Developers and business with the same degree of concern on this issue that the APCD exhibits, albeit with a different perspective, have expressed serious reservations about the integrity of URBEMIS. Are these concerns dismissed out of hand with no attempt to verify the soundness beyond your belief that it must be okay because you are using it.

RESPONSE: The Staff Report contains a detailed discussion of why URBEMIS is appropriate for this rule, and why it was chosen over other models. The District has completed extensive research, including hiring a consultant to review existing models to determine the most appropriate, comparisons of models, and detailed model research and has determined that URBEMIS is the most appropriate model for the rule. See Response to Comments # 157.

107. COMMENT: The socioeconomic impact predictions for Rules 9510 and 3180 were calculated using dated methodology (1995) that does not factor in the impact of the meteoric increases in valuations and costs and burden of stagnant incomes regarding affordability.

RESPONSE: The Socioeconomic impact report uses median price data up to 2005. Most data was no older than 2003. The methodology is standard for the air pollution rule development process and is not dated.

108. COMMENT: The financial windfall that will occur if these rules are implemented could total tens of millions of dollars per year in the valley. What accountability is associated with the “mitigation accounts”? Who determines and what is the definition of quantifiable and enforceable mitigation projects?” Is there an audit of these accounts and by whom? How were the fee levels determined? Are they equitable?

RESPONSE:

1. Accountability – The District has successfully managed over $100 million in grant money over the last decade. The District has an outside auditing company to provide assurance to the Governing Board and the public that funds are appropriately managed. The California Air Resources Board has also audited the District.
   Definition of quantifiable – The project to be funded must have emission factors, process rates, and use data, necessary to calculate baseline emissions and emission reductions after the project is implemented.3.
   Enforceable – The project must have a mechanism that ensures that the project will be implemented and that emission reductions will be achieved during the specified timeframe.
2. Fee level determination – The fee levels are based on the average cost of reductions projected for each year for each pollutant. See also Response to Comment #114.
3. The fees are equitable because they are based on emissions generated by the project and each project's emissions are quantified using the same well-accepted models and factors.

109. COMMENT: APCD's goal over the next ten years to reduce the ozone and PM10 emissions targets new development only. If the housing bubble bursts and the corresponding emissions from new growth cease, will the burden shift to commercial, industrial and/or existing housing in order to meet the goals?

RESPONSE: The emission reduction targets for ISR in the PM10 and ozone plan are based on the *predicted* growth in emissions from new development. ISR reduces, through on-site and/or off-site measures, emissions generated by new growth. If that growth does not occur as predicted, for example in a 'bubble burst' scenario, then the emissions from new development will be less than predicted. If the emissions do not occur, they would not have to be reduced through the ISR program. In this situation, ISR does not have to adjust the emission reduction 'burden', or assess additional emission reductions.

110. COMMENT: There seems to be confusion about the degree of compatibility of these rules with the CEQA process, adding additional burden for businesses in meeting timelines and development schedules.

RESPONSE: See Response to Comment #8 and the Staff Report, Section IV.C.

111. COMMENT: Those of us who are tasked with promoting and marketing the valley for business locations and as a quality place to live and work are very concerned about the air quality issues that we fact. Certainly the air quality is a factor in decisions made by individuals and businesses alike when determining the suitability of the valley for their purposes. The major challenge is to address

those issues in a fair and balanced way with techniques and plans that are based on sound logic and a strong scientific basis.

RESPONSE: The District concurs with the author's statement.

Business, Industry & Government Coalition of the South San Joaquin Valley
Date: August 30, 2005

112. **COMMENT:** Our organization and its members share a deep commitment to improving air quality in the South Valley and applaud all reasonable efforts to attain Federal and State mandates. Draft Rule 9510, as we are coming to understand it, is the program that will be employed by the San Joaquin Valley Unified Air Pollution Control District to involve indirect sources, those land uses that attract or generate motor vehicle trips, in the mitigation of air emissions. The required reviews of the draft rule are delineated, however, the fees associated with the draft rule are not easily understood.

The presentation on Draft Rule 9510 – DESIGN (Decreasing Emissions' Significant Impact from Growth and New Development) gave several members of our organization cause for alarm after the initial public meeting was held. While there were references to fee schedules and proposed costs for building permits, the method describing the establishment of fees was not clearly reviewed. The Building Industry members of our organization are well aware of Public Facility Fees, Govt. Code 66000. Using that base of reference, the description about fee collection and fee usage was not congruent with their experience with Public Facility Fees. Upon further review after the meeting, the fees established through the Health & Safety Codes of California are the references for the Air Board's proposed fees. These fees are "news" to our members and additional information would be very helpful.

RESPONSE: See Response to Comment #6 and the Staff Report Section I(B) for a discussion on District authority for the rule.

113. **COMMENT:** For the next public meeting, scheduled September 1, 2005, our request is to have staff provide information about the process establishing the fee each year and how the fees are used for programs and projects under the authority of the Air Board. We want to know about the programs and the proposed costs for programs that will be instituted pursuant to Health & Safety Code 42311 (g). Our read of the statute indicates these fees are set annually based on estimated costs of air pollution control programs that will be conducted in the following year. In the event all funds are not expended, the fee revenue will carry over to the next year and will, then, reduce the fees for the subsequent year. What is the reporting mechanism and public process for these fees? While there are specific requirements outlined in the statute, none of our membership

was aware of actual dates for the public hearings and none were aware of what projects are in process for this year or their related cost(s).

RESPONSE: The fee amount is based on the anticipated cost of reductions in each year. Staff performed an analysis of historical project funding costs from our existing grant programs that have successfully contracted over $100 million and examined the potential for projects in the future based on the emission inventory and population of project candidates, the technologies available to reduce emissions from the source, whether the reductions will be surplus in the future based on proposed and adopted regulations on the potential project candidates, and the feasibility the project. Based on these factors, the District made percentage funding estimates for each type of project for each year. This information allows the District to calculate a projected average cost-effectiveness for each year. To further verify these numbers, staff prepared project mix spreadsheets based on available projects and funding for each year to demonstrate that the cost-effectiveness averages are achievable. This information has been added to Appendix E of the staff report.

114. COMMENT: In concert with the fees proposed through H&S Code 42311(g) are the fees outlined in Draft Rule 3180. Those fees are cost recovery based – cost recovery for administering Rule 9510. We ask for clarification on how that rate is developed and how applicants will be billed for the actual hours of staff time to evaluate and review proposed projects. We also ask to be informed if the weighted average labor rate will be reviewed in a public meeting or public hearing prior to annual establishment. The Health and Safety Code reference for the cost recovery fees appears to be in section 40604. The draft report of Staff indicates that section 40604 was codified as a result of legislation SB709, Florez, from the past fiscal year. Section 40604 is devoid of explanation about the fee structure other than to indicate there will be a schedule of fees and the fee schedule "shall be designed to yield a sum not exceeding the estimated cost of the administration of this chapter and mitigation of emissions and the filing of applications". How will this fee be published and through what public process? The project fees allow for annual rollover; how will the administrative fees be managed? If estimated costs are higher than annual costs, how will notification occur and what mechanism will be used to refund overpayment? We are hoping that the public meeting on September 1st will provide answers to this fee.

RESPONSE: The District will use the same average weighted labor rate method that it has used for many years in processing stationary source permits. It is based on labor and overhead rates used to develop the District's budget that is adopted in a public hearing each June. The project review fees are based on the hours predicted for a relatively simple project. Projects proposing standard on-site measures and having air quality impact assessments that use standard factors and default changes that have been agreed to in advance are expected to be covered by the fee amount. Complex projects are expected to require

additional staff analysis and review time that would result in costs that exceed the application fee. The District will be using a project management and billing system to track hours for the project. An applicant can request the status of labor charges at any time. The amounts accumulated to date can be obtained from the database and provided to the applicant. When the District staff completes its review and determines the off-site fee amount, they will generate an invoice that itemizes charges for review and the proposed off-site fee amount.

115. COMMENT: We are concerned that implementation of additional fees (Rules 9510 and 3180) associated with new construction will adversely affect the addition of sorely needed housing stock to the South Valley. Our region of the state is expected to take the brunt of the projected population growth, and we are already woefully under stocked. Our coalition believes that inadequate attention has been placed on studying the socio-economic implications of implementing the proposed fees.

Reducing PM10 and NOX emissions from indirect sources is a commitment thrust upon everyone in the Central Valley. Adding additional reviews and controls during the planning phase of construction is workable as long as all steps in the review process are clearly communicated and upheld. Compounding the issue of added reviews are the added fees for air pollution control and emission reduction projects that are not well known to members of our organization. As requested, providing more information about the type of projects, costs for current year and the process for the annual review of these fees would be most beneficial. Added study and discussion about the factors that influence the socio-economic status of the Central Valley are desired before these draft rules are presented to the Board of Directors for their consideration and vote.

Thank you for your attention to our concerns and we ask that this letter be read into the public record during the meeting on September 1, 2005.

RESPONSE: The District recognizes that the rule may add a relatively small cost to development; however, the rule is structured to maximize benefits for designs and features incorporated into the project that will reduce the fees and add value to the development. It is possible to significantly reduce the fee with measures now commonly included in projects. The District is committed to streamlining the review process wherever possible and strives to minimize costs and delays. The analysis will be accomplished with URBEMIS for most projects. URBEMIS is very easy to use and can be operated using information typically required by local agencies during the CEQA review process.

INDUSTRY

The Construction Industry Air Quality Coalition (CIAQC)

Date: September 15, 2005

The Construction Industry Air Quality Coalition (CIAQC) is composed of the Southern California Contractors Association and the Southern California chapters of the Associated General Contractors Association, Building Industries Association, Engineering Contractors Association and Rock Products Association. Its membership includes 3,500 construction/development companies.

116. **COMMENT:** 2.0 Applicability: The potential emissions from constructing 2,000 square feet of commercial space, 9,000 square feet of educational space and 10,000 square feet of government space appear too small when compared to emissions from constructing 50 residential units, 39,000 square feet of general office space and 25,000 square feet of industrial space.

RESPONSE: The difference is due to different trip rates for different land uses. Commercial space generates many trips per 1000 square feet compared to other land uses.

117. **COMMENT:** While the rules do not have an effective date, the District should consider the economic impact on small contractors with a high percentage of Tier 0 engines of setting relatively small development project baselines in 2006. An annually decreasing baseline from, say, 200 residential units, 10,000 square feet of commercial space, etc., in 2006 would allow small contractors more time to upgrade their fleets and compete in the bidding process.

RESPONSE: The current approach in the rule using the baseline for each year construction occurs and emission based thresholds provides more incentive to purchase or rent the cleanest equipment at the earliest date. Once in use, the cleaner equipment is available for all future projects subject to the rule. Although small contractors may have an older fleet, those are the equipment and vehicles that are in need of upgrade.

118. **COMMENT:** 3.0 Definitions: The use of computer modeling to estimate construction emissions from potential land uses would eliminate many small contractors unless they can seek advice from the District on how to employ these models. Also, CARB should offer assistance in identifying a diesel emission control device that has been verified for typical diesel engines as well as instruction on the use of the construction emission calculator. Ideally, the contractor or developer could submit to the District the number and types of machines he proposes to use on a project and the number of hours he proposes to run them, and the District would estimate his emissions.

RESPONSE: The District will provide assistance on the use of models to calculate construction emissions and staff can run the models for the applicants on a time and materials basis.

119. COMMENT: 4.1.5 Housing projects directly assisted by government housing funds: Why is government assisted housing exempt from mitigation?

RESPONSE: Based on comments received, the District has removed this exemption so that sources are treated based solely on their emissions.

120. COMMENT: 5.0 The draft rule implies in 5.3 that the APCO is willing to produce an AIA from information supplied by the developer. Is that correct?

RESPONSE: The District will prepare air quality impact assessments if the applicant provides the information needed as inputs in the model.

121. COMMENT: 6.0 A developer should be given emission reduction credit for mitigating windblown dust (PM10) as a result of constructing buildings and landscaping an area.

RESPONSE: The developer is already required to mitigate windblown emissions to comply with District Regulation VIII – Fugitive Dust Rules, therefore, the reductions would not be considered surplus.

122. COMMENT: 7.0 Off-site Mitigation Calculations and Fee Schedules for Construction Activities: In order to be reasonably contemporaneous with emission increases, off-site mitigation should be designated and purchased by the District no later than six months after the payment of the funds by the developer.

RESPONSE: The District commits to spend any funds received as quickly as possible. The programs envisioned require an applicant to come to the District to request funds for qualifying projects, so there may be times when funds take longer than six months to expend.

California Building Industry Association (CBIA)
Date: September 15, 2005

California homebuilders, represented by the California Building Industry Association (CBIA) and its five affiliated Building Industry Associations (BIAs) located in the San Joaquin Valley, are respectfully submitting comments on the Draft Rules, 9510 and 3180 ("proposed rules") of the San Joaquin Valley Air Pollution Control District ("the District").

123. **COMMENT:** CBIA continues to be troubled by what it sees as several fundamental flaws in the District's plan to assess new "air quality mitigation" obligations on new development in the Central Valley:

1) The District has failed to show a nexus between the impacts of new development on air quality in the region and the massive amount of new fees it proposes charging for this purported impact;
2) The District is using flawed scientific modeling to justify charging massive new fees on housing and economic development;
3) The district singles out new development to bear the burden of its new mitigation scheme which contains highly questionable calculations and a woefully deficient cost-benefit analysis.
4) The District has failed to adequately explain what it intends to do with these new fees (taxes) – somewhere between $300 million and $450 million over the next five years – and how charging them will improve the region's air quality; and
5) The District has failed to acknowledge and account for the impacts of these new fees on the region's economy or on housing affordability.

RESPONSE: See Response to Comments #124 through #142 below.

124. **COMMENT:** For these and other reasons, CBIA remains strongly opposed to the adoption of the proposed rules and urges the District to withdraw them and, working with citizens and other stakeholders in the region, begin the work of developing a more responsible, equitable and scientifically grounded plan for improving air quality in the central valley.

In the pages that follow CBIA will enunciate in detail both its fundamental concerns as well as other defects in the proposed rules.

RESPONSE: Opposition noted. See Response to Comment #17 for additional information on the development of these rules.

125. **COMMENT:** The District has failed to demonstrate the required legal nexus for imposing its proposed fees. This has been an ongoing concern of CBIA's and thus far the responses to it given by the District have only caused to make that concern grow. Indeed, the sheer weight of the mitigation fees being proposed by the District for new housing, alone – somewhere between $300 million and $450 million over the next five years – demands a clear description as to what the impacts are that justify the District's fee plans and how the level of fees to be charged are supported by anticipated costs.

RESPONSE: Although the District is not subject to the Mitigation Fee Act (See Response to Comment #52), the District's legal counsel has prepared an analysis of nexus requirements. The analysis identifies if a nexus is required, and discusses the following:

The applicability of the 5th amendment of the US Constitution.

- The analysis finds that the fees resultant from the rule are subject to the "reasonable relationship" test established by *San Remo Hotel LP v. City and County of San Francisco*[2].
- Therefore, if the fee is collected from a development because of the expected air pollution from that development, and the fee is used to offset the type and amount of pollution caused by that development – the fee will likely pass under the reasonable relationship test.

California Mitigation Fee Act

- The analysis finds that the Mitigation Fee Act may not apply to the ISR rules, for the reasons cited from the District in the text of Comment # 126, and in the Response to Comment #52.

California Proposition 13

- The analysis finds that Proposition 13 does not apply to the ISR rules.

California Proposition 218

- The analysis finds that Proposition 218 does not apply to the ISR rules.

California Subdivision Map Act

- The analysis finds that the SMA does not preempt the District from assessing fees on a subdivision.

126. COMMENT: Remarkably, however, the District denies there is a problem. To summarize the District's position, the Mitigation Fee Act (AB 1600) does not apply to these types of fees because (1) the District has no approval authority over development projects, is not imposing the fee as a condition of approval of a development project, and the fee is purely regulatory in nature, (2) AB 1600 only applies to fees for "public facilities" and mitigation measures such as diesel retrofit programs are not "facilities," and (3) even if AB 1600 doesn't apply, the district has met the nexus standard under the Act as well as any other legal standard.

This analysis contains multiple flaws. Government Code Section 66000(b) defines a fee as a monetary exaction other than a tax or special assessment, whether established for a broad class of projects by legislation of general applicability or imposed on a specific project on an ad hoc basis, that is charged by a local agency to the applicant in connection with approval of a development project for the purpose of defraying all or a portion of the cost of public facilities related to the development project. The proposed rules are applicable to a broad range of projects. Likewise, the proposed project-level analysis of on-site

[2] *San Remo Hotel, L.P. v. City and County of San Francisco*, (2002) 27 Cal.4th 643, 669-670.

mitigation constitutes an ad hoc, project-specific review. Both types of analyses therefore apply to the proposed rules.

RESPONSE: See Response to Comment #52.

127. COMMENT: Indeed, the District is a local agency subject to the Mitigation Fee Act. Government Code Section 66000 (c) defines "Local agency" as “a county, city, whether general law or chartered, city and county, school district, special district, authority, agency, any other municipal public corporation or district, or other political subdivision of the state.” Certainly the District qualifies as a special district, agency, or other political subdivision of the state.

RESPONSE: The District is considered a local agency, but this distinction is not relevant. The Mitigation Fee Act does not apply to the ISR rules. See Response to Comment #52 for more information.

128. COMMENT: The attempt to limit the application of this statute to public facilities is also incorrect. Government Code Section 66000(d) includes within the definition of "Public Facilities" “public improvements, public services and community amenities.” Cleaning up the air is a service provided by government and, as such, provides a benefit to the community.

Comment 64 states that the District does not have the authority to impose conditions of approval and contemplates that any project review will occur after the local agency has completed its approval of the project. The developer will be “allowed” to either include on site mitigation measures or pay a fee. Regardless of the choice of words, it is impossible to characterize this requirement as anything other than a fee or exaction on new development. If this is not enforceable as an exaction, then it is voluntary and the District cannot take credit for it as a control measure for purposes of demonstrating compliance with the SIP goals and the Federal Clean Air Act requirement to demonstrate reasonable further progress.

RESPONSE: The District does agree that the ISR program may require a fee from new development. However, the District disagrees with this interpretation of air emission reductions as a public service under GC 66000(d). In addition, the Mitigation Fee Act does not apply to the ISR rules. See Response to Comment #52 for more information.

129. COMMENT: The District’s attempt to define itself out of the Constitutional requirement that nexus be demonstrated is highly questionable. As noted in Government Code Section 66005(c): “It is the intent of the Legislature in adding this section to codify existing constitutional and decisional law with respect to the imposition of development fees and monetary exactions on developments by local agencies. This section is declaratory of existing law and shall not be

construed or interpreted as creating new law or as modifying or changing existing law."

RESPONSE: See Response to Comment #125 for the findings of the District's analysis of nexus requirements. See also Response to Comment #52.

130. COMMENT: It is important to examine that larger body of existing law. The constitutional standards for legislatively enacted development fees of general applicability, such as the proposed indirect source fee on new development, are less stringent than are the standards for fees imposed on specific developments on an individual and discretionary basis (see *Ehrlich v. City of Culver City* 12 Cal. 4th 854, 50 Cal. Rptr. 2d 242; 1996). Where a development fee is imposed generally on a broad class of property owners, it need only bear a reasonable relationship to the impacts of the development project (Id. at 875-876, 50 Cal. Rptr. 2d at 256,257). In adopting the fee, the city must make the "nexus" findings set forth in Government Code section 66001.

RESPONSE: Although the Mitigation Fee Act does not apply to the ISR rules (see Response to Comment #52), the rule has been designed to meet this test. The District analysis contained in the staff report for the rule provides supporting information to draw this conclusion.

131. COMMENT: The District uses a flawed analysis to produce huge sums to be collected as fees on new housing and new businesses. According to an analysis conducted by Sierra Research (see attached letter) using the numeric emission reduction goals in the District's approved SIP Measures for NOx and PM-10, as well as the assumptions set forth in Section 7.2 of Draft Rule 9510, including the stated ton-per-year mitigations costs, the District will require a total of $38,844,869 to meet the SIP's emission reduction goals for calendar years 2006 through 2010. Assuming the District's "worst case" fee scenario of $856 per unit in 2006, rising to $2841 per unit in 2010, the District could collect as much as $292,719,600. The disparity between the cost of the service and the fee charged is 754%. Even at a lowered standard of review of "reasonableness," a disparity of that magnitude will not survive judicial scrutiny.

RESPONSE: The District has addressed the analysis that Sierra Research provided in Response to Comments #143 to #162. In these responses, the District details which parts of the analysis provided by Sierra Research are flawed and/or inaccurate.

132. COMMENT: Again, the proposed rules are in direct conflict with California law as they are proposing to collect fees well in excess of what might be justified under a nexus test. State law is clear about what burden is on local agencies which propose to impose new fees on development. Government Code Section 66005(a) says "When a local agency imposes any fee or exaction as a condition

of approval of a proposed development … or development project, those fees or exactions shall not exceed the estimated reasonable cost of providing the service or facility for which the fee or exaction is imposed."

RESPONSE: As stated in Response to Comment #52, the Mitigation Fee Act does not apply to the ISR rules. The author points out a significant reason why. Section 66005(a) clearly states "as a condition of approval". The District cannot place conditions of approval on development projects through the ISR program, as it is a ministerial action. In addition, the fees are designed to mitigate only a fraction of project emissions and there is nearly zero potential for over mitigating. The fees are tonnage based (what is required to buy one ton of reduction for a particular pollutant) and are charged on a tonnage base. For example, if a project is required to mitigate 2 tons of NOx, then the price per ton is multiplied by 2 to obtain the off-site emission reduction fee.

133. COMMENT: Discretionary, site specific fees, the kind that the District proposes to impose on individual development projects after a project-specific analysis of all on-site mitigation measures, are subject to the stricter "essential nexus" and "rough proportionality" requirements of *Nollan v. California Coastal Commission,* 483 U.S. 825, 107 S. Ct. 3141 (1987), and *Dolan v. City of Tigard*, 512 U.S. 374,114 S. Ct. (1994); see discussion in *Ehrlich* at 12 Cal. 4th 876, 50 Cal. Rptr. 2d at 256,257; *City of Monterey v. Del Monte Dunes at Monterey Ltd*., 526 U.S. 687, 119 S. Ct. 1624, 1635, 143 L. Ed. 2d 882 (1999).

RESPONSE: Although the District will not be making discretionary actions, the Rule has been designed to meet this test. The District has prepared an analysis of nexus requirements. See Response to Comment #125 for the findings of the analysis.

134. COMMENT: In spite of repeated requests from various local agencies and members of the public, the District has not made available any calculations of the amount of emissions credits that will be awarded for on-site mitigation measures. For reasons explored in greater detail in Sierra Research's comment letter, the URBEMIS model was not designed to, and is incapable of, accurately calculating the amount of emissions reductions from most of the design or location-based indirect source mitigation measures included in the District's proposed mitigation checklist. The unknown cost of the deferred mitigation (achieved after the fact through a grant program) makes an accurate analysis of proportionality even more difficult. For this reason, any project-specific fee calculation will be suspect, and subject to the higher standard of review.

RESPONSE: The onsite emission reduction measures are calculated using the URBEMIS v8.7 mitigation component. The model is available for free at urbemis.com. The author's statement that URBEMIS is, "was not designed to, and is incapable of, accurately calculating the amount of emissions reductions

from most of the design or location-based indirect source mitigation measures included in the District's proposed mitigation checklist," is inaccurate at best, and misleading at worst.

The URBEMIS model is maintained by a state-wide working group that includes representatives from air districts throughout California, state agency representatives (such as CalTrans). Proposed changes to the model are vetted through peer review. The last model update, sponsored by the District, was changes to the Area Source module, specifically overhauling and quantifying the mitigation section.

The model components and methodologies are available to the public in the URBEMIS User's Guide, available at South Coast Air Quality Management District's website http://www.aqmd.gov/ceqa/urbemis.html, and will be made available at the District's website. In addition, the details of the model and the recent update are available in the Staff Report and as Appendix D-Recommended Changes to URBEMIS.For more information on URBEMIS components, see Response to Comment #9.

The author's second main point is that, "the unknown cost of the deferred mitigation (achieved after the fact through a grant program) makes an accurate analysis of proportionality even more difficult." The cost of 'deferred mitigation' is exactly that of the off-site emission reduction fee. The applicant is assessed a fee based on the calculations provided in the rule. The per-ton fee is also provided in the rule. The applicant is assessed an administrative fee, stated in Rule 3180 as 4% of the off-site fee. The applicant is also assessed time and materials for the AIA review in excess of that covered by the application fee, detailed in Rule 3180. This is the full extent of fees. The 'deferred mitigation' fee is expressly stated in the rules.

135. COMMENT: The District has failed to explain its calculations in determining a massive revenue-raising plan or the cost-benefit of the plan. According to the proposed rules, the District plans to raise between $300 million and $450 million in fees between 2006 and 2010 from housing alone. Similar fees will be collected from new schools, hospitals, government facilities, transportation projects, retail, office, and industrial development. The use of these funds, presumably, is to cut NOx emissions by 4.1 tons per day and PM-10 emissions by 5.2 tons per day. Yet, the District's own estimates show that NOx will cost an estimated $4,650 per ton in 2006, rising to $13,250 per ton in 2010 and that PM-10 reductions will cost $2,907 per ton, climbing to $13,850 per ton in 2010. These totals are far less than the fee revenue the District intends to raise during the same period.

RESPONSE: The rule's emission calculations are designed to identify a level of reductions from new development that will meet the SIP targets at the cost per ton predicted each year for each pollutant. The $300-450 million for residential

development severely overstates the fee potential and is based on an erroneous analysis of the rule requirements and incorrect calculations. For a detailed analysis of the cost effectiveness calculations, please review Appendix E – Cost Effectiveness Analysis for Rule 9510 ISR. For a detailed analysis of the emission reductions, please review Appendix B – Emissions Reductions Analysis for Rule 9510 ISR.

136. COMMENT: The District has failed to lay out a coherent plan for using its mitigation plan to actually clean the air and to account for it. How the District intends to spend the massive amounts of money it is proposing to raise remains unclear. This in light of the recent concerns expressed by the District's Governing board that the District has not expended its existing motor-vehicle surcharge fees – representing over $50 million in taxpayer dollars – on mitigation measures in a timely and effective manner. In addition, in advancing these proposed rules – again, raising hundreds of millions of dollars over the next five years – the District has failed to present a clear and specific program to insure timely expenditures for measures that reduce emissions proportionately in the areas contributing fees.

RESPONSE: The District will provide additional information to clarify the proposed plan for expending any fees collected and has amended Appendix E – Cost Effectiveness Analysis for Rule 9510 ISR accordingly. The District has successfully contracted over $100 million in funds for air quality projects.

137. COMMENT: Finally, the District has failed to adequately recognize or account for the impact of the proposed rules on housing affordability and the region's economy. The Socioeconomic Analysis examines narrowly examines housing impacts in terms of homebuilder profits without any similar analysis of housing cost and affordability impacts. This overlooks some important facts. Fees have a direct impact on homebuyers. According to a national study, every $1,000 added to the price of a home, locks more than 23,000 California families out of the housing market. Further, $1,000 to $4,000 added to the purchase price of a home escalates dramatically when it is financed with a typical 30 year mortgage. What this does to housing affordability in the region is completely ignored. In addition, the Analysis overlooks the impact of higher housing costs on the regional economy. First, more money spent on housing means less money spent on other goods and services. Second, higher housing costs discourage new business development as housing costs are viewed by executives as having the biggest impact on labor costs. Finally, fewer buyers mean fewer homes to be built which means fewer construction jobs and the profound ripple effects on the regional economy. Right now, home construction represents more than $7 billion in annual economic output in the Central Valley and is responsible for creating nearly 70,000 new jobs every year.

RESPONSE: First, the August 24, 2005 Socioeconomic Analysis provided at the September 1st workshop contains an analysis of housing costs and affordability impacts in Section 6.3 – Impacts on Affected Industries. Section 6.3 ¶1 states, "In addition to impacts on homebuilders, the section analyzes how changes in price affect prospective homebuyers and renters," and contains *Affordable Housing for Low-and Moderate Income Households* as a subsection. The analysis found:

> *…that while the residential fee that the typical residential development would pay under Draft Rule 9510 and 3180 can increase the amount of household income required to finance the purchase of a new home, the estimated increase represents a small fraction of the original household income required to finance a new home the event no air quality fees were in place. The affect of the fees on rents is similarly small.* Page 1 Executive Summary

Second, 100 percent of all off-site funds collected will be spent on emission reduction projects in the San Joaquin Valley. This will create economic activity and jobs. Many of these projects involve the construction industry; for example, road paving to control PM10. The District recognizes that all off-site fees have an impact on the cost of development; however, the emission reductions obtained from the rule will benefit all residents of the San Joaquin Valley.

Finally, refer to Response to Comment #53 for additional information.

138. COMMENT: In addition to the impacts on housing, those on businesses and public service activities have not been fully analyzed. Half of the vehicle trips addressed by the proposed rules are assumed to come from non-residential uses, but it remains unclear how much non-residential uses are going to pay their mitigation obligations (fees). The Socioeconomic Analysis fails to mention fees for new schools, medical facilities or public facilities such as government offices, roads and libraries. The Socioeconomic Analysis concludes that the impact on commercial and industrial development will be significant, but fails to identify Valley-wide costs based on the full range of non-residential uses, or the ripple effect on public agencies, business start-ups and expansions, job generation and the cost of goods and services.

RESPONSE: The District is unsure where the author is referencing the assumptions on vehicle trips. The cost to any sector is proportional to the emissions caused by indirect, area, and construction emissions generated by the project. The potential cost to any development can be calculated using the URBEMIS model to calculate emissions and the cost of reductions for the year of development and fee formula from the rule. The fee formula and cost of reductions applies to all development subject to the rule equally.

Valley-wide impacts would be speculative. As stated in the Socioeconomic Analysis (p. 42), "It is not clear how the development will adjust to the additional costs." Although the analysis states that, "a typical commercial or industrial development could absorb air quality fees in 2006 or 2010," developers may choose to pass on the cost to the buyer or renter. This aspect is unknown, and any projected valley-wide impacts as a result would be speculative and non-quantifiable.

139. COMMENT: The proposed rules 9510 lack effectiveness estimates for on-site mitigation that lead to uncertainty and inaccurate fees. Appendix C contains a 12-page checklist of mitigation measures that developers must consider for their project. Project applicants are instructed to justify why they did not apply a particular mitigation measure if they decided not to use it. However, the checklist provides no control efficiencies for the measures, making it impossible for project developers to reach an informed decision about the most cost-effective methods. Of greatest concern, a large number of mitigation measures are not included in URBEMIS, and their effectiveness must be negotiated between the project applicant and the District. These off-model mitigation decisions inject great uncertainty and potential inaccuracy into determining the amount of mitigation provided and fees exacted.

RESPONSE: The effectiveness of on-site measures varies depending on the design of the project and the land uses and transportation systems supporting the project. A single percentage number for each on-site measure is not appropriate. Please see Response to Comments #7 and #9 on URBEMIS quantification of measures. It should be noted that URBEMIS is free, available to the public, and user-friendly.

140. COMMENT: The proposed rules will create an expansive new bureaucracy to perform duties that duplicate and conflict with existing local planning processes. Local jurisdictions already have the ability to address and mitigate construction and operational emissions of new development through environmental reviews – pursuant to the California Environmental Quality Act (CEQA). The most recent draft of the proposed rules actually appears to dismiss this likelihood for greater conflict and overlap with CEQA by eliminating previously published schedules for District staff's performance of project reviews, mitigation analyses and fee calculations. Indeed, at a recent District-sponsored workshop regarding the proposed rules, District staff essentially said that their measures were separate from those identical ones mandated by CEQA. Indeed, the failure of the District to clarify its role as a "responsible agency" within the meaning of CEQA will foster conflicts with local governments, result in conflicting mitigation standards and requirements and fuel legal challenges – with direct and negative implications for job-generating business projects, affordable housing, schools, roads, and medical and public facilities urgently needed in the area.

RESPONSE: The rule will be revised to make the District's timeline more closely match CEQA timelines. An applicant may come to the District prior to or concurrent with the local agency discretionary application. This is similar current District consultation in its role as a commenting agency. Once the applicant has settled on a project design and scope and on-site measures that will be used for reducing air impacts, the District or the applicant can prepare an air quality impact assessment to determine project baseline emissions, mitigated emissions, and a off-site fee, if any is required. There will be no conflict with local agency mitigation standards since all on-site measures will be sent to the agency for voluntary review and the District will not accept conflicting measures. In addition, it is the responsibility of the applicant to ensure that measures selected are approvable by the public agency. If a selected measure is not approvable, the District will remove the selection and re-assess the project's air impacts. Although more projects will be subject to analysis under this rule, air quality is a critical concern in the San Joaquin Valley and should be receiving this additional attention.

141. COMMENT: The proposed rules lack essential information on construction emission reduction requirements. The latest draft rule requires new development to reduce construction emissions, but does not provide any details on how emission reduction requirements will be calculated. At the September 1st rule workshop, District staff was unable to confirm that a construction emissions "calculator" would be available during the public comment period, or indeed prior to Board consideration of the rule. The homebuilding industry will be directly affected by this provision of the rule, but we cannot gauge the impact of the requirement without information on the assumptions and methods for calculating project emissions. It's requested that this information be provided with time for public review period or eliminate construction emission requirements from the proposed rules.

RESPONSE: URBEMIS V 8.7 is available to quantify construction emissions. The District is working on enhancements to the default values in the model and will be considering a spreadsheet based calculator if it is more appropriate. This will be completed at least 30 days prior to program implementation.

142. COMMENT: For these reasons, as well as reasons previously placed on the record, we request that the District withdraw these proposals as inequitable and unworkable and unenforceable. Continuing down this path is a waste of public resources, which could be better put to use in developing alternative control measures well-designed and well-calculated to achieve compliance with the emission reduction goals set forth in the SIP.

RESPONSE:

- The District considers the ISR Rules to be equitable
  Fees and assessment are emissions based and same for all land-uses.

- The District considers the ISR rules to be workable.
  The rules set a clear path of what is required and how to achieve that. The URBEMIS model is used statewide by air districts and public agencies for project-specific air impacts.
- The District considers the ISR rules to be enforceable.
  The District is granted the authority to promulgate and enforce the rules through the following:
  The Clean Air Act Sec. 110 (5)(C) and 110 (5)(D)

Sierra Research
Date: September 15, 2005

On behalf of the California Building Industry Association (CBIA), Sierra Research (Sierra) is pleased to submit the following comments on the revised draft Indirect Source Rules (ISR) 9510 and 3180 released by the San Joaquin Valley Unified Air Pollution Control District (the District) in late August.

Our comments in this letter expand upon those presented before the District at the September 1st workshop. As directed by CBIA, our comments focus on, but are not limited to, technical and modeling issues related to the use of the URBEMIS model under the proposed rules based on our independent review of the model and its underlying assumptions. In this review we were assisted by Dowling Associates, Inc. (Dowling), a transportation planning firm with extensive travel demand modeling experience supporting a number of the San Joaquin Valley Transportation Planning Agencies (TPAs).

Our comments are summarized briefly blow. Detailed explanations of each comment follow in attachment A.

143. COMMENT: Summary
Our overarching concerns with the draft ISR rules stem from their use of the URBEMIS model to calculate pollutant emission impacts from development projects and the fact that URBEMIS broadly overstates vehicular emission impacts from residential projects. Our analysis of typical single-family residential projects indicates that URBEMIS overstates vehicle emissions of both NOx and PM_{10} (the two pollutants targeted by these ISR rules) by over 70%. Since the mitigation fees that developers would pay under the proposed rules are directly related to the emission impacts calculated by URBEMIS, this model also substantially inflates the fees developers should be required to pay by roughly the same percentage. Our key concerns are summarized below.

RESPONSE: Sierra Research's conclusions are based on erroneous information. URBEMIS is designed to estimate all emissions related to a development project and counts all trips going to and coming from the development as is appropriate for a project level analysis. This accounts for the

higher emission numbers. By using trip counts using both ends of the trip, URBEMIS can credit developers who design their projects to generate less trips with reductions for both ends of the trips that were reduced. To avoid charging a fee on emissions that may be attributable to another new or existing indirect source, the fee formula is based on 50% of the baseline emissions after mitigation is applied onsite. The regional transportation model used as a comparison with URBEMIS is flawed when used for a project level analysis. The fees are not inflated compared to the impact. Sierra incorrectly calculated the potential fees.

144. **COMMENT:** URBEMIS Defaults Are Biased High – Most but not all of our concerns with the URBEMIS model result from its heavy reliance on detailed default assumptions that are not likely to be well understood by project applicants required to use the model under the proposed rules. As our analysis shows, a number of these default assumptions substantially overestimate residential project emissions in the following areas:

- by about 20% for NOx due to over-represented heavy-duty vehicles in the fleet mix;
- by over 20% for NOx, ROG and PM_{10} because of older age distribution assumptions; and
- by roughly 50% for PM_{10} due to incorrect silt loading factors; and
- by 20-30% for all pollutants from overstated average vehicle trip lengths in the San Joaquin Valley.

RESPONSE: The District will provide revised defaults accounting for land use specific fleet mix information, a Valley specific silt loading factor, and updated trip length data prior to rule implementation. The District will consider an age correction factor; however, more evidence of the validity of this approach is needed.

145. **COMMENT:** URBEMIS Is Inconsistent With SIP Methodology – Region-wide pollutant emissions calculated under State Implementation Plans (SIPs) use a more rigorous set of models to determine motor vehicle travel impacts and resulting emission impacts than represented in URBEMIS. During the ISR rule development, the District has provided no clear evidence that URBEMIS is capable of calculating emissions from development projects in a manner that is consistent with SIP-level emissions and has simply asserted its appropriateness for use under these rules.

To test the District's assertion, Sierra and Dowling performed an equivalent, side-by-side analysis of travel and emissions impacts of a typical hypothetical

"suburban fringe" residential project using both URBEMIS and the Fresno County regional travel demand model (one of several county-level travel demand models used to calculate vehicle travel under the SIP). (As in URBEMIS, emission impacts were calculated using the Air Resources Board's EMFAC2002 vehicle emission factor model.) Our analysis found that URBEMIS estimates over 60% higher vehicle miles traveled (VMT) and over 50% higher emissions for all pollutants than the travel model/SIP-based approach. Moreover, this discrepancy cannot apparently be corrected by using "better" URBEMIS inputs than the default assumptions built into the model. Thus, these findings cast doubt on the validity of broadly applying URBEMIS under the ISR rule as URBEMIS clearly does not produce SIP-consistent emission impacts.

RESPONSE: Prior to implementation, the District will provide updated default values to provide the most accurate emission estimates possible. Regional travel demand models are not practical for project level analysis. The rule requires 50 percent of baseline emissions to be mitigated. The 50 percent more than accounts for emissions due to counting both ends of the trips related to the project. URBEMIS counts two way trips to account for the total impact of the project. When used in analyze a single project, this is appropriate measure of impact. When looking at regional impacts, only half of the trips should be counted since if every project, new and existing were examined at once it would exactly double count the trips. Using URBEMIS will result in consistent analysis from project to project. Emission reductions achieved by the rule from offsite measures will be calculated using emission factors and methods consistent with the SIP. Onsite measures will be credited in accordance with EPA Voluntary and Emerging Emission Measures Policy.

146. COMMENT: Residential Fees Appear Understated in Socioeconomic Report – In addition to the comments summarized above on the URBEMIS model, we also have concerns with the fee estimates for typical residential developments contained in the District's socioeconomic analysis of the ISR rules. Table 16 of the socioeconomic report cites "worst-case" fee estimates ranging from $856 per unit in 2006 to $2,841 per unit in 2010. The supporting text offers no explanation of how these estimates were developed.

Its fundamental flaws notwithstanding, Sierra independently estimated residential fees using URBEMIS, and the fee formulas and cost reduction ratios contained in the August drafts of Rule 9510 and 3180. Our analysis found fees were twice as high ($1,607-$7,971 per unit) over the same period for a single-family residential development, assuming a default housing density of 3 units/acre. When the housing density was doubled (to 6 units/acre), per unit fees were still over 50% higher ($1,295-$5,556 per unit) than those cited (without explanation) In the socioeconomic report. . We also calculated fees assuming a 93% vs. 7% split between single and multi-family units, based on the average number of new single- and multi-family housing units permitted in the San Joaquin Valley in

2002 obtained from the California Department of Finance (http://countingcalifornia.cdlib.org/title/castat.html). Even under these mixed use assumptions, our fee estimates ranged from $1,550-$7,702 per unit, still nearly twice as high as those in the socioeconomic report.

Thus, we question how the estimates in that report were developed. Our analysis suggests that the worst case residential fees are substantially higher than those employed in the socioeconomic analysis. If this is correct, then the impacts quantified in the study are understated and would need to be revised.

RESPONSE: Sierra incorrectly calculated the construction emission reductions. This accounts for the differences between the District's numbers in the socio-economic impact report and Sierra's inflated numbers.

147. COMMENT: Revenue From Residential Fees Will Dramatically Exceed the Cost of Purchasing Mitigation Needed to Meet ISR SIP Commitments – Using information developed by the District for this rulemaking, Sierra prepared estimates of the funds that will be generated from residential fees and spent purchasing mitigation between 2006 and 2010. We found incoming fee revenue exceeded outgoing mitigation expenses by $146 to $728 million depending on the level of the fee assumed (the percent difference ranges from 377% to 1,873%). The magnitude of these differences indicates that the rule is seriously flawed. There are two primary reasons for the discrepancy between fee revenue and mitigation expenses. First, as noted above, URBEMIS default assumptions include biases that lead to significant overestimates of project emissions, which in turn lead to overpayment of mitigation fees. Second, there is a fundamental flaw in the fee formulas developed for the rule that overstates the cost of purchasing mitigation.

The fee formulas are designed to advance to the District a monetary sum necessary to mitigate excess emissions not mitigated onsite for a period of ten years. Assuming no onsite mitigation, the operational NOx formula requires payment for 2.5 times and the operational PM_{10} formula requires payment for 5 times the estimated base year emissions. The important point is that developers would be required to pay mitigation fees that offset several years of project emissions. Mitigation expenses, however, are not denominated in years. Instead they represent a single one-time purchase that continues to provide emission reductions for multiple years. According to the staff report the average project life for NOx mitigation is 7 years and for PM_{10} it is 12 years.

Thus, assuming no onsite mitigation, a project applicant can expect to pay for 17.5 years of mitigation for the base year NOx emissions of the project (i.e., 2.5 × 7) and 60 years of mitigation for the base year PM_{10} emissions of the project (i.e., 5 × 12). This bias is extreme and comes on top of the significant default biases incorporated into URBEMIS. Collectively, they explain the huge absolute

and percentage difference between incoming fees and outgoing mitigation expenses. Since the residential fees in this analysis are used to purchase all of the ISR SIP mitigation commitments, the inclusion of both residential and non-residential (e.g., industrial) development fees would only worsen the already enormous inconsistency between ISR revenue and expenses.

RESPONSE: The fee formula does not include a project life multiplier of 7 or 12 years. Any funds collected will be used on projects with average project lives of 7 for NOx or 12 years for PM10, so the mitigation is effective for that long on average. The fee formula calculates an amount of emissions in tons that must be mitigated at the cost of reductions for each year. For most projects funded, the reductions may be considered permanent since at the end of the project life new engines/devices will be purchased that achieve reductions that are equivalent or better.

148. COMMENT: Conclusions.
The draft ISR rules have serious and fundamental flaws related to their reliance on URBEMIS and its extreme overstatement of residential project emissions. Moreover, our analysis of incoming and outgoing revenue streams indicates that the ISR fee formulas dramatically overstate the amount of revenue needed to buy emission reduction offsets for NOx and PM_{10} at "market" prices estimated by the District.

RESPONSE: The District strongly disagrees with this conclusion. Sierra based its conclusions on erroneous calculations and comparisons.

SIERRA RESEARCH
ATTACHMENT A
DETAILED COMMENTS

Our detailed comments on the ISR rules are presented below. Some of these comments were provided by Sierra to the District in July in response to the preceding versions of the draft rules. For completeness and where relevant as related to the District's response to these earlier comments, they are repeated in this letter. At the end of each of these comments, we have listed the District's response as contained in Appendix A of the August version of the ISR rule packet and provided follow-up comments to these responses.

149. COMMENT: URBEMIS Fleet Mix Overstates Residential Project Emissions – One of the most striking instances of inappropriate default data in URBEMIS is the distribution of vehicle types (e.g., passenger cars, light trucks, heavy trucks, etc.) or "fleet mix" employed in the model. Fleet mix differences can significantly impact calculated vehicle emissions because of the relative stringency imposed on different vehicle types under emission certification standards adopted and implemented by the state Air Resources Board (ARB). Generally speaking,

passenger cars must meet more stringent (i.e., lower) emission standards than larger vehicle types such as heavy-duty trucks.

The default fleet mixes in URBEMIS (which vary slightly by calendar year) are based on statewide average distributions contained in ARB's EMFAC2002 model. Those default distributions assume that roughly 3% of the vehicles are heavy-duty vehicles (trucks and buses). This is reasonable for a statewide or air basin average of a large vehicle fleet, but clearly not representative of the mix of vehicles operating in a new residential project. New residential projects are not likely to contain any heavy-duty vehicles (in the "operating" phase following construction). Thus, the use of the URBEMIS default fleet mixes that contain heavy-duty vehicles is clearly inappropriate for these projects.

Table 1 compares the results of URBEMIS runs with default and "no heavy-duty" adjusted fleet mixes. These URBEMIS runs were performed for hypothetical 100-unit residential development with single family detached housing for calendar year 2005 using default assumptions for the remaining inputs and assume no mitigation.

The upper portion of Table 1 shows the existing default fleet mix and the corrected fleet mix which was adjusted by removing all heavy-duty vehicle categories and renormalizing the remaining percentages. The lower portion compares operating emissions calculated by URBEMIS using each fleet mix. Although the emission impacts for ROG and PM_{10} are minimal, NOx emissions are some 23% lower (2.13 vs. 2.76 tpy) when representative fleet mix is used to model residential project emissions.

Table 1
Emission Impacts of Corrected Vehicle Fleet Mix
(SJV Fleet, Calendar Year 2005)

Vehicle Class	Default Mix (%)	Adjusted Mix (%)
Light Auto	56.1	58.1
Light Truck 1	15.1	15.6
Light Truck 2	15.5	16.1
Med Truck	6.8	7.0
Light-Heavy Truck 1	1.0	-
Light-Heavy Truck 2	0.3	-
Med-Heavy Truck	1.0	-
Heavy-Heavy Truck	0.8	-
Line Haul	0.0	-
Urban Bus	0.1	-
Motorcycle	1.6	1.7
School Bus	0.3	-
Motor Home	1.4	1.5
FLEET TOTALS	100.0	100.0
Heavy-Duty Pct.	3.5	0.0
Operating Emissions (tpy) for 100-Unit Residential Project:		
ROG	2.18	2.16
NOx	**2.76**	**2.13**
PM_{10}	1.99	1.98

This is a clear instance where URBEMIS default inputs are not appropriate and significantly overstate NOx emissions and resulting mitigation fees that would be calculated under the District proposed ISR rules. This finding clearly points out the need for the District to thoroughly review the default assumptions in URBEMIS and carefully consider the technical capabilities of applicants as end users of the model under these rules.

RESPONSE: The District is working to ensure that the fleet mix assumptions in URBEMIS are appropriate for each land use type. The District will provide updated land use specific fleet mix information for residential development and possibly other land uses prior to rule implementation. URBEMIS data files containing the updated fleet mix data will be available for ease of use. We will accept changes to default information such as fleet mix when supported by adequate documentation. While the fleet average may somewhat overstate emissions [from] residential developments there are heavy-duty truck emissions associated with them. These include school buses, refuse collection, package delivery and other service vehicles.

150. COMMENT: Follow-Up – Refuse collection vehicles are contained in the heavy-heavy truck (HHT) category. In 2004, ARB adopted a statewide rule for controlling emissions from solid waste collection vehicles

(http://www.arb.ca.gov/regact/dieselswcv/dieselswcv.htm). Under that effort, a solid waste collection vehicle emissions inventory was prepared which identified the statewide population of both residential and commercial refuse collection vehicles as 11,778 in calendar year 2000. According to EMFAC2002, the statewide population of all HHTs in 2000 was 158,204. Thus, residential and commercial refuse collection vehicles represent only 7% (11,778 ÷ 158,204) of the total HHT population, with residential collection vehicles less than that.

Package delivery and other service vehicles generally span the light-heavy truck (LHT) and medium-heavy truck (MHT) categories, but the vehicle populations and vehicle miles traveled for those vehicles serving residential customers is likely much less than those serving commercial customers. Thus, the EMFAC2002 fleet percentages for the LHT and MHT categories still overstate the fractions of those vehicles serving residential areas.

To address these issues, the analysis presented earlier in Table 1 was revised to include school buses and all LHTs and MHTs at the same proportions of the original EMFAC2002 fleet mix. This addresses the District concern that school buses be included and conservatively overstates the representation of residential package delivery and other service vehicles. Since residential refuse collection vehicles represent a very small fraction of all HHTs (less than 7%), the HHT residential fleet fraction was set to zero. Using this revised residential fleet mix, NOx emissions were calculated to be 2.44 tpy, which are 12% lower (2.44 vs. 2.76 tpy) than those based on URBEMIS defaults.

Thus, we believe NOx emissions for a properly determined residential fleet mix are still 12-20% lower than if URBEMIS defaults are used, depending on what assumptions are made with respect to the package delivery and other service vehicle fractions of LHTs and MHTs.

RESPONSE: EMFAC emission projections are revised periodically to account for changes from adopted motor vehicle emission regulations. The next version of EMFAC is expected to be released in 2006. The District will help fund the next upgrade to URBEMIS to utilize the new EMFAC. The District's methodology for estimating land use specific fleet mixes will be available prior to rule implementation

151. COMMENT: URBEMIS Age Distribution Overstates Residential Project Emissions – Another area where URBEMIS does not accurately reflect particular project conditions relates to the distribution of vehicle ages internally built in to the model. The vehicle age distributions contained in URBEMIS are based on statewide average vehicle registrations for the entire on-road fleet contained in the EMFAC2002 model. These distributions likely reflect a generally older vehicle fleet than exists in a new residential project. Vehicle emissions strongly depend on vehicle age due to ARB's implementation of dramatically tighter

emission standards over the last 30 years. New vehicles today are approximately 10-20 times cleaner than those introduced in the early 1970s. And this trend will continue into the future. Thus, it is necessary to accurately represent the age distribution of a fleet of vehicles when calculating their emissions.

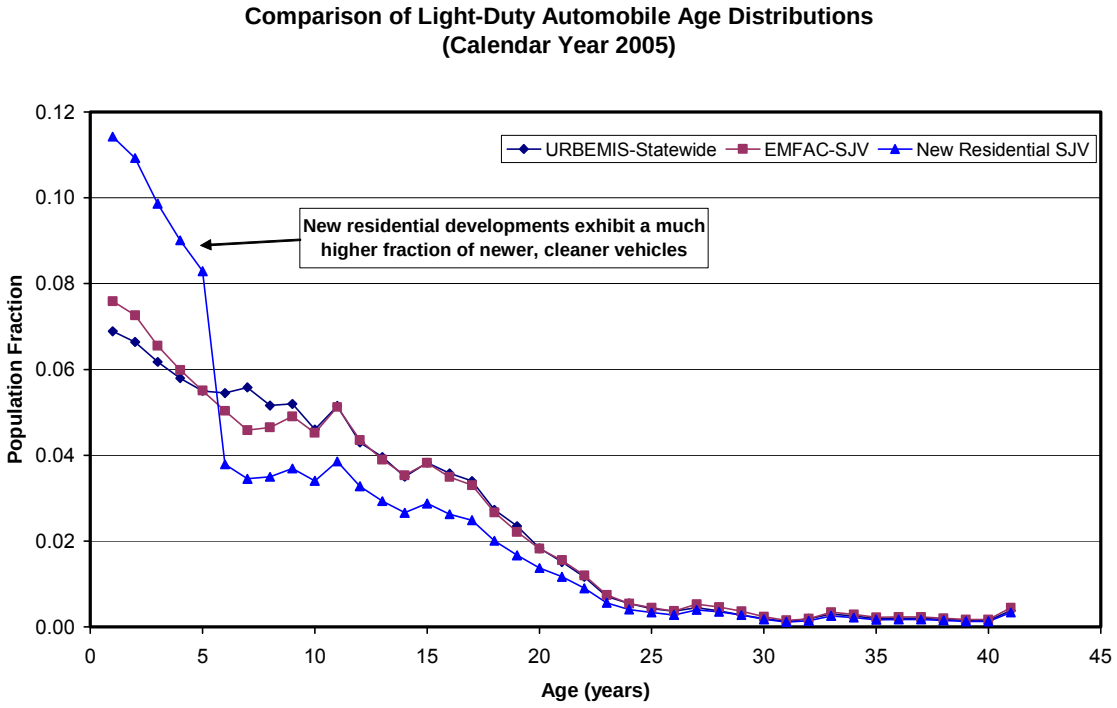
Our subcontractor Dowling has compiled statistics on housing age and vehicle fleet age from two readily available data sources: 1) the 2000 U.S. Census; and 2) the 2001 Caltrans Statewide Household Travel Survey. They compared vehicle age from households in the San Joaquin Valley in two groups:

1. "new" households defined as those that were ≤ 10 years old; and
2. "old" households defined as those older than 10 years.

Dowling found that the "new" housing areas had a 49.5% to 50.5% mix between vehicles ≤ 5 years old and vehicles > 5 years old. In the "old" household areas, the split between ≤ 5 year old vehicles and vehicles > 5 years old was 35.7% to 64.3%, indicating that new households in the San Joaquin Valley reflect a newer vehicle fleet than represented by the URBEMIS model defaults for the entire area.

Figure 1 illustrates the differences in vehicle age distributions between those in the EMFAC2002 model (upon which URBEMIS is based) and those developed for a typical new residential development based on Dowling's findings. As highlighted in Figure 1, new residential developments exhibit a much larger fraction of newer and therefore generally cleaner vehicles.

Figure 1



The emissions impact of using a younger age distribution typically found in new residential developments was determined from a series of spreadsheet calculations by individual model year using age-specific emissions factors extracted from the EMFAC2002 model.

Table 2 presents and compares resulting light-duty automobile exhaust emission factors (in grams per mile) during summer in calendar year 2005. Table 2 also shows the percentage difference in emission factors (and thus calculated project exhaust emissions) using the URBEMIS and New Residential age distributions.

Table 2
Exhaust Emission Impacts of Corrected Vehicle Age Distribution
(SJV Light-Duty Auto Fleet, Calendar Year 2005, Summer)

Quantity/Age Distribution	ROG	NOx	PM_{10}
Emission Factor (grams/mile) - URBEMIS Default	0.177	0.290	0.0082
Emission Factor (grams/mile) - New Residential	0.132	0.222	0.0065
% Difference (New Residential vs. URBEMIS)	**-25.6%**	**-23.3%**	**-20.5%**

As highlighted in Table 2, exhaust emissions of light-duty automobiles were found to be over 20% lower for ROG, NOx and PM_{10} when an age distribution representative of a typical new residential neighborhood is used compared to the

existing fleet-average age distribution contained in URBEMIS. These emission impacts calculated for automobiles are likely to be similar for light-duty trucks as well, which together with automobiles account for about 90% of the vehicles in a residential project fleet.

RESPONSE: The District will consider adding an age correction factor in the fee calculation formula for residential development. The emissions for PM10 in the table appear to be from exhaust and are small compared to the entrained road dust that is not affected by the age of the vehicle.

152. COMMENT: Unlike the previous fleet mix problem which can be addressed by issuing guidance to supply a different fleet mix in one of the URBEMIS input screens, the model cannot be easily revised to properly account for a representative residential vehicle fleet age distribution. The way URBEMIS is currently designed, it internally uses a series of calendar year and season specific emission factor files developed from "upstream" runs of the EMFAC2002 model for a statewide average vehicle fleet. Although it is possible to generate air basin-specific EMFAC2002 files, URBEMIS would need to be re-programmed to utilize these air basin-specific emission factors. More importantly, fleet age distributions for an air basin as a whole are still not likely to reflect those of a typical new residential project. This can clearly be seen from the "EMFAC-SJV" and "New Residential SJV" distribution plotted earlier in Figure 1.

The EMFAC2002 model maintained by ARB is designed to produce several types of outputs under the following three modes: 1) "Burden"; 2) "Emfac"; and 3) "Calimfac". URBEMIS is currently designed to work with "Emfac" mode outputs from EMFAC2002. Although EMFAC2002 can be run with different age distributions, this feature is only available under the "Burden" output mode, not the "Emfac" mode.

Thus, we believe the District will need to completely overhaul the design of URBEMIS and its interaction with ARB's "official" EMFAC2002 emission factor model or consider another analysis method/tool to adequately address this age distribution issue for residential project analyses under the ISR rules.

RESPONSE: The District continues to believe that URBEMIS is the appropriate tool for the job. The District will consider an off model vehicle age correction if well documented. However, the District believes that the fleet average is a reasonable assumption for new development projects. There are a number of factors that impact emissions including age, vehicle class, and fleet turnover. If more specific information is available, the District would consider utilizing project specific numbers.

153. COMMENT: Follow-Up – When asked to clarify this response at the September 1 workshop, District staff indicated that their primary concern with simply using the revised age distributions presented earlier by Sierra/Dowling was that light-duty vehicle class mixes may also be different in new residential areas than represented by URBEMIS defaults. Specifically, the concern was that residential vehicle fleets contain a much higher fraction of sport utility vehicles (SUVs) and pickups than represented in a region-wide fleet.

Our original analysis of the emission impacts of corrected vehicle age distribution was conservatively applied only to passenger cars (which make up less than 60% of the residential fleet), instead of all light-duty vehicles (which comprise roughly 90% of the fleet). We revised our original analysis to include all light-duty vehicles (which include both passenger cars and the light-duty truck categories) because the household survey data upon which the revised age distributions were based included both cars and light-trucks. And to conservatively address the District's concern that a residential fleet would contain a higher fraction of SUVs and pickups than in a region-wide fleet, we doubled the existing fraction of the Light-Duty Truck 2 (LDT2) category (which contains most of the SUVs and large pickups) from roughly 16% to 32%.

Table 3 compares the results of this revised analysis, which applies the newer age distribution to all light-duty vehicles and doubles the LDT2 fleet fraction, to those based on the original URBEMIS defaults. The percentage differences shown in Table 3 are very similar to those presented earlier in Table 2. The reason for this is that although light-duty trucks (specifically LDT2s) have been historically required to meet less stringent in-use emission standards than passenger cars, this gap in stringency has narrowed in recent years and more importantly, their standards have been tightened over time much like passenger car standards. Thus, dramatically increasing the assumed light-duty truck fraction in the residential fleet has much less effect on the relative emission impact compared to URBEMIS defaults and accounting for the younger age distributions of all light-duty vehicles found in newer residential vehicle fleets.

Table 3
Exhaust Emission Impacts of Corrected Vehicle Age Distribution and Doubled LDT2 Fleet Fraction
(SJV Light-Duty Vehicle Fleet, Calendar Year 2005, Summer)

Quantity/Age Distribution	ROG	NOx	PM_{10}
Emission Factor (grams/mile) - URBEMIS Default	0.180	0.345	0.0103
Emission Factor (grams/mile) - New Residential	0.133	0.267	0.0084
% Difference (New Residential vs. URBEMIS)	**-26.1%**	**-22.5%**	**-17.9%**

Therefore, even when accounting for a higher fraction of SUVs and pickups in new residential fleets, we maintain that URBEMIS still overstates NOx and PM_{10} exhaust emissions by approximately 20% due to unrepresentative age distribution assumptions. We believe we have provided the District with ample and readily-available evidence regarding residential fleet age distributions, whose impacts overwhelm those due to what may be higher SUV and pickup fractions in new residential developments. Furthermore, even if fleet data were collected through a survey of new residential developments, the District has not answered the question of how to apply these data since they cannot be accommodated within URBEMIS.

RESPONSE: The District still believes that URBEMIS is the best model for the job and has consistently stated that it would use better data when available. The District will consider applying an age correction factor to the output to address this concern.

154. COMMENT: URBEMIS Silt Loading Factors Inconsistent with ARB Inventory, Overstates Residential Project Emissions – This is another striking example where URBEMIS default assumptions dramatically overstate actual residential project emissions; in this case, by nearly 50% of total operating PM_{10} emissions.

The default silt loading factor supplied to the user by URBEMIS for calculation of entrained (i.e., fugitive dust) PM_{10} emissions is inconsistent with those used by ARB on its emissions inventory and the District's PM_{10} SIP.

In URBEMIS and in ARB's emissions inventory, fugitive dust PM_{10} emissions are calculated for vehicle travel on paved roads using the following equation:

$$EFpaved = k \times (sL/2)^{0.65} \times (W/3)^{1.5}$$

Where:

EFpaved is the emission factor (lb per vehicle mile traveled);
k is the particle size multiplier (0.016 for PM_{10});
sL is the road surface silt loading factor (in grams per square meter);
W is the average weight of vehicle traveling on the road (4,850 lbs is default).

The default road surface silt loading factor in URBEMIS is 0.1 grams per square meter. This value is higher and does not comport with San Joaquin Valley values used by ARB in its statewide inventory for entrained road dust on paved roads, which are different for each roadway type as follows:

- 0.020 g/m^2 for freeways
- 0.035 g/m^2 for major arterials

- 0.035 g/m^2 for collectors
- 0.320 g/m^2 for urban locals
- 1.6 g/m^2 for rural locals.

Using data compiled by the Federal Highway Administration (FHWA) under the Highway Performance Monitoring System (HPMS), the San Joaquin Valley exhibits the following travel percentages by the road types listed above:

- Freeways – 33.25%
- Major Arterials – 38.97%
- Collectors - 27.59%
- Urban Locals – 0.19%
- Rural Locals – 0.01%

The weighted average silt loading factor using these travel fractions and ARB's silt factors by roadway type was calculated to be 0.031 grams per square meter, which is well below the 0.1 default values contained in URBEMIS. Using this ARB and HPMS-based weighted average silt factor for the San Joaquin Valley in the above equation results in a paved road dust emission factor that is 53.6% below that based upon the URBEMIS default silt factor. Use of the ARB-consistent silt factor will also result in a 53.6% reduction in paved road dust PM_{10} emissions computed using URBEMIS defaults.

According to emissions inventory summary data available from ARB on-line at http://www.arb.ca.gov/ei/emsmain/reportform.htm paved road dust PM_{10} emissions make up about 90% of total on-road vehicle PM_{10} emissions in the San Joaquin Valley, excluding unpaved road travel. (We exclude unpaved road dust under the assumption that operating emissions of vehicles in a new residential project exhibit little travel on unpaved roads.) Thus, use of a paved road silt loading factor consistent with ARB's inventory would translate to a 48.2% reduction on total operation PM_{10} emissions of a residential project as described below:

$$\%Reduction = PavedFrac \times (1 - \%SiltReduction) + RemainingFrac$$
$$= 90\% \times (1-53.6\%) + 10\%$$
$$= 48.2\%$$

Where *PavedFrac* is the fraction of project emissions from paved road dust, *%SiltReduction* is the relative reduction in paved road emissions using the ARB-consistent silt factor compared to URBEMIS and *RemainingFrac* is the remaining project emissions of PM_{10} (from exhaust, brake wear and tire wear).

Again, this issue and the alarmingly high overstatement of PM_{10} emissions based on model defaults points out the need to further review and provide detailed guidance for use of URBEMIS in calculating project-specific emissions under the proposed ISR rules.

RESPONSE: The District concurs with Sierra's methodology and will ensure that the correct silt loading factors are utilized in URBEMIS defaults.

155. COMMENT: Follow-Up – We appreciate the District's response to correct the existing silt load factors in URBEMIS. However, when questioned during the September 1 workshop about how and when these silt loading corrections (as well as corrections related to the earlier fleet mix and vehicle age issues) would be addressed, staff indicated that these corrections to URBEMIS defaults would not be completed and released for review prior to the District Board hearing in mid-November for adoption of the ISR rules. Moreover, staff was unclear whether these corrections would be handled by revising the URBEMIS model, or by developing written guidance for users of the model under the ISR rules instructing them how to correct the overstated model defaults when applied to residential development projects.

Given the significance of the impacts of the flawed model defaults on the costs to comply with these proposed rules, we believe these model revisions or guidance documents should be developed and publicly reviewed before ISR rules are adopted if the District intends to pursue the rules despite URBEMIS' deficiencies.

RESPONSE: The District is developing guidance for preparing the air quality impact assessment required by the rule. The guidance will include the default silt-loading factor provided by Sierra Research. The District will provide URBEMIS data files updated with changes that can be used without having to enter the new data. The next upgrade to URBEMIS will contain much of the updated information. The staff report has been updated to describe the impact of these changes on the emissions estimates and economic impacts.

156. COMMENT: URBEMIS Is Inconsistent With SIP Methodology – When a typical residential project was modeled using both URBEMIS and a SIP-based modeling URBEMIS estimates over 60% higher vehicle miles traveled (VMT) and over 50% higher emissions for all pollutants than SIP-based approach.

This is not surprising. The URBEMIS model was originally written as a "sketch-planning" tool, designed to produce intentionally conservative analyses of localized emission impacts from different land uses. For over ten years, the URBEMIS model has been used to assess development project emissions under the California Environmental Quality Act (CEQA) review process. Under CEQA, use of URBEMIS as a conservative (i.e., over-predictive) screening tool is entirely appropriate for comparing project emissions to "significance thresholds"

established under air district guidelines since CEQA requires disclosure of project impacts and significance, but not compliance with regional or state air quality plans or standards. Under this process, URBEMIS-based emission impacts can acceptably err on the side of caution or over-prediction.

RESPONSE: URBEMIS has been continuously updated to provide increased accuracy with each new version. Many of the default values that are based on statewide averages can be changed to use local information when available. The District appreciates the review conducted by Sierra Research to identify additional areas of improvement. The next version of URBEMIS will contain many of these improvements. In the interim, applicants will be instructed to enter local information that is currently available. This information will be provided in a District guidance document. Analyses prepared by the District will also use the local information. URBEMIS remains the best tool for performing project level analyses and provides reasonable estimates of project impacts.

157. COMMENT: Conversely, these ISR rules are being implemented to address specific emission reduction commitments made by the District in Ozone and PM_{10} SIPs for the San Joaquin Valley. Region-wide pollutant emissions calculated under these SIPs use a more rigorous set of models that have been validated with direct measurements to determine motor vehicle travel impacts and resulting emission impacts than represented in URBEMIS. During the ISR rule development, the District has provided no clear evidence that URBEMIS is capable of calculating emissions from development projects in a manner that is consistent with SIP-level emissions. The District has simply asserted the appropriateness of URBEMIS under these proposed ISR rules despite the fact that CEQA guidelines published by other air districts such as the Bay Area and Sacramento clearly characterize URBEMIS as a conservative sketch-planning tool.

RESPONSE: The District believes that URBEMIS has been improved beyond its characterization as a sketch planning tool. Very few of the modules of the program are overly conservative. Most modules rely on statewide averages extracted from the emission inventory which should not be considered conservative estimates. The most important module is the mobile source module that includes the same emission factors used to build the emission inventory. It does a good job of arriving at a composite emission rate needed for a project level analysis. Models can always be made more accurate by individualizing more and more input factors. The District believes that URBEMIS balances data requirements with reasonable output accuracy and ease of use. The travel demand models described by Sierra Research are extremely data intense and would be very costly to run for the approximately 1,000 projects that will be submitted to the District each year. It is uncertain whether the demand models are more accurate for project level analyses than URBEMIS with local information**.**

158. COMMENT: To test the District's assertion, Sierra and Dowling performed an equivalent, side-by-side analysis of travel and emissions impacts of a typical hypothetical "suburban fringe" residential project using both URBEMIS and the Fresno County regional travel demand model3 (one of several county-level travel demand models used to calculate vehicle travel under the SIP. (As in URBEMIS, emission impacts were calculated using the Air Resources Board's EMFAC2002 vehicle emission factor model.)

For our investigation, we considered a 500-unit single family residential project located within a 160-acre parcel in an undeveloped/lightly-developed area in Clovis northeast of downtown Fresno near the intersection of Minnewawa and Shepherd at the edge of the urban area. This was intended to represent a typical suburban project at the fringe of an urbanized area and roughly matches the default single family residential project density assumed in URBEMIS of three units per acre. We looked at travel activity and emissions during Summer 2010.

Dowling ran the Fresno COG travel demand model in 2010 for a baseline (no project) case and a "with project" case under which the 500-unit project was simulated within the affected traffic analysis zone. The detailed travel model outputs were then fed into ARB's current EMFAC2002/BURDEN model to calculate associated emission impacts with the added project. These results were then compared to an URBEMIS simulation of a 500-unit single-family residential project in the San Joaquin Valley. The URBEMIS run assumed pass-by trips were accounted for and assumed an urban land use type. Since we simulated a single land use (single family residential) in both the travel model and URBEMIS runs, there was no need to apply the "double-counting" correction within URBEMIS.

Our analysis found that URBEMIS estimated daily VMT from this project at 35,817, compared to 21,886 using the SIP-based travel model, an increase of nearly 64%. Emission impacts using URBEMIS were also higher for all pollutants and ranged above 50% compared to the SIP-based approach.

3 Regional travel models such as the Fresno County model mathematically simulate vehicle trip movements over a regional roadway network by dividing the region into demographically similar "traffic analysis zones" (TAZs) similar to census tracts. Demographic and socioeconomic data for each TAZ are used to estimate the number and types of person trips taken between each TAZ. These person trips are then translated into vehicle trips (or non-vehicle trips such as walking or bicycle trips) and loaded onto a series of roadway links that spatially approximate the actual regional roadway network.

From our analysis of the underlying elements of the two approaches, we have preliminarily concluded that the discrepancy in VMT is caused by two related factors:

1. overstated defaults trip lengths for typical suburban residential projects in the San Joaquin Valley; and

2. the inherent underreporting of short trips in household survey data upon which average trip length estimates are based.

The trip generation rates in both models were identically-matched because they both rely on the same source, trip generation rates by land use from the Institute of Transportation Engineers (ITE). The ITE Trip Generation rates are a more accurate representation of vehicle traffic at a particular land use than rates based on household travel surveys. The ITE rates are based on actual driveway traffic counts at many land uses across the United States, and do not rely on self-reporting of trips. Therefore, the use of ITE trip generation rates in URBEMIS would accurately represent total trip-making, if the characteristics of the higher numbers of trips were identical to the characteristics survey-based trips used to determine average trip lengths. However, there is evidence that this is not the case, particularly for trip lengths.

RESPONSE: The District will contact the 8 Valley transportation planning agencies to obtain new recommended trip lengths for each county. This information will be included in the guidance provided by the District for use in URBEMIS. The District is not convinced that using the Transportation Demand Model will provide more accurate results.

159. COMMENT: The 2000-2001 Caltrans travel survey included a parallel study of actual vehicle movements using GPS units. The vehicle movements from the GPS surveys were compared with the self-reported trips from the same households. Overall, the GPS surveys resulted in 29 percent more trips than the self-reported travel survey results.

A related study4 identified the characteristics of underreported trips.5 In particular, the study found that short trips were much more likely to be underreported in travel surveys. Although trips of 10 minutes or less made up 48 percent of the total sample, the short trips accounted for 71 percent of the trips that were missing in self-reported results but identified by the GPS survey. Therefore, the short trips were about 50 percent more likely to be missing from the travel survey results.

4 Joanna Zmud and Jean Wolf, "Identifying the Correlates of Trip Misreporting – Results from the California Statewide Household Travel Survey GPS Study," 10th International Conference on Travel Behaviour Research, August, 2003.

5 Joanna Zmud and Jean Wolf, "Identifying the Correlates of Trip Misreporting – Results from the California Statewide Household Travel Survey GPS Study," 10th International Conference on Travel Behaviour Research, August, 2003.

The URBEMIS model therefore overestimates vehicle-miles of travel by basing the total trip generation on the higher ITE Trip Generation rates, but basing the average trip length characteristics on a smaller survey-based subset of trips that excludes many of the shorter trips. Moreover, it may not be easy or simple to correct this discrepancy because unbiased GPS or instrumented vehicle data may not be available for the San Joaquin Valley.

RESPONSE: It seems that Sierra is attempting to discredit URBEMIS by over complicating the emission calculation process. The differences between the project modeling done by URBEMIS and the regional modeling done by transportation demand models are not a valid comparison. With minor corrections URBEMIS will produce results very close to the SIP inventory model and URBEMIS will continue to be improved with each new version.

160. COMMENT: Although our side-by-side analysis of URBEMIS against a SIP-based approach was limited to a single hypothetical case study of a suburban "fringe" residential development, this case was intentionally selected because in addition to being a common example, it also represented conditions (i.e., urban edge) where it was believed that travel impacts from both approaches would be in closest agreement. Thus, the fact that this case study showed URBEMIS overstated SIP-based travel and emissions impacts by over 60% and 50%, respectively, casts doubt on the validity of broadly applying URBEMIS under the ISR rule as URBEMIS clearly does not produce SIP-consistent emission impacts.

Under both public and private sector work performed throughout California for over twenty years, Sierra has found no precedent at any air pollution control district that employs a fundamentally inconsistent methodology in implementing, monitoring and tracking emission reductions of a district rule from that used to calculate its SIP-based commitments. Given the above findings, we believe District bears the "burden-of-proof" that URBEMIS is consistent with SIP-based methods.

RESPONSE: The District disagrees with the assertion that URBEMIS is fundamentally inconsistent with SIP commitment methodologies. Since the emission inventory is built on a regional basis, the differences in individual projects are not addressed. Benefits of on-site measures and surrounding land uses are not credited in the inventory. URBEMIS is the only tool that can quantify emissions and on-site measures at the project level using readily available emission factors and activity data consistent with other inventory models.

The SIP credit expected from the rule comes from two sources – off-site reductions purchased by the District through its grant programs, and onsite

reductions achieved through project design and infrastructure built into the project. The off-site reductions from projects such as diesel engine replacements and retrofits are quantified using engine specific emission factors and use data and enforced by legally binding contracts. These meet the most stringent SIP monitoring and tracking requirements. The onsite measures are voluntary measures selected by the project developer that are more difficult to quantify and monitor. The District will claim reductions from onsite measures in accordance with EPA's Voluntary and Emerging Measures Program. In this program, EPA recognized that many nonattainment areas will need to implement innovative measures that may not be as quantifiable as traditional SIP measures. Sierra has found no precedent for this at other Districts because the San Joaquin Valley is the first to pursue an indirect source program that will be claimed for SIP credit.

161. COMMENT: Residential Fees Appear Understated in the Socioeconomic Report – In addition to the comments summarized above on the URBEMIS model, we also have concerns with the fee estimates for typical residential developments contained in the District's socioeconomic analysis of the ISR rules. Table 16 of the socioeconomic report cites "worst-case" fee estimates ranging from $856 per unit in 2006 to $2,841 per unit in 2010. The supporting text offers no explanation of how these estimates were developed.

Its fundamental flaws notwithstanding, Sierra independently estimated residential fees using URBEMIS, and the fee formulas and cost reduction ratios contained in the August drafts of Rule 9510 and 3180. For construction emissions, project construction equipment emission factors were assumed to equal those of the statewide inventory. URBEMIS runs were generated for a 100-unit residential project in the urban San Joaquin Valley for calendar years 2006 through 2010 using model defaults except where noted below. A 4% administration fee was assumed and included in our comparisons. Attachment B provides the details of our analysis.

Our analysis found fees were twice as high ($1,607-$7,971 per unit) over the same period for a single-family residential development, assuming a default housing density of 3 units/acre. When the housing density was doubled (to 6 units/acre), per unit fees were still over 50% higher ($1,295-$5,556 per unit) than those cited (without explanation) in the socioeconomic report. We also calculated fees assuming a 93% vs. 7% split between single and multi-family units, based on the average number of new single- and multi-family housing units permitted in the San Joaquin Valley in 2002 obtained from the California Department of Finance (http://countingcalifornia.cdlib.org/title/castat.html). Even under these mixed use assumptions, our fee estimates ranged from $1,550-$7,702 per unit, still nearly twice as high as those in the socioeconomic report.

Thus, we question how the estimates in that report were developed. Our analysis suggests that the worst case residential fees are substantially higher than those employed in the socioeconomic analysis. If this is correct, then the impacts quantified in the study are understated and would need to be revised.

RESPONSE: Sierra calculated the construction emission fee incorrectly. The District-estimated costs will be lower for residential development after the analysis is revised to account for the change to the fleet mix and silt loading factor. If the trip length and vehicle age changes can be verified, they too would lower the impact of the fee.

162. COMMENT: Revenue From Residential Fees Will Dramatically Exceed the Cost of Purchasing Mitigation Needed to Meet ISR SIP Commitments – A spreadsheet was created to prepare an estimate of the revenue that would be generated from residential fees for the 2006-2010 period and the cost of purchasing the mitigation needed to supply the ISR SIP emission reduction commitments during the same time period. Key assumptions used to support the development of these estimates include:

Number of Residential Units Subject to the Rule – According to the Construction Industry Research Board, construction permits were issued for 34,000 residential units in the San Joaquin Valley in 2004. This value represents a mixture of single and multi-family homes and was held constant for the years 2006 – 2010. Since the ISR rule provides an exemption for residential projects that have less than 50 units, this value was discounted by 10% to determine the number of units that would be subject to the rule. Using this approach it was determined that a total of 153,000 units would be subject to ISR fees between 2006 and 2010.

Residential ISR Fees – As noted earlier there is considerable difference between the worst case fees employed in the District's socioeconomic analysis and those that result from the use of default assumptions employed in URBEMIS. Given the discrepancy (i.e., the fees based on default URBEMIS values exceed the District's worse case values), four scenarios were used to cover the potential range in fees:

1. One half district worst-case estimate employed in the socioeconomic analysis was used to represent the low end of potential fees;
2. District worse case fees from the socioeconomic analysis represent the only per unit fee estimate available from the District;
3. URBEMIS default values, which are based on a density of 3 homes per acre represent a true worst case fee; and
4. URBEMIS default values adjusted to represent a higher density of 6 homes per acre represents a lower cost fee.

A summary of the fees that would be required to comply with these scenarios is presented in Table 4. It shows that there are considerable differences between the worst-case District values and those produced using default assumptions from URBEMIS. The URBEMIS based values assume that developers do not supply any on-site mitigation and are required to pay the fee-based expense of mitigation. We do not know what level of on-site mitigation was included in the District's estimate.

Table 4
Per Unit Mitigation Fees ($) For Each of the Scenarios Considered

Calendar Year	One Half District Worst Case	District Worst Case	URBEMIS Default 3du/acre	URBEMIS 6du/acre
2006	468	856	1,545	1,245
2007	705	1,409	3,088	2,385
2008	1,001	2,001	4,847	3,584
2009	1,230	2,459	6,637	4,804
2010	1,421	2,841	7,665	5,343

RESPONSE: The District used 3 units per acre for single family dwelling units in the socioeconomic impact analysis and continues to arrive at the same numbers. Sierra uses a figure of 34,000 units per year for its estimates of overall potential fees. The District used 20,000 units per year based on historical data that included years when construction occurred at a much slower rate and population projections used for the District's attainment plans. We believe that it is inappropriate to base future projections on record years that many expect may be a bubble. If the growth rates do continue, that means that the impact of growth will be much greater than projected and the increased revenue from greater participation in the rule by more units would be needed to offset the additional emissions.

Residential Revenue – This value was computed by multiplying the number of units subject to the Rule times the annual fee (i.e., # of units × $/unit = $).

SIP Emission Reduction Targets – The ton/day pollutant specific reduction targets established in the SIP for NOx and PM_{10}. The same values were employed in the rule making and were documented in Appendix B of the ISR rules packet.

District-Estimated Cost of Reductions – The annual pollutant specific $/ton cost of reductions specified in the residential fee schedule for Rule 9510.

Revenue Demanded – This value was computed by multiplying the pollutant specific incremental ton per day reduction commitment established in the SIP by

the District estimated cost pollutant specific reductions by 365.25 (average days per year) by 1.05 (to account for a combination of the administrative fee of Rule 3180 and an assumed 1% application fee). A key assumption in this calculation is that developers did not provide any onsite mitigation, so the District purchased all of the reductions needed to satisfy the SIP commitment.

Attachment C presents a listing of the spreadsheet values developed for each of the above parameters for each the four mitigation fee scenarios listed above. A summary of the cumulative revenue and mitigation values computed for each scenario for the period from 2006 to 2010 is listed in Table 5. It shows that the revenue varies depending on the ISR fees established by the scenario and that the cost of mitigation is constant. Regardless of the scenario considered, incoming revenue exceeds the mitigation expense by a huge margin. As noted in the summary, we believe that this is a result of biases built into URBEMIS default assumptions and the mitigation fees established for operational emissions from residential units.

Table 5
Analysis of Residential Revenue and Mitigation Expense ($ in millions)

Fee Scenario	Revenue	Mitigation Expense	Unexpended Revenue	Relative Difference (%)
One Half District Worst Case	146.3	38.8	107.5	377%
District Worst Case	292.7	38.8	253.9	754%
URBEMIS Defaults	727.7	38.8	688.9	1,873%
URBEMIS High Density	531.2	38.8	492.4	1,368%

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

URBEMIS 8.7 ANNUAL AVERAGE EMISSIONS FOR
100-UNIT SF RESIDENTIAL DEVELOPMENT PROJECT (unmitigated)
USING ALL MODEL DEFAULT VALUES

Calendar Year	Construction Emissions (tpy)		Area Source Emissions (tpy)		Operational (Vehicle) Emissions (tpy)		Area+Operational Emissions (tpy)		Total (C+A+O) Emissions (tpy)	
	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10
2006	30.75	2.59	0.30	0.61	2.58	1.99	2.88	2.60	33.63	5.19
2007	29.38	2.48	0.30	0.61	2.42	1.99	2.72	2.60	32.10	5.08
2008	28.01	2.35	0.30	0.61	2.24	1.99	2.54	2.60	30.55	4.95
2009	26.66	2.28	0.30	0.61	2.05	1.98	2.35	2.59	29.01	4.87
2010	25.36	2.18	0.30	0.61	1.87	1.98	2.17	2.59	27.53	4.77

URBEMIS 8.7 ANNUAL AVERAGE EMISSIONS FOR
100-UNIT SF HIGH-DENSITY (6 units/ac) RESIDENTIAL DEVELOPMENT PROJECT (unmitigated)
USING ALL MODEL DEFAULT VALUES (except single family residential density)

Calendar Year	Construction Emissions (tpy)		Area Source Emissions (tpy)		Operational (Vehicle) Emissions (tpy)		Area+Operational Emissions (tpy)		Total (C+A+O) Emissions (tpy)	
	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10
2006	26.30	1.79	0.30	0.61	2.29	1.76	2.59	2.37	28.89	4.16
2007	25.14	1.70	0.30	0.61	2.14	1.76	2.44	2.37	27.58	4.07
2008	23.98	1.59	0.30	0.61	1.98	1.76	2.28	2.37	26.26	3.96
2009	22.85	1.53	0.30	0.61	1.82	1.76	2.12	2.37	24.97	3.90
2010	21.75	1.45	0.30	0.61	1.66	1.76	1.96	2.37	23.71	3.82

URBEMIS 8.7 ANNUAL AVERAGE EMISSIONS FOR
100-UNIT SF RESIDENTIAL DEVELOPMENT PROJECT (unmitigated)
USING ALL MODEL DEFAULT VALUES

Calendar Year	Construction Emissions (tpy)		Area Source Emissions (tpy)		Operational (Vehicle) Emissions (tpy)		Area+Operational Emissions (tpy)		Total (C+A+O) Emissions (tpy)	
	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10
2006	12.62	0.81	0.21	0.61	1.86	1.43	2.07	2.04	14.69	2.85
2007	*12.07*	*0.77*	*0.21*	*0.61*	*1.73*	*1.43*	1.94	2.04	14.02	2.81
2008	*11.53*	*0.72*	*0.21*	*0.61*	*1.61*	*1.43*	1.82	2.04	13.34	2.76
2009	*10.98*	*0.68*	*0.21*	*0.61*	*1.48*	*1.43*	1.69	2.04	12.67	2.72
2010	10.43	0.63	0.21	0.61	1.35	1.43	1.56	2.04	11.99	2.67

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

SJV DRAFT RULE 9510 ISR NOx IMPACT FEE CALCULATIONS

Formula:

$$AIMF_{NOx} = \sum_{i=1}^{n} [(EBE_i \times 7.5 / 3) - (EBE_i \times 7.5 \times APM_i)] \times CNR$$

Calendar Year	Cost of NOx Red ($/ton)
2006	$4,650
2007	$7,100
2008	$9,350
2009	$11,600
2010	$13,250
2011	$13,250
2012	$13,250
2013	$13,250
2014	$13,250
2015	$13,250

where
- AIMF = Air Impact Mitigation Fee (in dollars)
- i = each phase
- n = last phase
- EBE = Estimated Baseline Emissions of NOx as documented in the District approved air impact assessment application (in tons/year)
- APM = Actual Percent Mitigation, as documented in the District approved air impact assessment application (as a fraction of one)
- CNR = Cost of NOx Reductions (in dollars per ton)

$$CN\ AIMF_{NOx} = \sum_{i=1}^{n} [AEE_i - (0.8 \times SEE_i)] \times CNR$$

where
- CN AIMF = Construction NOx Air Impact Mitigation Fee (in dollars)
- i = each phase
- n = last phase
- AEE = Actual Estimated Equipment NOx Emissions as documented in District approved air impact assessment application (in total tons)
- SEE = Statewide Average Equipment NOx Emissions as calculated by the District (in total tons)
- CNR = Cost of NOx Reductions (in dollars per ton)

Calculations:

					Area + Operational Sources						Construction Sources				
	Calendar Years				Estimated Baseline	Actual Percent	Air Impact Mitigation	Area+Ops	Actual Equipmt	Assumed	State Avg Equipmt	Constr Air Impact	Constr	Total
Scenario	Start	End	Phases	Units per Phase	Emissions EBE (tpy)	Mitigation APM (%)	Fee AIMF ($)	Fee/Unit ($)	Emis AEE (total tons)	% AEE Over SEE	Emis SEE (total tons)	Fee CN AIMF ($)	Fee/Unit ($)	Fee/Unit ($)
SF Resid	2006	2006	1	100	2.88	0%	$33,480	$335	102.95	0%	102.95	$95,744	$957	$1,292
SF Resid	2007	2007	1	100	2.72	0%	$48,280	$483	141.85	0%	141.85	$201,422	$2,014	$2,497
SF Resid	2008	2008	1	100	2.54	0%	$59,373	$594	166.30	0%	166.30	$310,985	$3,110	$3,704
SF Resid	2009	2009	1	100	2.35	0%	$69,325	$693	184.82	0%	184.82	$436,176	$4,362	$5,055
SF Resid	2010	2010	1	100	2.17	0%	$71,681	$719	182.29	0%	182.29	$483,071	$4,831	$5,550
HD Resid	2006	2006	1	100	2.59	0%	$38,109	$381	79.19	0%	79.19	$73,643	$736	$1,038
HD Resid	2007	2007	1	100	2.44	0%	$43,310	$433	108.88	0%	108.88	$154,612	$1,546	$1,979
HD Resid	2008	2008	1	100	2.28	0%	$53,295	$533	127.80	0%	127.80	$238,989	$2,390	$2,923
HD Resid	2009	2009	1	100	2.12	0%	$62,540	$625	142.90	0%	142.90	$337,253	$3,373	$3,998
HD Resid	2010	2010	1	100	1.96	0%	$64,925	$649	141.21	0%	141.21	$374,211	$3,742	$4,391
MF Resid	2006	2006	1	100	2.07	0%	$24,064	$241	30.37	0%	30.37	$28,243	$282	$523
MF Resid	2007	2007	1	100	1.94	0%	$34,479	$345	41.63	0%	41.63	$59,168	$591	$936
MF Resid	2008	2008	1	100	1.82	0%	$42,426	$424	48.90	0%	48.90	$91,435	$914	$1,339
MF Resid	2009	2009	1	100	1.69	0%	$49,781	$498	54.65	0%	54.65	$128,968	$1,290	$1,787
MF Resid	2010	2010	1	100	1.56	0%	$51,675	$517	53.90	0%	53.90	$142,827	$1,428	$1,945

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

SJV DRAFT RULE 9510 ISR PM10 IMPACT FEE CALCULATIONS

Formula:

$$AIMFpm10 = \sum_{i=1}^{n} [(MBE - 0.5\ EBE)i \times 10\ MCE)i] \times CR$$

where
AIMF = Air Impact Mitigation Fee (in dollars)
i = each phase
n = last phase
EBE = Estimated Baseline Emissions of PM10 as documented in the District approved air impact assessment application (in tons/year)
MBE = Mitigated Baseline Emissions, as documented in the District approved air impact assessment application (in tons/year)
MCE = Mitigated Construction Emissions, as documented in the District approved air impact assessment application (as total tons)
CR = Cost of Reductions (in dollars per ton)

Calendar Year	Cost of PM10 Red ($/ton)
2006	$2,907
2007	$5,594
2008	$9,011
2009	$11,308
2010	$13,850
2011	$13,850
2012	$13,850
2013	$13,850
2014	$13,850
2015	$13,850

$$AIMFpm10 = \sum_{i=1}^{n} [(MBE - 0.5\ EBE)i \times 10\ MCE)i] \times CR$$

$$CN\ AIMFpm10 = \sum_{i=1}^{n} [(AEE)i - (0.8 \times SEE)i] \times CPR$$

where
CN AIMF = Construction PM10 Air Impact Mitigation Fee (in dollars)
i = each phase
n = last phase
AEE = Actual Estimated Equipment PM10 Emissions as documented in District approved air impact assessment application (in total tons)
SEE = Statewide Average Equipment PM10 Emissions as calculated by the District (in total tons)
CNR = Cost of PM10 Reductions (in dollars per ton)

Calculations:

					Area + Operational Sources				Construction Sources					
Scenario	Calendar Years Start	Calendar Years End	Phases	Units per Phase	Estimated Baseline Emissions EBE (tpy)	Actual Percent Mitigation APM (%)	Air Impact Fee AIMF ($)	Area+Op Fee/Unit ($)	Actual Equipm't Emis AEE (total tons)	Assumed % AEE Over SEE	State Avg Equipm't Emis SEE (total tons)	Constr. Air Impact Fee CN AIMF ($)	Constr. Fee/Unit ($)	Total Fee/Unit ($)
SF Resid	2006	2006	1	100	2.60	0%	$18,896	$189	4.89	0%	4.89	$6,402	$64	$253
SF Resid	2007	2006	1	100	2.60	0%	$36,361	$364	9.02	0%	9.02	$22,700	$227	$591
SF Resid	2008	2006	1	100	2.60	0%	$58,572	$586	13.76	0%	13.76	$55,814	$558	$1,144
SF Resid	2009	2006	1	100	2.59	0%	$73,219	$732	16.69	0%	16.69	$84,949	$849	$1,582
SF Resid	2010	2006	1	100	2.59	0%	$89,679	$897	19.55	0%	19.55	$121,845	$1,218	$2,115
HD Resid	2006	2006	1	100	2.59	0%	$18,823	$188	3.37	0%	3.37	$1,939	$20	$208
HD Resid	2007	2007	1	100	2.44	0%	$34,123	$341	5.80	0%	5.80	$6,490	$65	$406
HD Resid	2008	2008	1	100	2.28	0%	$51,363	$514	8.17	0%	8.17	$14,718	$147	$661
HD Resid	2009	2009	1	100	2.12	0%	$59,932	$599	9.17	0%	9.17	$20,738	$207	$807
HD Resid	2010	2010	1	100	1.96	0%	$67,865	$629	9.84	0%	9.84	$27,258	$273	$951
MF Resid	2006	2006	1	100	2.04	0%	$14,826	$148	1.20	0%	1.20	$1,571	$16	$164
MF Resid	2007	2006	1	100	2.04	0%	$28,529	$285	2.18	0%	2.18	$5,494	$55	$340
MF Resid	2008	2006	1	100	2.04	0%	$45,956	$460	3.31	0%	3.31	$13,417	$134	$594
MF Resid	2009	2006	1	100	2.04	0%	$57,671	$577	3.89	0%	3.89	$19,809	$198	$775
MF Resid	2010	2006	1	100	2.04	0%	$70,635	$706	4.45	0%	4.45	$27,735	$277	$984

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

SJV DRAFT ISR RULE FEE CALCULATIONS FOR TYPICAL RESIDENTIAL PROJECTS

Scenario	Calendar Year	Construction Emis %AEE Over SEE NOx	Construction Emis %AEE Over SEE PM10	Rule 3180 Admin Fee (%)	Per Unit NOx Fees Area+Op	Per Unit NOx Fees Constr.	Per Unit PM10 Fees Area+Op	Per Unit PM10 Fees Constr.	Total Fees Per Unit Area+Op	Total Fees Per Unit Constr.	Total Fees Per Unit Admin	Total	Total Less Admin
100-Unit SF Res	2006	0%	0%	4%	$335	$957	$189	$64	$524	$1,021	$62	$1,607	$1,545
100-Unit SF Res	2007	0%	0%	4%	$483	$2,014	$364	$227	$846	$2,241	$124	$3,211	$3,088
100-Unit SF Res	2008	0%	0%	4%	$594	$3,110	$586	$558	$1,179	$3,668	$194	$5,041	$4,847
100-Unit SF Res	2009	0%	0%	4%	$693	$4,362	$732	$849	$1,425	$5,211	$265	$6,902	$6,637
100-Unit SF Res	2010	0%	0%	4%	$719	$4,831	$897	$1,218	$1,616	$6,049	$307	$7,971	$7,665
100-Unit HD SF Res	2006	0%	0%	4%	$301	$736	$188	$20	$489	$756	$50	$1,295	$1,245
100-Unit HD SF Res	2007	0%	0%	4%	$433	$1,546	$341	$65	$774	$1,611	$105	$2,491	$2,395
100-Unit HD SF Res	2008	0%	0%	4%	$533	$2,390	$514	$167	$1,047	$2,557	$143	$3,727	$3,584
100-Unit HD SF Res	2009	0%	0%	4%	$625	$3,373	$599	$207	$1,225	$3,580	$192	$4,997	$4,805
100-Unit HD SF Res	2010	0%	0%	4%	$649	$3,742	$679	$273	$1,328	$4,015	$214	$5,556	$5,343
100-Unit MF Res	2006	0%	0%	4%	$241	$282	$148	$64	$389	$346	$29	$765	$735
100-Unit MF Res	2007	0%	0%	4%	$345	$591	$285	$227	$630	$818	$58	$1,506	$1,448
100-Unit MF Res	2008	0%	0%	4%	$424	$914	$468	$558	$892	$1,472	$94	$2,457	$2,364
100-Unit MF Res	2009	0%	0%	4%	$498	$1,290	$577	$849	$1,075	$2,139	$129	$3,342	$3,214
100-Unit MF Res	2010	0%	0%	4%	$517	$1,429	$706	$1,218	$1,223	$2,647	$155	$4,025	$3,870
Resid Mix - 93% SF, 7% MF	2006	0%	0%	4%	$328	$911	$186	$64	$515	$975	$60	$1,550	$1,490
Resid Mix - 93% SF, 7% MF	2007	0%	0%	4%	$473	$1,917	$358	$227	$832	$2,144	$119	$3,095	$2,976
Resid Mix - 93% SF, 7% MF	2008	0%	0%	4%	$582	$2,960	$577	$558	$1,159	$3,518	$182	$4,864	$4,677
Resid Mix - 93% SF, 7% MF	2009	0%	0%	4%	$680	$4,152	$722	$849	$1,401	$5,001	$256	$6,659	$6,403
Resid Mix - 93% SF, 7% MF	2010	0%	0%	4%	$705	$4,598	$884	$1,218	$1,589	$5,817	$296	$7,702	$7,406

Calendar Year	Worst-Case Socio Report Resid Fees Res Fees ($/Unit)	One-Half Worst-Case Resid Fees Res Fees ($/Unit)
2006	$856	$428
2007	$1,409	$705
2008	$2,001	$1,001
2009	$2,459	$1,230
2010	$2,841	$1,421

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:
34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)
10% of residential units exempted from ISR rules under the 50-unit project threshold
SocioHalf source of estimated residential fees (SocioWC = SE report/worst-case; SocioHalf = SE report/one half worst-case; URBDft = URBEMIS Defaults; URBHD = URBEMIS High Density)

	SJV ISR Residential Revenue				**SJV ISR Revenue Needed to Achieve SIP Targets**				
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$428	$13,096,800	2006	0.0	1.2	$4,650	$2,907	$1,337,845
2007	30,600	$705	$21,557,700	2007	2.8	2.4	$7,100	$5,594	$10,198,671
2008	30,600	$1,001	$30,615,300	2008	4.0	3.5	$9,350	$9,011	$8,104,425
2009	30,600	$1,230	$37,622,700	2009	5.0	4.6	$11,900	$11,309	$9,295,883
2010	30,600	$1,421	$43,467,300	2010	5.8	5.7	$13,250	$13,950	$9,908,045
Cumulative Totals 2006 to 2010:			**$146,359,800**						$38,844,869
Relative Difference in Revenue: (Supplied vs. Demanded)						377%			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold
** Includes 5% "overhead" fee; 4% admin fee per Rule 3180, plus assumed 1% application fee

RESPONSE: The table provided above fails to include the average project life of the emission reduction projects that will be funded by the revenue collected. This results in severely understating the revenue required to purchase emission reductions. NOx projects have an average life of 7 years. PM10 projects have an average life of 12 years. The $/ton number in the fee formula is based on annualized cost divided by annual reductions. This allows for comparison of projects with different project lives. To arrive at the funding needed to achieve the SIP emission reduction commitment, multiply the annual reductions required times the cost per ton of each pollutant.

The District considers it inappropriate to base housing projections on 34,000 units per year. The SIP growth projections are derived from population projections provided by the Valley transportation planning agencies. If these record growth rates continue until 2010, the SIP emission budgets will need to be increased and additional reductions would be needed to achieve attainment on schedule. Rule 9510 would provide some of these additional reductions if growth exceeds predictions.

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:

34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)
10% of residential units exempted from ISR rules under the 50-unit project threshold
SocioWC source of estimated residential fees (SocioWC = SE report/worst-case, SocioHalf = SE report/one half worst-case, URECdt = URBEMIS Defaults, UREHD = URBEMIS High Density)

	SJV ISR Residential Revenue				**SJV ISR Revenue Needed to Achieve SIP Targets**				
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$856	**$26,193,600**	2005	0.0	1.2	$4,650	$2,907	**$1,317,813**
2007	30,600	$1,409	**$43,115,400**	2007	2.9	2.4	$7,100	$5,594	**$10,198,671**
2008	30,600	$2,001	**$61,230,600**	2008	4.0	3.5	$9,350	$9,011	**$8,104,425**
2009	30,600	$2,459	**$75,245,400**	2009	5.0	4.6	$11,800	$11,308	**$9,295,883**
2010	30,600	$2,841	**$86,934,600**	2010	5.8	5.7	$13,250	$13,850	**$9,908,945**
Cumulative Totals 2006 to 2010:			**$292,719,600**						**$38,844,869**
Relative Difference in Revenue: (Supplied vs. Demanded)						**754%**			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold
** Includes 5% "overhead" fee: 4% admin fee per Rule 3190, plus assumed 1% application fee

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:

34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)
10% of residential units exempted from ISR rules under the 50-unit project threshold
URBDlt source of estimated residential fees (SocioWC = SE report/worst-case, SocioHalf = SE report/one half worst-case, URBDlt = URBEMIS Defaults, URBHD = URBEMIS High Density)

	SJV ISR Residential Revenue				SJV ISR Revenue Needed to Achieve SIP Targets				
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$1,545	**$47,283,711**	2006	0.0	1.2	$4,650	$2,907	**$1,337,845**
2007	30,600	$3,088	**$94,481,494**	2007	2.8	2.4	$7,100	$5,594	**$10,198,671**
2008	30,600	$4,847	**$148,331,356**	2008	4.0	3.5	$9,350	$9,011	**$8,104,425**
2009	30,600	$6,637	**$203,082,914**	2009	5.0	4.6	$11,600	$11,309	**$9,295,883**
2010	30,600	$7,665	**$234,541,633**	2010	5.8	5.7	$13,250	$13,850	**$9,908,045**
Cumulative Totals 2006 to 2010:			**$727,721,108**						**$38,844,869**
Relative Difference in Revenue: (Supplied vs. Demanded)						**1873%**			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold
** Includes 5% "overhead" fee: 4% admin fee per Rule 3180, plus assumed 1% application fee

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:

34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)

10% of residential units exempted from ISR rules under the 50-unit project threshold

URBHD source of estimated residential fees (SocioWC = SE report/worst-case, SocioHalf = SE report/one half worst-case, URECdt = URBEMIS Defaults, URBHD = URBEMIS High Density)

	SJV ISR Residential Revenue				**SJV ISR Revenue Needed to Achieve SIP Targets**				
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$1,245	**$38,107,242**	2006	0.0	1.2	$4,650	$2,907	**$1,317,813**
2007	30,600	$2,385	**$72,991,721**	2007	2.9	2.4	$7,100	$5,594	**$10,198,671**
2008	30,600	$3,584	**$109,659,478**	2008	4.0	3.5	$9,350	$9,011	**$8,104,425**
2009	30,600	$4,805	**$147,021,892**	2009	5.0	4.6	$11,800	$11,308	**$9,295,883**
2010	30,600	$5,343	**$163,483,390**	2010	5.8	5.7	$13,250	$13,850	**$9,908,945**
Cumulative Totals 2006 to 2010:			**$531,263,724**						**$38,844,869**
Relative Difference in Revenue: (Supplied vs. Demanded)						**1368%**			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold

** Includes 5% "overhead" fee: 4% admin fee per Rule 3180, plus assumed 1% application fee

RESPONSE: The tables provided above are based on erroneous information and so should be disregarded.

PETROtech Environmental Solutions
Date: September 19, 2005

Good morning. It was good to see you at the Chamber of Commerce Meeting on Friday.

163. **COMMENT:** My comment regarding SJVUAPCD Rule 9510 is as follows: I would like to see Exemption Section 4.1.4 changed to read as follows:

"Oil EXPLORATION, Production and Processing"

The way the exemption reads now, only Production and Processing would be covered.

RESPONSE: The Rule will be amended to read "Oil Exploration, Production and Processing.**"**

164. **COMMENT:** I also have a comment regarding Air Quality Guidelines for General Plans. Seyed, until about 5-7 years ago, residential development was ongoing, but it was a fraction of what it is today. I will bet that very few folds from Bakersfield paid attention to them when they were drafted. If PETROtech hadn't started doing Air Quality Impact Assessments, I would have never thought about Rule 9510. But the concern that folds have is based on their fears that sometimes Guidelines, or suggested control measures become part of the requirements.

RESPONSE: Comment Noted.

The California League of Food Processors (CLFP)

Date: September 15, 2005

165. COMMENT: CLFP's primary concern is that it is not entirely clear how some of the provisions of Rule 9510 will apply to a range of manufacturing applications, and the potential compliance costs. Based on a review of the draft CLFP suggests that the District amend the proposed rule as follows:

1. Expand the list of exemptions to include food processing facilities. These facilities should be exempted for the following reasons:
    - A large portion of NOx emissions at most food processing plants can be attributed to stationary sources such as boilers or dryers, and most of this equipment is, or soon will be, subject to new emissions reduction regulations.
    - Forklifts, one of the most common vehicles used at processing facilities, will soon be subject to new emissions control regulations.
    - Unlike many manufacturing and commercial operations, most food processors operate on a seasonal basis, and some only operate for a few months per year. This significantly limits the total amount of employee and product delivery vehicle traffic on the site.
    - A number of the emissions mitigation options suggested by the District are not viable for many food processing facilities. Most processing plants are located in rural areas near where the crops are grown. Charging workers for parking or providing free bus passes to encourage the use of mass transit won't be effective if there is no mass transit available. Cannery workers cannot telecommute or teleconference to conduct their duties, and few may want to ride a bicycle home after working a shift in a factory. Options for creating mixed use facilities may be quite limited. In the case of food processors and many other manufacturers, locating new facilities based on reducing worker travel will imply hauling the raw product further, generating longer trips and additional diesel emissions. The economic viability of investing in some energy savings devices may be limited by the seasonal nature of the business. So, there may be a narrow range of cost effective mitigation measures available to food processors.

RESPONSE: The District will expand the definition to include food manufacturing.

166. COMMENT: 2. The District should clarify how baseline emissions will be calculated for manufacturing and industrial facilities.

RESPONSE: Manufacturing and industrial facilities whose primary function is regulated by the District will be exempt. For those industries subject to the rule such as warehouse distribution centers, only indirect and area source emissions

are used for the baseline calculation. A proposed new facility going through the CEQA process would prepare an air quality impact assessment. The assessment would include an URBEMIS run to quantify area source and mobile source emissions. The facility would concurrently apply to the District for an Authority to Construct for any stationary source equipment/devices subject to permitting. District staff would then estimate stationary emissions.

167. **COMMENT:** 3. The District should consider the impact of cumulative regulatory costs on industry. Many firms located in the San Joaquin Valley are currently expending substantial funds to comply with an array of new air and water quality environmental regulations. Rule 9510 will place an additional cost burden on industry which will have a direct effect on competitiveness in the global marketplace.

RESPONSE: The District recognizes the cumulative impact of air regulations on industry and the major investments made in stationary source emission controls in compliance with District rules and regulations and has provided exemptions for sources whose primary function is permitted by the District.

Manufacturers Council of the Central Valley
Date: September 15, 2005

On behalf of the Manufacturers Council of the Central Valley, I want to thank you for the opportunity to provide comments on the draft rule 9510 (Decreasing Emissions' Significant Impact from Growth and New Development – DESIGN) and Draft Rule 3180 of the San Joaquin Valley Unified Air Pollution Control District's Rule 4309. The Council represents a number of food processing and related companies in the San Joaquin Valley including several who will be impacted by this rule – some quite significantly and others, quite unexpectedly, unless there are major modifications prior to its adoption by the Governing Board later this year.

These comments are intended to augment those submitted earlier by Rob Neenan of the California League of Food Processors and which we fully support, but will not, in the interest of time, duplicate.

168. **COMMENT:** As I have communicated to you in a telephone conversation and at the public workshop, the MCCV is particularly concerned with the lack of clarity provided in section 4.1.4 concerning development projects whose primary source of emissions are from stationary sources which are subject to rule 2201 or Rule 2010. At the minimum we would like to see the list of industries expanded to include food processing related companies (including snack foods, candy, milk and cheese), corrugated box manufacturers, can manufacturers, and wineries.

However, even this is insufficient to adequately address the concerns unless a categorical exemption is provided for these industries because the first question

that will be asked is what is the definition of primary? And the subsequent question is how will this be determined? For new developments, this will be somewhat straightforward:

A) If stationary source emissions are projected to be greater than 50 percent of the construction emissions (as calculated by the yet undeveloped emissions calculator) plus the indirect emissions (as calculated by URBEMIS) then project is EXEMPT
B) If less than 50 percent then project is NOT EXEMPT

However, if the development project is an expansion of an existing facility in a jurisdiction which requires discretionary approval, due to its particular ordinance, how will the district review the project and calculate the emissions? What will be the baseline? Will only that portion of the project that is being expanded be subject to the rule? Or will that revert to the policy of the jurisdiction? There are a number of questions that arise and this just touches the surface.

RESPONSE: The rule has been revised to clarify the sources that will be exempt from the rule.

Western States Petroleum Association (WSPA)
Date: September 16, 2005

The Western States Petroleum Association (WSPA[1]) would like to take advantage of the brief opportunity made available by District staff for industry to provide comment on the June 30, 2005 draft of the proposed Rule 9510 (Decreasing Emissions' Significant Impact from Growth and New Development – DESIGN). Our comments on critical development issues related to the rule are attached. We look forward to discussing these issues with the District during future workshop sessions and if necessary providing additional comments should it prove necessary. Preparation of such comments is a crucial aspect of the Rule development process and as such, should be afforded sufficient time for a thorough review of the draft District document and preparation of meaningful comments.

169. COMMENT: I. Indirect Source Review and the SIP
In our July 22, 2005 comments, the Western States Petroleum Association (WSPA) requested that the District designate requirements derived from the proposed regulation as "not federally enforceable". WSPA cited the Federal Clean Air Act at Section 110(a)(5)(A)(i) and the California Health and Safety Code at Section 39602, which we believe support our request.

The Clean Air Act (CAA) at section 110(a)(5)(A)(i) states the following:

1 WSPA is a non-profit trade association representing a full spectrum of companies which explore for, produce, refine, transport, and market petroleum and petroleum products in the Western United States.

"Any state may include in a state implementation plan, but the administrator may not require as a condition of approval of such a plan under this section, any indirect source review program. The administrator may review and enforce as part of an applicable implementation plan an indirect source review program which a state chooses to adopt and submit as part of its plan."

The California Health and Safety Code at Section 39602 states the following:

"…the state implementation plan shall only include those provisions necessary to meet the requirements of the Clean Air Act."

We believe that these sections of the Federal Clean Air Act (CAA) and the California Health and Safety Code when considered together clearly preempt inclusion of indirect source review programs in the California state implementation plan.

The District's response to our comment is contained in Appendix-A of September 1, 2005 draft of the proposed regulation. The District contends that indirect source review programs are required by the CAA, since emission reductions are required to attain ambient air quality standards.

WSPA disagrees. The indirect source review program proposed by the District would be enforceable as a "state only" requirement. Emission reductions from the program would still occur and would reduce ambient concentrations to the same extent. The designation of indirect source review requirements as "federally enforceable" or "non-federally enforceable" has no effect on the attainment of air quality standards.

In California, inclusion of indirect source review programs in state implementation plan is prohibited by H&SC Section 39602 and the CAA section 110(a)(5)(A)(i). Consequently, WSPA requests the proposed regulation include a statement that Rule 9510 is a "state only" regulation.

We believe this to be a critical issue since federal requirements contained in applicable implementation plans must be included in Title V operating permits for major sources. Therefore, under the proposed regulation, mitigation contracts entered into by major stationary sources would require approval (or veto) by the U.S. EPA.

RESPONSE: The District disagrees with the interpretation of CAA sections cited in the comment. The intent of the section was to prohibit EPA from requiring indirect source programs as a Federal Implementation Plan (FIP) measure. Since the District requires the reductions for Rule 9510 to meet commitments in the PM10 Plan, the rule must be enforceable. The enforcement approach we

are proposing is not traditional since this program breaks new ground. The emission reduction projects are enforceable by the District through contract legal actions, but not EPA. If the reductions from the rule and its measures are not achieved, EPA enforcement should require the District to take corrective action to make up for the reductions in accordance with CAA milestone requirements. Since EPA is precluded from requiring the program, they would need to use alternative strategies in the event that a FIP were promulgated.

170. COMMENT: II Rule Applicability

A. Applicability Trigger Date.

In our July 22, 2005 comments WSPA proposed that applications for development projects filed prior to the rule adoption date be reviewed under existing regulations. We continue to believe these development projects should be reviewed under existing regulations. Under existing regulations, projects with significant environmental effects must include all feasible mitigation. The District is provided with notice and an opportunity for commenting on all such projects that are conducted within the San Joaquin Valley. Consequently, the District either has had or will have an opportunity to comment on these projects and to propose mitigation for indirect source and area source emissions. WSPA sees no reason why these projects should have to undergo a second round of regulatory review.

B. Indirect Source Review

As pointed out in our prior comments, Health and Safety Code Section 40717.5 sets forth guidelines and procedures that must be followed by any air district that proposes to adopt or amend a rule or regulation pursuant to Section 40716 or Section 40717.

The requirements contained in Section 40717.5(a) through 40717.5(c) are designed to ensure that emissions from indirect sources are properly allocated to projects that cause an increase in vehicular activity and to ensure that indirect source review requirements are not duplicative of other requirements imposed by the District or other agencies.

The draft version of District Rule does not comply with H&SC Section 40717.5(a)(1) which limits the applicability of indirect source review to those activities that contribute to, "…air pollution by generating vehicle trips that would otherwise not occur".

The District response to WSPA comments (Appendix-A, comment #24, #29) and to similar comments submitted by other was that:

"by their nature new development projects ultimately result in new trips which would not otherwise occur".

The District does not provide any information in support of this generalization and has not made any attempt to determine which types of activities result in an increase in indirect source emissions. In response to other comments the District acknowledges that the proposed rule is intended to control growth induced emissions from indirect sources and new construction (Appendix-A, comment #2, #8, #16). Not all development projects result in growth.

In our July 22, 2005 comments WSPA requested that Rule 9510 be revised to limit rule applicability to indirect source and area source emissions increases. We continue to believe that indirect source review programs established under authority at H&SC Section 40717 and Section 40715.5 are limited to regulation of growth induced indirect source and area source emissions.

WSPA believes that indirect source emissions and area source emissions that are already occurring, or area included in an application for a development project filed before the rule adoption date, should be considered existing emissions and only emissions increase above existing emissions should be subject to Rule 9510 applicability.

RESPONSE: The rule does not target *all* new development, but that development that results in the generation of at least 2 tons per year of NOx or PM10. Certain development, such as an expansion of a manufacturing facility, would be exempt if it does not result in and *increase* of at least 2 tons per year of NOx or PM10 through area and mobile emissions. Therefore, the rule accounts for the *increase* in pollution generation from development projects, and does not place requirements on those developments that do not result in the increase stated above. It is the District's position that projects that result in an increase in pollution emissions are a part of growth. It would be impractical to determine on a case-by-case basis if a project subject to the rule that emits emissions above the applicability threshold is or is not a project resulting from growth in the region.

In regards to projects that have filed for City/County permits *prior* to implementation of the rule, the rule language will be revised to limit the applicability to projects that have applied for a discretionary permit prior to implementation date but have not yet received approval.

171. COMMENT: C Proposed Revision to Applicability
In light of the guidelines specified in the California H&SC at Section 40717.5, and District response to comments, WSPA requests that the following subsection of the Rule Applicability Section 2.0, be revised as follows:

Subsection 2.1

2.1 This rule shall only apply to those elements of a project that require discretionary approval and only if those elements are determined to be part of a development project that meets the following conditions

a. The application for the development project is filed on or after the effective date of this rule.
b. The development project results in an increase in emissions of a pollutant for which the area is designated as nonattainment for either the California, primary ambient air quality standards (CAAQS) or the national, primary ambient air quality standards (NAAQS), for ozone or PM10.
c. The development project results in an increase in indirect source or area source emissions above previously approved existing emissions.

RESPONSE: Comment noted.

172. COMMENT: Subsection 2.1.3

Section 2.1.3 specifies an applicability threshold level of 25,000 square feet for the industrial space category. In our prior comments WSPA requested that the industrial space category be separated into "light Industrial" space and "heavy industrial" space since the vehicle trip ends (VTE) generated by these land use categories differ significantly. For example, according to the institute of Transportation Engineers, "Trip Generation Manual (7th Edition)" the light industrial land use category generates 6.97 VTE per 1,000 square feet. The "heavy industrial" land use category generates 1.5 VTE per 1,000 square feet. The District response to our prior comment was that:

"Most heavy industrial projects would be exempt from this rule, so distinguishing between the different types of industrial would not be productive." (sic)

The District fails to explain why heavy industrial sources would be exempt from the rule's requirements. Furthermore, the District is now proposing to apply the rule to uncategorized discretionary projects involving more than 9,000 square feet. WSPA is again requesting that the "industrial use" category be separated into "light industrial" and "heavy industrial" categories and that the applicability thresholds for these land use categories be established at 25,000ft^2 and 100,000ft^2 respectively.

RESPONSE: Comment noted. The applicability section of the draft rule will be revised to include 25,000 square feet of light industrial, and 100,000 square feet of heavy industrial.

173. COMMENT: Subsection 2.1.9

Delete subsection 2.1.9. The District has not documented why any discretionary project, not otherwise included in a section 2.1 land use category and that is

greater than 9,000 square feet (~1.4 acre) is automatically presumed to have significant indirect source or area source emissions.

RESPONSE: The District prepared emission estimates for all projects listed in the section to determine if they would exceed 2 tons per year of either PM10 or NOx. These projects would be required to prepare an air quality assessment based on their actual design, on-site measures, and characteristics, so in some cases the assessment would determine that no off-site fee is required.

174. COMMENT: Subsection 2.3.2

Delete Subsection 2.3.2. With the exception of the applicability threshold established for "50 residential units", Subsection 2.3.2 supersedes and essentially eliminates the other land use category size thresholds. It can be easily argued that any land use involving nonresidential development, (e.g. commercial, industrial, medial, etc) could accommodate development projects that emit more than 2.0 tons per year of NOx or PM10 (~11ld/day or 0.5 lb/hr).

The District is also proposing that the amount of required mitigation be based on the ability of the property to accommodate future development, whether or not such future development is planned or included as part of the development project responsible for triggering review under this rule.

WSPA believes that developers should not have to provide mitigation for unplanned projects solely because the property has the potential for future development. Future discretionary projects might or might not result in an increase in emissions of air contaminants. Consequently, we request that Subsection 2.3.2 be deleted.

RESPONSE: The rule requires the applicant to come to the District at the last discretionary approval for the project. For industrial and commercial projects this may be a conditional use permit or site plan review. If the use is not known, the general trip rate for the expected use is used to calculate the proposed fee amount. Then, the applicant can use a fee deferral schedule to allow time to identify the actual use. If there were no increase in actual emissions based on the use, the applicant could revise the air assessment and the off-site fee would be not need to be paid.

175. COMMENT: III Definitions

WSPA requests that the following revisions be made to the definitions. We believe the proposed changes will ensure that the definitions are consistent with the stated purpose and applicability of the proposed rule, and will help clarify rule requirements.

Subsection 3.7

In our July 22, 2005 comments WSPA requested that the definition of a development project be revised to exclude projects that require discretionary approval but are required solely to comply with a rule regulation or order of a public agency.

For example, District prohibitory rules frequently require that source operators install control equipment on emission units such as tanks, steam generators, turbines, etc. Installation of the control equipment requires the issuance of an Authority to Construct (ATC) permit which typically involves discretionary approval of an "emission control plan" and control equipment. Depending on the control measure, a source operator could be required to retrofit literally hundreds of individual emission units. The District response to our concerns is summarized below:

> *"The current definition of a development project adequately addresses projects that have ancillary discretionary approvals relating to the project. The applicability of the rule includes not only discretionary approvals but, minimum sizes of projects that must comply with the rule."*

WSPA is confused by the meaning of the first sentence. WSPA requests that the District provide additional explanation of how the current definition of a development project addresses "ancillary discretionary approvals relating to the project".

WSPA assumes that the language contained in the second sentence of the District response means that the District believes that equipment retrofit projects (e.g. steam generators, vapor control systems, etc) are too small to trigger rule applicability. In some cases this may be true. In other cases the size of the control system or facility equipment could easily exceed size threshold specified for industrial sources.

The existing New Source Review Rule (Rule 2201) and many of the prohibitory rules adopted by the District recognize the difference between projects initiated for development and projects undertaken to comply with regulatory requirements. Consequently, WSPA is again requesting that the definition of a development project be revised as follows;

3.7 Development Project: any project, or portion thereof , that is subject to a discretionary approval by a public agency, and will ultimately result in the construction or reconstruction of a building, facility or structure. The Discretionary approval of a project undertaken solely to comply with a rule regulation or order of a public agency shall not be considered a development project.

WSPA also requests that the District staff report clarify the meaning of the word "facility". The use of the word units current context is consistent with the logical meaning of the word and implies that the word "facility" means *"something that is installed or erected to serve a particular purpose".*

RESPONSE: The definition of a development project, in combination with the baseline definition ("area source and operational emissions") effectively eliminates the type of projects the author is commenting about. Permitted equipment emissions are *not* included in the calculations. It is the District's position that all applicable projects that have a baseline above two tons per year of NOx or PM10 from the combination of area and mobile sources should be subject to the emission reduction requirements of the rule, excepting for stated exemptions, regardless of the reason for the project.

176. COMMENT: IV Exemptions

WSPA requests that the exemption section of the rule be revised to include the following changes:

Section 4.1.4

The District has proposed an exemption for a, "development project, whose primary source of emissions are from stationary sources subject to Rule 2201 (New and Modified Stationary Source Review Rule) or Rule 2010 (permits required…". WSPA supports the proposed exemption. However, WSPA requests that the District clarify several items related to the exemption.

First, in response to questions raised by stakeholders during the September 1, 2005 workshop, District staff stated that they though the phrase "primary source of emissions: meant 51% or more of the emissions. Second, in our reading of the proposed exemption we interpret the phrase "stationary sources" to mean air pollutant emitting activities, other than indirect sources and area sources; and not "stationary source" as defined by District Rule 2201.

Assuming our interpretation is correct, then the proposed exemption would be available to development projects where operational emissions from activities other than indirect sources or area sources, comprise 51% or more of the total operating emissions from the development project.

WSPA requests that the District address these issues in their staff report and either confirm our understanding of how the exemption will be applied or provide additional guidance on how subsection 4.1.1 is to be interpreted.

RESPONSE: The District has clarified the exemption section to provide more specifics on the applicable sources that qualify.

177. COMMENT: V Application Requirements

WSPA continues to believe that applications for development projects be submitted to public agencies prior to the effective date of the proposed rule should continue to be processed under the regulations in effect at the time of application submittal. Consequently, we have requested revisions to the applicability section of the rule to be revised accordingly.

Subsection 5.5.5

Delete Subsection 5.5.5. This subsection requires that mitigation, monitoring and reporting programs (MMRP) include provisions for failure to comply, such as stop work authority, permit revocation, civil enforcement, and or administrative appeal. WSPA believes that this subsection should be deleted. The District already has authority to enforce compliance with rules and regulations adopted by the District.

RESPONSE: The District will revise the section to refer to Response to Comment 180, which states the District's authority to enforce provisions of the rule.

178. COMMENT: VI Mitigation

WSPA continues to believe that H&SC Section 477.16 and 47717.5 limit indirect source review programs to control growth induced emissions from indirect sources and area sources. Mitigation should only be required to the extent that a development project causes an increase in indirect emissions or an increase in area source emissions that would not otherwise occur. As we discussed in our prior (July 22, 2005) comments on Rule 9510, WSPA supports the District proposal to allow developers to use a combination of onsite mitigations and offsite mitigation. Developers should also be able to use offsite mitigation resulting from voluntary control of operational emissions from existing development projects upon showing that the emission reductions are surplus and enforceable.

In our July 22, 2005 comments WSPA requested that the District provide a mechanism to enable developers to receive credit for surplus mitigation. We also requested that developers be allowed to provide offsite mitigation by controlling emissions from existing sources through enforceable offsite mitigation programs. Our prior comments are summarized below.

1. For construction emissions, if a developer employs an offsite mitigation strategy, the emission reductions continue to exist after construction is completed. These reductions should be credited to the developer and the developer should be allowed to use the reductions for mitigating construction emissions from future development projects.
2. For operational emissions, developers should receive credit for offsite emission reductions created through voluntary mitigation activities applied ot

previously approved projects. For example, a developer could revegetate or reclaim disturbed surfaces in order to reduce fugitive dust. The developer could then commit these reductions to construction or operational emissions from proposed development projects.

The District response to our comments was:

"The District will consider offsite mitigation proposed by a developer on a case by case basis.".

Based on the District's response, WSPA requests that he District revise Subsection 6.3 as follows:

Subsection 6.3

The requirements listed in Section 6.1 and Section 6.2 above can be met through any combination of onsite or offsite mitigation. Developers may also satisfy the requirements of Section 6.1 and 6.2 by providing mitigation made available by reducing emissions from offsite activities. "the District will consider offsite mitigation proposed by a developer on a case by case basis."

RESPONSE: The District has partially addressed the authors concerns in the September 1, 2005 draft Rule 9510 version in section 7.4.

7.4 The developer shall receive credit for any off-site mitigation measures that have been completed and/or paid for, prior to the adoption of this rule, if the following conditions have been met:

7.4.1 The prior off-site mitigation measures were part of an air quality mitigation agreement with the APCO; or

7.4.2 The developer demonstrates to the satisfaction of the APCO that the off-site emission reduction measures result in real and surplus reduction in emissions**.**

The District will be implementing an off-site emission reduction program that uses fees from the rule to achieve the tonnage reduction required. The District believes that this is the most efficient and effective way to acquire, achieve and track off-site emission reductions. Off-site emission reduction projects that have been coordinated and approved through the District by means of an Air Quality Mitigation Agreement have been thoroughly analyzed and will be administered by the District. Therefore, emission reductions from Air Quality Mitigation Agreements are appropriate to use in the ISR program. However, although a project applicant may be able to find and fund off-site emission reduction projects, it is undesirable to have an applicant administer off-site emission reduction projects to be reviewed by the District on a case-by-case basis. For the purposes of consistency, efficiency, and enforceability, it is most appropriate for off-site emission reduction projects to be administered under the same program.

Applicants and the general public may propose projects for funding through the District's off-site emission reduction program, and the program will have annual review and reporting available to the public.

PUBLIC:

Ann M. Gallon
Date: September 6, 2005

I attended the Sept. 1 Workshop in Bakersfield. This was my first involvement with the Air Pollution Control District. I planned to address you as a private citizen, but all the developers with lengthy statements were a bit intimidating – especially their off screen head nodding and grimacing. They obviously were distressed to have any "controls" of their development projects come under discussion and regulation.

179. **COMMENT:** What I would have said is that I applaud your plans to contain pollution in our Valley, and I would urge you to stick to your guns – or even tighten up on some rules. As an aside, my stepson once sued the EPA on behalf of the Canadian people for not enforcing their own regulations and causing acid rain which drifted over Canada. The Canadian government prevailed in calling the EPA into action.

RESPONSE: Comment Noted.

180. **COMMENT:** Applicability to developers of 50-plus residential homes gives them wiggle room to design multiple projects so they could fall under that 50-unit threshold. Another concern of mine is that developers of fewer than 50 units may be less sophisticated in the industry and may create more pollution than you will prevent in the larger developments. I urge you to consider dropping the applicability to 25 units.

RESPONSE: The 50-unit applicability for residential units was specifically chosen for the following reasons:

1. Based on the District's data on the number and units of development occurring in the valley, a threshold of 50 units would capture the majority of the pollution generation from new developments while keeping the number of projects for District assessment at a practical level.
2. Modeling shows with no on-site measures, 50 units may generate approximately 2 tons per year of NOx in 2006
3. This threshold, with the associated 'penetration' of the rule, achieves the emission reductions committed to in the PM10 and ozone plans.

The District will be vigilant to prevent 'piecemealing' of projects to evade compliance with the rule. Rule 9510 §2.3.1 and §2.3.2 specifically address the issue of contiguous or adjacent properties. In addition, District Rule 1110 (Circumvention) states:

A person shall not build, erect, install, or use any source operation, the use of which, without resulting in a reduction in the total release of air

contaminants to the atmosphere, reduces, dilutes or **conceals an emission which would otherwise constitute a violation** of Division 26 of the Health and Safety Code of the State of California or **of these Rules and Regulations**. This rule shall not apply to cases in which the only violation involved is of Section 41700 of the Health and Safety Code of the State of California or of Rule 4102 (Nuisance of these Rules and Regulations. **Violation of this rule is a misdemeanor pursuant to the provisions of Section 42400 of the Health and Safety Code of the State of California**.
(Sections are bolded for emphasis)

181. COMMENT: To give you an example of development traffic, in July we endured seven days of 8am-4pm diesel truck traffic past our home. Trucks were hauling fill dirt to one large residential lot around the corner from us. The whole week we had to remember to close our front windows against the diesel fumes, noise, and dust clouds rising from dirt shoulders.

Mind you, this was a HOT July and we were trying to use just our evaporative cooler (needs open windows to vent) to save money. When the truck traffic continued into the next week I finally called our Supervisor's office to complain and ask if the trucks could travel on the arterial roads instead of on our residential street. I wrote down the following IN and OUT times one morning for 30 minutes:

IN	OUT
	9:35
9:39	9:41
9:44	9:48
9:51	10:01
9:58	10:09
10:05	

By Wednesday, when Supervisor Watson's field rep, Trice Harvey, arrived at our house to look into our complaint, wouldn't you know it – the truck traffic was over. And he said he couldn't tell trucks which roads to take to a construction site. We were going to be pretty much stuck with traffic when there is building going on in our area.

RESPONSE: The author's comments on truck traffic is noted. In addition, the District's Regulation VIII (Fugitive PM10 Prohibitions) contain prohibitions concerning the emissions of dust from construction sites, bulk materials hauling and carryout/trackout. Although these are requirements, certain developments on occasion do not comply with the rule. The District is responsible for enforcing compliance with the rules and employs field inspectors for these issues; however, it is not always possible to catch violations as they occur at the widely disbursed construction sites within the Valley. The District maintains a complaint

hotline for the public to call when they see a violation of the District's rules, including violations of Regulation VIII and Rule 4102 (Nuisance).

County of Residence	**Toll Free Number**
San Joaquin, Stanislaus, Merced	**(800) 281-7003**
Madera, Fresno, Kings	**(800) 870-1037**
Tulare, Valley portion of Kern	**(800) 926-5550**

182. **COMMENT:** So… please stand firm with the building industry – and with Cal Trans who seemed to think they were exempt from air pollution regs – and let's ask everyone to take their share of the responsibility for cleaning up OUR AIR.

RESPONSE: Comment Noted.

183. **COMMENT:** PS That argument of one man about mitigation fees of $2000 pricing thousands of people out of homes in California was statistical but not logical. If they can *only* qualify for a $300,000 home and the $2,000 fee is going to put them "out of the market," then they can just drop their expectations and builder options and by a home for $295,000. Also, it is bad financial planning to try to buy the most expensive house you can qualify for.

RESPONSE: Comment Noted.

ENVIRONMENTAL

Clean Water & Air Matter (CWAM)
Date: September 15, 2005

Thank you for the opportunity to comment on the above mentioned draft rules as proposed for the District. In addition to my verbal comments made during the September 1, 2005 workshop, I wanted to touch on the following topics.

184. COMMENT: No net gain does not equal a loss. When we begin to mitigate more pollution than we create while adding new pollutants, we will finally begin to achieve reductions in total pollutant levels. Until this happens, we are still adding to the pollutant total without ever actually subtracting anything.

RESPONSE: The author's comment does not hold when applied to mobile emissions. Emissions from mobile sources are reducing over time due to regulations on new vehicles. For example, no net increase in the number of vehicles would result in lower future emissions from vehicle turnover to cleaner fleets. The District takes this and other factors into account in the PM10 and Ozone attainment plans. The plans identify growth and reductions in source categories. The plans quantify the reduction from current District rules and proposed rules as well as state and federal regulations, and then model future emissions to determine if the District may reach attainment for applicable pollutants. For development projects, the 'subtracting' occurs through on-site and off-site emission reductions *and* mobile emission reductions over time. The PM10 and Ozone plans have determined that the ISR rule, in addition to existing and future rules and conditions, will help the Valley clean the air and reach attainment.

185. COMMENT: The Californian Environmental Quality Act (CEQA) is very clear when it comes to mitigation measures and how they must be available for public review before the decision makers (who also must have them for review) vote on the project. In reference to Section 5.0 Application Requirements it is imperative that the mitigation measures not be deferred until after project approval.

In Sundstrom v. County of Mendocino (1st Dist. 1988) 202 Cal. App. 3d 296 [248 Cal Rptr. 352] the court ruled that the deferral of an environmental assessment (in this case a hydrological study) until after the project approval violated CEQA's policy that impacts must be identified before project momentum reduces or eliminates the agency's flexibility to subsequently change it course of action. In addition, because the permit authorized the applicant himself, subject to planning staff approval, to conduct the required analysis, the county had violated CEQA's requirement that an agency's decisionmaking body must ultimately review and vouch for all environmental analysis mandated by CEQA. (202 Cal.App.3d at 306-308]

RESPONSE: Rule 9510 §5.0 has been revised to make application and review of ISR projects concurrent with or prior to the CEQA process a project would undertake with the local land use agency. It should be noted that the ISR program does not involve discretionary approval and therefore not itself a CEQA process. Additionally, compliance with District Rules is a *requirement,* not mitigation.

186. COMMENT: Furthermore, local agencies are instructed to integrate the CEQA review process into the other planning and environmental review procedures they are legally or otherwise obligated to conduct. To the maximum extent feasible, CEQA procedures and other procedures should run concurrently, rather than consecutively. (Pubic Resources Code Section 21003 subd. (a).) Regarding Comment #50- CEQA is a state law and does not vary by jurisdiction. This comment should be changed.

RESPONSE: Concerning timing of application to the ISR program, see the response to comment above. Although CEQA itself does not vary by jurisdiction, the implementation of the time requirements does. CEQA provides the master timeline in the framework of minimum and maximum times for various activities. Each jurisdiction has the authority to implement CEQA with procedures that reduce a particular activity's time to far below the maximum time allowed under CEQA. Therefore, each jurisdiction may have a different timeline for project review and approval based on individual procedures that comply with CEQA. The District will not change response to comment #49 from the June 30, 2005 workshop.

187. COMMENT: While there are exceptions, contextually, the agency is creating a broad, sweeping plan to cover many projects, including but not limited to, commercial, industrial and residential. Consideration of public involvement in the process would facilitate information regarding mitigation at the beginning of the process, rather than after the project has been approved.

This issue, when addressed early in the application process can carry over to all levels of approval, rather than have the public or decision makers continually have to request effective, enforceable mitigation as part of the project not only with the lead agency, but the responsible agency as well.

RESPONSE: While the District concurs that public involvement is important, and will amend the rule and staff report to include mechanisms for public involvement, the ISR program is *not* a CEQA process. ISR is a ministerial action not subject to CEQA, per PRC §21080 *Division Application to Discretionary*

Projects; Nonapplication; Negative Declarations; Environmental Impact Report Preparation (b)(1):

(b) This division does not apply to any of the following activities:
(1) Ministerial projects proposed to be carried out or approved by public agencies.

188. COMMENT: There should be some method for the dispersal of funds to account for project area pollutants and either the on-site or near-by mitigation funded by said project. Money going into the big pot in Fresno and ending up who knows where, by some group that has asked, will not address source point pollution.

RESPONSE: The District will track the location, by City and County, of the projects funded through the off-site emission reduction fund. The District will also complete annual reporting of how much, where and what tons of reductions occurred, which will be made available to the public. The District is unsure of the author's intent with the comment on point source pollution. This rule does not attempt to address emissions from source points. However, if an off-site emission reduction project is a point source, that information will be available in the District's annual reporting, and upon request.

189. COMMENT: Regarding the pollution prevention proposals, it would a be beneficial to have some long-term pollution reduction by means of phyto-remediation. Trees are known, quantifiable and effective pollution reduction technique. The use of trees should be encouraged to help cleanse the valley air. This mitigation could be achieved with tree farms using mitigation banking credits for a controlled system of distribution.

RESPONSE: The District is aware of the air quality benefits of trees. Specifically, trees reduce ambient temperature (reducing formation of ozone), cool housing and AC units (reduce energy consumption), cool cars and paving in parking lots (reduced evaporation of volatiles[6]). It is also known that some of these benefits are quantifiable. The District would entertain a tree program as an off-site project if it meets the requirements set forth in the rule, including cost effectiveness.

190. COMMENT: Enforcement of air quality mitigation measures is the responsibility of the District. I mention again in these comments a critical issue: Currently the district is notified of a project's start when there is a complaint filed by a member of the public. While this is not always the case, this type of complaint based enforcement system is inefficient as best and at worst, a heavy burden on the public to be responsible to see that the approved mitigation measures are actually followed or the best possible attempt to prevent more air pollution

6 McPherson, E. Gregory. Sacramento's parking lot shading ordinance: environmental and economic costs of compliance. Landscape and Urban Planning 57 (2001) 105-123

RESPONSE: The District is notified of the start of a project through several means. The CEQA process allows an opportunity for the District to review and comment on development projects within the Valley. The District also receives Dust Control Plans (DCP) and Notifications from project developers as a *requirement* of Regulation VIII (Fugitive PM10 Prohibitions). It should be noted that District rules are *requirements* and not mitigation, and the District has the authority to take enforcement action for non-compliant projects. The District is notified of Regulation VIII non-compliance through mandatory self-reporting (DCPs, etc.)

191. COMMENT: Additionally, it would be beneficial to both the public and all decision makers reviewing environmental air quality assessment to have the inputs for the baseline for the modeling runs at the beginning of the reports and if the report is quoted in the document, in the text of the document as well.

RESPONSE: The preparation of environmental CEQA documents is the responsibility of the lead agency. The District will make project specific information available to the lead agency and the public (See Response to Comments #8 and #59), but the District cannot prescribe a format that lead agencies must follow.

Kern-Kaweah Chapter of the Sierra Club
Date: September 15, 2005

Here are the comments of the Kern-Kaweah Chapter of the Sierra Club. Our chapter has 1,600 members and there are a few thousand other Sierra Club members in the San Joaquin Valley.

My copy of the September 1 draft is post marked August 26. Does the Air District Staff believe in summer vacation and Labor Day Weekend?

Instead of including our July 15, 2005 letter by reference, we put chunks of it in this letter and put the rest at the end of this letter.

GENERAL REMARKS ON THE RULE

192. **COMMENT:** At the September 1 workshop I learned that air quality regulations forbid the development industry from sheltering those of us with low or even moderate incomes. At previous workshops I learned that air quality regulations prevent farmers from feeding us and prevent various industries from affording to employ us. Perhaps the best plan is for residents to continue to suffer asthma and for those who die prematurely of heart or lung disease to be eulogized as "heroes of the economy".

RESPONSE: Comment Noted.

193. **COMMENT:** Our previous comments applauded 6.1 "The developer shall mitigate 100% of the construction emissions associated with its development project." Construction emissions do not last as long as operational emissions, but exposure to pollution is the same whether the pollution is from construction or from operation; thus, mitigation for construction emissions should be briefer and equally vigorous as construction from operation.

RESPONSE: The draft rule does not require 100% mitigation from construction. Rule 9510 Section 6.1.1 states that exhaust emissions must be reduced from the statewide average by 20% for NOx and by 45% for PM10.

194. **COMMENT:** We object to having developers choose consultants to prepare an Air Impact Assessment; we think consultants will not be chosen by developers unless they make findings as favorable to the developer as possible. The air impact assessment must be produced by the District or by a consultant of the District's choosing. Developers shall pay for the air impact assessment.

RESPONSE: The District will require all inputs and assumptions for the Air Impact Assessment, per the requirements of the rule. This information is contained in the application. The District will review the inputs, assumptions and modeling for accuracy, and will require additional information and/or revision for items that are inaccurate, inconsistent or unjustified. The modeling must be replicable and reasonable, and the emission reduction measures selected must be incorporated into the project and enforced through either other public agency requirements or by a District Monitoring and Reporting Schedule.

195. **COMMENT:** I did not find anything about mitigation by replacing inefficient equipment. Our July 18, 2005 letter said: "If existing equipment is replaced because it is worn out, no mitigation credits must be given unless the new equipment is better than other equipment that could be used. The mitigation credit must be limited to the difference in cost between the cheapest equipment that could have been obtained and the lower emitting equipment that was obtained."

RESPONSE: It is unclear if this comment pertains to on-site emission reduction or off-site emission reductions. For on-site emission reductions from construction, no justification is necessary to achieve credit for cleaner engines. For off-site emission reductions, the reductions will be achieved through the ISR off-site funding program, which will follow criteria and established emission reduction calculations. For programs that replace existing engines with new engines, the old engine must be operational and have a remaining useful life that is the basis of the emission reductions. How those emission reductions are calculated depends on the type of project and the specific components of the project. See the Staff Report and Appendix E – Cost Effectiveness Analysis for additional information on off-site emission reduction projects.

GENERAL REMARKS ON THE NOx REDUCTION OF THE RULE

196. COMMENT: Rule 9510 sets the goal of reducing emissions from projects that produce more than two tons per year of NOx by half. There is no justification for mitigating only 50% of emissions. Reducing NOx by half, rather than complete reduction, would be acceptable if all trips to or from the regulated development projects were to other projects that also reduced their NOx emissions by half. For the most part, rule 9510 regulates new development projects on the edge of town; most of the trips associated with those projects will be to or from long established business, recreational or work sites that have never paid any air quality mitigation fee and have no on site mitigation. If the trip to those sites had been made from an older development nearer the established sites, air emissions would be less. That is why the goal should be complete mitigation for all polluting emissions from all sources including Area Sources.

RESPONSE: The goal of the rule is to achieve an emission reduction from growth that was identified in the PM10 and ozone plans. The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. The rule sets levels that are in compliance with state law regarding indirect source regulations and are feasible to achieve. Charging a fee for trips that are the responsibility of another new source or an existing indirect source would not equitably distribute responsibility for existing and new vehicle trips as required by H&S 40717.5. The 33% accounts for declining mobile emissions over a ten year period – see the fee formula.

197. COMMENT: How much NOx will future vehicles make? When will increased gasoline prices cause us to use fewer light trucks and more efficient sedans? The staff report, bottom of page 3, says cars are predicted to decrease pollution between 1994 and 2003. Has this occurred?

RESPONSE: NOx emissions were reduced substantially between 1994 and 2003; however, certain heavy-duty diesel vehicles showed an increase during that period due to use of computer controls that enabled the vehicles to meet emission tests but emit at higher levels during actual operation. This problem has now been corrected. The amount of future NOx is identified in Attachment 2 of Appendix B – Emissions Reduction Analysis for Rule 9510 (ISR). Studies of the effects of gasoline prices indicate that very large price increases would be needed to significantly change travel behavior.

198. COMMENT: Here are examples where rule 9510 may cause someone to pay more than their share to mitigate air quality. Someone might move to a newly built home in order to take a job near that home; they would create emissions only when they drove to established business, recreational sites not I their new neighborhood or visited persons living a distance from their new home. A retired person who moved to a newly built home in order to be near the people they most often visit would generate fewer emissions than most of those who move to a newly built home. These exceptional cases do not seem to justify making this rule weaker or more complex.

RESPONSE: The District recognizes that there are a variety of factors that affect emissions from new projects. It is infeasible to model or account for all this variation at the development stage. In addition, there is no guarantee that those cases of less-emissions, same-house would occur over the ten years assessed by the rule, let alone the life of the project. The District considers the URBEMIS model to be the most accurate model available that meets the needs of the ISR rules. More information on URBEMIS may be found in the Staff Report and in Appendix D – Recommended Changes to URBEMIS.

APPENDIX A: RESPONSE TO COMMENTS

Industry and Public:

199. COMMENT: Comment 1 Each individual development must be held responsible for all the travel it generates. When persons move to the edge of town from a site closer to the center of town, their old home is occupied; the emissions of their old home do not change. The emissions of their new home must all be mitigated. Consider a mitigation fee for those who move into an existing home that is further from the center of the City than their previous home.

RESPONSE: The District agrees that each individual development should be responsible for the trips it generates, but also must consider that the reductions required must be fair and feasible. The District may consider a future rule revision or other program to address existing indirect sources.

200. **COMMENT:** Comment 7 If the emissions of a structure continue beyond ten years, so should the mitigations. Can the air district prove that cleaner cars will allow us to attain PM 10 and ozone standards in ten years and prevent increased emissions thereafter? What if attainment in does not permanently occur?

RESPONSE: The mobile source regulations currently in place and scheduled to go into effect in the next few years provide for a cleaner car and truck fleet well into the future even when accounting for projected growth in trips and vehicle miles traveled. Continued diligence will be required to ensure maintenance of the standards. This is accomplished through a maintenance plan that will provide the reductions needed to keep emissions from increasing due to growth.

201. **COMMENT:** Comments 11 and 18 Response 11 correctly anticipates new standards. Response 18 implies that PM 2.5 is not likely to be one of those new standards because attaining PM 10 standards will control PM 2.5. So far it looks like a lot of PM 10 is geologic particulates that are not as harmful as the smaller particles included in PM 10. The smaller particles, PM 2.5, are products of combustion or are a combination of ammonia and NOx. If so, decreasing PM 10 will not decrease PM 2.5.

RESPONSE: The rule is designed to reduce both fugitive dust PM10 and combustion PM10. Most engine replacement and retrofit projects provide NOx and PM10 benefits. Most of the combustion PM10 is comprised of the fine fraction less than 2.5 micrometers in diameter. The PM10 standard cannot be achieved without fugitive PM10 reductions and so must be part of this rule.

202. **COMMENT:** Comment 25 Some recreational space reduces motor vehicle use, such as a park that many persons can easily access on foot or by bicycle. Some recreational space increases motor vehicle use, such as a motocross facility or any facility that attracts visitors from a distance.

RESPONSE: Recreational uses that attract vehicle trips and exceed the operational threshold of 2 tons/year of NOx or PM10 will be subject to the rule. Uses that attract pedestrians or bicyclists would not trigger the rule.

203. **COMMENT:** Comments 67 and 70 The Socioeconomic impact of these rules must include the decrease in the cost of illness and death that this rule will cause. The cost of illness includes pain, suffering, premature loss of income, absence from school, absence from work and loss of companionship. To estimate the incidence of these events, please consult physicians who have reported such figures to CARB; for example, there are 106,695 workdays lost in Kern County due to PM10.

RESPONSE: See Response to Comment #98.

204. **COMMENT:** Comment 87 I do not bicycle on very hot days and most folks stay indoors those days. When I do bicycle on days of elevated ozone levels, I expose myself to ozone rather than use my car to raise ozone levels for everyone else. There are, or would be if bike paths are constructed, many persons as virtuous as I.

RESPONSE: Comment Noted.

205. **COMMENT:** Comment 96 Mitigating air pollution as close as reasonably possible to the source of the pollution may be more acceptable to the public than distant mitigation; however, insistence on mitigating in the immediate area can be used as a way to make mitigation more difficult.

RESPONSE: See Response to Comment #188.

206. **COMMENT:** Comment 98 Limiting mitigations to those that match the source of the mitigations can be used as a way to make mitigation more difficult. A ton of NOx generated by Valley traffic is the same as a ton of NOx mitigated by reducing Valley generation of electricity from fossil fuel.

RESPONSE: See Response to Comments #188.

207. **COMMENT:** Comment 102 As inflation and the completion of the most cost effective measures occur, how will mitigation fees be increased?

RESPONSE: Off-site fees are dictated by the amount it would take to offset a ton of the applicable pollutant. The District has included the fee schedules for 2006 through 2008. If an adjustment is required, for example, if during implementation the District finds that there aren't enough off-site projects achieve the set cost-effectiveness, the District can amend the cost-effectiveness schedule in the rule through a rule amendment. Rule amendment procedures are standard, and must be adopted by the Board.

EPA

208. **COMMENT:** Comment 7 p. A 25 Is EPA completely satisfied with this response to their thoughtful comment?

RESPONSE: See Response to Comment #5 for additional comments to the issue of surplus mitigation.

209. **COMMENT:** Comment 18 p. A 28 A high density residential project far from jobs, shopping, schools and other services does not decrease emissions except for trips between residents. A high density project that enables residents to

access jobs, shopping, schools and other services on foot, bus or bicycle decreases emissions and should get credit for on site mitigation.

RESPONSE: See Response to Comments #7 and #9 for discussion on URBEMIS on-site measure quantifications.

210. COMMENT: Comment 36 p. A 30 We are pleased that low-income housing is not exempt from the rule. Low-income housing often has elderly residents whose diseased lungs and hearts are especially susceptible to air pollution. Government can help pay the small cost of clean air for poor people if the voters wish.

RESPONSE: Comment noted.

Remarks On The Wording Of The Rule

211. COMMENT: 1.1
Does the reference to "particulate matter" include PM 2.5 and the smaller particles such as PM 0.1 that can be inhaled from ambient air into the blood stream? Comments 11 and 18 apply: Response 11 correctly anticipates new standards. Response 18 implies that PM 2.5 is not likely to be one of those new standards because attaining PM 10 standards will control PM 2.5. So far it looks like a lot of PM 10 is geologic particulates that are not as harmful as the smaller particles included in PM 10. The smaller particles, PM 2.5, are products of combustion or are a combination of ammonia and NOx. If so, decreasing PM 10 will not decrease PM 2.5.

RESPONSE: See Response to Comments #57 and #65 for the Districts response to which pollutants, and how much reduction was chosen.

212. COMMENT:2.1.8
Comment 25 applies: Some recreational space reduces motor vehicle use, such as a park that many persons can easily access on foot or by bicycle. Some recreational space increases motor vehicle use, such as a motocross facility or any facility that attracts visitors from a distance.

RESPONSE: The Air Quality Impact Assessment uses URBEMIS to calculate mobile source emissions from each project. URBEMIS uses trip generation rates for each type of use and allows for different trip rates to be used for different types of recreational facilities. This will allow for an accurate differentiation between the uses mentioned in the comment.

213. COMMENT: 2.3.1 & 2.3.2
We wish to thank whoever brought to your attention that the draft of 9510 dated June 30, 2005 did not address cumulative impact of adjacent development.

These paragraphs at least call our attention to this failing. As I understand 2.3.1 & 2.3.2, if I had one piece of land big enough to build 147 units, I could build 49 residential units that rule 9510 would not apply to. Then, in lieu of inheritance I could give each of my two children land so that they each build 49 residential units. We would thus build 147 residential units without having to comply with rule 9510. No one would ever know if I benefited financially from my children's property.

RESPONSE: See Response to Comment #214.

214. COMMENT: The only way I can write rule 9510 to avoid this problem and avoid high administrative cost is to say that even one house will be subject to this rule but that small tracts can pay a mitigation fee, rather than have their emissions determined and mitigated.

Our comments of July 18, 2005 on 2.2 and 4.2 of rule 9510 are included here:

The rule should apply to even the smallest projects so that developers do not piece meal. Building many little developments can have a major cumulative effect; CEQA has cumulative impact concerns. Among the 6 30 05 comments that supported not omitting projects that make only two tons of NOx and only two tons of PM 10 per year was one by a City of Clovis employee who forecast developments of 49 houses. Dr. Nipp has commented on over a dozen housing developments that somehow had just under ten tons per year of NOx and just under ten tons per year of ROG. Several years ago several natural gas 48 or 49 MW cogeneration power plants were built in Kern County; 50 MW plants had to be reviewed by the California Energy Commission.

These exemptions could also increase administrative costs and give some developers an advantage over others. What happens if soon after a new 20,000 square feet store is occupied, it fails or for some other reason becomes general office space? The store has paid a fee that it would not have paid if it had been built as general office space.

Please disregard our next paragraph of July 18, 2005; it is in error. It read: The rule could say that if a project is small, and no developer has enough land at the site to develop any other source of emissions small projects could be exempted.

RESPONSE: The District added rule language that prohibits piecemealing of projects to evade the applicability threshold. In addition, the District will implement procedures for identifying non-compliant projects and will have staff assigned to ensure compliance with the rule.

215. COMMENT: 3.22 & 3.23
In view of the decrease in emissions that will result from replacing some of our private auto travel with public transit, we might need to mitigate emissions form public transit construction less stringently than emissions from other construction. Since building new roads leads to more car and truck use, and therefore more pollution, road building emissions must be strictly mitigated.

RESPONSE: The District has determined that transit projects involving construction in excess of 2 tons total of NOx and PM10 combined should remain subject to the rule.

216. COMMENT: 4.1.4
Agriculture should be among these exemptions provided it is regulated under other rules as provided in the SB 700 series of bills.

RESPONSE: See Response to Comment #45.

217. COMMENT: 4.3
Transportation Projects should not be exempt from the requirements of the rule. If more roads, as opposed to mass transit, are made available, more people will use the roads rather than mass transit. This is called induced traffic. If bicycle paths and mass transit become available, some of us will choose to use them.

RESPONSE: The District specifically exempted transportation projects from the 'operational emission reduction requirements of the rule. Transportation projects are subject to the construction emission reduction requirements of the rule. Although not part of this rule, the District may consider including operational and area requirements in a future rule or rule amendment.

218. COMMENT: 5.0
CEQA provides that information such as provided by an AIA be available to the public and to decision makers before any discretionary action is approved. Please change the first sentence of 5.0 so that if complies with the CEQA.

RESPONSE: The District intends to submit air quality impact assessments to local agencies so that they may use them in their CEQA documents prepared for the land use approval. Although the rule provides analysis and emission reductions that will be useful in the CEQA process, the main focus of the rule is attainment of PM10 and ozone standards. (See Response to Comments #8 and #59). Also keep in mind, the ISR program is not discretionary approval and therefore *not* a CEQA process (See Response to Comment #187).

219. COMMENT: 5.1
Any consultant involved by any developer must be identified.

RESPONSE: The District will amend the rule language to include the above.

220. COMMENT: 5.4.1.1
Does this say that any mitigation required by laws existing before a development occurs can not be counted as an indirect source mitigation under rule 9510? We hope the answer to this question is "yes". The Air District intends to obtain agreed upon mitigations, as 5.5.6 shows.

RESPONSE: Any on-site measure that is quantifiable through the APCO approved model shall be counted towards on-site emission reduction. Only measures that do not have an enforcement mechanism through city/county or other requirements will be required to complete a monitoring and reporting schedule with the District.

221. COMMENT: 6.1.1
Are a 20% reduction in NOx emissions and a 45% reduction in PM10 emissions all developers are reasonably capable of, or is it just enough to attain a CAA standard deadline? Why does the Federal Clean Air Act allow areas like Bakersfield, that fail to attain daily 8 hour ozone standards on more days than any other place in the USA, to employ RACM, not BACM?

Does the Air District intend to wait for 2007 to complete a plan to attain federal 8-hour ozone standards? If so, how do you justify this to children who can not play outdoors when there is too much ozone in the air?

RESPONSE: The emission reduction requirements were based on the availability of new technology that can achieve the results allowing for a reasonable period of time for equipment owners to phase in the cleaner equipment considering the high cost of large construction equipment and its long useful life.

The District is working as rapidly as it can on 8-hour ozone planning. We are currently working with a Northern California 8-hour State Implementation Plan Working Group to coordinate the modeling and other efforts to get the plans out on time. The atmospheric modeling now beginning is needed to identify the reductions required. The District continually works to identify control measures that can be adopted to achieve reductions as early as possible. The District's goal is to complete the 8-hr plan in the spring of 2007.

Appendix C: On-Site Mitigation Checklist

222. **COMMENT:** Except for push mowers, this is identical to our July 18, 2005 letter. Local office holders must be tested on various parts of appendix C and recalled if they fail.

RESPONSE: Comment Noted.

223. **COMMENT:** 1 Bicycle Infrastructure:
Class II bike lanes on arterial/collector streets are more dangerous than class I.

RESPONSE: Comment noted. The corresponding URBEMIS mitigation component states "Percent of Arterials/Collectors with Bike Lanes: Or Where Suitable, Direct Parallel Routes Exist." 'Bike Lane' is the Class II category. 'Bike Path' is the more desirable Class I category. In addition, the District believes appropriate "complete street" planning adequately addresses the issue of safety.

224. **COMMENT:** 7 Pedestrian Oriented Infrastructure:
Place store entrances just off the sidewalk. Folks dislike walking across busy, un-shaded parking lots.

RESPONSE: The District will add the above to the items listed under "Pedestrian Oriented Infrastructure"

225. **COMMENT:** 16 Parking
Some employers offer employees about $40/month in lieu of free parking; employees who accept are left to choose among transit, bicycle, car pool, walking etc.

RESPONSE: This type of measure is appropriate for projects where the building tenant is known at the time the project review is accomplished. It could be included as an employer Transportation Demand Management Program. The emission reductions will depend on individual measures that the employer will implement and the pedestrian, bicycle, and transit service at the project site.

226. **COMMENT:** 25 Energy Efficiency
Provide space for outdoor passive solar clothes dryers, once known as wash lines and space for portable indoor drying racks.
Shaded, reflective or white roofs are not as good as the items you mention, but they are better than dark, unshaded roofs. Roof overhangs that shade windows in summer decrease heating costs.
Water heater should be located in most sinks so that a central hot water heater does not need to be turned on just to get hot water in one sink.
Provide fluorescent lighting, including compact bulbs.

If air conditioners, rather than swamp coolers, are insisted upon, they should be placed on the ground, north of the building, in the shade.

RESPONSE: The items listed above relate to the individual components that may increase energy efficiency. The On-Site Emission Reduction List contains the following measure:

> *Increase the building energy efficiency rating above what is required by Title 24 requirements. This can be accomplished by any combination of the following (this list should not be considered comprehensive):*

The list mentioned is an 'idea list' to inform the applicant of the variety of components that are available. The District will amend the list as additional energy-saving components are identified.

227. COMMENT: 47 Landscaping
At least let folks know push mowers are available at stores and they lower body weight.

RESPONSE: The District has a Public Information Department that has an excellent track record in getting the word out on the many options available for individuals to reduce their air impacts.

Appendix F: Socioeconomic Analysis

228. COMMENT: We agree that the affect of rule 9510 on home prices and rents will be small if the assumptions of the study by "Applied Development Economics" are made. We think that in general and in the Valley's housing market, supply and demand have a much greater effect on price than costs do; therefore we think the rule will have negligible effect on prices.

Our remarks on comments 67 and 70 above apply.

RESPONSE: Comment Noted.

229. COMMENT: If rule 9510 results in increased use of public transit, it will decreases the amount of money spent on gasoline. Sixty per cent of America's crude oil is imported. If residents divert money from partly imported gasoline to local products and to paying the wages of those employed by public transit, it will increase the gross domestic product of the Valley except for a decrease in money going to local oil drilling and refining. Would the net of this have a significant effect on Valley incomes? What if we decrease crude imports without decreasing local crude oil production?

RESPONSE: The District believes that although the implementation of Rule 9510 will have some economic impacts, it also will have a potentially significant beneficial economic effect on the San Joaquin Valley's economy through funding

off-site emission reduction projects. For example, a PM10 project may be paving unpaved roadways. This could result in an increase in jobs. However, the District does not speculate on the rule's potential secondary impact on the petroleum industry due to increase or decrease in fuel use.

230. COMMENT: If society desires a certain rate of home ownership among those with lower income, or otherwise wishes to increase the standard of living for those with lower income society can subsidize their mortgage payments, pay more for their work or tax them less and tax others more.

RESPONSE: Comment Noted.

Environmental Defense
Association of Irritated Residents
Steven and Michele Kirsch Foundation
Union of Concerned Scientists
Latino Issues Forum
Relational Culture Institute
Center for Energy Efficiency and Renewable Technologies
Fresno Metro Ministry
Natural Resources Defense Council
Merced/Mariposa County Asthma Coalition
Earthjustice
Date: September 14, 2005

We represent national, regional and local environmental, public health, and community organizations that are actively engaged in finding solutions to the San Joaquin Valley's air pollution. We have been closely following the district's development of DESIGN (Rule 9510) and the accompanying air impact assessment application fee (Rule 3180). We believe that together these rules have great potential for reducing and mitigating air pollution that accompanies growth in the Valley.

As noted in the comment letter many of us signed regarding the June 30 version of the draft rules, we believe the two rules have great potential for improving the quality of life for everyone in the Valley, and not just through the direct benefit of cleaner air. The two rules can increase opportunities and incentives for affordable housing located near jobs; reduce the climb in daily vehicle miles traveled; reduce traffic congestion and encourage viable transportation choices; protect agricultural lands from encroachment; and be the first words in a regional conversation about how to best accommodate growth without increasing pollution.

We believe that the September 1 version of the draft rule is an improvement over the June 30 draft. We are pleased that the latest draft has more detail. We also appreciate the district's effort to prevent gaming of the rule by ensuring that projects on contiguous

or adjacent property under common ownership of a single entity will be treated as one project. However, we believe that overall, the current version still falls short of ensuring that the DESIGN program meets its full potential to reduce air pollution.

We urge the district to consider the following comments and make appropriate changes to the September 1 draft rule before submitting it to the board for approval.

231. COMMENT: Section 2.0 Applicability. The thresholds for the size of developments covered by the rule are too high. The thresholds appear to be set to cover developments that would be expected to produce two or more tons per year of pollution. Neither the staff report nor the draft rule provides any strong logic for ignoring developments that produce less than 2 tons but at least 1 ton per year. Leaving tons on the table unnecessarily reduces the rule's effectiveness and eliminates cost-effective opportunities to protect public health. The thresholds should be set to cover developments that produce 1 ton or more per year.

RESPONSE: See Response to Comments #57 and #180 for the District's determination of the applicability level.

232. COMMENT: Section 3.5 Definition of Baseline Emissions. The wording for this definition needs to be clearer. The current wording leaves it unclear whether the first year of the project or any phase of the project is included in the baseline emissions. Additionally, as we discuss below, the emissions covered should include reactive organic gases.

RESPONSE: See Response to Comment #91.

233. COMMENT: Section 3.14.7 Definition of Recreational. The definition is too inclusive. It should be refined to ensure that facilities within this category generate similar levels of pollution. A community park, for instance, does not generate the same amount of pollution as a movie theater. Movie theaters and fitness clubs are probably more appropriately included in commercial categories.

RESPONSE: See Response to Comment #88.

234. COMMENT: Section 4.1.5 Housing Projects Exemption. This definition needs to be clearer. It appears that the district is interested in exempting housing that would qualify as affordable housing and that is receiving public funding to ensure its status as affordable housing. However, the definition as it now stands could be interpreted as offering a much broader exemption, and including any housing that receives federal- or state-backed loans. The definition should be more clearly and narrowly stated to reflect the district's intent.

RESPONSE: The District has eliminated this exemption in the proposed rule.

235. COMMENT: Section 5.3 Air Impact Assessment (AIA), Section 5.4 On-site Mitigation Checklist, Section 5.5 Mitigation Monitoring and Reporting Program (MMRP), and Section 5.6 Air Impact Mitigation Fee Deferral Schedule (FDS). The rule should overtly guarantee public access to documents and information required by these sections. While state law would allow public access, to ensure that access is available in a timely fashion, and not subject to delays resulting from the need to file public records act requests, the rule should specifically note that the district will make available to the public the application and information described in sections 5.3, 5.4, 5.5 and 5.6 within two weeks of the district's receipt and review of these documents.

RESPONSE: The ISR program will not be a discretionary program, and thus is not subject to the public review requirements of CEQA (See Response to Comment #187). The District will be including mechanisms for public agency and public review of certain ISR documents. See Response to Comment #8 for Public Agency access. See Response to Comment #59 for public access. See Response to Comments #178 and #188 for public access to the Off-Site Program.

236. COMMENT: Section 6.1 Construction Equipment Emissions. Construction equipment emissions reduction goals should be set as a minimum standard for individual vehicles, not as a fleet average. We applaud the district's inclusion in this draft of a section specifically requiring reductions in construction vehicle tailpipe pollution. Uncontrolled construction equipment represents some of the dirtiest and most health-threatening mobile emissions. However, the fleet average approach suggested in the draft rule fails to protect those working and living closest to, and therefore at most risk from, the emissions from individual pieces of the dirtiest uncontrolled equipment. We recommend requiring a minimum level of control for all construction equipment that limits emissions to those achieved by Tier 1 controlled construction equipment, in combination with a fleet average as described in the rule.

RESPONSE: The District does not have the authority to set emission standards for mobile sources. Please see Response to Comment # 6 for additional information.

237. COMMENT: Section 6.2 Operational and Area Source Emissions. The rule should fully mitigate the most health-threatening indirect source pollutants. We are pleased that the district has clarified that PM 2.5 will be included in the emissions controlled. However, we continue to believe that, like the June 30th version, the September 1 draft rule does not provide the level of health protection warranted. The rule addresses only oxides of nitrogen (NOx) and coarse and fine particulate matter (PM 10 and PM 2.5). It should also require mitigation of reactive organic gases (ROG), a precursor that leads to the

formation of ground-level ozone. Mobile sources account for almost 40% of ROG emissions in the San Joaquin Valley.

Additionally, the draft rule continues to call for reducing just a third of the NOx emissions and half of the operational PM 10 emissions over a ten-year period. This approach leaves the majority of pollutants produced by a new development unmitigated. The district staff has arrived at these discounts short of 100 percent mitigation to avoid double counting. It has thus assumed that every vehicle traveling to or from a new development is starting or ending the trip at another new development also covered by the rule. This is an unreasonable expectation.

At the very least, if the district believes it must discount mitigation levels to avoid double counting, it should arrive at the proposed discount in a logical, defensible fashion. The district should engage the URBEMIS update advisory group, composed of professional air regulators familiar with the model and the literature on land use and transportation, to define a reasonable and defensible default number for discounting trips to avoid double counting.

RESPONSE: See Response to Comments #57 and #65 for the District's response on the amount, pollutant type, and calculations for emission reductions. By ensuring that the program does not mitigate more than half the trips generated by the project, the District is ensuring compliance with the H&S Code that requires indirect source programs to differentiate between new and existing trips. URBEMIS accounts for all trips related to a development but does not differentiate between new and existing trips. When analyzing a project in an area that is planned but not built out, some of the trips will be going to new development that will also be subject to the rule in the future and other trips will be going to existing development not subject to the rule. Both types of trips should not be charged to the project being analyzed so that impacts are fairly allocated among all uses

238. COMMENT: Additionally, the mitigation requirement should extend beyond ten years. One need not look very far in California to see that most buildings continue to attract pollution-emitting traffic for much longer than ten years. The DESIGN rule should more faithfully reflect the real life of—and real life of emissions from—the development project. We suggest a minimum of 30 years, which assumes a development will last at least as long as a standard mortgage.

The rule should also recognize that developments have variations in emissions over their lives. This change reflects the changing demographics in housing developments over time, and the changing uses of buildings, including commercial and industrial buildings. The rule should include that variation in emissions modeling and the district should require a review of actual emissions from projects at least once every five years to ensure that the match between emissions and required mitigation is strong.

RESPONSE: See Response to Comment #198 for the District's response on variations.

239. COMMENT: Section 10.2 Administration of Mitigation Funds. Mitigation measures should be permanent. The district, in Section 10.2, the draft rule indicates that it will use mitigation fees to fund quantifiable, enforceable and surplus NOx and PM10 emissions from off-site mitigation projects. All mitigation, whether on-site or off-site, should be permanent as well.

Some mitigation measures, such as the incremental improvement from retrofitting a diesel truck engine, are not permanent. The incremental improvements last only as long as that retrofitted or replaced engine is in operation and go away once a newer, cleaner engine replaces that older engine. Yet the pollution those measures intend to mitigate do not change. Therefore, short-term mitigation measures should be sequenced with other mitigation measures, to ensure that mitigation lasts as long as the mitigated pollution does.

RESPONSE: The District disagrees with this commenter's characterization of permanent reductions. The key is that all equipment and vehicles wear out and must be replaced over time. If the old equipment is replaced at the end of its useful life with new equipment that is as clean or cleaner than the old equipment then the emissions continue at the same or lower rate and the reductions should be considered permanent. If the equipment were replaced with dirtier equipment at the end of its useful life, the reduction would not be permanent. The District uses project life estimates from the Carl Moyer program that are very conservative. For example, ag IC engines are allowed a project life of 7 years, but our experience in the grant program has shown that many engines are operated for 20 to 30 years.

240. COMMENT: The District Should Develop Long-Term Measures with Mitigation Funds, and Invite the Public to Participate.

The September 1 draft, like the earlier drafts, is vague and uncertain about how monies will be spent and leaves critical decision-making about spending the funds up to the air district. The district should use the Carl Moyer program as a model. Broad areas for expenditure are outlined in the statute establishing the Moyer program, and then the lead regulatory agency, after public workshops and hearings, adopts guidelines about the specifics of how the Moyer funds will be spent.

Mitigation funds collected from developers for off-site mitigation should help create and fund long-term air pollution mitigation measures. Improving transportation choices by investing in vanpool systems and providing incentives for affordable housing located near existing job sites are examples of just two

long-term measures. The district needs to engage the public, local government and other agencies to identify the best uses of mitigation funds to get these long-term emissions reductions. The rule should establish development of a public process and guidelines for determining the best uses of the mitigation funds.

RESPONSE: Long-term measures as described in the comment may be funded if they can meet the reductions are quantifiable and enforceable. There will be opportunities to add programs once the rule is adopted.

241. COMMENT: Include Discussion of Health Costs of Air Pollution**.**
In the staff draft report, in the draft rules, and in the socioeconomic analysis, there is no indication that air pollution costs money. There is no indication that the main purpose for this and every other rule adopted by the air district is to make the air healthier to breath. The air district staff, and by extension the air district board, does itself and the cause of clean air a disservice by continually ignoring this critical issue. Dirty air is costly. It impairs health and costs residents in time lost at work, in lost productivity, in lost days at school, in direct health care costs. It also costs crop damage and materials damage. More than a decade ago, researchers established that not meeting federal ambient air quality standards in the Los Angeles air basin costs that region at least $9 billion a year.

We continue to be disappointed by the district staff's refusal to note in its rule reports and socioeconomic analyses that air pollution has costs, especially health costs. We urge the district to use this rulemaking opportunity to bring to the public's attention the very real health costs associated with air pollution. Ample information is available from the California Air Resources Board and other state and national environmental agencies to help district staff provide sound information about the costs of air pollution.

RESPONSE: See Response to Comment #98.

242. COMMENT: Finally, we applaud the district for its decision to develop rules 9510 and 3180, and we appreciate the district staff's hard work on this rule. We hope to see another draft that incorporates the changes we have recommended. We also look forward to further discussions with the district about the rule as it moves forward.

RESPONSE: Comment Noted.

Yokuts Group, Sierra Club
Date: September 1, 2005

243. COMMENT: While I think several of the commentators today made the point, I, as a long-time low-income person, would like to tell your socioeconomic that, yes, a $100 increase in rent or mortgage, DOES make a difference. Obviously

he has never been in the position of not having enough money to pay all of his bills.

I'm not qualified to comment on the rest of the presentation, but that I do know about.

RESPONSE: The author's comment on the impacts of pricing on low income persons is well taken. It is important to point out that the rule exempts housing of less than 50 units; and it applies to only *new* housing developments. In addition, the impacts discussed in the Socioeconomic Analysis are the unlikely 'worst-case' scenario where all developments contain no sidewalks, all residential is built at 3-units per acre, there are no transit services, bike racks or any other measure that reduces emissions. The District believes that the exemptions and applicability stated above as well as the more likely, less-fee scenario reduce the impacts on housing affordability beyond that stated in the Socioeconomic Analysis.

244. COMMENT: And I would agree with Kathryn that the cost of *not* doing anything about pollution has to be spelled out. All too often only the costs of rectifying our past neglect are all we look at. That, actually is only relevant when comparing the benefits of several alternatives for cleaning our air.

RESPONSE: The District believes that rule by rule analysis of the health benefits of individual rules is not appropriate; however, the cumulative benefit of the District's attainment strategy on health is extremely important. The District will be revising the Staff Report to include discussion on health impacts as addressed in the PM10 and Ozone plans.

Late Comments

City of Manteca
October 7, 2005

245. COMMENT: The Manteca City Council recently adopted the attached Resolution opposing the adoption of Draft Rules 9510 and 3180. We are aware that we live in a non-attainment area. We are also in favor of lowering the amount of PM-10 and NOx emissions. However, before the assessment of additional fees occurs, a program needs to be presented that will show how the funds collected will be used to lower the emissions.

We will be happy to reconsider our actions when a positive plan has been presented.

RESPONSE: The District has provided a clear and positive plan for use of fees in Appendix E – Cost Effectiveness Analysis for Rule 9510. Detailed program guidance for new programs will be developed once the rule is adopted.

Resolution No R2005-446
A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF MANTECA OPPOSITION THE SAN JOAQUIN AIR POLLUTION CONTROL DISTRICT DRAFT RULES 9510 AND 3180

246. COMMENT: WHEREAS, the San Joaquin Valley Air Pollution Control District has proposed two potentially costly draft rules (9510 and 3180) that will impose new taxes and fees on every new office building, home, retail store, restaurant and other private development in the counties of Fresno, Madera, Merced, Kern, Kings, San Joaquin, Stanislaus and Tulare; and

RESPONSE: The Draft Rules 9510 and 3180 do not apply to all new development, nor does it place fees on all development. Please refer to Response to Comment #170. See also Response to Comments #46, #51, and #78, and #175.

247. COMMENT: WHEREAS, every Central Valley Resident will pay for these new air district taxes and fees, as business pass along their new costs through increased prices on goods and services; and

RESPONSE: Please refer to Response to Comments #89, #138, and #180.

248. COMMENT: WHEREAS, adding tens of millions in new taxes and fees every year will hamper the Valley's economic development and job-growth in a region that has among the highest unemployment rates in California; and

RESPONSE: Please refer to Response to Comment #137. See also Response to Comment #55 and #102.

249. COMMENT: WHEREAS, the air district taxes and fees will exacerbate the housing affordability problem in the Central Valley by adding more than $50 million in new costs each year to the construction of homes and apartments, driving up the cost of mortgages and rents and pricing thousands of families out of homes they can no longer afford; and

RESPONSE: Please refer to Response to Comment #137.

250. COMMENT: WHEREAS, the air district taxes and fees would fund the expansion of a bureaucracy that lacks accountability or any specific plan to improve air quality. The air district has failed to present a plan of what improvements to the region's air quality it will make with its new taxes and fees; and

RESPONSE: Please refer to Response to Comments #101, #104, #108, #113, #114, #115 and #137, and #188. Also refer to Rule 9510 Section 10.

251. COMMENT: WHEREAS, the air district has failed to provide scientific evidence to support the new taxes and fees it is proposing; and

RESPONSE: Please refer to Response to Comments #135. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards.

252. COMMENT: WHEREAS, the air district taxes and fees will interfere and conflict with local government land use authority by creating a new and competing review process, that will erode local control over land-use decision making; and

RESPONSE: Please refer to Response to Comments #8, #81, #133, and #140. . In addition, please refer to the Staff Report Section (B) *District Authority and Limitations*, and Section (D) *State Environmental Review – CEQA*

253. COMMENT: WHEREAS, the air district land-use power is redundant and conflicts with existing environmental rules and safeguards, such as the California Environmental Quality Act and existing air quality and environmental reviews.

RESPONSE: The District does not have land-use power, nor does it desire to usurp the local land-use authorities discretion on land use power. Please refer to Response to Comments #8, #81, #133 and #140. In addition, please refer to the Staff Report Section (B) *District Authority and Limitations*, and Section (D) *State Environmental Review – CEQA*

254. COMMENT: ***NOW, THEREFORE, BE IT RESOLVED*** that the City Council of the City of Manteca opposes the San Joaquin Valley Air Pollution Control District Draft Rules 9510 and 3180

RESPONSE: Opposition noted. The District notes that the substance of the letter is unsupported - see Response to Comments #245 to #253.

STOP the AIR BOARD TAX – We'll All Pay! (Coalition)

A.L. Gilbert Company.
African American Chamber of Commerce of San Joaquin County
Building Industry Association of Central California
Building Industry Association of the Delta
Building Industry Association of Kern County
Building Industry Association of San Joaquin Valley
Building Industry Association of Tulare and Kings Counties
Business, Industry & Government (BIG) Coalition of the South San Joaquin Valley
Cal Bennett's
California Black Chamber of Commerce
California Building Industry Association
California Business Properties Association
California Manufacturers & Technology Association
California Mexican American Chamber of Commerce
California Restaurant Association
California Retailers Association
California Senior Advocates League
California Taxpayers' Association
Central California Hispanic Chamber of Commerce
Constructing Industry Air Quality Coalition
Consulting Engineers and Land Surveyors of California
Consumers First, Inc
City of Avenal
City of Clovis
City of Escalon
City of Lodi
Coalinga Area Chamber of Commerce
Greater Bakersfield Chamber of Commerce

Greater Merced Chamber of Commerce
Howard Jarvis Taxpayers Association
J.F. Shea Co., Inc
KRC Safety
Kern County Farm Bureau
Kern County Hispanic Chamber of Commerce
Kern County Taxpayers Association
International Council of Shopping Centers
Lemke Construction
Lodi Association of REALTORS, Inc
Lodi Chamber of Commerce
Madera Hispanic Chamber of Commerce
Matthews Homes
National Association of Industrial and Office Properties – California Chapters
National Coalition of Hispanic Organizations
National Tax Limitation Committee
Orange Belt Board Realtors
Raymus Homes
Rainscape
Reason Foundation
San Joaquin Valley Black Chamber of Commerce
San Joaquin Chamber of Commerce
Scolari Tile & Co., Inc
Self-Help Enterprises
Sharp Insurance & Bonding
Small business Action Committee
The Hispanic Chamber of Commerce of Stanislaus County
Tulare and Kings Counties Builders Exchange
The Tulare/Kings Hispanic Chamber of Commerce
Tulare Chamber of Commerce
Tulare County Association of REALTORS
Tulare County Farm Bureau
Valley Taxpayer's Coalition
Valley Outdoor Advertising
Visalia Chamber of Commerce

255. COMMENT: On behalf of small business, labor, taxpayer, local government, community and other diverse organizations, we strongly oppose draft Rules 9510 and 3180. These measures will impose new taxes and fees on Central Valley residents, hurting our economic development and job-growth but offering no accountability and no guarantees of cleaner air.

RESPONSE: New Taxes: The Draft Rules 9510 and 3180 do not apply to all new development, nor does it place fees on all development. Please refer to

Response to Comment #170. See also Response to Comments #46, #51, and #78, and #175.

Hurt Economy: Thee is no factual evidence that implementation of the rules will hurt the economy. Please See the Staff Report and Appendix F – Socio Economic Impact Analysis for more information. Please refer to Response to Comment #137. See also Response to Comment #55 and #102.

Accountability: The authors' statement is untrue. Accountability is built into the rule. Refer to Rule 9510 Section 10. See also Response to Comments #101, #104, #108, #113, #114, #115 and #137, and #188.

256. COMMENT: The proposed rules will impose a slew of new taxes and fees that will apply to every newly constructed property – offices, homes, retail stores, restaurants and small or large businesses. Combined, these taxes and fees are expected to cost hundreds of millions of dollars over the next five years. This fee will price tens of thousands of families out of housing they can afford and worsen the housing crisis in the Central Valley.

RESPONSE: New Taxes: The Draft Rules 9510 and 3180 do not apply to all new development, nor does it place fees on all development. Please refer to Response to Comment #170. See also Response to Comments #46, #51, and #78, and #175.

Costs of Rule: The District analyzed the calculations that the BIA provided via Sierra Research, and concluded that the analysis was flawed and inaccurate. Please see Response to Comments #161 and #162.

Housing Impact: The Socioeconomic Impact Analysis did not find a significant impact to housing builders or housing buyers/renters. See the Staff Report and Appendix F for more information. In addition, please see Response to Comments #137, #41, and #53.

257. COMMENT: By imposing similar costs on new businesses, these measures will hamper the Valley's economic development and job-growth which will be particularly disastrous in a region that has among the highest unemployment rates in California.

Ultimately, these additional costs will be passed along to consumers, meaning we all pay.

RESPONSE: The District disagrees that the rule will hamper economic development in the Valley. Please see Response to Comment #55.

258. **COMMENT:** Most troubling is the fact that there are no accountability mechanisms built into the draft Rules and no guarantees that the funds will actually improve the air quality. The Air Board has failed to present a detailed list of the specific air-quality-improvement activities it intends to pursue and has failed to provide credible scientific support for the proposed rules.

RESPONSE: Accountability: The authors' statement is incorrect. Accountability is built into the rule. Refer to Rule 9510 Section 10. See also Response to Comments #101, #104, #108, #113, #114, #115 and #137, and #188.

Credible Scientific Support: Again, the authors' statement is not valid. The District has been developing the rule over several years, involving extensive research and documentation. Please refer to Response to Comments #135, the Staff Report, and associated Appendixes. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards.

259. **COMMENT:** Lastly, the new bureaucracy will interfere with local government land use decision-making by creating a new and unworkable process that erodes local control over land-use planning. This will stall much-needed new housing, businesses and other economic growth in our communities. For example, the draft Rules are redundant and even conflict with existing environmental rules and safeguards, such as the California Environmental quality Act and Existing air quality and environmental reviews

RESPONSE: First, 100% of off-site fees will be used for off-site emission reduction programs only. None of the off-site fees will be used for District administration or other uses. Second, the rules are not redundant, conflicting, unworkable, or otherwise interfere with the environmental review process, existing laws, or the land-use agencies' discretionary land use authority.

The District does not have land-use power, nor does it desire to usurp the local land-use authorities discretion on land use power. Please refer to Response to Comments #8, #81, #133 and #140. In addition, please refer to the Staff Report Section (B) *District Authority and Limitations*, and Section (D) *State Environmental Review – CEQA*

260. **COMMENT:** Draft Rules 9510 and 3180 are misguided solutions that will hurt every Central Valley Resident, potential new homeowners and renters and the

economic climate in the Central Valley. For these reasons we the undersigned oppose draft Rules 9510 and 3180 and urge your opposition as well.

RESPONSE: Opposition Noted. The District notes that the substance of the letter is unsupported – See Response to Comments #255 to #259 above.

Merced County Economic Development Corporation (MCEDCO)
Dated September 13, 2005
Received September 19, 2005

261. **COMMENT:** On behalf of the Merced County Economic Development Corporation (MCEDCO) we urge members of the San Joaquin Valley Air Pollution Control District (Air Board) to oppose draft Rules 9510 and 3180. The draft Rules will impose hundreds of millions in new fees on residential, commercial and business developments, discourage investments and job growth throughout the Central Valley and hinder affordable housing without any guarantee that they will directly improve the situation

RESPONSE: The factual evidence supports the District's position that the Draft Rules will have a less-than-significant effect on the housing market in the Valley, and a minimal effect on other land use projects. In addition, there is no supporting evidence that the rules would 'discourage investments and job growth'. Finally, there is solid scientific evidence that the rules will benefit the air quality of the valley. The District has been developing the rule over several years, involving extensive research and documentation. Please refer to Response to Comments #135, the Staff Report, and associated Appendixes. Accountability is built into the rule as draft Rule 9510 Section 10. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards. See also Response to Comment #55.

262. **COMMENT:** MCEDCO is a private/public nonprofit 501c4 organization that offers economic development expertise to the incorporated cities and unincorporated communities within Merced County. MCEDCO's primary mission is to promote and facilitate net, new employment growth, encourage increased corporate investment and assist in the diversification of the Merced County economy. MCEDCO focuses on retention and expansion of existing businesses, small business start-up, and recruitment of new enterprises

MCEDCO's efforts serve the entire community by encouraging new jobs opportunities for residents, increased sales and improved productivity for local business and new tax and fee revenues to support programs and services

offered by the cities and county. Without new business investment, employment growth is not realized and subsequently residential growth falters.

California is already recognized as a costly business location. Businesses frequently cite high fees and development expenses as a disincentive to new investment. The rising cost of property in tandem with additional fees and high operating costs jeopardizes potential wealth generation opportunities.

Environmental issues, in particular clean air for the Valley, are important matters to prospective business investors. However, MCEDCO is concerned that the draft Rules may not directly improve the situation and may deter residential and other construction that is often considered a primary trigger to economic development.

RESPONSE: The District recognizes the author's concerns. However, the District has provided detailed calculations of the emission reductions predicted by the rule as well as potential off-site emission reduction projects available, Appendix B and E respectively. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards. See also Response to Comment #55.

263. COMMENT: The draft Rules may also thwart affordable housing, a top priority in the Merced area given our ranking as the least affordable community in the nation. Balancing environmental concerns with affordable housing and new employment is a daunting challenge, not likely to be furthered by the draft Rules. Efforts to improve air quality are supported by the MCEDCO provided that said activities reflect a balanced approach with a clear plan for improvements.

RESPONSE: The District feels that it has met the criteria stated by the author. The draft ISR rules are part of a larger plan, the PM10 and ozone attainment plans, that identified emissions inventories for various activities and land uses, looked at the predicted growth, identified controls, modeled future air quality and determined a mix of actions that would reduce air pollutant emissions to bring the valley into attainment for PM10 and ozone. Part of this plan (also mandated by state law – SB 709) is to reduce emissions from indirect and area sources. As stated in Response to Comment # 17, the ISR development process has taken several years, multiple workshops, as well as working with the state-wide URBEMIS working group, careful analysis of existing regulations and programs. For more information, please see the Staff Report and associated Appendixes.

SUMMARY OF COMMENTS AND RESPONSES FROM THE PUBLIC WORKSHOP HELD ON JUNE 30, 2005

EPA: No comment received.

ARB: No comment received.

Industry and Public:

General Comments

1. **COMMENT:** The rule does not address the increase in trip length or vehicle trips resulting within the region from existing development.

RESPONSE: The purpose of the rule is to mitigate the emissions that result directly from new development. While the growth in the footprint of the region can result in increased travel, it is not practical to assign that growth to an individual development.

2. **COMMENT:** With new housing growing the housing inventory by at most 3% a year, we are therefore ignoring 97% of the homes and cars that create pollution. Our legislators have a responsibility to address the issue head on and not hide behind the pretense that burdening 3% of the households can mitigate the pollution of the other 97%.

RESPONSE: The District agrees that Rule 9510 does not address the emissions associated with existing residential, commercial, and industrial development. Given the requirements of the Health and Safety Code Section 40717.5, the District is precluded from regulating emissions resulting from existing trips associated with existing development. The purpose of the rule is to mitigate growth which is occurring at a rate of about 3% per year. In 10 years, the cumulative growth will constitute 30 percent of emissions. In other words, without growth at the projected rate, emissions would be 30 percent lower in 10 years.

3. **COMMENT:** Stakeholders are gravely concerned about the District's ability to take on these complex new tasks accordant workload.

RESPONSE: The District has a long history of analyzing the impact from new developments and suggesting appropriate mitigation. Additionally, the District has extensive experience operating incentive program to purchase off-site emissions reductions. In conjunction with the rule adoption the District will provide an assessment of workload and an appropriate staffing recommendation.

4. **COMMENT:** There needs to be protections built into the program for speedy processing of air quality assessments.

RESPONSE: The draft rule contains timelines for the District process applications. The District received a number of comments concerning how those timelines relate to the land-use approval process. The District will make every effort to ensure that the timelines in the rule do not unduly delay the land-use approval process. The rule allows developers to submit applications prior to beginning the CEQA process. For projects where the project description is not expected to change, all analysis and preliminary emissions estimates can be accomplished prior to the CEQA document being released for public review.

5. **COMMENT:** Why are only NOx and PM10 being addressed when CEQA requires all pollutants to be quantified and mitigated to the extent that they exceed thresholds?

RESPONSE: Rule 9510 is being developed to meet commitments that the District has made in the PM10 and Ozone attainment demonstration plans. The District has not committed to reductions of other pollutants in this rule. While the mitigation contained in the rule will help applicants comply with CEQA that is not the primary purpose of the rule. The revision to the GAMAQI document will outline how this rule will work under CEQA.

6. **COMMENT:** Not all of the classes of development projects identified in Section 2.2 are defined in Section 3.11.

RESPONSE: The District will make the appropriate changes ensure that there are no internal discrepancies in the rule.

7. **COMMENT:** Most buildings in the SJVAB last longer than ten years. The ten-year period should be expanded to at least thirty years, since that is the term of the standard mortgage.

RESPONSE: The District selected ten years based upon a number of factors. First, since the rule has been committed to attain the federal ozone and PM10 standards in 2010 the ten-year time frame is sufficient to get past the attainment deadlines and ensure that they last into the maintenance period. Also, utilizing a thirty-year time period would have a significant financial impact on the region.

8. **COMMENT:** What would happen if a change of use occurs and the previous use required fees that were already paid, and the actual use did not?

RESPONSE: The District is not proposing to re-assess a project at change of use. The program will only deal with new construction.

9. **COMMENT:** Better clarification of the definition of "baseline emissions" is needed.

RESPONSE: The District will ensure that the definition is clear.

10. **COMMENT:** Consultants should either be chosen by the District or the District itself should performed the Air Impact Assessment, so that consultants will be less likely to manipulate numbers.

RESPONSE: The District can ensure that air impact assessments are properly performed. This can be achieved with the District performing the analysis or with private consultants performing an analysis that is reviewed by the District.

11. **COMMENT:** Projected NOx emissions reductions exceed the 2010 SIP commitment. The reductions should stay in line with SIP commitments.

RESPONSE: The District has utilized the plan commitment as a guideline for rule development but the final emissions reductions will be governed by developing an effective rule. Final reductions from the rule will be within range of the SIP commitment. It is also important to achieve as many reductions as feasibly possible, since there are numerous new standards that the District will need to meet.

12. **COMMENT:** The inclusion of the proposed rule in the SIP is prohibited by the Health and Safety Code since this is voluntary compliance with the Clean Air Act and not required.

RESPONSE: The emissions reductions associated with the rule are required to achieve attainment of the federal ozone and PM10 standards and are therefore federally required and are commitments in two federally enforceable plans.

13. **COMMENT:** All requirements pertaining to indirect source review or derived there from should be designated as "not federally enforceable."

RESPONSE: See previous response.

14. **COMMENT:** The inclusion of the proposed rule in the SIP is prohibited by the Health and Safety Code since the authority for this rule is to attain a state, not federal, ambient air quality standard.

RESPONSE: The District is not aware of any such prohibitions since the emissions reductions associated with the rule are needed to attain the applicable National Ambient Air Quality Standards.

15. **COMMENT:** The definition of a development project should include the following additional language: The issuance of a permit for construction or reconstruction, where such permit is required solely to comply with a rule, regulation or order of a local agency shall not be considered to be a development project. The issuance of an operating permit shall not be considered a development project.

RESPONSE: The current definition of a development project adequately addresses projects that have ancillary discretionary approvals relating to the project. The applicability of the rule includes not only discretionary approvals, but also minimum sizes of projects that must comply with the rule.

16. **COMMENT:** It appears that the mitigation measure resulting from this rule are to be used to comply with mandates of attainment plans for ameliorating existing air pollution problems in the Valley. That is, the rule is not primarily intended to prevent new pollution from occurring, they are intended to address pollution that has occurred/is occurring from existing development. Case law in this area would indicate that new development should not be expected to remedy impacts created by previously approved and existing development.

RESPONSE: The purpose of the rule is to reduce the emissions impact from projected development in the San Joaquin Valley not existing development. The emissions inventory in the relevant PM10 and ozone plans contain estimates of emissions totals that include the growth in emissions. The emissions reductions commitment for this rule does not exceed the emissions projected for growth, and therefore only addresses the impact of new development.

17. **COMMENT:** It is unclear how the District will track the various developments and the various iterations of each approval.

RESPONSE: The District will work with local government agencies to ensure that appropriate tracking mechanisms are in place.

18. **COMMENT:** PM2.5 should be included as well.

RESPONSE: The definition for PM10 includes particulates less than 10 microns in size. By definition this would include PM2.5 emissions.

19. **COMMENT:** The rule should require that all NOx and PM emissions be mitigated.

RESPONSE: There are specific previsions of the Health and Safety Code that make it difficult to mitigate 100 percent of projects emissions without violating state law. Additionally, the District has committed to specific emissions reduction levels in the applicable ozone and PM10 plans. The District can achieve these reductions without requiring 100 percent mitigation from projects.

20. **COMMENT:** Discounting the trips at 50% is not defensible. The District should engage the URBEMIS group, composed of professional air regulators to define a reasonable and defensible default number for discounting trips.

RESPONSE: The purpose of discounting the trips by 50% is to ensure that the district does not charge fees on both ends of a trip. If the District did not discount the trips by 50% there is a very real possibility of charging both residential and commercial projects for the same trips, which could result in double counting.

21. **COMMENT:** The rule should recognize the variation in emissions over the life of the development. Therefore, the rule should include a review of actual emissions every five years to ensure that the match between the emissions and the required mitigation is strong.

RESPONSE: The URBEMIS model contains average assumptions for types of development projects. While there is some variation from project to project, and over the life of a project, the assumptions in the model are adequate when applied over a large number of projects.

Applicability

22. **COMMENT:** What was the basis for establishing the project build-out thresholds?

RESPONSE: The project build-out thresholds are based upon the emissions associated with those types of projects. The thresholds reflect 2 tons per year. By setting project build-out thresholds, the District can address the maximum amount of the emissions associated with new development while minimizing the administrative burden on small projects.

23. **COMMENT:** The rule should be set to cover developments that upon build-out create 1 ton or more per year of any pollutant. The size associated with each development project listed in section 2.2 would then be cut in half.

RESPONSE: See previous response.

24. **COMMENT:** The applicability section should include the following language: The increase in emissions from the development project result from an increase in vehicular activity that would not otherwise occur, or the increase in emissions from the development project results from new area sources, not previously authorized.

RESPONSE: By their nature new development projects ultimately result in new trips that would not otherwise occur.

25. **COMMENT:** Other land use categories should be added, such as recreational space and military bases, since these activities generate a significant number of vehicular trip ends.

RESPONSE: The District will add these categories.

26. **COMMENT:** The industrial space threshold should be replaced with light industrial space at 25,000 square feet and heavy industrial space at 100,000 square feet, since trip generation from these types of land use differ significantly.

RESPONSE: Most heavy industrial projects would be exempt from this rule, so distinguishing between the different types of industrial would not be productive.

29. **COMMENT:** The proposed rule does not comply with H&SC Section 40717.5(a)(1) which limits the applicability to activities that contribute to "…air pollution by generating vehicle trips that would not otherwise occur."

RESPONSE: By their nature new developments ultimately result in new trips that would not have otherwise occurred.

30. **COMMENT:** Under the proposed rule, the installation of equipment, wherein such installation requires a public agency "exercise judgment" in approving the permit, would make the project discretionary and subject to Rule 9510 even though the project might not result in vehicular activity.

RESPONSE: These projects would not be subject to the rule since the size of the equipment would be lower than the applicability thresholds of the rule.

31. **COMMENT:** 55,000 square feet of general office space is excessive.

RESPONSE: Comment noted.

32. **COMMENT:** The rule should not retroactively apply to permit applications filed prior to the effective date of the rule. This appears to defer or circumvent CEQA

analysis. The seriousness of the pollution problem in the SJVAB makes all information on air pollution and its mitigation extremely pertinent and necessary to consideration of development projects prior to project approval.

RESPONSE: The rule is not intended to replace the CEQA review for projects. The mitigation developed for a project through the CEQA process can be credited to the requirements of the rule.

33. **COMMENT:** The applicable square footage thresholds in section 2.2 are discriminatory in that "government space" thresholds are considerably less than non-government identified spaces.

RESPONSE: The applicable square footage thresholds are based upon emissions estimates for different land-use types. These estimates are influenced by a number of factors including trip generation rates that are specific to each land-use type. Government spaces tend to have higher trip rates, so a lower threshold for those spaces are warranted.

34. **COMMENT:** Will the rule as it relates to urban residential development be applicable to development proposed in the unincorporated areas of the county?

RESPONSE: The rule will apply to new development projects in the entire San Joaquin Valley Air Basin.

35. **COMMENT:** The definition of "discretionary" projects would be applied inconsistently throughout the SJVAB since different jurisdictions handle them differently. By defaulting to the jurisdictions' interpretation of the term, the District is allowing for the rule to be applied inconsistently.

RESPONSE: The District does not have the authority to change the local government process. Therefore the District is defaulting to the jurisdictions' interpretation, so as not to interfere with the local jurisdictions' land use authority.

36. **COMMENT:** A simplified and flexible approach should apply to all projects smaller than the exemption thresholds. Smaller projects should be exempt from the detailed analysis, but should still be required to implement all feasible onsite mitigation strategies and make a contribution to offsite mitigation.

RESPONSE: Projects that go through CEQA and have a significant impact are required to implement all feasible mitigation.

Exemptions

37. **COMMENT:** There should be a new exemption section added, section 4.3, which should include the following: Any project subject to federal Section 7 or Section 10 consultations with the United States Fish and Wildlife Services (USFWS) or a 2081 consultation with California Department of Fish and Game (CDFG), since these projects will require life of project mitigation.

RESPONSE: It is not understood how a project that is required to mitigate the life of the project for Fish and Wildlife, would mitigate their air impact. Therefore, this exemption will not be added.

38. **COMMENT:** Section 4.1.4 should read as follows: A development project where the emissions primarily result from direct sources or from emissions units as defined by Rule 2201 (New and Modified Stationary Source Review Rule); or projects subject to Rule 2010 (Permits Required). Examples of exempt sources can be expanded to include: Oil Production and Natural Gas Production, Refineries and Natural Gas Processing Plants, Waste Disposal and Waste Management Facilities, Mineral Extraction and Processing Plants.

RESPONSE: Comment noted, with the exception of waste facilities and mineral facilities. These types of facilities may include a significant traffic component, therefore they should be subject to the rule. The stationary source emissions associated with all facilities will not be included.

39. **COMMENT:** Section 4.1.4 needs to be modified to include gas plants, bulk loading terminals, and gas liquid processing plants.

RESPONSE: See previous response.

40. **COMMENT:** The 50 unit exemption is bound to result in “gaming” or several tract maps coming in at 49 units.

RESPONSE: The District will modify the rule to minimize the potential for circumventing the requirements of the rule.

41. **COMMENT:** The exemption for the applicability should be extended to the reconstruction of owner occupied low-income housing.

RESPONSE: Reconstruction of a single unit would be below the thresholds for rule applicability.

42. **COMMENT:** What is the rationale for exempting transit and transportation projects?

RESPONSE: The exemptions for transit and transportation projects were intended to be from the operational emissions portion of the rule. Since these

projects do not generate or attract trips it would not be appropriate to include these projects operational emission. There are significant emissions from the construction of these projects. The rule will be modified so that the construction requirements apply to transportation projects. Transit projects will continue to be exempt, since they are ultimately considered mitigation.

43. **COMMENT:** This rule is akin to the local conformity rule, Rule 9110 and overlaps with US EPA's General Conformity requirements of 40 CFR 51. In fact, the conformity rules are more stringent that this proposed rule. Sources subject to general conformity should be exempt from the rule.

RESPONSE: In some cases the general conformity rule is more stringent than the DESIGN rule. In those cases federal sources will be given credit for the efforts to meets conformity requirements. In other cases, federal sources are not required to mitigate their emissions if they are already included in the SIP. In those cases the DESIGN rule would be more stringent than the general conformity provisions.

44. **COMMENT:** The definition of projects subject to the rule does not address whether general, regional, community, or specific plan adoption would be considered "discretionary" projects subject to the rule. These plans and subsequent information for URBEMIS inputs are too general to furnish precise estimates of pollution as a result of those plans. Therefore, the consideration and adoption of specific plans should be exempt from the rule, unless the adopting land jurisdiction does, in fact, intend to issue development/construction permits pursuant to a specific plan without subsequent environmental analysis.

RESPONSE: As long as the general, regional, community, or specific plan are not the last discretionary approval of a project or portion of that project, the rule would not be applied to these approvals, but rather to the later more specific discretionary action for the project. If these plans were the last discretionary approval, perhaps the plan or CEQA document could contain a condition of approval or mitigation measure requiring the developer to provide an analysis to the District once the project design is finalized and prior to final ministerial site plan review or subdivision map or issuance of the building permit.

CEQA

45. **COMMENT:** The proposed rule does nothing to protect against CEQA lawsuits with respect to air quality mitigation.

RESPONSE: Due to limitations in state law, the District is unable to develop a rule that provides the same level of mitigation that some communities are seeking through the CEQA process. The District has established a program

through which project proponents can work with the District to fully mitigate their projects through CEQA.

46. **COMMENT:** There is a disconnect between the levels of significance in the Guidelines for Assessing and Mitigating Air Quality Impacts (GAMAQI) and the proposed rule.

RESPONSE: The purpose of the rule is to assist the District in attaining clean air standards. The rule is not intended to satisfy the requirements of CEQA. However, the GAMAQI will be revised to describe how compliance with this rule would affect CEQA.

47. **COMMENT:** What is the basis for the exemption of projects that have a mitigated baseline below two tons per year? Is this basis evidence that 10 projects in the same area producing less than two tons per year each are not cumulatively considerable under CEQA?

RESPONSE: The threshold was in part determined by selecting a level where reductions achieved would meet the commitments outlined in the PM10 and ozone plans. The revisions to the GAMAQI will outline the issue of cumulative impacts, in relation to this rule.

48. **COMMENT:** The District should include in this rulemaking, clear direction from the Governing Board to amend the GAMAQI, through a public hearing process, to formally adopt the concept of NOx mitigation over ten years in Air Quality Assessment methodology for CEQA documents. This would provide clear direction for the connection of this rule to CEQA and provide support for the Lead Agency in the current challenges to Air Assessment methodology in CEQA documents.

RESPONSE: The District will continue to improve its CEQA process to insure that appropriate analysis and mitigation are included for projects. Pending Governing Board adoption of this rule, the GAMAQI will be revised through a public process.

49. **COMMENT:** Please clarify why the District is not committed to amending the GAMAQI to define the exact role that this rule will have in the CEQA process, which would clearly provide relief for local government in CEQA litigation in a matter, air impacts, for which the District is the recognized expert.

RESPONSE: As was mentioned previously, the purpose of the rule is to achieve the emissions reductions necessary to attain the federal PM10 and ozone standards. The primary purpose of the rule is not CEQA compliance. However, the GAMAQI will be revised, and will provide clarification on how this rule works under CEQA.

50. **COMMENT:** The appropriate time for District analysis of projects under the rule would be during the early consultation process, before the overall environmental analysis of a project is completed and before the mitigation measures are approved for the project.

RESPONSE: Since the timelines for land use approval and CEQA vary greatly from jurisdiction to jurisdiction, the District cannot prescribe a timeline that will fit all jurisdictions. To that end, it is up to the developer to determine when would be the best time to approach the District. It is the District's preference that it is as early in the process as practicable so that the analysis and impact assessement could be completed prior to circulation of the CEQA document.

Regulatory Process

51. **COMMENT:** The best time to analyze and mitigate environmental impacts is at the comprehensive higher plan level. However, this rule discourages master planning in favor of piecemeal, small projects due to the liabilities stated for changes in design.

RESPONSE: The applicability of the rule at the last discretionary approval stage does not provide a disincentive to planning at a higher plan level. In fact, the opposite is true. Building in mitigation at the comprehensive plan level will assist in complying with the requirements of the rule.

52. **COMMENT:** The proposed rule creates a major burden for project applicants by imposing new requirements for preparation of detailed air quality studies.

RESPONSE: Many projects are already doing comprehensive analysis during the CEQA process. It is intended that the analyses and work for this rule provide a foundation for and/or complement the analyses required under CEQA. The District will work to provide tools and training to streamline the analysis process.

53. **COMMENT:** The mitigation agreement is wholly duplicative of the mitigation procedures set forth in CEQA, and will create chaos and confusion.

RESPONSE: Given that mitigation is consistent with the CEQA process it should not create chaos or confusion. The mitigation should in most cases be included as a mitigation measure in the CEQA document. Measures provided by the developer after the CEQA process is complete will require an agreement to ensure compliance.

54. **COMMENT:** The requirement for a new assessment based on changes to the construction schedule approaches absurdity with a master-planned community. How can one accurately predetermine market forces over a 20-year period?

RESPONSE: The fact that the rule is applied at the last discretionary approval of a project will mitigate the need to reanalyze projects. If a project is phased over an extremely long period of time it is appropriate to re-analyze the project if the schedule is significantly altered.

55. **COMMENT:** There is a conflict when the review of the Air Impact Assessment Application is to be done and when the review and assessment of the EIR must be accomplished.

RESPONSE: The District will not prescribe when the application is required. Therefore, it is likely that the same analysis could be used for both purposes.

56. **COMMENT:** The developer, who might be expected to pay for the mitigation fees in order to get land entitlements, may not be the same entity that purchases the project to eventually build the development. So if the latter decides to terminate the project and not build, there would be an administrative headache in terms of refunds.

RESPONSE: The District has offered the option for a fee deferral agreement that could defer the fees for projects that have an uncertain future.

57. **COMMENT:** The 30 day review process, plus the time necessary to process an application will significantly add to the development review time for a project's approval.

RESPONSE: The District has altered the timeframes in the rule to ensure that the rule will not result in unnecessary delays in the development process.

58. **COMMENT:** How would the rule apply to Master Plan Communities/Developments? Would each project in that plan need to be evaluated or just the plan? The difference in administration of the two options would be enormous.

RESPONSE: The rule requires the review at the last discretionary approval for a project.

59. **COMMENT:** The approval of the Air Impact Assessment should be done prior to CEQA hearings, and the details of the calculations should be made available to the public prior to those hearings.

RESPONSE: It is the District's intent to have the Air Impact Assessment available prior to the adoption of the project.

60. **COMMENT:** We request that the 30 day review period for determining an application complete be shortened to 10 days, since that is more in line with the 10 day review period for Initial Study consultation comments, and since URBEMIS analyses can be done within a matter of minutes, with the exception of EIRs since those can have a 30 day response time.

RESPONSE: Comment noted.

61. **COMMENT:** We request that the District forward a copy of the URBEMIS findings to the local jurisdictions for incorporation in their CEQA documentation prepared for projects.

RESPONSE: The District is willing to share information with local jurisdictions and in fact regularly comments on CEQA documents.

62. **COMMENT:** The rule proposes that cities and counties withhold building permits pending satisfaction of the District requirements.

RESPONSE: The rule does not include this provision.

63. **COMMENT:** The District should ensure timely public access to information used to calculate emissions. This would include publishing the information.

RESPONSE: The District will make all appropriate information available to the public.

Mitigation Fee Act

64. **COMMENT:** The draft rule fails to comply with the nexus test required by AB1600.

RESPONSE: The District has determined that this rule is not subject to AB 1600 (the Mitigation Fee Act) for two reasons. First, the District has no approval authority over development projects and, therefore, is not imposing a fee as a "condition of approval of a development project." Any fee will be assessed as a separate regulatory fee after the project has been approved by the local land use agency. Second, the Mitigation Fee Act applies only to fees assessed for the purpose of defraying the cost of "public facilities." The District does not believe that air pollution mitigation projects such as diesel engine retrofits are public facilities. However, notwithstanding the above, the District has met the "nexus" test under the Mitigation Fee Act or any other legal standard. New developments subject to the rule attract pollution caused by construction activities and vehicle traffic. The rule seeks to mitigate such pollution by allowing the developer to (1) include on-site mitigation measures in the design of the development that mitigate the types of air pollution caused; and/or (2) pay a fee

that will be used to fund emissions reduction projects, such as engine retrofits, that will mitigate the types of air pollution caused. Thus, the purpose of the fee and its uses are clear. In addition, there is clearly a reasonable relationship between new development and a fee imposed to mitigate the air pollution it causes. Finally, the fees will be reasonable in amount in that they will be directly tied to the cost of reducing the emissions caused by the development. The fee is established on a site-specific basis through URBEMIS modeling designed to determine the amounts and types of excess emissions caused by the development and then calculating the cost of reducing those emissions. URBEMIS is currently the best tool in existence for quantifying such emissions and has been used in similar contexts in the past. Thus, the fee meets all nexus requirements outlined in AB 1600.

65. **COMMENT:** The draft rule does not distinguish between the two-prong analytical paths in AB1600.

RESPONSE: See previous response.

66. **COMMENT:** The District has not circulated any documentation reflecting a nexus study.

RESPONSE: See previous response.

Socioeconomic Impact Analysis

67. **COMMENT:** The District has not released a socioeconomic impact analysis as required by the Health and Safety Code.

RESPONSE: The District will be distributing the socioeconomic impact analysis in conjunction with this draft of the rule.

68. **COMMENT:** The socioeconomic Impact analysis should demonstrate the impacts on the following: housing costs, rents, low-income families.

RESPONSE: Comment noted.

69. **COMMENT:** The socioeconomic Impact analysis should demonstrate the impacts of the processing, fee and mitigation proposals on new businesses.

RESPONSE: Comment noted.

70. **COMMENT:** The socioeconomic analysis should make a note of the overall costs to the public of air pollution.

RESPONSE: The District will include a general discussion of the impacts of air pollution on public health in the socioeconomic analysis.

URBEMIS

71. **COMMENT:** URBEMIS is a useful tool for calculating emissions only at the "sketch planning" level. It is not capable of evaluating specific design elements and operational measures, and accordingly, there is no way to do an accurate project-specific analysis of mitigation.

RESPONSE: The District does not agree. In fact, URBEMIS has been utilized to analyze the impact from projects through the CEQA process for years. The model has recently been updated based upon an extensive review of travel behavior studies to ensure that it provides proper credit for design features that are built into a project.

72. **COMMENT:** Please clarify how URBEMIS will be used in the process. Is the operating assumption that all discretionary development, regardless of its consistency with the general plan, is "new" for the purposes of modeling (i.e. additional development, and not replacing land uses/emissions already assumed within the model), or will the assessment be based on its placeholder land use?

RESPONSE: The analysis will be conducted at the last discretionary approval for a project regardless of whether the project is consistent with the existing general plan. If the general plan is the last discretionary approval for that particular land-use the district will analyze the land-use based upon the highest emitting use that could be built under that land-use category. The modeling would be based on approved land uses or those proposed in the case of a large plan area that contains the project being analyzed. This will enable credit to be taken for innovative community design and layout.

73. **COMMENT:** The URBEMIS fleet mix overstates residential emissions by roughly 50%. It is based on the statewide mix of vehicle types, which is comprises 3% of heavy-duty trucks.

RESPONSE: The District is working to ensure that the fleet mix assumptions in URBEMIS are appropriate for each land-use type. While the fleet average may somewhat overestimate emissions residential developments there are heavy duty truck emissions associated with them. These include school buses, refuse collection, package delivery, and other service vehicles.

74. **COMMENT:** The URBEMIS age distribution overstates residential project emissions. The defaults are based on the statewide mix of vehicle types, which are generally older than a new residential fleet. Vehicles, in new housing units that were 10 years or younger, had a 50/50% split on vehicles 5 years or

younger, and older than five years. Housing units older than 10 years had a 36/64% split. This problem cannot be easily revised within the current framework of URBEMIS.

RESPONSE: The District believes that the fleet average is a reasonable assumption for new development projects. There are a number of factors that impact emissions including age, vehicle class, and fleet turnover. If more specific information is available, the District would consider utilizing project specific numbers.

75. **COMMENT:** URBEMIS silt loading factors for entrained PM10 emissions overstate residential project emissions by nearly 50%.

RESPONSE: The District will ensure that the correct silt loading factors are utilized.

76. **COMMENT:** URBEMIS trip lengths are inconsistent with TPA model data and recent statewide travel surveys.

RESPONSE: The District will continue to update trip lengths with local data as the model is updated. Project proponents can utilize project specific information in lieu of the URBEMIS defaults.

77. **COMMENT:** URBEMIS default vehicle speed and estimated vehicle speeds vary by as much as 50-100% of survey data.

RESPONSE: The defaults for vehicle speeds may be modified if project specific information is available.

78. **COMMENT:** URBEMIS is not based on the most recent version of EMFAC in the Ozone SIP.

RESPONSE: As the URBEMIS model is updated it will be updated with the most recent version of EMFAC that is available. The District will ensure that emissions are credited to the Ozone SIP in the proper SIP currency.

79. **COMMENT:** Many commercial and industrial buildings are permitted and built, not knowing who the tenant will be in advance. How will URBEMIS estimate emissions for these types of development?

RESPONSE: In this case the analysis will assume the highest emitting use that would be allowed under the land-use designation.

Construction

80. **COMMENT:** Construction activities are not considered to be indirect sources.

RESPONSE: The purpose of the rule is to mitigate the emissions associated with new developments, not just indirect source emissions.

81. **COMMENT:** The rule overlaps and conflicts with existing District and ARB regulations that control emissions from construction activities and equipment, specifically Regulation VIII and the Dust Control Plan requirement.

RESPONSE: The District is proposing modifications to the rule that do not target dust emissions, but rather target mitigating emissions associated with the construction fleet.

82. **COMMENT:** There is no precedent in District or state regulations that require 100% mitigation of a particular source. 100% mitigation is not reasonable or feasible, as required by CEQA.

RESPONSE: Comment noted.

83. **COMMENT:** Regulation VIII should address more stringent controls on fugitive PM10 from construction activities and not an indirect source rule.

RESPONSE: Comment Noted.

84. **COMMENT:** The Regulation VIII list serve and mailing list should be notified of the rule.

RESPONSE: Comment noted.

On-site Mitigation

85. **COMMENT:** Reductions from many of the individual measures on the Mitigation Checklist are “off-model.”

RESPONSE: The rule includes the provisions that the APCO can approve alternative modeling methodologies. This would include approving appropriate “off-model” adjustments for mitigation that cannot be analyzed in URBEMIS. Many of the mitigation measures that are currently not included in URBEMIS have been removed from the checklist.

86. **COMMENT:** The Mitigation Checklist needs to be reviewed and modified with input from the development community.

RESPONSE: The District is happy to discuss the checklist with stakeholders.

87. **COMMENT:** Reduction measures such as requiring motorists to abandon vehicles in lieu of intermittent bus scheduling or biking on a 100 degree not appear capable of substantially reducing the amount of smog forming pollutants in our air.

RESPONSE: Any reduction in vehicle use would reduce emissions. URBEMIS accounts for differences in transit service and the quality of the road system to accommodate bicycling. The District is not requiring any on-site mitigation measures, but allowing them to be used. It is the discretion of the developer and the local jurisdiction to require those types of measures.

88. **COMMENT:** Most local jurisdictions are concerned about the mitigation measures being land use and urban design strategies, since these matters are not the District's province. By intending to consider and apply mitigation measures after all other analysis is done, it would appear that the rules would be positioning the District as the ultimate authority on land use and urban design.

RESPONSE: The mitigation measures in the checklist are voluntary. A developer can choose many measures, some measures, or no measures from the checklist. It is up to the local jurisdiction to approve of those measures, in regards to their land use authority. The District expects any design and infrastructure measures must comply with all local development standards and would be included in city/county approved plans and maps. The District has no authority to require that particular measures be included in the project.

89. **COMMENT:** If mixed uses or conjunctive residential and non-residential uses are considered to be a mitigation measure, how will the timing of construction be controlled, since commercial uses tend to postpone construction until the demographics can be analyzed?

RESPONSE: The project will be credited based upon the uses that are planned to be constructed. If the planned uses were changed that would be considered in a subsequent analysis.

90. **COMMENT:** Local land use jurisdictions should be made a party to any mitigation agreements entered with the developer.

RESPONSE: Comment noted.

Off-site Mitigation

91. **COMMENT:** The District has calculated that fees will escalate rapidly and allows for APCO adjustment based on actual costs. This fails the nexus test.

RESPONSE: The District has eliminated the option for APCO discretion to change the fee amount.

92. COMMENT: The District fails to state how the fees will be used.

RESPONSE: The fees will be utilized to purchase emissions reductions through the District's incentive programs.

93. COMMENT: The sequencing of payments does not fit the reality of permitting, financing, and constructing homes.

RESPONSE: The district has provided the option of paying the fees based upon the schedule in the rule, or through a fee deferral agreement with the District. The fee deferral agreement allows the flexibility to collect the fees based upon the project's unique financing situation.

94. COMMENT: The Mitigation Fee Act states that local agencies shall not require the payment of fees until the date of final inspection or the date of certificate of occupancy.

RESPONSE: See response to #64 above.

95. COMMENT: The fee formula needs to be simplified so that there is predictability and a lack of opportunity for controversy.

RESPONSE: The District will develop templates and/or calculators that will allow applicants to easily assess their projects and have predictable outcomes.

96. COMMENT: The impact revenue should be used, first and foremost, within the immediate area of the project that the fees are collected from.

RESPONSE: Fees collected from a project will be spent to mitigate the impacts associated with the particular development project.

97. COMMENT: The district should indicate whether increased district enforcement of existing regulations would be an eligible expenditure of mitigation fees. Air quality improvement would be expected given the responses from the District that its enforcement staff is very limited when apparent violations have been reported.

RESPONSE: The District is not proposing to utilize fees to increase enforcement staff other than staff to enforce the provisions of this rule.

98. **COMMENT:** The fees collected should be used on "traceable" mitigation measures (mitigation must be traced to the activity which the agency approves) as specified in CEQA. Since the proposed rule mainly targets vehicle traffic, traffic synchronization appears to be a logical solution.

RESPONSE: The District proposes to utilize funds for cost-effective emissions reduction projects. The District will track the emissions reductions achieved through the expenditure of fees generated by the rule. If an application for grant funds for traffic synchronization were submitted, the District would assess whether or not it could be funded based on cost-effectiveness and other criteria such as whether the reductions can be verified over time.

99. **COMMENT:** The APCD should develop a Regional Intelligent Transportation Authority (RITA) responsible for regional traffic synchronization, regional transit and intermodal planning, assisting cities with TCM implementation, and integrated collaboration with Caltrans. RITA should be funded by the rule and Section 40605(b) surcharge fees.

RESPONSE: The District will continue to assess opportunities, such as this suggestion, to utilize fees to achieve cost-effective emissions reductions.

100. **COMMENT:** The emissions reduction calculations for off-site mitigation need to calculate the benefit from a new piece of equipment to a less-emitting new piece of equipment.

RESPONSE: There are a variety of incentive programs that the fees can be utilized for. In some cases it is appropriate to compare a base new piece of equipment to less-emitting new piece of equipment. In other cases, where there is useful life left in a piece of equipment, and the equipment is taken out of service, it is appropriate to provide credit for emissions that are eliminated by retiring the old equipment.

101. **COMMENT:** Developers should receive credit for offsite emission reductions created through voluntary implementation of additional mitigation measures applied to previously approved projects. For example, a developer could revegetate or reclaim disturbed surfaces in order to reduce fugitive dust. The developer could then commit these reductions to construction or operational emissions from proposed development projects.

RESPONSE: The District will consider off-site mitigation proposed by a developer on a case-by-case basis. Any mitigation must be surplus and quantifiable.

102. **COMMENT:** We opposed the unilateral authorization to adjust the cost of controls. The APCO should be allowed to adjust the cost of reductions after

providing notice and an opportunity for public comment. We strongly believe that any increase in the mitigation fees should be subject to a cost effectiveness analysis and the approval of any fee increase should be subject to approval by the Governing Board.

RESPONSE: The District has eliminated the APCO discretion to modify fees.

103. **COMMENT:** It is a concern that the District intends to use these revenues primarily to fund existing programs and activities such as scrapping old vehicles and replacing lawnmowers, rather than to partner more closely with cities and counties to make alternative transportation more accessible and useful. The best use of the money would be to expand/create mass transit systems and alternative transportation routes in the Valley, and to fund measures that reduce traffic volume and relieve traffic congestion.

RESPONSE: The District will consider programs that achieve cost-effective emissions reductions.

104. **COMMENT:** The District should ensure that the off-site mitigation measures are permanent, as opposed to the short-term benefit of replacing engines. Examples include vanpool systems, incentives for locating affordable housing close to existing job sites.

RESPONSE: While the benefits from the District's incentive programs are credited for a short period of time, the actual reductions from the projects will continue. Additionally, the District has committed a specific tonnage requirement in the short-term to attain the ozone and PM10 attainment deadline of 2010. If the reductions were stretched over an extended period of time the District would not meet its plan goals, or attain the standards. It should also be noted that vanpool systems are currently eligible projects under the REMOVE II incentive program, and would be eligible for funds collected under this rule.

105. **COMMENT:** The District needs to engage the public, local government, and other agencies to identify the best uses of the funds, and establish a public process and guidelines for determining those best uses.

RESPONSE: Any new incentive program is subject to Governing Board approval, and thus it will be subject to public review.

106. **COMMENT:** Long-term reductions strategies may appear costly at first, but they can have the largest cumulative emissions avoidance benefits, making them cost effective in the long run. Not only will initial reductions occur, but they will have a self-perpetuating ripple effect of infill and/or redevelopment.

RESPONSE: Cost-effectiveness calculations used by the Moyer Program and the District account for the project life, so long lived projects with low annual reductions may have good cost-effectiveness compared to short lived projects with higher annual reductions. The proposed rule is primarily focused on existing incentive program projects, since they are already established and can demonstrate cost-effective reductions. Upon adoption of the rule, the District will take a closer look at other types of emission reduction projects, and develop incentive program and procedures for viable and cost-effective project types.

107. COMMENT: Similar to an investment portfolio, the District needs to identify a variety of short-, mid- and long-term off-site mitigation strategies.

RESPONSE: See previous response.

Rule 3180

108. COMMENT: If the air impact Assessment Application is done at the same time as the SJVAPCD review of the air impact in a CEQA document, the rule could be a source of funding for the SJVAPCD review of EIR documents.

RESPONSE: It may be possible that some projects that would have been reviewed under CEQA, would now be subject to this rule which requires a more comprehensive look at it. To that end, the District needs to recover any time and materials spent related to this rule.

109. COMMENT: The administrative fee should be reduced initially, and there should be a sunset clause on it once the basic fund is built up to the point that the interest revenue from the funds is sufficient to cover the cost of the program.

RESPONSE: The District will amend the portions of the rule, which is subject to a public review and adoption, if the need arises.

COMMENTS FROM FOCUSED WORKSHOPS HELD ON MARCH 11, 15, 24, 31, 2004

EPA:

1. **COMMENT:** The District should ensure that a "District approved model" is identified by name in the rule and that their use is appropriate based on consultation with EPA and other federal agencies.

   RESPONSE: The rule specifies the District approved model and allows additional models to be approved by the District.

2. **COMMENT:** Section 5.3.2.3 allows the use of the Institute of Transportation Engineers Trip Generation Manual. It is unclear whether this is the same manual that was developed by the Department of Transportation (DOT). We consider the trip generation rates in the DOT manual to be appropriate.

   RESPONSE: The Institute of Transportation Engineers Trip Generation Manual is used by the California Department of Transportation (DOT).

3. **COMMENT:** More specificity is needed for sections: 5.1, 5.3.1.1, 5.3.2.2-4, 5.3.3.6, 5.4.2-3, 5.5, and 5.7.2.2-3, 5.7.3.2

   RESPONSE: Comment noted.

4. **COMMENT:** Section 3.27 defines a "vested project," however; the rule does not specify the process by which a project will be designated as "vested." The rule should indicate what minimum components are required to become a "vested project."

   RESPONSE: "Vested projects" is a relatively standard development procedure in which the developer requests the applicable agency to vest his/her project. If a project is vested, it cannot be liable for future changes in regulations for that agency. In exchange for that status, the applicable agency may require other items or actions of the developer. The procedure for vesting status varies by jurisdiction. The current version of the rule should eliminate the need to specify that process, since vested projects will be treated the same as non vested projects.

5. **COMMENT:** Section 3.25 excludes developments where streets are a portion of the project from the definition of "transportation projects." Rule 9510 should not allow sources to receive credit for road paving associated with new developments, which it appears to allow by this definition and the exemption contained in Section 4.3. The rule should also define those developments where streets are a portion of the project.

RESPONSE: The definition of transportation projects has been modified to exclude projects where the traffic surfaces are a portion of the project. It would be virtually impossible to define developments where the traffic surfaces are a portion of the project, since most developments are designed to accommodate transportation. The emissions from constructing internal roads in a project are included in the construction emissions for the land use and are not considered a transportation project.

6. **COMMENT:** Section 5.5 would be clearer if it stated that the developer shall provide the project information "Upon final local agency discretionary approval."

RESPONSE: Comment noted.

7. **COMMENT:** The District needs to ensure that the level of mitigation that is required under Section 5.1 exceeds the level of mitigation already required under other rules and programs in place, specifically Regulation VIII.

RESPONSE: URBEMIS contains district-specific emission factors, and therefore only the portion of non-regulated emissions will be counted in the estimated project baseline total. The emissions totals contained in Appendix B already have Regulation VIII control subtracted from them.

8. **COMMENT:** In order to ensure consistency between the implementation of this rule and the transportation conformity activities of the MPOs, the District may want to work with these agencies on implementation procedures or additional rule language.

RESPONSE: The District will coordinate with the MPOs.

9. **COMMENT:** Rule 9510 should distinguish the various types of agencies and the various types of permits that would be subject to the rule.

RESPONSE: Many jurisdictions handle permits and projects differently. However, writing a prescriptive rule that identified every kind of project at varying stages of planning would be extremely difficult. To that end, the wording of the current rule meets our needs. If an individual agency had a question regarding their coverage by the rule, the District could make a determination.

10. **COMMENT:** Monitoring programs in Section 5.3.3.6 should be further described for clarity.

RESPONSE: Comment noted.

ARB: No comments.

INDUSTRY/PUBLIC:

Trips

1. **COMMENT:** The proposed program should only regulate new trips and not redirected trips.

RESPONSE: The proposed program has been designed to regulate new sources of emissions.

2. **COMMENT:** Double-counting trips will lead to overestimating and overcharging.

RESPONSE: The proposed program will not be double-counting trips and appropriate modifications have been made to prevent that.

3. **COMMENT:** Trip lengths in URBEMIS are not accurate.

RESPONSE: The trip lengths in URBEMIS are based on data submitted by the local transportation planning agencies. If project specific trip lengths are available, they should be used instead of URBEMIS defaults.

4. **COMMENT:** URBEMIS double-counts reductions from existing rules.

RESPONSE: URBEMIS contains district-specific emission factors, and therefore only the portion of non-regulated emissions will be counted in the estimated project baseline total.

5. **COMMENT:** There are emissions impact from mitigation measures, such as lighting, and increased energy use.

RESPONSE: Any emissions impact from this rule will be considered under CEQA. Emissions from power generation is small in comparison to emissions reduced from vehicles and combustion equipment used at the project site due to emission controls at the power plant and higher efficiency of electrical equipment such as electric lawnmowers.

6. **COMMENT:** There should be a de minimis level of new trips.

   RESPONSE: The rule sets an applicability threshold based upon the emissions from a project.

URBEMIS/Analysis

7. **COMMENT:** URBEMIS is not reliable for establishing a fee schedule.

   RESPONSE: The district maintains that URBEMIS is the right tool for this program. URBEMIS contains district and state specific emissions factors, and is the most widely-used air emissions model in the State of California, and many courts have made decisions based on its output. URBEMIS has also been updated to reflect the state-of-the-science on air mitigation measures.

8. **COMMENT:** Future changes to URBEMIS should be a public process.

   RESPONSE: URBEMIS is owned by all the air districts in the state of California, as well as ARB. The district does not have direct control over whether or not changes to URBEMIS should be public.

9. **COMMENT:** The option of another model should be given.

   RESPONSE: Comment noted.

10. **COMMENT:** Consultants should not be conducting an analysis of the development. There is opportunity for "tweaking" the numbers. It would be more efficient and consistent if the District were to do it.

    RESPONSE: There are adequate safeguards in place to ensure that the District can verify the work of applicant or the applicant's consultant. Each URBEMIS run creates a document that specifies any changes that were made to default values. The District can then verify any changes with the applicant or the applicant's consultant.

11. **COMMENT:** The District should use a checklist approach instead of an analysis approach, so that the process is streamlined and there is no fee.

    RESPONSE: Emissions reductions associated with each mitigation measure is dependant upon project specific variables, and therefore cannot be streamlined to a checklist approach.

12. **COMMENT:** There needs to be clear time limits on analyses conducted by the District.

RESPONSE: Comment noted.

13. **COMMENT:** The Expedited Review option sends a mixed message, almost a pay-to-pollute message.

RESPONSE: Comment noted.

14. **COMMENT:** Construction emissions should be addressed, since some projects can take up to 10 years to fully construct.

RESPONSE: Comment noted.

15. **COMMENT:** There should be an appeals section for all analyses.

RESPONSE: Comment noted.

On-Site Mitigation

16. **COMMENT:** The proposed rule would allow the District to indirectly regulate land use at the local level through its required on-site mitigation measures.

RESPONSE: The current draft of rule 9510 gives the developer the option of how to comply with the rule. If certain on-site mitigation measures, such as mixed use development, are not allowed in a jurisdiction, then the developer cannot use that measure. On-site mitigation measures are designed to give the developer the option to reduce the emissions on-site. The developer can choose from a broad range of on-site mitigation measures. Any on-site measures that reduce emissions will reduce the amount emissions that need to be mitigated through fees. This rule does not impinge upon local agency land use authority.

17. **COMMENT:** Some mitigation measures, such as traffic signals or sidewalks, are not put in place for 5-20 years.

RESPONSE: Traffic flow improvements, such as traffic signals, will not be used as a mitigation measure under this program. Sidewalks, if used as a mitigation measure, should be constructed prior to operation of the project.

18. **COMMENT:** Credit should be given for high-density residential projects.

RESPONSE: Comment noted.

19. **COMMENT:** Some of the on-site mitigation measures lack enforceability or may not work.

RESPONSE: The mitigation measures in URBEMIS have been revised to help alleviate that problem. Also, the current version of the rule requires developer and the district will enter into a mitigation agreement that will include provisions for enforcement, in the event that the local jurisdiction does not have enforcement mechanisms in place.

20. **COMMENT:** The fees from this program will overlap with traffic mitigation fees.

RESPONSE: Fees collected for traffic mitigation are primarily aimed alleviating congestion and/or fixing roads. While those items may have an incidental, temporary air benefit, this program intends to directly mitigate emissions from projects. If an activity is conducted or developed, or a mitigation measure is included for traffic mitigation, and it benefits air quality, the assessment/URBEMIS will quantify the air quality benefits.

21. **COMMENT:** There should be a list of mitigation measures so that developers can fast track the process.

RESPONSE: Comment noted. Please see Appendix C.

22. **COMMENT:** The effectiveness of the mitigation measures is unlikely given the climate of the SJVAB.

RESPONSE: The mitigation measures included in the new mitigation component of are based on the most recent research available.

23. **COMMENT:** The district should provide the control efficiencies of the proposed mitigation measures.

RESPONSE: The control efficiencies are contained in Appendix D of this staff report.

24. **COMMENT:** The list of mitigation measures should be open-ended, to allow for new and innovative measures.

RESPONSE: While the District would like to encourage new and innovative mitigation measures, each measure needs to have substantial evidence demonstrating the emissions are in fact reduce because of that measure. The District will consider giving credit to additional mitigation measures as they are proposed.

25. **COMMENT:** The 30-day review time period is excessive given the timelines required by CEQA. It should be 10 days.

RESPONSE: The District will streamline the process where possible**.**

26. **COMMENT:** Title 24 is already being implemented.

RESPONSE: The mitigation measure seeks to take credit for emissions reductions achieved by going above and beyond Title 24.

General

27. **COMMENT:** The program should regulate existing as well as new homebuyers.

RESPONSE: The District is precluded by the Health and Safety Code from charging fees to mitigate existing trips.

28. **COMMENT:** The District should consider an annual fee approach for residential sources.

RESPONSE: Due to provisions of the Health and Safety Code, this approach would be an excessive administrative and enforcement burden.

29. **COMMENT:** Indirect regulations are not the way to go.

RESPONSE: The concept of mitigating the indirect emissions from new development has a long history of being implemented through the California Environmental Quality Act. Likewise, the purpose of this program is to mitigate the impacts of new development.

30. **COMMENT:** Area sources do not generate new vehicle trips.

RESPONSE: The applicability has been changed to reflect new emissions.

31. **COMMENT:** Why is the District focusing on the cleanest developments in the air basin?

RESPONSE: New development is not necessarily the cleanest developments. Depending upon location of the new development, it could be responsible for more vehicle miles traveled and/or trips.

32. **COMMENT:** The District should form a technical advisory committee.

RESPONSE: Comment Noted.

Applicability

33. **COMMENT:** This program should include schools, regional parks, and churches.

RESPONSE: This program will include any new development that is estimated to emit equal to or more than the threshold where indirect sources are the primary source of emissions from the project.

34. **COMMENT:** The current wording of Section 2.0 would include projects that come to the District for an Authority to Construct. Is it the District's intent to include those projects?

RESPONSE: It was not the original intent. The exemptions have been expanded to exempt projects where stationary sources of emissions from a development are the primary source of emissions.

35. **COMMENT:** The current wording of Section 2.0 would exclude State projects, because they do not have to apply for or obtain development permits.

RESPONSE: The new wording should include state projects.

Exemptions

36. **COMMENT:** Low-income housing should not be exempt because 1) residents tend to drive older, more polluting vehicles, 2) there are higher concentrations of people, and 3) those residents can benefit from alternate forms of transportation.

RESPONSE: Comment noted. There is no exemption for low-income housing in the current version of the rule.

37. **COMMENT:** If there is not an exemption for low-income housing with a broader scope, many contractors will go out of business.

RESPONSE: Comment noted.

38. **COMMENT:** Structures that are required to obtain a Permit to Operate (PTO) should be exempt from the rule.

RESPONSE: See response to comment #34.

39. **COMMENT:** Infill projects, schools, public parks, and other public facilities should be exempt.

RESPONSE: See response to comment #33.

40. **COMMENT:** General plans, specific plans, and community plans should be exempt from the rule.

RESPONSE: The rule applies to the last discretionary approval for a project.

Nexus

41. **COMMENT:** The Nexus should identify the benefits of the program.

RESPONSE: As with all District rule, an analysis of the emissions reduction associated with the rule has been developed.

Misc.

42. **COMMENT:** The rule should not distinguish between ministerial and discretionary projects.

RESPONSE: Many jurisdictions handle discretionary and ministerial differently. However, writing a prescriptive rule that identified every kind of project at varying stages of planning would extremely difficult.

43. **COMMENT:** Local agencies may use the Mitigation Agreement as a tool to hinder mitigation for projects.

RESPONSE: Local agencies may disapprove of measures in a Mitigation Agreement due to health, safety, and welfare reasons. For example, if a bus bulb was desired, but the bulb interferes with a pedestrian element, it might be a legitimate cause for disapproval.

44. **COMMENT:** How will the Bakersfield Metropolitan Project be addressed?

RESPONSE: That project will be handled separately through a “task force.”

45. **COMMENT:** How will overlap with CEQA be handled?

RESPONSE: This rule may meet many of the air-related CEQA issues for development in this air basin. The Guidelines for Assessing and Mitigating the Air Quality Impacts (GAMAQI) document will be revised and adopted prior to implementation of the program, and will explicitly define how the district interprets this program in relation to CEQA.

46. **COMMENT:** The socioeconomic analysis should look at the per unit cost differential between a home built in a large residential development and a home built on a smaller development.

RESPONSE: Comment noted.

47. **COMMENT:** The socioeconomic analysis should consider the costs of health if the program was not implemented.

RESPONSE: The socioeconomic analysis is an analysis that is mandated by the Health and Safety Code. That portion of the cost does not require a health benefit analysis. That type of analysis is better handled at the plan stage when demonstrating attainment of a health based standard.

48. **COMMENT:** There should be a clause in the rule that protects developers from later changes of the rule, similar to the Safe Harbor clause in habitat regulations.

RESPONSE: Any potential changes to District rules go through a public process. Any discussion of exemptions to rules or changes to rules should be handled through that process.

49. **COMMENT:** There should not be an administrative fee as well.

RESPONSE: An administrative fee is imperative to recover the districts costs associated with administering this program.

50. **COMMENT:** There should be a broader spectrum of stakeholders involved.

RESPONSE: Notices are distributed via newspapers in all eight counties and published on the district's website. Whether or not portions of the public choose to become involved is up to them.

51. **COMMENT:** The draft rule is silent on enforcement mechanisms. How will this be enforced?

RESPONSE: Any on-site mitigation measures included in the design of the project will be identified in a mitigation checklist. Those measures that do not have an enforcement mechanism through the local agency will be subject to a mitigation agreement between the district and the developer. That agreement will identify those measures and their enforcement.

52. **COMMENT:** The proposed certified mitigation program to be administered by local agencies is impractical.

RESPONSE: Comment noted.

Off-Site Mitigation

53. **COMMENT:** Section 5.8 should allow local jurisdictions to use the fees collected because they may know of local opportunities.

RESPONSE: The District will consider local projects when allocating any fees collected through this program.

54. **COMMENT:** Section 5.8 needs to be more specific.

RESPONSE: Comment noted.

55. **COMMENT:** There should be an appeals section for the expenditure of fees.

RESPONSE: See response to comment #15.

56. **COMMENT:** A process for fee reimbursement should be provided if emissions reductions are not achieved.

RESPONSE: Comment noted.

57. **COMMENT:** There needs to be a mechanism in place to expand off-site projects.

RESPONSE: Comment noted.

58. **COMMENT:** Fee expenditures should be located in the jurisdiction of origination.

RESPONSE: Fee expenditures will be located in a manner that will mitigate the emissions impact from the project.

59. **COMMENT:** All fleets should have the opportunity to obtain grants.

RESPONSE: The district is currently drafting a fleet grant program. Any fleet that submits a cost-effect project consistent with the District's guidelines will be eligible to receive funds.

60. **COMMENT:** There should be an appeals section for all project types, not just the Complete Analysis.

RESPONSE: See response to comment #15.

61. **COMMENT:** The grant programs should focus on diesel and smoking vehicles.

RESPONSE: The grant programs will focus on getting the most cost effective emissions reduction.

62. **COMMENT:** There should not be a limitation on spending the fees on research.

RESPONSE: The district needs to obtain immediate and quantifiable emissions reduction. Research does not meet the district objectives for this program.

63. **COMMENT:** The fees should go towards traffic congestion mitigation.

RESPONSE: The purpose of the program is to mitigate the impacts of development on air quality. While traffic congestion may be a part of the air quality problem, there are already traffic congestion fees in some jurisdictions. Also, traffic congestion mitigation is a temporary fix to the air quality problem. Studies have shown that increasing traffic flow increases capacity, and more capacity attracts more traffic.

COMMENTS FROM SCOPING MEETINGS HELD ON OCTOBER 7 - 9, 2003

EPA: None received.

ARB: None received.

INDUSTRY:

1. COMMENT: Public input and oversight should be built into the process.

RESPONSE: The District intends to provide periodic reports to the District Governing Board that will be available to the public that will enable public oversight. The development of the indirect source rules will be conducted in an open public process that allows for public input at every stage.

2. COMMENT: The fee structure implemented should be a Mello-Roos based fee requiring an annual payment by the owner of record.

RESPONSE: The DESIGN program is designed to reduce the impact that new development has on the growth in emissions. The program gives credit to projects based upon design features that are incorporated into a project to reduce emissions. Any fees charged are utilized to make up the gap between mitigation measures incorporated in the project and a 50% reduction in emissions. This type of program would not be appropriate for a Mello-Roos based program.

3. COMMENT: This program should be handled similarly to that of the school district fees.

RESPONSE: The calculation and collection of school fees is relatively simple compared to calculating air quality impacts of the project. The proposed program gives the opportunity for a project applicant to incorporate design measures that could potentially reduce emissions over the life of that project. This means that each project may need its own determination of emissions after on-site mitigation have been accounted for to calculate the appropriate fee amount.

4. COMMENT: How will the indirect source fee's impact on air pollution be measured and monitored?

RESPONSE: Projects funded with indirect source fees will have annual reporting requirements that will demonstrate that the emissions claimed are being achieved. The District will physically inspect all projects to ensure that the project is accomplished as claimed by the applicant for the funds and will credit those reductions in the appropriate attainment plans and progress reports.

5. **COMMENT:** What provisions will be made for repealing the fee if it is enacted but is not effective at reducing air pollution from automobiles?

RESPONSE: The emission reductions achieved from any fee collected will be subject to reporting and monitoring requirements. All projects that are based on retrofit or replacement of old technology with new technology must use equipment/devices that are emission certified or verified by the California Air Resource Board (ARB) and so are proven effective. The District will consider a periodic review of the entire program to ensure that the anticipated emissions reductions have in fact occurred. District staff would then present the results of the review and a recommendation to the governing board.

6. **COMMENT:** An indirect source fee will act as a disincentive for homebuyers to help clean the air by purchasing a new home.

RESPONSE: The decision to purchase a new home is influenced by a number of factors. If a subdivision incorporates on-site mitigation measures that reduce trips and area source emissions, which would lessen the fee amount and add value to the development, there may be more of an incentive to purchase a new home.

7. **COMMENT:** If fees are to be charged based on automobile usage, all development, not just new development, should be charged.

RESPONSE: The purpose of the program is to reduce the emissions associated with new development. The District prefers a preventative approach. One of the key features of the DESIGN program is to incorporate mitigation measures on-site, which will reduce emissions over the life of the development. This is possible during the design of new projects. It would not be feasible to "retrofit" existing homes and development; accordingly, they would probably pay 100% of the fee amount.

8. **COMMENT:** Infill developments with special measures incorporated into their design should receive a credit from this program.

RESPONSE: The reductions achieved by the DESIGN program are a combination of on-site design elements and off-site emissions reductions that are achieved by buying emissions reductions with fees to make up any shortfall

in on-site mitigation. In-fill projects that incorporate design features that reduce the emissions associated with the project will be given credit for those reductions and will reduce their potential fee amount.

9. **COMMENT:** Fees should be roughly proportional to the number of trips generated by that land use, as directed by the U.S. Supreme Court in the case of Nollan v. California Coastal Commission (1987) and Dolan v. City of Tigard (1994).

RESPONSE: The District expects any fee collected under this rule to meet this condition. The fee formula is based upon the emissions associated with the project.

10. **COMMENT:** The District needs to demonstrate how assessing a fee on land development will mitigate air pollution from automobiles.

RESPONSE: The purpose of the program is to mitigate the emissions associated with new development through on-site mitigations and potential fees. The District will outline the Nexus between any potential fees charged and the projects that they are mitigating.

11. **COMMENT:** Fees should be collected no earlier than at the final inspection or certificate of occupancy and paid at close of escrow, when the calculated emissions would actually begin.

RESPONSE: The fees need to be collected early enough to achieve emissions reductions prior to occupancy. Collecting the fee at occupancy would not provide adequate time to achieve the necessary emissions reductions prior to occupancy. Additionally, not all local agencies within the SJVAB have a Certificate of Occupancy permit for all uses, which would make enforcement of proposed requirements difficult. The proposed Rule 3180 may include the option for a Fee Deferral Agreement, which will operate under the capabilities of the local agency involved.

12. **COMMENT:** Fees should be collected at close of escrow, so <u>all</u> homebuyers are charged. This will lower the fee and generate funding at a much quicker rate.

RESPONSE: Please see Response #7.

13. **COMMENT:** Funds generated should be restricted for use in the jurisdiction where they were generated and should be restricted to uses that relate directly to whichever land use is paying the fee.

RESPONSE: The District will utilize any fees collected to mitigation the impact of the emissions associated with the projects that paid the fees.

14. **COMMENT:** Funds should be collected by the local agency at the building permit stage, and that local agency should utilize the funds for emission reduction activities. The local agency would then provide periodic reports to the District.

RESPONSE: The District has over 10 years of experience managing projects that reduce emissions. Providing training and oversight to all jurisdictions within the SJVAB, to ensure proper use of the funds and track emissions reductions would be time-consuming. Also, the District wants to ensure that existing local agency funds are not replaced with indirect source funds to pay for a project that would have occurred anyways. In order to utilize the funds generated in the most efficient and consistent manner, the District has proposed to manage the funds collected.

15. **COMMENT:** Consideration should be given to projects with low-cost housing or in economically depressed areas.

RESPONSE: The District will consider potential exemptions during the rule development process. On-site measures that enable people to use alternatives to the automobile for their personal transportation needs are very important in low-income areas.

16. **COMMENT:** Several jurisdictions already have fees for the purpose of reducing traffic congestion and automobile emissions that it creates. There should not be another fee that accomplishes the same purpose.

RESPONSE: The District will calculate the benefit of mitigation that is included in the project. If existing fees result in real, quantifiable, surplus emissions reductions the District will credit those reductions to the project.

17. **COMMENT:** There may be some overlap with conformity analyses. This needs to be addressed.

RESPONSE: Emission reductions from the indirect source program are reflected in the motor vehicle conformity budgets in the PM10 Plan. When budgets are set for the next ozone plan, they will also reflect emission reduction estimates. Conformity analysis done for individual transportation projects could take into account changes in trip generation rates and VMT resulting from mitigation incorporated by new development when determining if the transportation project will result in a decrease or increase in emissions. However, the transportation models may not provide the level of detail that would enable the user to provide input for individual development projects.

18. **COMMENT:** How will final build out versus phasing be addressed?

RESPONSE: That issue will be discussed at length during the Administrative Procedures focused workshop.

19. **COMMENT:** The applicant should assume the responsibility of interacting with the District.

RESPONSE: The District has incorporated this suggestion into the rule language.

20. **COMMENT:** Fees collected through this program should not fund projects that would have otherwise occurred.

RESPONSE: The District agrees that these projects not be funded. The District will take suggestions on how to prevent that.

21. **COMMENT:** The computed fee should be increased by 25% or more to fund projects that would improve our air, instead of just offsetting emissions.

RESPONSE: The DESIGN Program is being developed to ensure that any fees will meet the nexus standard. Thus, the fee cannot be set "above" the anticipated emissions.

22. **COMMENT:** Double counting should be addressed.

RESPONSE: The District is limiting the mitigation associated with the project to 50% of the projects base year emissions. This eliminates any potential double counting.

23. **COMMENT:** Funds should not be spent on public education processes or research type activities, but on projects where emissions reductions are quantifiable.

RESPONSE: It is mandatory that all projects funded will result in real and quantifiable emissions reductions. The specific policies on how the funds will be spent will be included in the draft staff report at the final workshop.

24. **COMMENT:** A grant-like program could potentially result in large amounts of fees collected with no projects being implemented. An expenditure program managed by the District and/or the Councils of Governments (COGs) should be developed.

RESPONSE: The District is currently formulating how the funds will be spent.

25. **COMMENT:** The District should clearly explain the relationship between the reductions from this program to the CEQA threshold discussions in the District's Guide to Assessing and Mitigating Air Quality Impacts (GAMAQI). The GAMAQI should be used as an implementation tool for this rulemaking project and it should be updated to provide consistent direction on the preparation of environmental documents.

RESPONSE: The District will calculate emissions for each project based on mitigation measures included in the project. If a project has agreed to mitigation measures as part of CEQA, then those measures will be reflected in the emission calculation. It is anticipated that the GAMAQI will be revised after the rules are adopted to show the relationship between the rules and CEQA.

26. **COMMENT:** Construction emissions should be included in the emissions total, and hence, subject to a fee.

RESPONSE: The District intends to include mitigation for construction emissions in the formula.

27. **COMMENT:** It is likely that mitigation fees will be used to fund the most cost-effective projects first. Thus, as time goes on, costs associated with pollution reduction projects will probably rise. The schedule of fees should be subject to upwards revisions based on this contingency.

RESPONSE: The types of projects available for funding are not static. The District has analyzed the types of projects that it anticipates will be available in the near future and has adjusted the cost-effective factor appropriately for future years.

APPENDIX B

Emissions Reduction Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Indirect Source Review)

December 15, 2005

EMISSION REDUCTION ANALYSIS FOR RULE 9510 (Indirect Source Review)

I. INTRODUCTION

Both the 2003 PM10 Plan and the Extreme Ozone Attainment Demonstration Plan, contain emissions reduction commitments for proposed Rule 9510 of 4.1 tons per day of NOx and 5.2 tons per day of PM10 to be achieved by 2010. Those estimates were based on assumptions at the time and are commitments that are necessary to assist the district in meeting the federal and state PM10 and ozone standards. This appendix contains emissions and emissions reduction estimates that update those original estimates.

II. BASELINE EMISSIONS

A. Sources of Emissions from New Development

It is generally accepted in both air quality and transportation planning, as well as in case law that new emissions occur from new development. The construction of new structures is undertaken in order to accommodate the growth in population of a particular area. With the projected growth and development in the San Joaquin Valley Air Basin (SJVAB), there will also be a corresponding growth in emissions from energy usage, landscape maintenance equipment, wood combustion, motor vehicles, and entrained dust from paved and unpaved roads.

Energy Usage

Emissions associated with energy usage from new development primarily occur from two different sources, electricity generation and fuel combustion. NOx and PM10 emissions result from using space heating, water heating, cooking, and from other miscellaneous electrical appliances/equipment. ARB estimates fuel combustion emissions from natural gas, distillate oil or LPG, using EPA emission factors, and gas sales.[1] Emissions attributed to use of electricity generated at power plants are not easily quantified due to the variety of sources that supply electricity, which are located in and out of the basin and the state. Therefore, electrical generation emissions associated with new development will not be quantified or addressed for this program.

1 Air Resources Board, Emissions Inventory Procedural Manual, Vol. III, Methods for Assessing Area Source Emissions, October 1997 with revisions through November 1998, section 7.2-7.3.

Landscape maintenance equipment

Landscape maintenance equipment generates NOx and PM10 emissions from fuel combustion (gasoline, diesel, or LPG or CNG) and from evaporation of unused fuel. Equipment in this category can include leaf blowers, lawn mowers, trimmers, edgers, chainsaws, chippers, etc. ARB uses the OFF-ROAD model to estimate PM10 and NOx emissions using population, activity duration, and emission factors.[2] URBEMIS uses OFF-ROAD results and quantifies emissions by the number of homes and business units.[3] Based on District analysis, the growth in NOx and PM10 emissions from residential landscape maintenance equipment is relatively small, 15 tons per year, despite a projected increase of nearly 1.8 million pieces of residential landscape equipment in the SJVAB. The primary reason for the small emissions increase is that the new equipment is significantly cleaner than the older equipment.

Wood Combustion

Residential wood combustion emissions of PM10 and NOx come from burning wood or similar materials inside fireplaces, wood stoves and inserts. ARB estimates emissions totals using the following factors: tons of wood used per house, BTU rating per cord, number of houses, fraction of active wood combustion devices, average number of days burned per house, and other representative factors.[4] The recent amendment to Rule 4901 (Wood Burning Fireplaces and Wood Burning Heaters) will reduce a significant portion of emissions from those devices. Rule 4901 contains limits on wood combustion devices in new development, however, it still allows new devices in a development of a certain size or larger. Therefore, reductions from this category can still occur if the development can still install those devices and chooses not to.

Motor Vehicle Emissions

Motor vehicle emissions is the largest category of emissions attributed to new development. The inventory includes estimates of exhaust and evaporative VOCs, NOx, and PM10 associated with exhaust, tire wear and brake wear. On-road motor vehicles account for approximately 43% of the entire NOx inventory for 2002.[5] ARB estimates emissions from on-road vehicles using the EMFAC2002 model, which uses emission factors, vehicle numbers and vehicle activity. Emission rates are derived primarily from direct testing by the state or EPA. Vehicle population and vehicle age data are obtained from the Department of Motor Vehicles (DMV). Travel activity, which includes vehicle miles traveled (VMT), distribution of VMT by speed, the number of trips taken per vehicle each day, are provided by the California Department of Transportation

2 Staff report for Public Meeting to Consider Approval of the California Small Off-road engine emissions inventory, http://www.arb.ca.gov/msei/off-road/pubs/sore_final.doc

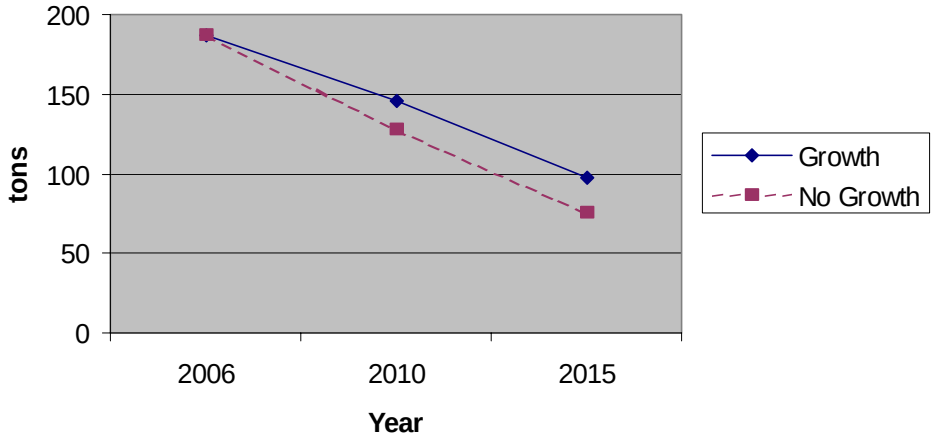
3 URBEMIS2002 Users' Guide, Version 7.4, May 2003, Appendix B.

4 Air Resources Board, Emissions Inventory Procedural Manual, Vol. III, Methods for Assessing Area Source Emissions, October 1997 with revisions through November 1998, section 7.1.

5 2003 PM10 Plan, Chapter 3, NOx Emissions Inventory

(Caltrans), local Metropolitan Planning Organizations (MPOs), local Councils of Governments (COGs), and fleet monitoring.[6] URBEMIS quantifies vehicle emissions attributed to a particular development based on the emission factors and vehicle activity found in EMFAC2002, in combination with project specific data. While the motor vehicle emissions inventory in both the PM10 and ozone plans show that vehicle emissions are declining, emissions would have declined even more if growth were not to occur, thus hampering the ability of the region to reach attainment of the PM10 and ozone standards. The following chart shows the emissions from all motor vehicles for the current population if it would have remained constant (No-Growth), and the emissions from vehicles for the projected population as reported in the 2003 PM10 Plan emissions inventory (Growth). Based on an analysis performed by ARB using EMFAC2002, which can be found in Attachment 1, the difference is an estimated 17.3 tons per day of NOx attributed to projected increase in growth in the SJVAB between 2006 and 2010.

Figure 1
Difference in NOx Emissions for All Vehicle Types



Re-entrained Road Dust

PM10 emissions from road dust occur by vehicles driving on unpaved roads, or by vehicles entraining or re-entraining dust on paved roads. ARB estimates PM10 emissions by using the following factors for different road types: silt loading on roads, vehicle weight, and VMT traveled. The majority of new development occurs on or creates new paved roads, however, some development in rural areas still use unpaved roads. Unpaved road emissions are estimated by using an emission factor and total VMT traveled.[7]

6 Overview of the On-Road Emissions Inventory, http://www.arb.ca.gov/msei/on-road/briefs/emfac6.pdf

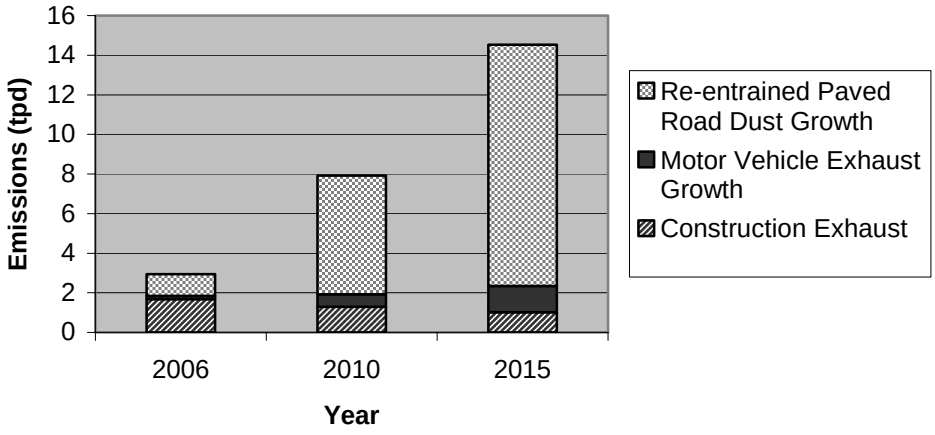
7 Air Resources Board, Emissions Inventory Procedural Manual, Vol. III, Methods for Assessing Area Source Emissions, October 1997 with revisions through November 1998, section 7.9-7.10.

Construction

This category of emissions differ slightly from the others, since all emissions from construction are due to new development, regardless of growth in the category. Emissions associated with construction activities occur for the purpose of building residential, commercial, industrial, institutional, or governmental structures. Emissions result predominantly from equipment associated with site preparation work, which may include scraping, grading, loading, digging, compacting, and other operations. ARB estimates construction emissions by utilizing a computer model called OFF-ROAD. The construction emissions in the OFF-ROAD model are estimated using the population, activity, and fuel usage of the varied types of construction equipment.

The following figure demonstrates PM10 emissions and emissions growth from construction equipment, re-entrained paved road dust, and vehicle exhaust associated with new development.

Figure 2
PM10 Emissions from Development



B. Projected Emissions from New Development

The following table illustrates the projected growth in emissions, as can be discerned from the emissions inventory:

Total Emissions Attributed to Land Use Growth in the SJVAB in 2010

NOx

Emissions Category	Emissions from Growth In 2010 (tpd)	Emissions from Growth during 2006-2010 (tpd)
On-road Vehicles[A]	2.2	17.3
Construction Equipment[C]	21.3	21.3
Total NOx	**23.5**	**137.8**

PM10

Construction Equipment[C]	1.4	1.4
On-road Vehicles[A]	0.2	0.6
Paved Road Dust[B]	1.1	5.2
Total PM10	**2.7**	**13.4**

A. Emissions Growth between 2006 and 2010 was estimated based on an ARB EMFAC 2002 version 2.2 run, dated June 10, 2005 (Attachment 1). This will be revised to obtain a total for 2006.

B. 2003 PM10 Plan emissions inventory

C. ARB Emission Inventory for 2010

It should be noted that some sources of emissions from new development are not included in the above table for several reasons. While there may be difficulties in assessing what portions of the emissions inventory are resulting from new growth, there are new emissions from growth occurring. Therefore, the above table represents a conservative estimate of what will occur, and does not overestimate. Therefore, any reductions applied to the emissions outlined in the above table will represent a conservative estimate of actual reductions resulting from this program.

III. EMISSIONS REDUCTION OPTIONS FOR NEW DEVELOPMENT

A. On-site Project-Specific Emissions Reductions

On-site mitigation measures and their corresponding emission reduction methodologies were developed by Nelson/Nygaard and put into URBEMIS. The following discussion lists measures/conditions, if implemented that would result in emissions reductions from a development project. The maximum percent reduction is in general terms. The actual reduction relies on project specific information and factors, and how the mitigation measure is used in combination with other measures.

Increase Energy Efficiency Beyond Title 24

This measure would reduce emissions by decreasing the amount of natural gas that is needed and in turn combusted for a particular development. Examples of how this could be achieved include: using insulation in the attic and walls, insulating ductwork, using whole house fans, double-paned and/or high performance glazed windows, maximizing the use of natural lighting, installing EnergyStar appliances, orienting the

building north or south to utilize passive heating and cooling, designing the building to maximize natural ventilation, or any number of other items that would decrease the use of natural gas, and therefore decrease emissions. The emissions reductions associated with this mitigation measure in URBEMIS would require a quantification of the % reduction beyond what is already required by Title 24 as determined by a computer model developed for Title 24 purposes.

Electrical landscape maintenance equipment

This measure would reduce emissions by eliminating some or all of the combustion of gasoline or diesel in standard landscape equipment by replacing it with equipment that relies on batteries, an electrical outlet, or manually-powered equipment. Emissions reductions are quantified by using the % of the development that would use non-combustion powered equipment.

Hearth

This measure would reduce emissions by eliminating construction of a wood combustion device that would have otherwise been allowed under Rule 4901.

Net Residential Density

Emissions reductions from this measure would occur when an individual from a particular residential use forgoes the use of the automobile and uses an alternate form of transportation. A considerable volume of research has investigated the links between density and travel behavior and has determined that there is a significant and quantifiable relationship between residential density and automobile use. Three key studies of travel behavior and density itself have identified elasticities, which has been used to develop a formula to determine the reduction in vehicle trips and vehicle miles traveled, and the corresponding emissions reductions. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 55%.

Mix of Uses

Emissions reductions from this measure would occur when an individual forgoes the use of the automobile and uses other forms of transportation. Research has shown that there is an impact of diversity or mix of uses on travel behavior, which can occur at the macro-scale, such as jobs-housing balance. Numerous studies of travel behavior and mix of uses have identified elasticities, which has been used to develop a formula to determine the reduction in vehicle trips and vehicle miles traveled, and the corresponding emissions reductions. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 9%.

Local Serving Retail

Emissions reductions from this measure occur when an individual forgoes the use of the automobile, since the proximity of the retail encourages other forms of transportation. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 2%.

Transit Service

Emissions reductions from this measure would occur when an individual forgoes the use of the automobile and uses transit. Transit choices could include buses, light rail, dedicated shuttles, and trolleys. Since emissions from transit services already exist, the elimination of trip(s) from the automobile would result in emissions reductions. URBEMIS determines emissions reductions from transit use based on a Transit Service Index, which is based on the latest California-specific research on transit use. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 15%.

Bicycle and Pedestrian Facilities

Emissions reductions from this measure would when an individual forgoes the use of the automobile and uses a bicycle or walks. Since the use of a bicycle or the action of walking does not emit emissions, the elimination of trip(s) from the automobile would result in emissions reductions. URBEMIS determines emissions reductions from bicycle use and pedestrian activities based on quantitative values of network density, sidewalk completeness and bike lane completeness. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 9%.

Affordable Housing/Senior Housing/ Assisted Living

This measure would reduce emissions by designating residential units as deed-restricted below-market-rate (BMR) housing. Research has shown that lower-income households and senior citizens own fewer vehicles and drive less. By designating residential units as deed-restricted BMR, only lower-income individuals that use the automobile less would occupy those units, which would result in lower emissions due to less automobile use. The maximum reduction in trips/VMT and resulting emissions and resulting emissions that may occur from this measure is calculated to be 4%.

Transportation Demand Management Programs

TDM Programs can include free transit passes, parking restrictions and telecommuting. Emissions reductions from this measure would occur when a landlord provides an incentive, such as transit passes, to individual(s), who then forgoes the use of the automobile and uses transit. These programs provide an incentive for the individual(s) to use the transit, and studies have show that these programs both increase transit ridership and reduce vehicle trips. The maximum reduction in trips/VMT and resulting emissions and resulting emissions that can be achieved under this measure is 25%.

Fleet Modifications

Reductions from this measure occur when a fleet owner makes vehicle specific modifications or agrees to purchase and/or use only vehicles with controls, such as a particulate filters or catalysts. There are numerous options available. The maximum reduction in emissions that can be achieved under this measure varies by control option.

It is important to note that many of the mitigation listed above requires a change in travel behavior of an individual in order for the emissions reductions to occur. It is not guaranteed that the mitigation measures will be successful at changing travel behavior to the exact amount as calculated, however, it represents the best estimate/projection of what will occur based on the most recent research conducted on existing travel behavior to date.

B. Off-site Emissions Reductions

In the event that the emissions impact of a particular project is not fully mitigated on site a proportional fee will be assessed and collected for the NOx and PM10 emissions not mitigated. The fees collected would be placed into a mitigation fund for each pollutant and county, and expended on projects that reduce emissions of that pollutant in that county, utilizing a grant-like program. The district has over eleven years experience with grant programs designed to reduce primarily NOx, and some VOC. Each grant program has had strict guidelines on emissions reductions, qualifying equipment, and the related administration of the program. Based on that experience, the District has decided that a grant program would provide the most cost-effective emissions reductions for the money that will be collected.

The District has employed the California Air Resources Board (ARB) and the California Department of Transportation document "*Methods to Find the Cost Effectiveness of Funding Air Quality Projects"* for finding the cost effectiveness and emission reduction benefits for a wide variety of emission reduction projects. This document can also be accessed through an associated on-line database. The methods described are generally accepted and include: a list of information needed to calculate cost effectiveness, emission factors, project life, defaults that may be used when project-specific data is not available (assumptions) and formulas to calculate vehicle emission reductions for three major pollutants, NOx, PM10, and VOC's. Many of those methods were used to develop the grant programs that could be funded under this program.

The most successful District grant program has been the Heavy-Duty Engine Incentive Program. This program replaces older model high polluting engines with newer and cleaner burning engines. Eligible project types funded under the heavy-duty program include, but are not limited to: on-road and off road vehicles and equipment, agricultural pump engines, marine vessels, forklifts, truck stop electrification technology, and school bus projects.

The Voluntary Accelerated Vehicle Retirement (Scrap) Program is designed to accelerate the voluntary retirement of older, higher polluting passenger vehicles. Monetary incentives are provided to individuals who agree to scrap their high polluting passenger vehicles. Ideally, this incentive money will help them purchase newer vehicles with cleaner burning engines.

The Light and Medium Duty Vehicle Incentive Program is designed to encourage the purchase and use of cleaner engine technology for passenger vehicles. To be eligible under the program, the light and medium duty vehicles must be powered by natural gas, electricity, fuel cells, or gasoline-electric hybrid technology.

The Carl Moyer Program provides incentive funds for significant near-term reductions in NOx. Eligible project types under the Carl Moyer Program include: new alternative fuel vehicle projects, on and off-road vehicle engine replacement projects, agricultural pump engine replacements, locomotive engine replacements, marine vessels, forklifts, and airport ground support equipment engine replacements. Projects are funded based on cost effectiveness, utilizing criteria developed by the state in coordination with the air districts and the statewide Incentive Program Implementation Team (IPI).

In addition to the sources listed above, the District receives grant funds from other state and federal funding sources including: the State's Lower Emission School Bus Program, Peaker Plant Offset funds, and the State's NOx and PM Program funds.

IV. EMISSIONS REDUCTION OPTIONS FOR CONSTRUCTION

Construction PM10 emissions can be mitigated in numerous ways. The following discussion lists measures/conditions, if implemented that would result in emissions reductions from construction activities. The percent reduction identified was based on the URBEMIS2002 Users' Guide.

A. On-site Reduction Options

There are several on-site construction emissions reductions available. The following lists the current mitigation measures that reduce PM10 and NOx. There is a statewide effort to update the construction portion of URBEMIS, so there may be more mitigation measures identified that are not included in this appendix.

Equipment Exhaust Control

There are several options available for controlling NOx and PM10 emissions from equipment used for construction. Options can include, purchasing newer equipment, altering fuel usage, modifying an engine, using exhaust after-treatments, or renting equipment that help meet the rule requirements. New equipment can provide a high percentage of emissions reductions, depending on the horsepower and the year of the equipment. Reductions that can occur from using newer equipment reductions range from 8-62% for PM10, and 20-38% for NOx. Different fuels are available for use that would reduce emissions from construction equipment. Ultra-low sulfur diesel can achieve a 5-9% reduction in PM10. Alternative diesel fuels can achieve 5-16% reduction in NOx and a 40-63% reduction in PM10. Diesel oxidation catalysts can reduce PM10 by 25-50%. Diesel particulate filters can reduce PM10 by 85%. Selective Catalytic Reduction can reduce NOx by 80% and PM10 by 25%.

Worker Commute Trip Reductions

This measure would entail using a shuttle to take construction workers to a retail establishment for lunch. This would eliminate numerous trips, which would reduce vehicle exhaust, and entrained and/or re-entrained road dust. The maximum PM10 reduction from this measure is 1.3%.

B. Off-site Reduction Options

Since any fees collected will reduce construction emissions off-site, the same emissions reduction options listed in section III above apply.

V. PROJECT-SPECIFIC EMISSIONS REDUCTIONS

Each development project, subject to Rule 9510, will have an assessment of the project performed. The assessment will include an APCO-approved model run that identifies the project or project phase baseline emissions and the emissions reduction resulting from on-site mitigation measures. The remaining emissions will be quantified and will fund emissions reduction project(s), using the fee formulas identified below.

Area and Operational NOx Fee Formula

The NOx fee formula must identify the total tonnage of mitigation required, subtract the tonnage mitigated on-site, and multiply the remaining tonnage by the cost of reductions in order to determine the cost to reduce emissions off-site.

Figure 3

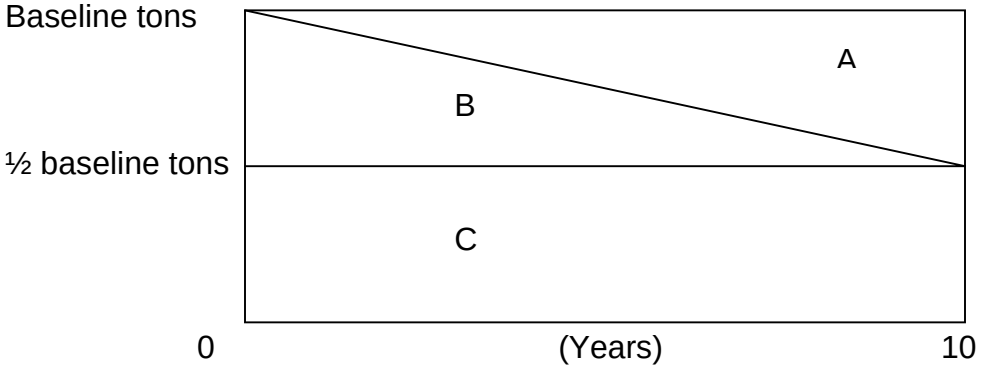


Figure 3 represents a development project's NOx emissions over a period of ten years. Section A represents the emissions reductions projected to be achieved from ARB's tailpipe control, which is 25% of the total project's 10 years emissions. The remaining 75% is the project's estimated NOx emissions for ten years. The mitigation required by Rule 9510 is represented by the triangle B, which equal to a third of the non-A section. Thus, the total tonnage of mitigation required can be identified as follows:

$$\frac{\text{Estimated Baseline Emissions (tons) x 10 years x 75\%}}{3}$$

which is equal to:

$$\text{EBE (tons) x 2.5}$$

The next step is to subtract the percent reduction achieved from on-site mitigation measures. This is determined by using the estimated baseline emissions over ten years and applying the percent mitigation, as follows:

$$\text{Estimated Baseline Emissions (tons) x 10 years x 75\% x Actual \% Mitigation} = \text{EBE x 7.5 x APM}$$

Thus,

$$\text{(EBE x 2.5) - (EBE x 7.5 x APM)}$$

determines the total emissions remaining to mitigate off-site. That number then needs to multiplied by dollars per ton, in order to determine total dollars required to mitigation emissions off-site. The resulting NOx Air Impact Mitigation Fee is as follows:

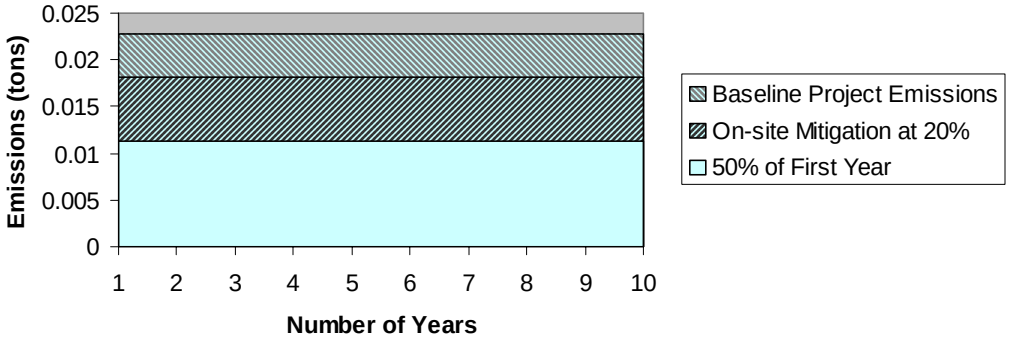
$$\text{[EBE x 2.5] - [EBE x 7.5 x APM] x [Cost of NOx Reductions/ton]}$$

It is important to note that the percent reduction achieved onsite, results in a greater reduction of the NOx fee. While on-site mitigation is not required, the "bigger bang for the buck" is achieved with as much on-site mitigation as possible.

Area and Operational PM10 Fee Formula

The Air Impact Mitigation Fee for PM10 is more straightforward since a project's PM10 emissions remain relatively constant over the life of the project. For ease of understanding, Figure 4 below demonstrates the relationship between baseline emissions, mitigated emissions and half of the baseline emissions.

Figure 4
PM10 Project Emissions and Reductions Compared to 50% of the First Year Emissions



The required PM10 mitigation is half of the baseline emissions for ten years. In order to determine the emissions that are subject to a fee, half of the baseline emissions need to be subtracted from the Mitigated Emissions and multiplied by cost of reductions in dollars per ton. Thus the resulting PM10 Air Impact Mitigation Fee is calculated as follows:

(Mitigated PM10 emissions – ½ Baseline PM10 emissions) (Cost of PM10 Reductions)

Construction Formulas

The Air Impact Mitigation Fees for construction are based on the project's estimated construction equipment emissions, and compared to the statewide fleet average emissions. The required information is as follows: 1)a list of construction equipment used, 2)the model year, and 3)the hours estimated to be used is compiled, which can be determined from the National Construction Estimator or using project-specific information if known. Then the model specific emission factors are used to determine the actual estimated emissions (designated as AEE). The same hours are multiplied by a statewide average fleet emission factor for a particular year, to determine the statewide average estimated emissions (designated as SEE). Since the requirement is to reduce construction NOx emissions by 20% beyond the statewide average, this is determined as follows:

NOx Construction = (AEE) – [(1.00 x SEE) – (SEE x 0.20)]
(AEE) – [1.00SEE – 0.20SEE]
(AEE – 0.8SEE)

PM10 is almost identical, except that the requirement is to reduce construction PM10 emissions by 45% beyond the statewide average.

PM10 Construction = (AEE) – [(1.00 x SEE) – (SEE x 0.45)]
(AEE) – [1.00SEE – 0.45SEE]
(AEE – 0.55SEE)

VI. EMISSIONS REDUCTIONS FROM RULE 9510

Both the 2003 PM10 Plan and the Extreme Ozone Attainment Demonstration Plan, contain emissions reduction commitments for proposed Rule 9510 of 4.1 tons per day of NOx and 5.2 tons per day of PM10 to be achieved by 2010. Those estimates were based on assumptions at the time and are commitments that are necessary to assist the district in meeting the federal and state PM10 and NOx standards. The methodology contained in this section and related attachments demonstrate the draft emission reductions for the program.

As part of determining the emissions reductions, sources that are exempt from the rule need to be subtracted out. The District has numerous years of experience in commenting on projects subject to CEQA. Based on that experience and the thresholds contained in Rule 9510, it is estimated that 15% of all development project emissions will be exempt from the provisions that rule. Attachment 2 and Attachment 3 identify the growth in emissions for each pollutant for each year, and subtract the emissions that will be exempt from the program. Once the emissions subject to the program are identified, the required mitigation is applied, which is 33.3% of baseline NOx emissions over ten years, 50% of baseline operational PM10 emissions over ten years, 20% of construction NOx emissions and 45% of construction PM10 emissions. The reductions achieved on-site were calculated by multiplying the estimated percent of sources opting to use on-site measures, the percent reduction achieved on-site, by the baseline emissions. Off-site reductions were estimated differently. Since grant programs typically rely on project life to determine cost effectiveness and emissions reductions, the reduction was divided by the average project life for that pollutant's cost-effectiveness, which is 7 years for NOx and 12 years for PM10, and spread out over that number of years. Attachment 2 and 3 contain the detailed emission reductions calculations. The results of those calculations reveal that the program, as currently defined, will result in reductions of 5.4 tons per day of NOx in 2010 and 5.8 tons per day of PM10 in 2010.

Attachment 1 - Emissions and Growth in Emissions from Motor Vehicles

Passenger Cars						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	46,763,000	1,186,080	27.53	25.64	1.69	282.88
CY 2007	48,037,000	1,215,840	25.06	23.34	1.73	260.25
CY2008	49,324,000	1,246,060	22.80	21.26	1.77	239.16
CY2009	50,625,000	1,276,970	20.74	19.32	1.81	219.49
CY2010	51,952,000	1,308,670	18.80	17.52	1.85	200.89
CY2011	53,253,000	1,340,690	17.11	15.87	1.90	184.01
CY2012	54,544,000	1,373,190	15.61	14.39	1.94	168.64
CY2013	55,835,000	1,406,290	14.28	13.07	1.99	154.78
CY2014	57,127,000	1,440,000	13.12	11.89	2.04	142.42
CY2015	58,427,000	1,474,400	12.12	10.85	2.08	131.38
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	46,763,000	1,186,080	27.53	25.64	1.69	282.88
CY 2007	46,817,000	1,184,970	23.52	21.39	1.68	242.70
CY2008	46,857,000	1,183,740	20.86	18.97	1.68	217.58
CY2009	46,878,000	1,182,430	18.52	16.81	1.67	194.91
CY2010	46,885,000	1,181,030	16.38	14.86	1.67	174.13
CY2011	46,849,000	1,179,460	14.55	13.13	1.67	155.73
CY2012	46,784,000	1,177,840	12.96	11.61	1.67	139.41
CY2013	46,702,000	1,176,250	11.58	10.29	1.66	125.00
CY2014	46,601,000	1,174,680	10.39	9.13	1.66	112.39
CY2015	46,487,000	1,173,100	9.37	8.14	1.66	101.32
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	1,220,000	30,870	1.54	1.95	0.05	17.55
CY2008	2,467,000	62,320	1.94	2.29	0.09	21.58
CY2009	3,747,000	94,540	2.22	2.51	0.14	24.58
CY2010	5,067,000	127,640	2.42	2.66	0.18	26.76
CY2011	6,404,000	161,230	2.56	2.74	0.23	28.28
CY2012	7,760,000	195,350	2.65	2.78	0.27	29.23
CY2013	9,133,000	230,040	2.70	2.78	0.33	29.78
CY2014	10,526,000	265,320	2.73	2.76	0.38	30.03
CY2015	11,940,000	301,300	2.75	2.71	0.42	30.06

Light-Duty Truck (GVWR < 3,751 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	19,277,000	504,871	16.65	16.97	0.75	191.39
CY 2007	19,879,000	518,651	15.59	15.63	0.77	177.66

CY2008	20,503,000	532,766	14.54	14.39	0.78	164.45
CY2009	21,148,000	547,300	13.50	13.21	0.80	151.41
CY2010	21,810,000	562,308	12.50	12.10	0.82	138.99
CY2011	22,456,000	577,812	11.70	11.10	0.84	128.18
CY2012	23,103,000	593,638	10.97	10.22	0.86	118.33
CY2013	23,754,000	609,742	10.27	9.41	0.88	109.08
CY2014	24,410,000	626,177	9.61	8.68	0.90	100.56
CY2015	25,072,000	642,987	9.02	8.01	0.93	92.73
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	19,277,000	504,871	16.65	16.97	0.75	191.39
CY 2007	19,374,000	505,480	14.54	14.03	0.75	163.40
CY2008	19,478,000	506,121	13.21	12.57	0.74	147.26
CY2009	19,582,000	506,782	11.96	11.22	0.74	132.09
CY2010	19,683,000	507,465	10.80	10.01	0.74	118.19
CY2011	19,756,000	508,326	9.87	8.96	0.74	106.40
CY2012	19,816,000	509,186	9.04	8.04	0.74	95.88
CY2013	19,869,000	510,001	8.26	7.22	0.74	86.35
CY2014	19,912,000	510,803	7.55	6.49	0.74	77.79
CY2015	19,949,000	511,590	6.93	5.86	0.74	70.11
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	505,000	13,171	1.05	1.60	0.02	14.26
CY2008	1,025,000	26,645	1.33	1.82	0.04	17.19
CY2009	1,566,000	40,518	1.54	1.99	0.06	19.32
CY2010	2,127,000	54,843	1.70	2.09	0.08	20.80
CY2011	2,700,000	69,486	1.83	2.14	0.10	21.78
CY2012	3,287,000	84,452	1.93	2.18	0.12	22.45
CY2013	3,885,000	99,741	2.01	2.19	0.14	22.73
CY2014	4,498,000	115,374	2.06	2.19	0.16	22.77
CY2015	5,123,000	131,397	2.09	2.15	0.19	22.62

Light-Duty Truck (GVWR 3,751 to 5,750 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	14,206,000	363,542	11.60	15.81	0.74	133.05
CY 2007	14,550,000	373,494	11.03	14.80	0.76	125.36
CY2008	14,919,000	383,713	10.48	13.85	0.78	117.89
CY2009	15,308,000	394,213	9.95	12.93	0.80	110.66
CY2010	15,718,000	405,048	9.44	12.05	0.83	103.67
CY2011	16,150,000	416,094	8.90	11.17	0.85	96.52
CY2012	16,591,000	427,382	8.39	10.34	0.87	89.90
CY2013	17,045,000	438,884	7.89	9.56	0.90	83.57
CY2014	17,507,000	450,596	7.40	8.83	0.92	77.55
CY2015	17,972,000	462,557	6.97	8.16	0.95	72.09

Total - No Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	14,206,000	363,542	11.60	15.81	0.74	133.05
CY 2007	14,180,000	364,010	10.37	13.49	0.74	116.90
CY2008	14,173,000	364,523	9.61	12.29	0.74	107.14
CY2009	14,175,000	365,028	8.90	11.17	0.74	98.08
CY2010	14,185,000	365,543	8.25	10.14	0.74	89.63
CY2011	14,208,000	366,056	7.59	9.16	0.75	81.45
CY2012	14,230,000	366,582	6.99	8.27	0.75	74.06
CY2013	14,257,000	367,092	6.42	7.46	0.75	67.24
CY2014	14,281,000	367,573	5.87	6.72	0.75	60.96
CY2015	14,300,000	368,032	5.41	6.06	0.75	55.36
Total - Difference						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	370,000	9,484	0.66	1.31	0.02	8.46
CY2008	746,000	19,190	0.87	1.56	0.04	10.75
CY2009	1,133,000	29,185	1.05	1.76	0.06	12.58
CY2010	1,533,000	39,505	1.19	1.91	0.09	14.04
CY2011	1,942,000	50,038	1.31	2.01	0.10	15.07
CY2012	2,361,000	60,800	1.40	2.07	0.12	15.84
CY2013	2,788,000	71,792	1.47	2.10	0.15	16.33
CY2014	3,226,000	83,023	1.53	2.11	0.17	16.59
CY2015	3,672,000	94,525	1.56	2.10	0.20	16.73

Medium-Duty Truck (GVWR 5,751 to 8,500 lbs)

Total - Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	5,521,000	141,790	5.01	7.94	0.29	57.52
CY 2007	5,679,000	146,113	4.79	7.46	0.30	54.45
CY2008	5,844,000	150,494	4.57	7.00	0.31	51.57
CY2009	6,017,000	155,025	4.36	6.56	0.32	48.81
CY2010	6,196,000	159,717	4.16	6.15	0.33	46.11
CY2011	6,369,000	164,373	3.96	5.74	0.33	43.46
CY2012	6,547,000	169,143	3.77	5.35	0.34	40.99
CY2013	6,728,000	174,015	3.60	4.99	0.36	38.71
CY2014	6,914,000	178,995	3.44	4.65	0.37	36.65
CY2015	7,105,000	184,102	3.29	4.34	0.38	34.70
Total - No Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	5,521,000	141,790	5.01	7.94	0.29	57.52
CY 2007	5,535,000	142,403	4.47	6.84	0.29	50.71
CY2008	5,552,000	142,967	4.16	6.25	0.29	46.84
CY2009	5,571,000	143,548	3.87	5.71	0.29	43.19
CY2010	5,591,000	144,140	3.60	5.20	0.29	39.82
CY2011	5,603,000	144,606	3.35	4.73	0.29	36.65
CY2012	5,615,000	145,080	3.12	4.30	0.30	33.75

CY2013	5,628,000	145,550	2.91	3.91	0.30	31.12
CY2014	5,640,000	146,015	2.72	3.55	0.30	28.80
CY2015	5,653,000	146,480	2.54	3.24	0.30	26.65
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	144,000	3,710	0.32	0.62	0.01	3.74
CY2008	292,000	7,527	0.41	0.75	0.02	4.73
CY2009	446,000	11,477	0.49	0.85	0.03	5.62
CY2010	605,000	15,577	0.56	0.95	0.04	6.29
CY2011	766,000	19,767	0.61	1.01	0.04	6.81
CY2012	932,000	24,063	0.65	1.05	0.04	7.24
CY2013	1,100,000	28,465	0.69	1.08	0.06	7.59
CY2014	1,274,000	32,980	0.72	1.10	0.07	7.85
CY2015	1,452,000	37,622	0.75	1.10	0.08	8.05

Light Heavy-Duty Truck (GVWR 8,501 to 10,000 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	2,281,000	34,879	2.13	5.00	0.12	12.85
CY 2007	2,304,000	35,651	1.96	4.95	0.12	11.55
CY2008	2,321,000	36,449	1.84	4.89	0.13	10.52
CY2009	2,334,000	37,270	1.74	4.84	0.13	9.70
CY2010	2,344,000	38,123	1.68	4.71	0.13	9.01
CY2011	2,351,000	38,998	1.65	4.58	0.13	8.49
CY2012	2,356,000	39,887	1.63	4.46	0.13	8.06
CY2013	2,362,000	40,784	1.63	4.34	0.13	7.67
CY2014	2,371,000	41,696	1.63	4.23	0.13	7.34
CY2015	2,384,000	42,634	1.64	4.13	0.13	7.04
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	2,281,000	34,879	2.13	5.00	0.12	12.85
CY 2007	2,246,000	34,746	1.91	4.82	0.12	11.24
CY2008	2,205,000	34,626	1.74	4.64	0.12	9.99
CY2009	2,161,000	34,511	1.61	4.48	0.12	8.97
CY2010	2,115,000	34,405	1.51	4.24	0.12	8.13
CY2011	2,068,000	34,309	1.45	4.02	0.11	7.46
CY2012	2,021,000	34,213	1.40	3.82	0.11	6.91
CY2013	1,976,000	34,113	1.36	3.63	0.11	6.42
CY2014	1,934,000	34,014	1.33	3.45	0.11	5.98
CY2015	1,897,000	33,921	1.31	3.28	0.10	5.60

Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	58,000	905	0.05	0.13	0.00	0.31
CY2008	116,000	1,823	0.10	0.25	0.01	0.53
CY2009	173,000	2,759	0.13	0.36	0.01	0.73

CY2010	229,000	3,718	0.17	0.47	0.01	0.88
CY2011	283,000	4,689	0.20	0.56	0.02	1.03
CY2012	335,000	5,674	0.23	0.64	0.02	1.15
CY2013	386,000	6,671	0.27	0.71	0.02	1.25
CY2014	437,000	7,682	0.30	0.78	0.02	1.36
CY2015	487,000	8,713	0.33	0.85	0.03	1.44

Light Heavy-Duty Truck (GVWR 10,001 to 14,000 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	624,000	10,645	0.76	2.78	0.06	4.45
CY 2007	626,000	10,885	0.75	2.67	0.05	4.18
CY2008	630,000	11,133	0.74	2.57	0.05	3.93
CY2009	637,000	11,387	0.72	2.47	0.05	3.67
CY2010	645,000	11,651	0.70	2.33	0.05	3.42
CY2011	653,000	11,922	0.68	2.19	0.05	3.18
CY2012	664,000	12,200	0.66	2.06	0.05	2.98
CY2013	674,000	12,484	0.64	1.93	0.05	2.79
CY2014	686,000	12,773	0.62	1.81	0.05	2.63
CY2015	699,000	13,071	0.60	1.70	0.05	2.46
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	624,000	10,645	0.76	2.78	0.06	4.45
CY 2007	611,000	10,609	0.73	2.60	0.05	4.07
CY2008	599,000	10,576	0.70	2.43	0.05	3.73
CY2009	590,000	10,544	0.67	2.29	0.05	3.40
CY2010	582,000	10,514	0.63	2.10	0.05	3.09
CY2011	575,000	10,489	0.60	1.92	0.04	2.80
CY2012	569,000	10,465	0.56	1.76	0.04	2.56
CY2013	564,000	10,442	0.53	1.61	0.04	2.34
CY2014	560,000	10,420	0.50	1.48	0.04	2.15
CY2015	556,000	10,400	0.47	1.35	0.04	1.96
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	15,000	276	0.02	0.07	0.00	0.11
CY2008	31,000	557	0.04	0.14	0.00	0.20
CY2009	47,000	843	0.05	0.18	0.00	0.27
CY2010	63,000	1,137	0.07	0.23	0.00	0.33
CY2011	78,000	1,433	0.08	0.27	0.01	0.38
CY2012	95,000	1,735	0.10	0.30	0.01	0.42
CY2013	110,000	2,042	0.11	0.32	0.01	0.45
CY2014	126,000	2,353	0.12	0.33	0.01	0.48
CY2015	143,000	2,671	0.13	0.35	0.01	0.50

Medium Heavy-Duty Truck (GVWR 14,001 to 33,000 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	1,844,000	32,324	4.23	20.26	0.61	31.38
CY 2007	1,897,000	33,004	3.94	19.34	0.58	29.10
CY2008	1,951,000	33,694	3.69	18.42	0.57	27.07
CY2009	2,005,000	34,411	3.45	17.53	0.56	25.24
CY2010	2,058,000	35,155	3.22	16.29	0.54	23.47
CY2011	2,113,000	35,925	3.00	15.10	0.52	21.80
CY2012	2,168,000	36,711	2.79	13.96	0.50	20.22
CY2013	2,223,000	37,512	2.60	12.87	0.49	18.77
CY2014	2,279,000	38,329	2.40	11.85	0.48	17.36
CY2015	2,334,000	39,167	2.23	10.88	0.46	16.05
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	1,844,000	32,324	4.23	20.26	0.61	31.38
CY 2007	1,849,000	32,166	3.83	18.83	0.56	28.33
CY2008	1,853,000	32,009	3.49	17.48	0.54	25.68
CY2009	1,856,000	31,864	3.19	16.21	0.52	23.34
CY2010	1,857,000	31,726	2.90	14.68	0.49	21.15
CY2011	1,859,000	31,605	2.64	13.27	0.46	19.15
CY2012	1,860,000	31,488	2.39	11.96	0.43	17.32
CY2013	1,859,000	31,376	2.17	10.76	0.41	15.68
CY2014	1,859,000	31,267	1.96	9.65	0.39	14.15
CY2015	1,857,000	31,163	1.77	8.65	0.37	12.76
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	48,000	838	0.11	0.51	0.02	0.77
CY2008	98,000	1,685	0.20	0.94	0.03	1.39
CY2009	149,000	2,547	0.26	1.32	0.04	1.90
CY2010	201,000	3,429	0.32	1.61	0.05	2.32
CY2011	254,000	4,320	0.36	1.83	0.06	2.65
CY2012	308,000	5,223	0.40	2.00	0.07	2.90
CY2013	364,000	6,136	0.43	2.11	0.08	3.09
CY2014	420,000	7,062	0.44	2.20	0.09	3.21
CY2015	477,000	8,004	0.46	2.23	0.09	3.29

Heavy Heavy-Duty Truck (GVWR 33,001 to 60,000 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	4,845,000	31,643	6.00	82.30	1.85	44.21
CY 2007	4,978,000	32,260	5.70	78.05	1.72	41.00
CY2008	5,123,000	32,896	5.44	73.87	1.65	38.44
CY2009	5,281,000	33,555	5.18	69.88	1.60	36.18
CY2010	5,449,000	34,235	4.90	64.43	1.52	33.93
CY2011	5,628,000	34,939	4.64	59.06	1.44	31.99

CY2012	5,817,000	35,648	4.39	53.91	1.37	30.10
CY2013	6,019,000	36,370	4.13	49.01	1.31	28.31
CY2014	6,235,000	37,118	3.91	44.50	1.26	26.84
CY2015	6,451,000	37,891	3.68	40.44	1.22	25.19
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	4,845,000	31,643	6.00	82.30	1.85	44.21
CY 2007	4,852,000	31,440	5.49	75.87	1.67	39.47
CY2008	4,866,000	31,251	5.10	69.98	1.57	36.07
CY2009	4,890,000	31,071	4.73	64.51	1.48	33.09
CY2010	4,918,000	30,896	4.37	57.97	1.37	30.23
CY2011	4,951,000	30,738	4.03	51.80	1.27	27.78
CY2012	4,989,000	30,577	3.71	46.09	1.18	25.48
CY2013	5,034,000	30,420	3.41	40.86	1.10	23.37
CY2014	5,086,000	30,279	3.15	36.19	1.03	21.61
CY2015	5,133,000	30,148	2.90	32.08	0.97	19.78
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	126,000	820	0.21	2.18	0.05	1.53
CY2008	257,000	1,645	0.34	3.89	0.08	2.37
CY2009	391,000	2,484	0.45	5.37	0.12	3.09
CY2010	531,000	3,339	0.53	6.46	0.15	3.70
CY2011	677,000	4,201	0.61	7.26	0.17	4.21
CY2012	828,000	5,071	0.68	7.82	0.19	4.62
CY2013	985,000	5,950	0.72	8.15	0.21	4.94
CY2014	1,149,000	6,839	0.76	8.31	0.23	5.23
CY2015	1,318,000	7,743	0.78	8.36	0.25	5.41

School Bus

Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	186,000	3,982	0.32	2.54	0.10	3.59
CY 2007	190,000	4,082	0.31	2.57	0.10	3.39
CY2008	195,000	4,185	0.31	2.60	0.10	3.35
CY2009	200,000	4,290	0.31	2.63	0.10	3.26
CY2010	205,000	4,398	0.31	2.65	0.10	3.22
CY2011	210,000	4,512	0.31	2.67	0.10	3.19
CY2012	216,000	4,627	0.32	2.66	0.10	3.15
CY2013	221,000	4,743	0.31	2.64	0.10	3.03
CY2014	227,000	4,861	0.31	2.62	0.10	2.93
CY2015	232,000	4,981	0.31	2.60	0.10	2.81
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	186,000	3,982	0.32	2.54	0.10	3.59
CY 2007	185,000	3,978	0.30	2.50	0.10	3.30
CY2008	185,000	3,975	0.29	2.47	0.10	3.17

CY2009	185,000	3,972	0.29	2.43	0.09	3.01
CY2010	185,000	3,969	0.28	2.39	0.09	2.90
CY2011	185,000	3,969	0.28	2.34	0.09	2.80
CY2012	185,000	3,968	0.27	2.27	0.09	2.69
CY2013	185,000	3,967	0.26	2.20	0.09	2.53
CY2014	185,000	3,966	0.25	2.13	0.08	2.39
CY2015	185,000	3,963	0.24	2.06	0.08	2.23
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	5,000	104	0.01	0.07	0.00	0.09
CY2008	10,000	210	0.02	0.13	0.00	0.18
CY2009	15,000	318	0.02	0.20	0.01	0.25
CY2010	20,000	429	0.03	0.26	0.01	0.32
CY2011	25,000	543	0.03	0.33	0.01	0.39
CY2012	31,000	659	0.05	0.39	0.01	0.46
CY2013	36,000	776	0.05	0.44	0.01	0.50
CY2014	42,000	895	0.06	0.49	0.02	0.54
CY2015	47,000	1,018	0.07	0.54	0.02	0.58

Urban Bus						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	330,000	2,407	1.30	4.70	0.08	11.25
CY 2007	338,000	2,468	1.29	4.69	0.08	11.08
CY2008	347,000	2,531	1.28	4.68	0.08	10.88
CY2009	356,000	2,595	1.28	4.67	0.08	10.78
CY2010	365,000	2,661	1.27	4.66	0.08	10.55
CY2011	374,000	2,730	1.27	4.64	0.08	10.29
CY2012	384,000	2,800	1.26	4.56	0.08	9.87
CY2013	393,000	2,870	1.26	4.54	0.08	9.41
CY2014	403,000	2,942	1.26	4.44	0.08	9.05
CY2015	413,000	3,014	1.25	4.40	0.08	8.47
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	330,000	2,407	1.30	4.70	0.08	11.25
CY 2007	330,000	2,406	1.25	4.56	0.07	10.78
CY2008	329,000	2,404	1.21	4.44	0.07	10.32
CY2009	329,000	2,403	1.17	4.31	0.07	9.97
CY2010	329,000	2,402	1.14	4.19	0.07	9.51
CY2011	329,000	2,402	1.11	4.07	0.07	9.04
CY2012	329,000	2,401	1.07	3.90	0.07	8.45
CY2013	329,000	2,401	1.04	3.79	0.06	7.86
CY2014	329,000	2,400	1.02	3.61	0.06	7.37
CY2015	329,000	2,398	0.98	3.49	0.06	6.72

Total - Difference						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	8,000	62	0.04	0.13	0.01	0.30
CY2008	18,000	127	0.07	0.24	0.01	0.56
CY2009	27,000	192	0.11	0.36	0.01	0.81
CY2010	36,000	259	0.13	0.47	0.01	1.04
CY2011	45,000	328	0.16	0.57	0.01	1.25
CY2012	55,000	399	0.19	0.66	0.01	1.42
CY2013	64,000	469	0.22	0.75	0.02	1.55
CY2014	74,000	542	0.24	0.83	0.02	1.68
CY2015	84,000	616	0.27	0.91	0.02	1.75

Motorhome

Total - Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	531,000	34,851	0.84	2.04	0.03	21.00
CY 2007	552,000	36,150	0.80	2.01	0.03	19.78
CY2008	574,000	37,508	0.75	1.97	0.03	18.26
CY2009	598,000	38,927	0.70	1.93	0.03	16.91
CY2010	624,000	40,417	0.66	1.86	0.03	15.57
CY2011	651,000	42,003	0.60	1.79	0.03	14.09
CY2012	679,000	43,650	0.56	1.72	0.03	12.73
CY2013	709,000	45,360	0.50	1.63	0.04	11.26
CY2014	741,000	47,134	0.45	1.54	0.04	9.86
CY2015	772,000	48,973	0.40	1.46	0.04	8.67
Total - No Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	531,000	34,851	0.84	2.04	0.03	21.00
CY 2007	538,000	35,232	0.78	1.95	0.03	19.27
CY2008	546,000	35,632	0.71	1.87	0.03	17.33
CY2009	554,000	36,045	0.65	1.78	0.03	15.65
CY2010	563,000	36,475	0.59	1.68	0.03	14.04
CY2011	573,000	36,951	0.53	1.57	0.03	12.39
CY2012	583,000	37,440	0.48	1.47	0.03	10.92
CY2013	593,000	37,940	0.42	1.36	0.03	9.41
CY2014	604,000	38,449	0.37	1.25	0.03	8.04
CY2015	615,000	38,965	0.32	1.15	0.03	6.89

Total - Difference						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	14,000	918	0.02	0.06	0.00	0.51
CY2008	28,000	1,876	0.04	0.10	0.00	0.93
CY2009	44,000	2,882	0.05	0.15	0.00	1.26
CY2010	61,000	3,942	0.07	0.18	0.00	1.53
CY2011	78,000	5,052	0.07	0.22	0.00	1.70
CY2012	96,000	6,210	0.08	0.25	0.00	1.81
CY2013	116,000	7,420	0.08	0.27	0.01	1.85

CY2014	137,000	8,685	0.08	0.29	0.01	1.82
CY2015	157,000	10,008	0.08	0.31	0.01	1.78

Motorcycle

Total - Growth

	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	342,000	38,680	2.17	0.55	0.02	20.14
CY 2007	352,000	39,251	2.14	0.57	0.03	20.42
CY2008	361,000	39,854	2.06	0.57	0.02	19.23
CY2009	369,000	40,483	1.99	0.56	0.02	18.12
CY2010	376,000	41,132	1.93	0.56	0.02	17.19
CY2011	383,000	41,807	1.88	0.56	0.02	16.31
CY2012	389,000	42,499	1.85	0.56	0.02	15.62
CY2013	395,000	43,204	1.83	0.56	0.02	15.05
CY2014	401,000	43,920	1.81	0.57	0.02	14.58
CY2015	408,000	44,655	1.80	0.57	0.02	14.21

Total - No Growth

	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	342,000	38,680	2.17	0.55	0.02	20.14
CY 2007	343,000	38,255	2.08	0.55	0.02	19.89
CY2008	343,000	37,861	1.95	0.54	0.02	18.27
CY2009	342,000	37,486	1.84	0.52	0.02	16.79
CY2010	339,000	37,121	1.74	0.51	0.02	15.52
CY2011	337,000	36,780	1.66	0.49	0.02	14.37
CY2012	333,000	36,453	1.59	0.48	0.02	13.42
CY2013	330,000	36,136	1.53	0.47	0.02	12.61
CY2014	327,000	35,827	1.48	0.46	0.02	11.91
CY2015	324,000	35,529	1.43	0.45	0.02	11.32

Total - Difference

	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	9,000	996	0.06	0.02	0.01	0.53
CY2008	18,000	1,993	0.11	0.03	0.00	0.96
CY2009	27,000	2,997	0.15	0.04	0.00	1.33
CY2010	37,000	4,011	0.19	0.05	0.00	1.67
CY2011	46,000	5,027	0.22	0.07	0.00	1.94
CY2012	56,000	6,046	0.26	0.08	0.00	2.20
CY2013	65,000	7,068	0.30	0.09	0.00	2.44
CY2014	74,000	8,093	0.33	0.11	0.00	2.67
CY2015	84,000	9,126	0.37	0.12	0.00	2.89

San Joaquin Valley - Total						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	96,748,000	2,385,690	78.53	186.52	6.33	813.73
CY 2007	99,384,000	2,447,850	73.37	176.07	6.25	758.21
CY2008	102,094,000	2,511,290	68.48	166.08	6.27	704.76
CY2009	104,878,000	2,576,430	63.91	156.53	6.30	654.24
CY2010	107,741,000	2,643,520	59.57	145.29	6.30	606.01
CY2011	110,590,000	2,711,800	55.70	134.46	6.30	561.51
CY2012	113,456,000	2,781,370	52.19	124.18	6.32	520.59
CY2013	116,360,000	2,852,260	48.93	114.56	6.34	482.43
CY2014	119,300,000	2,924,540	45.95	105.61	6.38	447.77
CY2015	122,271,000	2,998,430	43.32	97.54	6.43	415.80
Total - No Growth						
	VMT	**Pop***	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	96,748,000	2,385,690	78.53	186.52	6.33	813.73
CY 2007	96,860,000	2,385,690	69.25	167.42	6.09	710.08
CY2008	96,988,000	2,385,690	63.03	153.93	5.95	643.40
CY2009	97,114,000	2,385,690	57.40	141.45	5.83	582.49
CY2010	97,233,000	2,385,690	52.20	127.97	5.68	526.32
CY2011	97,291,000	2,385,690	47.65	115.47	5.54	476.01
CY2012	97,315,000	2,385,690	43.59	103.99	5.42	430.85
CY2013	97,326,000	2,385,690	39.89	93.55	5.30	389.92
CY2014	97,319,000	2,385,690	36.58	84.13	5.20	353.53
CY2015	97,284,000	2,385,690	33.68	75.81	5.12	320.71
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	2,524,000	62,160	4.12	8.65	0.16	48.13
CY2008	5,106,000	125,600	5.45	12.15	0.32	61.36
CY2009	7,764,000	190,740	6.51	15.08	0.47	71.75
CY2010	10,508,000	257,830	7.37	17.32	0.62	79.69
CY2011	13,299,000	326,110	8.05	18.99	0.76	85.50
CY2012	16,141,000	395,680	8.60	20.19	0.90	89.74
CY2013	19,034,000	466,570	9.04	21.01	1.04	92.51
CY2014	21,981,000	538,850	9.37	21.48	1.18	94.24
CY2015	24,987,000	612,740	9.64	21.73	1.31	95.09

* Note: The EMFAC model slightly redistributed vehicle populations within vehicle classes; however, the total vehicle population are all CY2006 numbers. See below:

CY2007 with CY2006 Veh Pop: 2,385,695 Compared to: 2,385,690
% Difference: 0.00021%

Attachment 2
NOx Emissions and Emissions Reductions

	NOx Emissions (tons per day)								
Emission Inventory Category	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Total Growth in Motor Vehicle Emissions[A]	0.0	8.3	11.6	14.3	16.4	17.9	19.0	19.8	20.2
Total Annual Growth in Motor Vehicles Emissions[A]	0.0	8.3	3.2	2.7	2.1	1.5	1.1	0.7	0.5
Rule Penetration (tpd)[B]	0.0	7.1	2.7	2.3	1.8	1.3	1.0	0.6	0.4
On-Site Reductions									
Estimated Sources to perform on-site reductions[C]	40%	45%	50%	55%	60%	65%	70%	70%	70%
Average Mitigation achieved on-site (%)[C]	7%	9%	11%	13%	14%	15%	15%	15%	15%
Reductions from 2006 Development	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reductions from 2007 Development		0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Reductions from 2008 Development			0.2	0.1	0.1	0.1	0.1	0.1	0.1
Reductions from 2009 Development				0.2	0.2	0.1	0.1	0.1	0.1
Reductions from 2010 Development					0.1	0.1	0.1	0.1	0.1
Reductions from 2011 Development						0.1	0.1	0.1	0.1
Reductions from 2012 Development							0.1	0.1	0.1
Reductions from 2013 Development								0.1	0.1
Reductions from 2014 Development									0.0
Total On-site Reductions[D]	**0.0**	**0.3**	**0.4**	**0.6**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**
Off-site Reductions									
Remaining Subject Emissions[E]	0.0	6.8	2.6	2.2	1.6	1.2	0.9	0.5	0.4
Reductions from 2006 Development	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Reductions from 2007 Development		2.4	2.4	2.4	2.4	2.4	2.4	2.4	
Reductions from 2008 Development			0.9	0.9	0.9	0.9	0.9	0.9	0.9
Reductions from 2009 Development				0.8	0.8	0.8	0.8	0.8	0.8
Reductions from 2010 Development					0.6	0.6	0.6	0.6	0.6
Reductions from 2011 Development						0.4	0.4	0.4	0.4
Reductions from 2012 Development							0.3	0.3	0.3
Reductions from 2013 Development								0.2	0.2
Reductions from 2014 Development									0.1
Total Off-site Reductions[F]	**0.0**	**2.4**	**3.4**	**4.1**	**4.7**	**5.1**	**5.4**	**5.6**	**3.3**
Total Reductions	**0.0**	**2.7**	**3.8**	**4.7**	**5.4**	**5.9**	**6.3**	**6.5**	**4.2**

A. ARB performed an EMFAC2002 model run that estimated the growth between 2006 and 2015 (Attachment 1). Since this analysis needs growth per year, the current year's missions are subtracted by the previous year's emissions to obtain the annual growth.

Medium-Heavy and Heavy-Heavy Duty emissions have been reduced by 12% to account for through-valley traffic

B. Rule penetration is estimated to be 85% based on District experience with CEQA projects.

C. Staff estimate

D. Determined by multiplying rule penetration of operational emissions, estimated sources to perform on-site reductions, average mitigation achieved on-site, and adding the reductions for each year

E. Determined by subtracting a particular years on-site reduction from the Rule Penetration of Operational Emissions for that year.

F. Determined by multiplying Remaining Subject Emissions with 250%, and dividing by 7 to account for the average project life of the estimated emission reduction projects.

G. The rule requires mitigation of 250% of the first years emissions. That total was then divided by 7 to account for the average project life of the estimated emission reduction projects.

On-Site reductions are reduced over time to account for the reduction in mobile emissions

Attachment 3
PM10 Emissions and Emissions Reductions

EMISSIONS INVENTORY CATEGORY	ANNUAL GROWTH IN PM10 EMISSIONS (tons per day)[A] 2006	2007	2008	2009	2010	2011	2012	2013	2014
Operational PM10 Emissions									
Re-entrained Paved Road Dust[B]:									
Freeway	0.4	0.4	0.4	0.3	0.3	*0.3*	*0.3*	*0.3*	*0.3*
Collector Streets	0.1	0.1	0.1	0.1	0.1	*0.1*	*0.1*	*0.1*	*0.1*
Major Streets	0.4	0.4	0.4	0.4	0.4	*0.5*	*0.5*	*0.5*	*0.5*
Local Streets	0.2	0.2	0.1	0.2	0.2	*0.2*	*0.2*	*0.2*	*0.2*
Rural Streets	0.4	0.4	0.4	0.4	0.4	*0.5*	*0.5*	*0.5*	*0.5*
On-road vehicles[C]	0.0	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Total Annual Growth in Operational PM10 Emissions	**1.1**	**1.2**	**1.1**	**1.3**	**1.3**	**1.5**	**1.5**	**1.5**	**1.5**
Cumulative Growth in Operational PM10 Emissions[D]	1.1	2.3	3.4	4.7	6.0	7.5	9.1	10.6	12.2
Rule Penetration of Operational Emissions (tpd)[E]	0.9	1.0	1.0	1.1	1.1	1.3	1.3	1.3	1.3
On-site Reductions									
Estimated Sources to perform on-site reductions[F]	40%	45%	50%	55%	60%	65%	70%	70%	70%
Average Mitigation achieved on-site (%)[F]	7%	9%	11%	13%	14%	15%	15%	15%	15%
Reductions from 2006 Development	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Reductions from 2007 Development		0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Reductions from 2008 Development			0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reductions from 2009 Development				0.08	0.08	0.08	0.08	0.08	0.08
Reductions from 2010 Development					0.09	0.09	0.09	0.09	0.09
Reductions from 2011 Development						0.13	0.13	0.13	0.13
Reductions from 2012 Development							0.14	0.14	0.14
Reductions from 2013 Development								0.14	0.14
Reductions from 2014 Development									0.14
Total On-site Reductions (tpd)[G]	**0.0**	**0.1**	**0.1**	**0.2**	**0.3**	**0.4**	**0.6**	**0.7**	**0.8**
Off-site Reductions									
Remaining Subject Emissions[H]	0.9	1.0	0.9	1.0	1.0	1.2	1.2	1.2	1.2
Reductions from 2006 Development	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2007 Development		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2008 Development			0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2009 Development				0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2010 Development					0.4	0.4	0.4	0.4	0.4
Reductions from 2011 Development						0.5	0.5	0.5	0.5
Reductions from 2012 Development							0.5	0.5	0.5
Reductions from 2013 Development								0.5	0.5
Reductions from 2014 Development									0.5
Total Off-site Reductions[I]	**0.4**	**0.8**	**1.2**	**1.6**	**2.0**	**2.5**	**3.0**	**3.5**	**4.0**
Total Operational PM10 Reductions[J]	**0.4**	**0.9**	**1.3**	**1.8**	**2.3**	**2.9**	**3.5**	**4.2**	**4.8**

A-P

See footnotes on following pages.

EMISSIONS INVENTORY CATEGORY	ANNUAL EMISSIONS (tons per day)[K] 2006	2007	2008	2009	2010	2011	2012	2013	2014
Construction Equipment Emissions									
Total Construction Equipment NOx Emissions[L]	26.9	25.5	24.1	22.7	21.3	20.1	18.9	17.6	16.4
Construction Equipment PM10 Equivalent[M]	17.9	17.0	16.1	15.1	14.2	13.4	12.6	11.7	10.9
Rule Penetration of Construction Equipment Emissions (tpd)[E]	15.2	14.4	13.7	12.9	12.1	11.4	10.7	10.0	9.3
On-site Reductions									
Estimated Sources to perform fleet reductions (%)[F]	10%	20%	30%	40%	50%	50%	50%	50%	50%
Average Fleet Reductions (%)[N]	20%	20%	20%	20%	20%	20%	20%	20%	20%
Construction Fleet Reductions[G]	**0.3**	**0.6**	**0.8**	**1.0**	**1.2**	**1.1**	**1.1**	**1.0**	**0.9**
Off-site Reductions									
Remaining Emissions (tpd)[4]	14.9	13.9	12.8	11.8	10.9	10.3	9.6	9.0	8.4
Reductions from 2006 Development	0.4	0.4	0.4	0.4	0.4	0.4	0.4		
Reductions from 2007 Development		0.4	0.4	0.4	0.4	0.4	0.4	0.4	
Reductions from 2008 Development			0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2009 Development				0.3	0.3	0.3	0.3	0.3	0.3
Reductions from 2010 Development					0.3	0.3	0.3	0.3	0.3
Reductions from 2011 Development						0.3	0.3	0.3	0.3
Reductions from 2012 Development							0.3	0.3	0.3
Reductions from 2013 Development								0.3	0.3
Reductions from 2014 Development									0.2
Total Off-site Reductions[O]	**0.4**	**0.8**	**1.2**	**1.5**	**1.8**	**2.1**	**2.4**	**2.2**	**2.1**
Construction Equipment Reductions[J]	**0.7**	**1.4**	**2.0**	**2.5**	**3.0**	**3.2**	**3.4**	**3.2**	**3.0**

A. Annual Growth in emisions were determined by subtracting one years emissions from the previous year's emissions.
Emissions' growth in 2011-2014 were determined by taking the difference between 2015 and 2010 and dividing that by 5 years.

B. The growth in these emissions were taken directly from the emissions inventory, and were reported by road type. Control for Regulation VIII is accounted for.

C. These totals were obtained from ARB. Current year's emissions are subtracted by the previous year's emissions to obtain the annual growth.

D. Cumulative growth was determined by creating a running total of emissions from each year

E. Rule penetration is estimated to be 85% based on District experience with CEQA projects.

F. District staff estimate

G. Determined by multiplying rule penetration of operational emissions, estimated sources to perform on-site reductions, average mitigation achieved on-site, and adding the reductions for each year.

H. Determined by subtracting a particular years on-site reduction from the Rule Penetration of Operational Emissions for that year.

I. Equals 5 x Remaining Subject Emissions That total was then divided by 12 to account for the average project life of the estimated emission reduction projects.

J. Determined by adding On-site Reductions and Off-site Reductions

K. Total emissions were used for each year, since all construction activity each year is for new development

L. These emissions were taken from ARB and interpolated based on 2005, 2010, and 2015.

M. Modeling in the 2003 PM10 indicated that 1.5 tons of NOx are equivalent to 1.0 tons of PM10.

N. This is a rule requirement

O. Determined by multiplying Remaining Subject Emissions with 20%, and dividing by 7 to account for the average project life of the estimated emission reduction projects.

P. Determined by multiplying Remaining Subject Emissions with 45%, and dividing by 12 to account for the average project life of the estimated emission reduction projects.

ANNUAL PM10 EMISSIONS (tons per day)[K]

EMISSIONS INVENTORY CATEGORY	2006	2007	2008	2009	2010	2011	2012	2013	2014
Construction PM10 Exhaust Emissions									
PM10 Exhaust from Construction Equipment[L]	1.7	1.6	1.5	1.4	1.4	1.3	1.2	1.2	1.1
Rule Penetration of Construction PM10 & PM10 Equiv. Emissions (tpd)[E]	1.4	1.4	1.3	1.2	1.2	1.1	1.0	1.0	0.9
On-site Reductions									
Estimated Sources to perform on-site reductions (%)[F]	10%	20%	30%	40%	50%	50%	50%	50%	50%
Average Mitigation achieved on-site (%)[N]	45%	45%	45%	45%	45%	45%	45%	45%	45%
Onsite Reductions (tpd)[G]	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**
Off-site Reductions									
Remaining Emissions (tpd)[H]	1.4	1.2	1.1	1.0	0.9	0.8	0.8	0.8	0.7
Reductions from 2006 Development	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reductions from 2007 Development		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reductions from 2008 Development			0.04	0.04	0.04	0.04	0.04	0.04	0.04
Reductions from 2009 Development				0.04	0.04	0.04	0.04	0.04	0.04
Reductions from 2010 Development					0.03	0.03	0.03	0.03	0.03
Reductions from 2011 Development						0.03	0.03	0.03	0.03
Reductions from 2012 Development							0.03	0.03	0.03
Reductions from 2013 Development								0.03	0.03
Reductions from 2014 Development									0.03
Reductions from 2015 Development									
Total Off-site Reductions[P]	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**
Total Construction PM10 Reductions (tpd)[J]	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

TOTAL ESTIMATED PM10 REDUCTIONS (tpd)	**1.2**	**2.4**	**3.6**	**4.7**	**5.8**	**6.6**	**7.5**	**7.9**	**8.3**

A. Annual Growth in emisions were determined by subtracting one years emissions from the previous year's emissions. Emissions' growth in 2011-2014 were determined by taking the difference between 2015 and 2010 and dividing that by 5 years.

B. The growth in these emissions were taken directly from the emissions inventory, and were reported by road type. Control for Regulation VIII is accounted for.

C. These totals were obtained from ARB. Current year's emissions are subtracted by the previous year's emissions to obtain the annual growth.

D. Cumulative growth was determined by creating a running total of emissions from each year

E. Rule penetration is estimated to be 85% based on District experience with CEQA projects.

F. District staff estimate

G. Determined by multiplying rule penetration of operational emissions, estimated sources to perform on-site reductions, average mitigation achieved on-site, and adding the reductions for each year.

H. Determined by subtracting a particular years on-site reduction from the Rule Penetration of Operational Emissions for that year.

I. Equals 5 x Remaining Subject Emissions That total was then divided by 12 to account for the average project life of the estimated emission reduction projects.

J. Determined by adding On-site Reductions and Off-site Reductions

K. Total emissions were used for each year, since all construction activity each year is for new development

L. These emissions were taken from ARB and interpolated based on 2005, 2010, and 2015.

M. Modeling in the 2003 PM10 indicated that 1.5 tons of NOx are equivalent to 1.0 tons of PM10.

N. This is a rule requirement

O. Determined by multiplying Remaining Subject Emissions with 20%, and dividing by 7 to account for the average project life of the estimated emission reduction projects.

P. Determined by multiplying Remaining Subject Emissions with 45%, and dividing by 12 to account for the average project life of the estimated emission reduction projects.

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APPENDIX C

On-Site Emission Reduction Checklist for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications) and On-Site Enhancing Measures List

November 17, 2005

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MIXED USE OR NON-RESIDENTIAL ON-SITE EMISSION REDUCTION LIST

No.	Measure – Objective
	LOCATION
Bicycle Infrastructure	
M-1	Project is located within 1/2 mile of existing or planned Class I or II bike lanes on arterial/collector streets, or where a suitable parallel route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
Mass Transit Infrastructure	
M-2	Project is located within 1/4-1/2 mile of a transit stop. *(URBEMIS Location: Operation Emissions: Mitigation Measures: Transit Service Node)*
	* Office floor area ratio is 0.75 greater within 1/4 mile of existing transit stop.
Mixed Use/Density	
M-3	Include high density residential, mixed, or retail/commercial uses on site or locate near (within a 1/2 mile of project center). *(URBEMIS Location: Operational Emissions: Mitigation Measures: Mix of Uses Node and/or Operational Emissions: Mitigation Measures: Local Serving Retail)*
	* Day care facilities
	* Restaurant or cafeteria
	* Bank or ATM
	* Dry cleaners
	* Post office / services
	* Entertainment (movie / video)
	* Recreation facility / fitness center
	* Public Park
	* Residential development / On-site employee living spaces
M-4	Average Residential density is 7 Dwelling Units (DU) per acre or greater. *(URBEMIS Location: Land Use Selection - Acreage)*
	▪ Project contains ancillary residential units - "Granny Flats"
M-5	Designate a portion of residential units as deed-restricted below-market-rate (BMR) housing. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Affordable Housing Node)*
	▪ Include Affordable Housing/Senior Housing/ Assisted Living
	BICYCLE/PEDESTRIAN
Bicycle Storage	
M-6	Provide Class I and Class II bicycle parking facilities on-site. Bicycle parking facilities should be near destination points and easy to find. At least one bicycle parking space for every 20 vehicle parking spaces. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* One bicycle parking space for every 10 car parking spaces is considered appropriate.
	* Provide secure bicycle storage at public parking facilities.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-7	Provide shower and locker facilities to encourage employees to bike and/or walk to work, typically one shower and three lockers for every 25 employees. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-8	Provide Class I bicycle parking at apartment complexes or condos without garages. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*

Pedestrian- Bicycle Oriented Infrastructure

M-9	Install Class I or II bike lanes on arterial/collector streets, or where a suitable route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
M-10	Install complete, separate, safe, and convenient pedestrian sidewalks/paths that connect multiple uses. This can be implemented through the following project designs: *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
	* Provide direct pedestrian connections
	* Provide paths and building access which are physically separated from street parking lot traffic and that eliminates physical \barriers such as walls, berms, landscaping and slopes that impede the use of pedestrians, bicycle facilities, or public transportation vehicles
	* Place store entrances close to adjacent sidewalks.
	* Provide pedestrian signalization and signage to improve pedestrian safety
	* Provide continuous sidewalks separated from the roadway by landscaping and on-street parking.
	* Provide clearly delineated crosswalks at intersections.
	* Provide on and off-site pedestrian facility improvements such as overpasses and wider sidewalks
	* Provide on and off-site pedestrian facility improvements such as trails linking them to designated pedestrian commuting routes and/or on-site overpasses and wider sidewalks.
	* Provide street lighting
	* Provide shaded pathways (e.g. provide street trees or building overhangs)
	* Link cul-de-sacs and dead-end streets to encourage pedestrian and bicycle travel
	* Provide traffic calming modifications to project roads, such as narrower streets, speed platforms, bulb-outs and intersection modifications designed to reduce vehicle speeds, to encourage pedestrian and bicycle travel.
	* Provide a parking lot design that-includes clearly marked and shaded pedestrian pathways between transit facilities and building entrances
	* Provide pedestrian access between bus service and major transportation points and destination points within the project.
	* Minimize building setback to adjacent existing or planned pedestrian infrastructure
	* Setback distance is minimized between development and transit, bicycle, or pedestrian corridor
	* Setback distance is minimized between development and neighboring properties

TRANSPORTATION DESIGN

Signage

M-11	Provide a display case or kiosk displaying transportation information in a prominent area accessible to employees, residents, or visitors. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Display Bike Route Maps
	* Display Bus Schedules
	* Display other transportation information such as carpooling, carsharing, etc.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
Streets	
M-12	Project design uses models by the Local Government Commission (LGC) in the "Smart Growth Guidebook," such as: street block patterns that form an interconnected grid, short block faces, numerous alleys and narrow streets. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
PARKING	
Strategies: Pricing and Preferential Parking	
M-13	Develop and implement parking pricing strategies, such as charging parking lot fees to low occupancy (single occupant vehicles) vehicles. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-14	Provide preferential parking spaces near the entrance of buildings for those who carpool/vanpool/rideshare and provide signage. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
Parking Amount	
M-15	Provide parking reduction. The following are guidelines: *(URBEMIS Location: Operational Emissions: Mitigation Measures: Parking Supply)*
	* Office 25%
	* Medical office 8%
	* Commercial 5%
	* Industrial 10%
	* Additional 10-20% if located along transit station
BUILDING/SITE DESIGN	
Energy Efficiency	
M-16	Increase the building energy efficiency rating above what is required by Title 24 requirements. This can be accomplished by any combination of measures. The following is an idea list of measures that may be implemented to achieve this measure (this list should not be considered comprehensive): *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
	General
	* Participate in and implement available PUC energy-efficient rebate programs including air conditioning, gas heating, refrigeration, and lighting programs.
	* Install efficient heating and other appliances, such as water heaters, cooking equipment, refrigerators, furnaces and boiler units beyond Title 24 requirements (see Title 24, Part 6, Energy Efficiency Standards for Residential and Nonresidential Buildings: http://www.energy.ca.gov/title24/standard)
	* Capture waste heat and re-employ it in nonresidential buildings.
	* Trees should be carefully selected and located to protect the building(s) from energy consuming environmental conditions and to shade paved areas
	* Improve the thermal integrity/efficiency of buildings, and reduce the thermal load with automated and timed temperature controls or occupant sensors.
	Roof
	* Install "Green Roof" System
	* Install EPA/DOE Energy Star labeled roof materials
	* Install roof photovoltaic energy systems as a standard feature (on new homes)

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-16	*Solar Design*
Cont	* Design buildings with proper orientation, fenestration, and other design components that maximize the potential of passive cooling and heating, include shading master plan
	Components
	* Use devices that minimize the combustion of fossil fuels.
	* Install low nitrogen oxide (NOx) hot water heaters.
	* Install high efficiency Energy Star heating or ground source heat pumps
	* Install energy efficient interior lighting.
	* Install built-in energy efficient appliances.
	* Install door sweeps and weather stripping if more efficient doors and windows are not available.
	* Install energy-efficient and automated controls for air conditioning
	* Install of energy-efficient lighting (includes controls) and process systems such as water heaters, furnaces and boiler units.
	* Install electrical outlets on the exterior walls of both the front and back of residences or all commercial buildings to promote the use of electric landscape maintenance equipment.
	* Install electric vehicle recharging station with both conductive and inductive charging capabilities in residential garages / parking lots.
	* Install a gas outlet for use with outdoor cooking appliances, and in any proposed fireplaces, including outdoor recreational fireplaces or pits.
	* Use low energy street lights (i.e. sodium).
	* Use low energy traffic signals (i.e. light emitting diode).
	* Install Medium Efficiency Filters
	* Install High Efficiency Filters
	* Install HEPA (High Efficiency Particle Arrestance) Filters
	* Install "whole-house" or "fresh-air" ventilation system

Building Maintenance/Indoor Air Quality

M-17	Reduce VOC emissions from Architectural Coatings⊗ *(URBEMIS Location: Area Emissions: Architectural Coatings - Nonresidential)*
	* Use Low-VOC Coatings
	* Use surfaces that do not require coatings, such as stone or brick
	* Use No-VOC Coatings

Fuel Combustion

M-18	Provide Electrical outlets at front and rear of residences for the use of electrically powered landscape equipment (See Measure 47 below) *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
M-19	Provide electrical outlets at non-residential units for the use of electrically powered landscape equipment. In combination with Measure M-31 below. *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
M-20	Reduce Wood Fireplaces and/or Woodstove above that required by District Rule 4901. *(URBEMIS Location: Area Emissions: Hearth Fuel Combustion Node)*

OPERATIONAL MEASURES

Telecommunication

M-23	Implement an employee telecommuting policy *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Install videoconferencing system
	* Include teleconferencing capabilities, such as web cams or satellite linkage, which will allow employees to attend meetings remotely without requiring them to travel out of the area.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-23	* Offer low cost financing to employees for the purchase of telecommuting equipment, or lend company-owned equipment.
Cont	* Provide satellite work offices when appropriate. Applicable to office/industrial and educational institutions.

Alternative Transit

M-24	Provide guaranteed ride home⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-25	Provide carpool matching assistance⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-26	Provide Car-Sharing Services⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-27	Employ or appoint an Employee Transportation Coordinator to work with the TMA and the District⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Implement a rideshare program
	* Provide incentives to employees to carpool/vanpool, take public transportation, telecommute, walk, bike, etc.
	* Participate in an employee "flash-pass" program, which provides free travel on transit buses.
	* Provide transit pass subsidy (100%) and/or commute alternative allowance
	* Participate in alternative transportation programs such as CalTrans rideshare where deemed appropriate by local transportation planning agencies and/or APCD
	* Provide transit-use incentives, as approved by applicable transportation planning agencies such as subsidized transit passes and accommodation of unusual work schedules to encourage transit use
	* Provide funds for on line computer rideshare matching.
	* Provide an employer subsidized shuttle service to connect to existing transit sites.
	* Provide an employer subsidized free or reduced transit fares for midday central business district trips.
	* Provide financial incentives to carpoolers for vehicle tune-up or maintenance
	* Implement a lunchtime shuttle to reduce single occupant vehicle trips.
	* Provide Flextime for non-SOV (single occupancy vehicle) commuters
	* Maintain a fleet of bicycles for employee and business use
M-28	Provide transit pass subsidy (100%) and/or commute alternative allowance⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-29	Provide a display case or kiosk displaying transportation information in a prominent area accessible to employees or residents. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Provide ridesharing information in a homeowner's association package.

Work Schedules

M-30	Implement alternative work schedules such as compressed workweek schedules where weekly work hours are compressed into fewer than five days.⊗ Examples of these options are: 9/80, 4/40, 3/36 *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*

Landscaping

M-31	Project provides and/or requires use of electric maintenance equipment; including, but not limited to electric lawn mowers, electric leaf blowers. In combination with measure M-19. *(URBEMIS Location: Area Emission: Mitigation Measures Node)*
	* Prohibit gas powered landscape maintenance equipment within developments.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-31 *Cont*	* Contract only with commercial landscapers who operate with equipment that complies with the most recent California Air Resources Board certification standards, or standards adopted no more than three years prior to date of use.
	* Provide battery powered or electric landscape maintenance equipment for new residences, commercial and industrial land uses.

Fleet / Engines

M-32	Implement clean air business practices such as using low-emission delivery vehicles, contract with alternative-fuel waste hauling companies, contracting with carrier, delivery, security, or other services utilizing electric, low-emission, alternative fuel, convert fleet to cleaner vehicles or utilizing heavy-duty vehicles that are CARB certified to optional low-emission standards for NOx.⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: On-Road Trucks)*
	Medium Trucks - 5,751 to 8,500 lbs
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	Light Heavy - 8,501 to 10,000 lbs
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	Light Heavy - 10,001 to 14,000 lbs
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	Medium Heavy - 14,001 to 33,000 lbs
	* AZ Purifier & AZ Purimuffler (Cummins & Navistart: 1991-03)
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* DPM DPF muffler with/Series 6300 catalyst formulation
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Lubrizol Engine Control Systems Purifilter
	* Cleaire Longview (ultra low diesel)

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-32 Cont	*Heavy Heavy - 33,001 to 60,000 lbs*
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* Cleaire Flash and Match oxidation catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* DPM DPF muffler w/series 6300 catalyst formulation
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Lubrizol Engine Control Systems Purifilter
	* Cleaire Flash Match system (Cummins M11 engines only)
	* Cleaire Longview (ultra low diesel)
	Line Haul Vehicles >60,000 lbs
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* Cleaire Flash and Match oxidation catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* DPM DPF muffler w/series 6300 catalyst formulation
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Lubrizol Engine Control Systems Purifilter
	* Cleaire Flash Match system (Cummins M11 engines only)
	* Cleaire Longview (ultra low diesel)
	Urban Bus
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	School Bus
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	General
	* Utilize electric fleet vehicles
	* Utilize Ultra Low-Emission fleet vehicles
	* Utilize methanol fleet vehicles
	* Utilize liquid propane gas fleet vehicles

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-32	* Utilize compressed natural gas fleet vehicles
Cont	* Replace diesel fleet with alternative fuel engine technology and infrastructure
	* Retrofit existing equipment to reduce emissions using methods such as particulate filters, oxidation catalysts, or other approved technologies.
	* Fleet vehicles that use clean-burning fuels as may be practicable
	* Adopt a Vehicle Idling Policy requiring all vehicles under company control to adhere to a 5 minute idling policy.
	* Conversion to cleaner engines
	* Use of cleaner (reduced sulfur) fuel
	* Regular maintenance – keep equipment well tuned
	* Add-on control devices, e.g., particulate traps, catalytic oxidizers
	* Repower/Retrofit heavy-duty diesel fleet with cleaner diesel engine technology and/or diesel particulate filter after-treatment technology
	* Replace diesel fleet with alternative fuel engine technology and infrastructure
	* Replace auxiliary power units with cleaner engine technology, alternative fuels, or require electric connection while at loading dock
	* Replace diesel fleet vehicles with cleaner fueled low emission vehicles (i.e. school buses, buses, on- and off- road heavy duty vehicles, lighter duty trucks and passenger vehicles)

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

RESIDENTIAL ON-SITE EMISSION REDUCTION LIST

No.	Measure - Objective
	LOCATION
	Bicycle Infrastructure
R-1	Project is located within 1/2 mile of existing or planned Class I or II bike lanes on arterial/collector streets, or where a suitable parallel route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
	Mass Transit Infrastructure
R-2	Project is located within 1/4-1/2 mile of a transit stop. *(URBEMIS Location: Operation Emissions: Mitigation Measures: Transit Service Node)*
	Mixed Use/Density
R-3	Include high density residential, mixed, or retail/commercial uses on site or locate near (within a 1/2 mile of project center) these uses to minimize the need for trips. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Mix of Uses Node and/or Operational Emissions: Mitigation Measures: Local Serving Retail)*
	* Day care facilities
	* Restaurant or cafeteria
	* Bank or ATM
	* Dry cleaners
	* Post office/services
	* Entertainment (movie/video)
	* Recreation facility/fitness center
	* Public Park
	* Residential development/On-site employee living spaces
R-4	Average Residential density is 7 Dwelling Units (DU) per acre or greater. *(URBEMIS Location: Land Use Selection- Acreage)*
	* Project contains ancillary residential units - "Granny Flats"
R-5	Designate a portion of residential units as deed-restricted below-market-rate (BMR) housing. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Affordable Housing Node)*
	* Include Affordable Housing/Senior Housing/ Assisted Living
	BICYCLE/PEDESTRIAN
	Bicycle Storage
R-6	Provide Class I bicycle parking at apartment complexes or condos without garages *(URBEMIS Location: Operational Emissions: Mitigation Measure: Transportation Demand Management Node)*
	Pedestrian- Bicycle Oriented Infrastructure
R-7	Install Class I or II bike lanes on arterial/collector streets, or where a suitable route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
R-8	Install complete, separate, safe, and convenient pedestrian sidewalks/paths that connect multiple uses. This can be implemented through the following project designs: *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
	* Provide direct pedestrian connections

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
R-18	* Provide paths and building access which are physically separated from street parking lot traffic and that eliminates physical \barriers such as walls, berms, landscaping and slopes that impede the use of pedestrians, bicycle facilities, or public transportation vehicles.
Cont	* Place store entrances close to adjacent sidewalks.
	* Provide pedestrian signalization and signage to improve pedestrian safety
	* Provide continuous sidewalks separated from the roadway by landscaping and on-street parking.
	* Provide clearly delineated crosswalks at intersections.
	* Provide on and off-site pedestrian facility improvements such as overpasses and wider sidewalks
	* Provide on and off-site pedestrian facility improvements such as trails linking them to designated pedestrian commuting routes and/or on-site overpasses and wider sidewalks.
	* Provide street lighting
	* Provide shaded pathways (e.g. provide street trees or building overhangs)
	* Link cul-de-sacs and dead-end streets to encourage pedestrian and bicycle travel
	* Provide traffic calming modifications to project roads, such as narrower streets, speed platforms, bulb-outs and intersection modifications designed to reduce vehicle speeds, to encourage pedestrian and bicycle travel.
	* Provide pedestrian access between bus service and major transportation points and destination points within the project.

Transportation Design

Signage

R-9	Provide a display case or kiosk displaying transportation information in a prominent area accessible to residents, or visitors. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Display Bike Route Maps
	* Display Bus Schedules
	* Display other transportation information such as carpooling, carsharing, etc.

Streets

R-10	Project design uses models by the Local Government Commission (LGC) in the "Smart Growth Guidebook," such as: street block patterns that form an interconnected grid, short block faces, numerous alleys and narrow streets. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*

Building/Site Design

Energy Efficiency

R-12	Increase the building energy efficiency rating above what is required by Title 24 requirements. This can be accomplished by any combination of measures. The following is an idea list of measures that may be implemented to achieve this measure (this list should not be considered comprehensive): *(URBEMIS Location: Area Emissions: Mitigation Measures Node)* *General*
	* Participate in and implement available PUC energy-efficient rebate programs including air conditioning, gas heating, refrigeration, and lighting programs.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
R-12	* Install efficient heating and other appliances, such as water heaters, cooking equipment, refrigerators, furnaces and boiler units beyond Title 24 requirements (see Title 24, Part 6, Energy Efficiency Standards for Residential and Nonresidential Building
Cont	* Trees should be carefully selected and located to protect the building(s) from energy consuming environmental conditions and to shade paved areas
	* Improve the thermal integrity/efficiency of buildings, and reduce the thermal load with automated and timed temperature controls or occupant sensors.
	Roof
	* Install "Green Roof" Technology
	* Install EPA/DOE Energy Star labeled roof materials
	* Install roof photovoltaic energy systems as a standard feature (on new homes)
	Solar Design
	* Design buildings with proper orientation, fenestration, and other design components that maximize the potential of passive cooling and heating, include shading master plan
	Components
	* Use devices that minimize the combustion of fossil fuels.
	* Install low nitrogen oxide (NOx) hot water heaters.
	* Install high efficiency Energy Star heating or ground source heat pumps
	* Install energy efficient interior lighting.
	* Install built-in energy efficient appliances.
	* Install door sweeps and weather stripping if more efficient doors and windows are not available.
	* Install energy-efficient and automated controls for air conditioning
	* Install of energy-efficient lighting (includes controls) and process systems such as water heaters, furnaces and boiler units.
	* Install electrical outlets on the exterior walls of both the front and back of residences to promote the use of electric landscape maintenance equipment.
	* Install electric vehicle recharging station with both conductive and inductive charging capabilities in residential garages / parking lots.
	* Install a gas outlet for use with outdoor cooking appliances, and in any proposed fireplaces, including outdoor recreational fireplaces or pits.
	* Use low energy street lights (i.e. sodium).
	* Use low energy traffic signals (i.e. light emitting diode).
	* Install Medium Efficiency Filters
	* Install High Efficiency Filters
	* Install HEPA (High Efficiency Particle Arrestance) Filters
	* Install "whole-house" or "fresh-air" ventilation system

Fuel Combustion

R-13	Provide Electrical outlets at front and rear of residences for the use of electrically powered landscape equipment (See Measure R-18 below). *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
R-14	Reduce Wood Fireplaces and/or Woodstove above that required by District Rule 4901. *(URBEMIS Location: Area Emissions: Hearth Fuel Combustion Node)*

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
	OPERATIONAL MEASURES
Alternative Transit	
R-15	Provide Car-Sharing Services⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
R-16	Transit pass subsidy (100%) and/or commute alternative allowance⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
R-17	Provide a display case or kiosk displaying transportation information in a prominent area accessible to residents. *(URBEMIS Location: Operational Emissions: Mitigation Measure: Transportation Demand Management Node)* * Provide ridesharing information in a homeowner's association package. * Provide an opportunity to receive either a complimentary bicycle or electric bicycle retrofit kit to each residential buyer * Provide electric shuttle or minibus service to transit stops * Provide free transfers between all shuttles and transit. * Operation of a shuttle bus to shopping, health care, public services sites and other nearby trip attractors to reduce automobile use.
Landscaping	
R-18	Project provides and/or requires use of electric maintenance equipment; including, but not limited to electric lawn mowers, electric leaf blowers, etc (In combination with measure R-13 above).⊗ *(URBEMIS Location: Area Emissions: Mitigation Measures Node)* * Prohibit gas powered landscape maintenance equipment within developments. * Contract only with commercial landscapers who operate with equipment that complies with the most recent California Air Resources Board certification standards, or standards adopted no more than three years prior to date of use. * Provide battery powered or electric landscape maintenance equipment for new residences.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

ON-SITE ENHANCING MEASURES

No.	Measure - Objective
	LOCATION
Mass Transit Infrastructure	
A	* Project is located within one mile of a park and ride lot operated by a transportation agency.
	TRANSPORTATION DESIGN
Transit Support	
B	Include transit support features in the project where deemed appropriate by the local agency with jurisdiction over the project as demand and service routes warrant subject to review and approval by local transportation planning agencies, including (but not limited to):
	* On-site/off-site turnouts
	* Route signs and displays
	* Bus turnouts/bulbs
	* Street lighting
	* Passenger benches
	* Shelters at transit access points
C	Develop park-and-ride lots
Streets	
D	Make street design/speeds consistent with requirements for neighborhood electric vehicles
	PARKING
Parking Amount	
E	Use of any excess parking over zone code requirements as on-site parking-n-ride lots.
Parking Construction	
F	Provide a parking lot design that includes clearly marked and shaded pedestrian pathways between transit facilities and building entrances
G	Loading and unloading facilities for transit and carpool/vanpool users. (Provide Signage)
H	Provide grass paving or reflective surface paving for unshaded parking lot areas, driveways, or fire lanes that reduce standard paving by 10% or more.
	* Portland concrete is the preferred paving material
	* Other reflective surfaces to be determined in consultation with SJVAPCD.
	* "Chip Seal" methodology
	* Green Pavement http://www.invisiblestructures.com/GP2/grasspave.htm
I	Structural soil should be used under paved areas to improve tree growth.
J	Provide electric vehicle charging facilities with preferential parking

ON-SITE ENHANCING MEASURES

No.	Measure - Objective
	BUILDING/SITE DESIGN
Telecommuting Infrastructure	
K	Provide necessary infrastructure for telecommuting
	* Provide fiber optic wiring and connections
	* Provide T1 wiring and connections
	* Install a teleconferencing facility
	* Install a on-site telecommunications center
	* Build new homes with internal wiring/cabling that allows telecommuting, teleconferencing, and telelearning
Landscaping	
L	Plant trees sufficient to shade 1/2 the paved area within 15 years after development is constructed.
M	Landscape with low-emission native drought-resistant species (plants, trees and bushes) to reduce the demand for gas powered landscape maintenance equipment. Contact the District for a list of low-emission trees and shrubs.
	OPERATIONAL MEASURES
Telecommunication	
N	Provide free-access telework terminals in multi-family projects
O	Provide a community videoconferencing system coordinated with TMA.
P	Design and implement "Shop by Telephone" or "Shop-by-Computer" services. Applicable to shopping centers and retail facilities.
Goods Movement	
Q	Establish delivery services. Applicable to retail facilities (frequent use), shopping centers, and restaurants.
R	If the development is a grocery store or large retail facility, provide home delivery service for customers.
S	Schedule goods movement for off-peak traffic hours.

APPENDIX D

Recommended Changes to URBEMIS for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

Area and On-road: Jones & Stokes Memo
Operational: Nelson/Nygaard Memo

November 17, 2005

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Jones & Stokes

Revised Memorandum

Date: October 20, 2004

To: Jennifer Barba, San Joaquin Valley Unified Air Pollution Control District

From: Tim Rimpo

Subject: **Recommendations for URBEMIS2002 On-Road and Area Source Mitigation Measures**

Introduction

This memorandum describes Jones & Stokes' proposed approach for updating URBEMIS2002's on-road and area source emission calculations and mitigation measures. The information included in the memo combines and modifies information in two previous memos based on comments received from the District and the URBEMIS Working Group during several conference calls held during the summer of 2004.

ON-ROAD MITIGATION MEASURES

The current version of URBEMIS2002 (version 7.5.0) includes operational mitigation measures that focus on travel behavior. They include measures designed to encourage individuals to walk, bike, or use transit in lieu of driving. A separate memo prepared by Nelson\Nygaard Consulting Associates (September 9, 2004) describes proposed changes to URBEMIS2002's operational mitigation measures.

In its current format, URBEMIS does not allow the user to enter mitigation measures to reduce on-road emissions associated with medium- and heavy-duty vehicles. This memorandum describes Jones & Stokes' proposed approach for incorporating operational on-road mitigation measures into URBEMIS2002.

The proposed addition of on-road mitigation to URBEMIS would focus on those measures that can be used to reduce emissions from diesel powered medium and heavy-duty engines (over 14,000 lbs). Although these on-road mitigation measures could be used to reduce emissions for any land use designation, they are most useful for land uses with a high percentage of on-road truck use, such as warehouses, manufacturing firms, and industrial uses. Other land uses that have a large number of on-road truck trips, such as large retail stores, may also reduce emissions using this new mitigation option.

Jones & Stokes' original proposal was to group on-road mitigation measures into the following four categories:

- Repower existing engines,
- Retrofit existing engines,
- Purchase new engines, and/or
- Use alternative fuels.

However, after discussing this topic with the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) during the May 13th, 2004 conference call, it became clear that this approach had too many uncertainties and could not be accurately estimated by URBEMIS.

Instead, for project applicants wishing to provide on-road mitigation for medium- or heavy-duty trucks, the applicant would be required to work with the SJVUAPCD to estimate the pounds per day and tons per year emission reductions associated with the project. URBEMIS would be modified so that the user has the option of entering the pounds per day and tons per year emission reductions as calculated by the SJVUAPCD.

This approach would work much the same way in other air districts. The project applicant would need to work with the air district to determine the emission reduction associated with a project. That emission reduction would then be entered directly into URBEMIS.

AREA SOURCE MITIGATION MEASURES

URBEMIS2002 currently can be used to estimate emissions from five categories:

- Natural gas fuel combustion,
- Woodstove fuel combustion,
- Fireplace wood combustion,
- Landscape fuel combustion, and
- Consumer products.

We propose adding one additional area source category, architectural coatings, to the area source emissions module. Each of these six area source emission categories is discussed separately below.

Natural Gas Combustion

Emission Factors

URBEMIS2002 can be used to estimate natural gas fuel combustion emissions from cooking and water and space heating using an approach first described in Tables A9-12, A9-12-A, and A9-12-B in the South Coast Air Quality Management District CEQA handbook (South Coast Air Quality Management District 1993). The equation used to estimate CO, ROG, NOx, and PM10 emissions from natural gas combustion is described in the URBEMIS2002 User's Manual. No changes are proposed to those emission factors.

Mitigation Measures – Natural Gas Combustion

URBEMIS currently includes three categories of area source mitigation measures: residential, commercial, and industrial. The residential and commercial categories include several mitigation measure check boxes that apply to space and water heating. They include:

- Solar water heaters;
- Central water heaters;
- Orient buildings north/south; and
- Increase insulation beyond Title 24.

One additional mitigation measure - all electric landscape maintenance equipment – is included in URBEMIS for residential and commercial land uses. That mitigation measure is described separately below under the landscape fuel combustion heading. Orienting buildings north/south is currently the only industrial mitigation measure included within URBEMIS.

Jones & Stokes proposes modifying the natural gas combustion mitigation measures so that only three measures are included, one each for residential, commercial, and industrial land uses. Each measure would be based on building energy efficiency relative to Title 24, California's energy efficiency regulation for residential and nonresidential buildings. The three URBEMIS measures are as follows:

- ❑ Residential Land Uses: Increase energy efficiency ___% beyond Title 24.
- ❑ Commercial Land Uses: Increase energy efficiency ____% beyond Title 24.
- ❑ Industrial Land Uses: Increase energy efficiency ____% beyond Title 24.

The user would be required to turn on the appropriate measure and enter the percentage increase in energy efficiency. Emission reductions would be proportional to the increase in building energy efficiency beyond Title 24. For example, the developer of a

commercial land use that proposes an increase in energy efficiency 10% beyond the Title 24 requirements would receive a 10% reduction in natural gas combustion emissions compared to uncontrolled emissions.

Title 24 requires that compliance (with Title 24) be demonstrated before a building permit can be issued. This requirement applies to any heated building in California. Consequently, the percentage increase in energy efficiency beyond Title 24 would be based on the required compliance documentation.

Residential natural gas combustion primarily includes space heating, water heating, and cooking. One comment raised during the May 13th conference call was whether natural gas used for cooking is properly accounted for in the above mitigation. Data published by the California Air Resources Board (Emission Inventory Source Category 7.2 Residential Natural Gas Combustion, Revised November 1998) lists the percentage of residential natural gas use by category. That evaluation shows that approximately six percent of natural gas used in California residences is for cooking. Title 24 includes specific measures for natural gas cooking equipment. Since Title 24 covers natural gas cooking and because the cooking category is relatively small compared to total gas use, the mitigation measures listed above for total natural gas are sufficient to account for natural gas used for cooking.

Wood Stoves, Natural Gas Fireplaces, and Wood Fireplaces

Currently, URBEMIS includes wood stoves and wood fireplaces as separate area source emission categories. We propose modifying how these two emission source categories appear within URBEMIS and adding a third category, natural gas fireplaces.

The user, upon selecting this category, would be shown a screen with four tabs, which represent four separate screens that can be selected. As illustrated in the following table, the first screen would list the percentage of woodstoves, natural gas stoves, and fireplaces associated with the selected residential land uses. The remaining three screens would show the values that could be modified by the user for woodstoves, natural gas fireplaces, and wood fireplaces, respectively.

In the San Joaquin Valley, the percentage of homes with each of the three hearth options would vary based on housing density allowed by the SJVUAPCD's Rule 4901. For example, if the residential land uses entered by the user had a housing density of three per acre, then URBEMIS would, on the first "hearth" screen, show the percentages in the second column of Table 1.

The following table illustrates the percentages for the three situations allowed by Rule 4901. Where the housing density is 3 per acre, 2 homes or 67% could use woodstoves and 33% of the homes would be allowed to have wood stoves. For housing densities

exceeding three per acre, the percentage of woodstoves would decrease and the percentage of natural gas stoves would increase. Where the density of homes is between 2 and 3, 100% of homes are assumed to have wood stoves. Finally, when the density of homes is 2 per acre, half are assumed to have a fireplace and half are assumed to have woodstoves.

Table 1. Wood Stove, Natural Gas Fireplace, and Wood Fireplace Percentages

	PERCENTAGE OF HOMES WITH THIS OPTION		
	3 or more homes per acre	More than 2, less than 3 homes per acre	2 or fewer homes per acre
Wood Stoves	67%	100%	50%
Natural Gas Stoves	33%	0%	0%
Fireplaces	0%	0%	50%
None of the Above	0%	0%	0%
Total	100%	100%	100%
Assumption	Assumes 3 per acre	Assumes 2.5 per acre	Assumes 2 per acre
Based on SJVUAPCD Rule 4901.			

For areas outside of the San Joaquin Valley, URBEMIS will assume the following percentages:

- Wood Stoves: 35%
- Natural Gas Stoves: 55%
- Fireplaces: 10%
- None of the above: 0%.

These percentages represent the existing percentages within URBEMIS for wood stoves and fireplaces while also assuming that the remaining homes will have natural gas stoves.

Each air district would have the option to modify these default percentages.

Wood Stove Emission Factors

The emission factors currently used by URBEMIS to calculate wood stove emissions are the most recently available, based on a review of the wood stove emission factors at the U.S. EPA's emission factor web site (http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s10.pdf). Consequently, no changes are proposed to URBEMIS' wood stove emission rates. The emission rate equations are listed in the URBEMIS2002 User's Manual.

Natural Gas Stove Emission Factors

Jones & Stokes will incorporate natural gas stove emission factors into URBEMIS using the AP-42 emission factors for natural gas combustion (U.S. EPA, 1998). Emissions will be estimated using the following equations:

Pounds per day = A * B * C * D

Tons per year = Pounds per day * (E / 2000)

Where: A = fireplace emission rate for each pollutant,

- 94 pounds NOx / standard cubic foot (scf),
- 40 pounds CO/scf,
- 5.5 pounds ROG/scf,
- 7.6 pounds PM10/scf, and
- 0.6 pounds SO_2/scf.

B = amount of natural gas burned per day (scf),
C = number of residential units,
D = percentage of units with natural gas fireplaces, and
E = days per year (for tons per year emission calculations).

The emission equation will assume that the average stove is 30,000 Btu's, that there is 1,020 Btu's per standard cubic foot of gas, that the stove is used for an average of 2 hours per day during the winter months, and 100 days per year (200 hours per year).

Wood Fireplace Emission Factors

The emission factors currently used by URBEMIS to calculate fireplace emissions are the most recently available, based on a review of the fireplace emission factors at the U.S. EPA's emission factor web site http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s09.pdf Consequently, no changes are proposed to URBEMIS' fireplace emission rates.

Wood Stoves, Natural Gas Fireplaces, and Wood Fireplaces Mitigation Measures

Currently, URBEMIS2002 has no mitigation measures for woodstoves or wood fireplaces (Natural gas fireplaces are not currently part of URBEMIS2002.). Mitigation measures will be included in URBEMIS2002. The proposed change will allow the user to make changes to the percentages of wood stoves, natural gas fireplaces, and wood fireplaces that will be installed in new residences.

Landscape Fuel Combustion

Emission Factors

Landscape maintenance equipment generates emissions from fuel combustion, from evaporation of unburned fuel, and from fugitive dust generated by equipment such as leaf blowers. Emissions include NOx, ROG, CO, and PM10. The emission factors used to estimate equipment emissions include exhaust and evaporation. Emission factors have not yet been developed for the fugitive dust generated by certain types of equipment generate.

Equipment in the landscape category includes lawn mowers, roto tillers, shredders/grinders, blowers, trimmers, chain saws, and hedge trimmers used in residential and commercial applications. Engines in this category are 25 horsepower or less. This category also includes air compressors, generators, and pumps used primarily in commercial applications (California Air Resources Board 2004).

The California Air Resources Board has enacted regulations to limit emissions from landscape maintenance equipment. Beginning in 1994 these regulations imposed emission limits on all landscape maintenance equipment sold. Those regulations became more stringent for equipment sold in 1999 and later. Consequently, the emissions from this source category are similar to automobile emissions in that the turnover in the equipment fleet plays an important part in how quickly emission reductions are achieved.

URBEMIS2002 estimates emissions from this source category based on the year in which the user is attempting to estimate emissions. The California Air Resources Board has prepared estimates of emissions in 2000 and 2010. The proposed equations for this source category are divided into residential and commercial categories. The residential equation applies only to SFHU. The commercial equation is based on emissions per business unit and includes multifamily residential land uses.

The equations shown below are similar to those currently used by URBEMIS except that the pounds of pollutant per single-family residential unit and commercial business have been updated to reflect recent data developed by the California Air Resources Board (Cordero, M. and W. Wong, 2003).

2000 Emissions - Residential
ROG (pounds/day) = 0.0077 pounds ROG / SFHU/day * SFHU
CO (pounds/day) = 0.0449 pounds CO / SFHU/day * SFHU
NOx (pounds/day) = 0.0003 pounds NOx / SFHU/day * SFHU
PM10 (pounds/day) = 0.0002 pounds PM10 / SFHU/day * SFHU

2000 Emissions - Commercial
ROG (pounds/day) = 0.1593 pounds ROG / Business Unit * Number Business Units
CO (pounds/day) = 0.9298 pounds CO / Business Unit * Number Business Units
NOx (pounds/day) = 0.0061 pounds NOx / Business Unit * Number Business Units
PM10 (pounds/day) = 0.0041 pounds / PM10 Business Unit * Number Business Units

2010 Emissions - Residential
ROG (pounds/day) = 0.0038 pounds ROG / SFHU/day * SFHU
CO (pounds/day) = 0.0305 pounds CO / SFHU/day * SFHU
NOx (pounds/day) = 0.0005 pounds NOx / SFHU/day * SFHU
PM10 (pounds/day)= 0.0001 pounds PM10 / SFHU/day * SFHU

2010 Emissions - Commercial
ROG (pounds/day) = 0.0899 pounds ROG / Business Unit *Number Business Units
CO (pounds/day) = 0.6310 pounds CO / Business Unit * Number Business Units
NOx (pounds/day) = 0.0094 pounds NOx / Business Unit * Number Business Units
PM10 (pounds/day)= 0.0013 pounds PM10 / Business Unit * Number Business Units

The residential emission factors shown in the 2000 emission equations are based on total California single family residential emissions divided by the total number of California SFHU in 2000. Similarly, the commercial emission factors for 2000 are based on total California non-farm business emissions divided by the California's total 2000 business units (U.S. Department of Commerce 2003). For the commercial equations, URBEMIS2002 bases the number of business units on the number of non single-family housing land uses specified by the user.

The 2010 emission rates are based on ARB's estimates of emissions for this source category, broken into residential and commercial categories.

URBEMIS2002 will use the emission rates shown for 2000 for 2000 emissions. For 2001 through 2009, URBEMIS2002 will use interpolated emission factors by assuming a uniform decrease in the emission rate each year between 2000 and 2010. In 2010 and succeeding years, the 2010 emission rates will be used.

Average annual emissions assume that daily emissions would occur only during the summer period of 180 days. The end user will be able to modify the length of the summer period.

Mitigation Measures – Landscape Fuel Combustion

URBEMIS2002 currently allows the user to specify a mitigation measure in which electric powered equipment can be used to replace gas-powered equipment. However, this is currently an all or none mitigation measure. The following measure will allow the user to enter a percentage representing the proportion of residential and non-residential equipment that will be replaced by electrically powered equipment as follows:

- Replace ____% of residential landscape equipment with electrically powered equipment and provide electrical outlets at the front and rear of residences.

- Replace ____% of non-residential landscape equipment with electrically powered equipment and provide electrical outlets for the use of such equipment.

Consumer Products

Emission Factors

Consumer products comprise one of the largest solvent-use categories of reactive organic gases in California. Consumer product emissions are any chemically formulated product used by household and institutional consumers. They include a wide range of product categories, including air fresheners, automotive products, household cleaners, and personal care products (California Air Resources Board, 2000).

Emissions associated with these products primarily depend on the increased population associated with residential development. URBEMIS estimates consumer products when one or more residential land uses have been selected by the user. ROG emissions associated with consumer product use are currently estimated with the following equation:

ROG (pounds/day) = 0.0171 daily pounds of ROG per person * number of residential units * 2.861 persons per residence

The revised consumer products emission factor equation includes modifications of the pounds ROG per person and persons per residence variables:

ROG (pounds/day) = 0.013 daily pounds of ROG per person * number of residential units * 2.93 persons per residence (will vary by county).

The ROG emission factor is based on an average of the total estimated ROG emissions from consumer products divided by the total California population (California Air Resources Board, 2004; California Department of Finance, 2004). The ROG pounds per person emission factor ranges from 0.1927 in 2003 to 0.2182 in 2020. An average of these emission factors – 0.2055 pounds ROG per person – will be incorporated into URBEMIS as the default emission factor.

The persons-per-residence shown in the equation above is a California average. Within URBEMIS, separate estimates of persons per residence will be included for each county.

Mitigation Measures – Consumer Products

No feasible mitigation measures have been identified to reduce consumer product emissions.

Architectural Coatings

Emission Factors

Currently, URBEMIS estimates architectural coatings emissions as part of the construction module but not as part of area sources. However, a percentage of buildings are repainted each year and the ROG emissions associated with those buildings will be incorporated as an area source emission category.

Architectural coating emissions will be calculated using the same approach as in the construction module except that two additional variables will be added, one for residential coatings and one for non-residential. Those variables, which can be edited by the user, will show the percentage of a project's total square footage that will be repainted each year. We currently propose using 10% for both residential and non-residential buildings. However, this value may change as we continue to research this issue. Also, the individual air districts will have the option of modifying this percentage.

Mitigation Measures – Architectural Coatings

There are few feasible mitigation measures available to reduce evaporative emissions associated with architectural coatings. The best approaches involve using materials that require no architectural coatings during building construction or using coatings with lower ROG content than are currently required by regulation.

Instead of being considered a mitigation measure, we will assume that the use of "no-coatings" building materials is part of the project. Consequently, the use of coatings free building materials would have to be accounted for within the unmitigated portion of URBEMIS. This could be accounted for be reducing the coating thickness or the conversion factors (2.7 for residential, 2.0 for non-residential) that is used to convert building square footage to the amount of surfact area to be painted.

Although the use of low ROG content coatings is a feasible mitigation measure, it is considered unenforceable, especially during the operational phase of a project. Consequently, no mitigation measures will be incorporated into the architectural coatings category of the URBEMIS area source mitigation measures.

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M E M O R A N D U M

To: Tim Rimpo

From: Patrick Siegman

Date: October 10, 2004

Subject: **Final Recommendations for URBEMIS 2002 Mitigation Measures**

Introduction

This memorandum sets out recommendations to revise the operational mitigation component of URBEMIS 2002. These have been developed with three main aims in mind:

- **Simplify** the existing mitigation component, which while extremely detailed, is daunting to new users and has extensive data requirements. In particularly, the division between "environment factors" and "mitigation measures" can be confusing.
- **Improve consistency.** Many of the inputs to the mitigation component are extremely subjective (e.g. whether some, few or no bike routes provide wide paved shoulders and have few curb cuts). We propose making these more quantitative, and/or providing additional guidance in the users' manual or within the program itself.
- **Improve accuracy and transparency.** While many of the inputs to the current mitigation component have been proven to have an impact of travel behavior, research is still at an early stage of assessing quantitative impacts, and how these interrelate with other mitigation strategies. The recommendations here update the current mitigation component in the light of new research.

An extensive body of research has been compiled as to the impacts of particular mitigation strategies on travel behavior. However, in general, this has either had an academic focus, or been undertaken for the purposes of developing citywide or regional travel models. For example, many agencies have sophisticated procedures for assessing non-single occupancy auto travel at the level of TAZ or above, but not at the development level. There is extremely little guidance on how to use this data in the type of application needed for URBEMIS 2002 – namely, to provide quantitative estimates of the impact on trip generation and vehicle miles traveled (VMT) at the development level.

Many agencies do provide credits for individual developments that implement mitigation measures, for example when assessing impact fees or conducting traffic studies. Some California examples include C/CAG in San Mateo County and VTA in Santa Clara County. A brief, national review was also conducted for purposes of this memorandum.1 In general, however, these credit programs are only loosely based on the latest travel research, and it could be argued that they function more at a policy level, in providing incentives for developers to incorporate elements such as demand management programs that the agency considers desirable.

The recommendations here therefore attempt to bridge the gap between academic studies and complex regional or area-wide models on the one hand, and more site-specific traffic assessments on the other hand. The emphasis is on providing the best possible estimate while minimizing data requirements. The overall effect, compared to the existing mitigation component, is to reduce the number of inputs required, but make them more quantitative.

It cannot be too highly stressed that the trip reductions recommended here are valid at a sketch-planning level only, and are subject to considerable uncertainty. While they should ideally be expressed as a range, in order to expressly account for this uncertainty, a single value is needed for purposes of the Indirect Source Review in order to allow the appropriate fee to be calculated. The same limitations noted in the documentation for the existing mitigation component still apply, and are worth repeating here:

> The URBEMIS 2002 mitigation component is a significant advance over past attempts to quantify the benefits of air quality mitigation measures, however, users should recognize that travel behavior is very complex and difficult to predict. The component relies on the user to determine factors critical to travel behavior that are somewhat subjective. As GIS and electronic traffic monitoring and data collection become a reality in many cities, the ability to identify factors critical to walking, bicycling, and transit use will be enhanced. The URBEMIS 2002 mitigation component provides a starting point for using currently available data to demonstrate the benefits of urban design and traditional mitigation measures in reducing air quality impacts.

1 Agencies contacted included: New York Metropolitan Transportation Council; Atlanta Regional Commission; Alameda County, CA; and San Luis Obispo County, CA.

The mitigation component results, however, should still be interpreted as the mid-point of a range. Recent research has pointed towards the dangers inherent in reporting precise values, when the results are the subject of considerable uncertainty (Shoup, 2003). However, although the methodological dangers are obvious, there is generally no question about the *direction* of the relationship, only its size and the appropriate variable. Some adjustment is better than none at all – which is what most conventional trip generation methodologies provide (Ewing & Cervero, 2001). In addition, existing project-level trip generation methodologies, even though well-accepted within the transportation planning and engineering profession, are themselves subject to considerable uncertainty, and results are reported with unwarranted precision (Shoup, 2003).

Other considerations that should be noted include:

- The key output that is sought here is reduction in *vehicle trips.* Research results, however, often report results in terms of VMT. Where no alternative is available, we assume that VMT is proportional to vehicle trips.
- Elasticities are generally used to make the calculations, since when used with care, they provide a satisfactory, means of preparing first-cut aggregate response estimates for various types of transportation system changes (Pratt *et. al.,* 2000). They also provide a transparent and accessible method of reporting results, that can be transferred from one region to another (Ewing & Cervero, 2001).
- There are major theoretical issues regarding the direction of causality that have still to be resolved in the research. For example, does an increase in density lower vehicle trip generation rates, or do more dense places attract people who tend to make fewer vehicle trips? For the purposes of this analysis, however, the distinction is unimportant. The key issue (using the same example) is that more dense places are associated with fewer vehicle trips.
- Local planning controls and development economics are assumed to provide an important "reasonableness" check on the recommended trip reductions. For example, reductions in parking supply will not normally be allowed unless the local jurisdiction is confident that complementary trip reduction measures will be applied. Equally, it is unlikely that frequent transit service will be provided to a destination with low potential ridership, given competing demands on an agency for service.

About the Trip Generation Manual

At its heart, the URBEMIS mitigation component is a tool for modifying the average trip rates reported in the Institute for Transportation Engineers' *Trip Generation* manual to make

them more accurate, so that they fairly reflect the particular characteristics of a proposed development. Before modifying these average rates, it is therefore useful to understand the manual itself: how the average rates were derived; the original data sources that underlie the manual; and the manual's own recommendations about when, and why, its average trip generation rates should be modified. Some key points are these:

- The ITE manual normally predicts trip generation from new buildings using just two variables. Typically, the user first selects a broad *land use type* (e.g. "High-Rise Residential Condominium/Townhouse"). Second, the user inputs the *quantity* of that land use type (e.g. "100 dwelling units").
- An important advantage of this simple approach is that very little information about a project is needed to predict trip generation, and trip generation calculations are simple.
- A primary disadvantage of such two-variable formulas is that they do not take into account the multiple other variables (parking price, transit service, etc.) that transportation research has shown to strongly affect trip generation, and so the variation in trip rates *within* each land use category is frequently very high.

Recognizing these points, the *Trip Generation* manual therefore advises the reader that the average trip generation rates reported in the manual "represent weighted averages from studies conducted throughout the United States and Canada since the 1960s. Data were primarily collected at suburban locations having little or no transit service, nearby pedestrian amenities, or travel demand management (TDM) programs. At specific sites, the user may wish to modify trip generation rates presented in this document to reflect the presence of public transportation service, ridesharing or other TDM measures, enhanced pedestrian and bicycle trip-making opportunities, or other special characteristics of the site or surrounding area."

However, while the studies may have been *primarily* conducted at such suburban sites, it appears from the sources referenced that for some land uses, particularly higher density residential land uses, many sites studied included at least some transit service, sidewalks, and other characteristics associated with lower vehicle trip rates. For the "High-Rise Residential Condominium/Townhouse", for example, the manual's text shows that sites were surveyed in such cities as Vancouver, Canada: a city where it is difficult to find high-density condominiums that lack sidewalks, transit service, and a mix of uses nearby.

As part of our research, we made several calls to and exchanged correspondence with the staff at the Institute for Transportation Engineers. The staff was unable to provide any additional data (beyond the text of the manual itself) on the characteristics of the developments used in its trip generation studies, and was also unable to provide the actual studies – the original data – which underlie the manual's conclusions. Therefore, it is not possible to define with certainty the precise characteristics of an "average site".

Given this paucity of information available on the original sources for the *Trip Generation* manual's, conclusions about the average characteristics of the different land uses in the manual (e.g., average residential density, or the percentage of neighborhood streets with sidewalks) necessarily must be estimated, rather than precisely calculated. Fortunately, a large body of other research on travel behavior and land use is available, and reasonable estimates can be made based upon this research.

Recommendations

1. Combine "environmental factors" and "mitigation measures."

URBEMIS 2002 distinguishes between "environmental factors" for pedestrians, cyclists and transit (i.e., the character of the existing neighborhood), and "mitigation measures" (i.e. those added by the development). The environmental factors both provide a mitigation measure in themselves (e.g. the credit for existing or planned transit service), and are also used to weight the mitigation measures (i.e., a lower credit is given for a mitigation measure in an area that has a low environmental factor).

The distinction does make it easier to give credits for specific mitigation measures (e.g. bus bulbs, sidewalks and bicycle parking). However, we recommend that the distinction be removed, since it also brings several important disadvantages. Most of these relate to either complexity, or the relative advantages of infill vs. greenfield development, as follows:

- The pedestrian environmental factors appear to be given less weight than the mitigation measures, even when it is taken into account that the environmental factors are also used to weight the mitigation measures. The credit for the surrounding pedestrian environment is 2%, compared to the maximum allowable reduction of 9%. This means that smaller, infill developments will be eligible for lower credits, since by their nature they will be more dependent on the surrounding environment and have more limited ability to fund mitigation measures.
- On a related point, the importance of the environmental factors compared to mitigation measures is largely a function of scale, i.e. development size. Larger projects, particularly on greenfield sites, will be starting from a "blank sheet," and on-site mitigation measures will be paramount. The appropriate trip reductions for smaller, infill developments, in contrast, will be more a function of the surrounding environment.
- Combining the environmental factors and mitigation measures would make the component easier to understand, particularly for inexperienced users. At present, the separation can be confusing.

2. Scale

This question relates to the area that should be analyzed. We recommend that this should be either the area within a half-mile radius from the center of the project, or the entire project area, whichever is larger. This is the same approach taken in the existing URBEMIS mitigation component. In effect, the smaller the development, the greater the consideration given to the wider project area.

3. Provide Post-Modeling Adjustments to Reward Other Mitigation Measures

One of the impacts of these recommendations would be to narrow the range of mitigation measures that are considered in the analysis. Some potential mitigation measures are excluded even though they are likely to have a travel behavior impact, either because they cannot be readily quantified, or because this would risk double counting an impact already quantified elsewhere (i.e. another variable, such as intersection density, serves as a proxy). We therefore recommend consideration of how post-model adjustments can be used to provide financial incentives for developers to incorporate these mitigation measures. This may include all those that are in the current mitigation component, but are not recommended for continued inclusion, including:

- Street trees
- Traffic calming
- Design maximizing visual interest for pedestrians, and “eyes on the street”
- Zero building setbacks
- Direct pedestrian connections
- Street furniture and artwork
- Pedestrian signalization and signage
- Street lighting
- Low speed limits on bicycle routes
- Safe routes to schools
- Bicycle parking ordinance
- Transit stop amenities
- Route signs and displays
- Bus turnouts and bulbs
- Structured parking

4. Modifying Average Trip Generation Rates

In general, both the recommended trip rate modifications and the overall philosophy of the mitigation component are similar to those in the existing URBEMIS model, and build extensively off this work. The major differences between the existing mitigation component and these recommendations are found in (a) the input variables, which are

designed to be more quantitative and less subjective, and are fewer in number, and (b) the formulas, which take advantage of the latest research on residential travel behavior.

Neighborhood-level trip generation and vehicle miles traveled vary by more than 80% in California cities (Figure 1). As the documentation for the existing mitigation component recognizes, areas with low trip generation and VMT levels have the highest development densities, a wide variety of uses within walking distance, safe and comfortable pedestrian access, paid parking requirements, and a high level of transit service.

Similarly, residential trip rates reported in the *Trip Generation* manual vary widely, both *within* individual land use types, and *between* land use types (Figure 2). For the land use type "Single Family Detached Housing", for example, reported rates ranged from a low of 4.31 daily trips per dwelling unit, to a high of 21.85 daily trips. The *Trip Generation* manual reports that, "This land use included data from a wide variety of units with different sizes, price ranges, locations and ages. Consequently, there was a wide variation in trips generated within this category." Between residential land use categories, the variation is still greater, as would be expected. For example, the average trip rate for the "Residential Condominium/Townhouse" land use type is 5.86 (or 39% lower than the average single-family detached house), while the lowest trip rate is 1.83 (or 80.9% lower). At the extremes, considering all residential land uses, the highest residential rate reported (21.85 trips/day) is more than ten-fold higher than the lowest rate reported (1.83 trips/day).

Figure 1 Daily Trips by Density, San Francisco Bay Area

	Households/Residential Acre					
	< 2	**2-5**	**5-10**	**10-20**	**20-50**	**> 50**
Mean Households/Residential Acre	1.4	3.6	6.7	13.5	30.6	121.9
Daily Vehicle Trips/Household	6.4	5.9	5.0	3.8	2.9	1.2
% Reduction in Daily Vehicle Trips/Household compared to lowest density areas	0%	9%	23%	41%	55%	82%

Source: MTC Household Travel Survey, 1990, cited in Holtzclaw, 2002

Figure 2 ITE Trip Rates for Selected Residential Land Uses

Land Use Code	Land Use Type	ITE Trip Rate		
		Low	Average	High
210	Single-Family Detached Housing	4.31	9.57	21.85
221	Low-Rise Apartment	5.1	6.59	9.24
230	Residential Condominium/Townhouse	1.83	5.86	11.79
222	High-Rise Apartment	3	4.2	6.45
232	High-Rise Residential Condo./Townhouse	3.91	4.18	4.93

Based on these data in Figures 1 and 2, and a wide range of additional transportation research, we have developed a set of formulas for modifying the average trip rates for residential land uses has been developed. For the URBEMIS user, the procedure for modifying residential trip generation rates will remain generally similar to the existing process, with three basic steps:

1. In the "Land Use Selection" screen, the user will enter the land use types (e.g. "Apartment, Low-Rise") and the number of dwelling units of each type.
2. Next, if the mitigation component is used, the user will be prompted to review the default values for several key variables (e.g. residential density, level of transit service) for each residential land use type. If the project's land uses have characteristics that are different from the default values (as they usually will be), the user will enter the correct values, in place of the default values.
3. Within the program, the formulas described hereafter will be used to calculate the resulting trip generation rates.

In keeping with the conclusions of current transportation research, a single set of formulas is used to modify the trip rates for all residential land use types. The input variables for these formulas assess five key land use characteristics (or "mitigation measures", in URBEMIS terms):

- Net residential density (measured by Households per Residential Acre)
- Mix of uses (using a jobs/housing measure)
- Presence of local-serving retail
- Level of transit service (measured by a transit service index)
- Bicycle and pedestrian friendliness (measured by an "pedestrian factor" index based on intersection density, sidewalk completeness, and bike lane completeness)

For each ITE residential land use type, a set of default values for these variables has been defined. If the default values for a residential land use type are left unchanged when running the mitigation component, then the resulting trip generation rate will be the standard ITE average trip generation rate for that land use type. For single-family detached housing, for example, the default values include a residential density of three units per residential acre, a transit service index score of 0 (representing no transit service within one-quarter mile of the site), and an intersection density of 250 intersections per square mile (typical of post-war cul-de-sac residential subdivisions). Figure 4 shows the default values for each land use type.

To achieve the lowest residential trip rate reported in *Trip Generation* (a manual which primarily measures stand-alone, single-use projects with little or no transit service), the input values required would include a density of 160 units per residential acre, the maximum level of transit service, the best possible mix of uses and local retail, and a pedestrian score equivalent to a complete sidewalk coverage with a network of blocks no larger than 300 feet on a side. This would result in a rate of 1.83 trips/day, or an 81% reduction from the average single-family house rate).

This is similar to the 82% difference in household trip generation between the lowest density areas with the poorest transit service (6.4 vehicle trips per household per day), and the highest-density areas with good transit and a higher quality pedestrian environment (1.2 vehicle trips per household per day), as shown in Figure 1. Figure 4 shows the input values that would be required to achieve this rate, as well as the input values required to achieve maximum possible reduction allowed.

In theory, choosing the maximum possible values for each of the *physical design variables* described above could result in a residential trip generation rate as low as 0.9 daily trips per unit. This represents a 90% reduction from the average rate for a single-family detached house. To achieve this rate, however, a neighborhood would have to have remarkable characteristics, similar to Manhattan or Hong Kong: a density of 380 units per acre, or more than three times the average density of San Francisco's densest neighborhoods (North Beach and Chinatown), the highest possible level of transit service, and so on.2

The recommended reductions for the individual physical design mitigation measures for residential uses are summarized in Figure 3. The remainder of the memorandum discusses the justification for these levels, along with the mitigation measures for non-residential uses. In general, the recommended maximums for individual components have been set at a level so that this overall 90% maximum reduction from the average single-family house

2 While rare in California, these extreme cases of Manhattan-like densities can be seen in projects such as San Francisco's single-room occupancy hotels for very low income residents, which achieve such densities by omitting parking and providing very small living quarters.

rate is maintained for residential land uses. While a greater reduction may sometimes seem warranted for an individual measure, a lower value has been selected to stay within this 90% maximum – a practice that helps avoid the considerable dangers of double counting.

In addition to the variables above, which primarily measure physical design characteristics, the formulas include mitigation measures that assess *demand management programs and similar measure*s. A maximum additional reduction of 7.75% from the average single-family house rate is possible through these measures.

Non-Residential Land Uses

For non-residential land uses, the general procedure for modifying rates is similar, and based upon many of the same research results. To modify non-residential trip generation rates, the following procedure is used:

1. For *physical design* mitigation measures, the formulas to determine percentage reductions are identical to the formulas for residential land uses, except for the 'Residential Density' measure, which cannot apply.
2. Additional mitigation measures are applied for *demand management programs and similar measures.* For non-residential uses, the number of available demand management measures is greater, as is the possible percentage reduction.

However, there is a key difference between the formulas used to modify residential rates, and the formulas used to modify non-residential rates:

1. For residential land uses, the percentage reductions shown for each mitigation measure refer to the percentage reduction from 9.57 trips per day (the rate for single family homes). The default values for each residential land use (Figure 4) are set at levels such that keeping these values generates the average trip rate for that land use.

2. For non-residential land uses, the percentage reductions shown for each mitigation measure refer simply to the percentage reduction from the average ITE trip generation rate for that land use. No special default values are required: they are simply set to create a 0% reduction as the starting value.

Figure 3 Summary of Recommended Trip Reductions

	Residential	Non-Residential	Comments
Physical Measures			
Net Residential Density	Up to 55%	N/A	
Mix of Uses	Up to 9%	Up to 9%	
Local-Serving Retail	2%	2%	
Transit Service	Up to 15%	Up to 15%	
Pedestrian/Bicycle Friendliness	Up to 9%	Up to 9%	
Physical Measures sub-total	*Up to 90%*	*Up to 35%*	
Demand management and similar measures			
Affordable Housing	Up to 4%	N/A	
Parking Supply	N/A	No limit	Only if greater than sum of other trip reduction measures
Parking Pricing/Cash Out	N/A	Up to 25%	
Free Transit Passes	25% * reduction for transit service	25% * reduction for transit service	
Telecommuting	N/A	No limit	Not additive with other trip reduction measures (see text)
Other TDM Programs	N/A	Up to 2%, plus 10% of the credit for transit and ped/bike friendliness	
Demand Management sub-total3	*Up to 7.75%*	*Up to 31.65%*	

3 This sub-total excepts the measures for parking supply and telecommuting, which have no limit.

Figure 4 Default Values for Residential Land Use Trip Generation Formulas

Default Values for Residential Trip Rate Formulas

Land Use Code	Land Use Type	Residential Density	Housing Units	Employees	Retail?	Transit Service	Intersection Density	Sidewalks	Bike Lanes	Ped factor	ITE Trip Rate Low	ITE Trip Rate Average	ITE Trip Rate High
210	Single-Family Detached Housing	3	100	17	no	0.00	250	0	0	0.06	**4.31**	**9.57**	**21.85**
221	Low-Rise Apartment	16	100	26	no	0.06	250	0.5	0	0.23	**5.1**	**6.59**	**9.24**
230	Residential Condominium/Townhouse	16	100	60	yes	0.10	400	1	0	0.44	**1.83**	**5.86**	**11.79**
223	Mid-Rise Apartment	38	100	60	yes	0.14	400	1	0	0.44	**NA**	**4.68**	**NA**
222	High-Rise Apartment	62	100	60	yes	0.14	400	1	0	0.44	**3**	**4.2**	**6.45**
232	High-Rise Residential Condo./Townhouse	64	100	60	yes	0.14	400	1	0	0.44	**3.91**	**4.18**	**4.93**

Trip Rates Resulting When Default Values Are Used

Land Use Code	Land Use Type	Reductions: Residential Density	Mix of Uses	Local Retail	Transit	Bike/Ped	Total	Resulting Trip Rate
210	Single-Family Detached Housing	0.0%	-0.6%	0.0%	0.0%	0.6%	0.0%	9.57
221	Low-Rise Apartment	27.9%	0.5%	0.0%	0.6%	2.1%	31.1%	6.59
230	Residential Condominium/Townhouse	27.9%	3.9%	2.0%	1.1%	3.9%	38.8%	5.86
223	Mid-Rise Apartment	39.8%	3.9%	2.0%	1.5%	3.9%	51.1%	4.68
222	High-Rise Apartment	44.8%	3.9%	2.0%	1.5%	3.9%	56.1%	4.20
232	High-Rise Residential Condo./Townhouse	45.1%	3.9%	2.0%	1.5%	3.9%	56.3%	4.18

Example Residential Trip Rate Calculations

Land Use Code	Land Use Type	Residential Density	Housing Units	Employees	Retail?	Transit Service	Intersection Density	Sidewalks	Bike Lanes	Ped factor	ITE Trip Rate Low	ITE Trip Rate Average	ITE Trip Rate High
210	"Worst Case" Single-Family	0.1	100	0	no	0.00	80	0	0	0.02	-	**-**	**21.85**
230	"Best Case" Res. Condo/Townhouse	160	100	150	yes	1.00	1300	1	0	0.67	**1.83**	-	**-**
NA	Maximum Possible Reduction	380	100	150	yes	1.00	1300	1	1	1.00	**NA**	**NA**	**NA**

Trip Rates Resulting When Example Values Are Used

Land Use Code	Land Use Type	Reductions: Residential Density	Mix of Uses	Local Retail	Transit	Bike/Ped	Total	Resulting Trip Rate
210	"Worst Case" Singe-Family Detached	-20.7%	-3.0%	2.0%	0.0%	0.2%	-21.5%	11.63
230	"Best Case" Res. Condo/Townhouse	51.4%	9.0%	2.0%	12.5%	6.0%	80.9%	1.82
NA	Maximum Possible Reduction	55.0%	9.0%	2.0%	15.0%	9.0%	90.0%	0.95

5. Data Requirements

Figure 5 shows the inputs that are required to complete the mitigation component in full, along with suggested data sources. Note, however, that the mitigation component can still be run, even if some of these inputs are missing. While no reduction would be granted for the particular mitigation measure for which the input was required, credits could be granted for other trip reduction measures.

Figure 5 Data Requirements and Suggested Sources

Required Input	Suggested Source		Comments
	Project	Surrounding Development	
Net residential density	Project plans	Block-level census data	Net residential data excludes land not devoted to residential uses
Number of housing units	Project plans	Block-level census data	Same basic source as for net residential density
Number of jobs	Project plans	Census Transportation Planning Package. Local jurisdiction may provide more current or fine-grained data	If data are only available per square foot, US Dept. Energy produces figures on average employee density
Local serving retail	Project plans	Site observations	
Below-market-rate units	Project plans	N/A	
Parking supply	Project plans	N/A	
Transit service	Transit agency maps/schedules		
Intersection density	Project plans	Street plans	Count can be automated if available in GIS
Sidewalk completeness	Project plans	Site observations	Count can be automated if available in GIS
Bike lane completeness	Project plans	Site observations	Count can be automated if available in GIS
Parking pricing	Development agreement or similar	Site observations (if applicable)	
Free transit pass provision	Development agreement or similar	N/A	
Telecommuting/flexible work schedules	Development agreement or similar	N/A	
Other TDM programs	Development agreement or similar	N/A	

6. Procedure for Small Projects

For developments in an established urban area below a certain size threshold, we recommend allowing them to adjust their trip generation rates based on the mode share in that census tract. This would avoid a disproportionate burden in gathering the data to document their likely trip reduction. (The analyst would need to certify that the project was similar in character to the existing development.) The recommended threshold is 50 average daily baseline vehicle trips, with the baseline being that calculated by URBEMIS before any of the reductions from mitigation measures are applied.

7. Substitute Methodologies

The recommended mitigation levels are, in our judgment, the most appropriate for a model that must apply to an extremely wide range of projects and geographic contexts. However, it must be recognized that there may be "special cases," where these standard reductions may not apply. For this reason, we recommend that any methodology for calculating reductions in VMT and vehicle trips may be substituted, provided that this is mutually agreed between the Air District and project proponent.

8. Measures Reducing VMT

The existing mitigation component allows for reductions in VMT (but not trip generation) for park-and-ride lots and satellite telecommuting centers. We do not recommend any changes to this aspect of the mitigation component.

9. Correction Factors

The existing mitigation component provides for trip type correction factors, based on evidence suggesting that certain trips are more likely to be captured by one mode rather than another. We do not recommend any changes to this aspect of the mitigation component.

A second correction factor in the existing mitigation component relates to trip distance, because, the documentation argues, bicycle and walking trips replace mostly shorter automobile trips. We recommend that this correction factor be eliminated, as there is little evidence to suggest that this phenomenon exists. Indeed, more complex changes in travel behavior are likely, such as mode shift to bicycling and walking trips being accompanied by a shift to closer destinations. For example, rather than drive to a grocery store on a freeway interchange, a household may walk to a smaller store in the neighborhood. Mixed use, compact neighborhoods are characterized by short overall trip lengths (see, for example, Kuzmyak et. al., 2003). Further evidence comes from the elasticities for trip reduction with respect to density, which are the same for both vehicle trips and VMT (Ewing & Cervero, 2001), suggesting that there is no impact on trip length.

Detailed Justification of Recommended Mitigation Levels

Default Values for Residential Land Uses

To develop the default values for residential land uses shown in Figure 4, we had to overcome a significant hurdle: ITE retains no data on the characteristics of the developments used in their trip generation studies. Default values for average density, transit service levels, and other variables had to be estimated using two alternative methods. First, we reviewed representative projects through research of literature and discussions with professionals in the fields of architecture and town planning, to ascertain typical ranges for density and other characteristics of each land use type (for useful summaries, see Calthorpe, 1993, and Local Government Commission,2002).

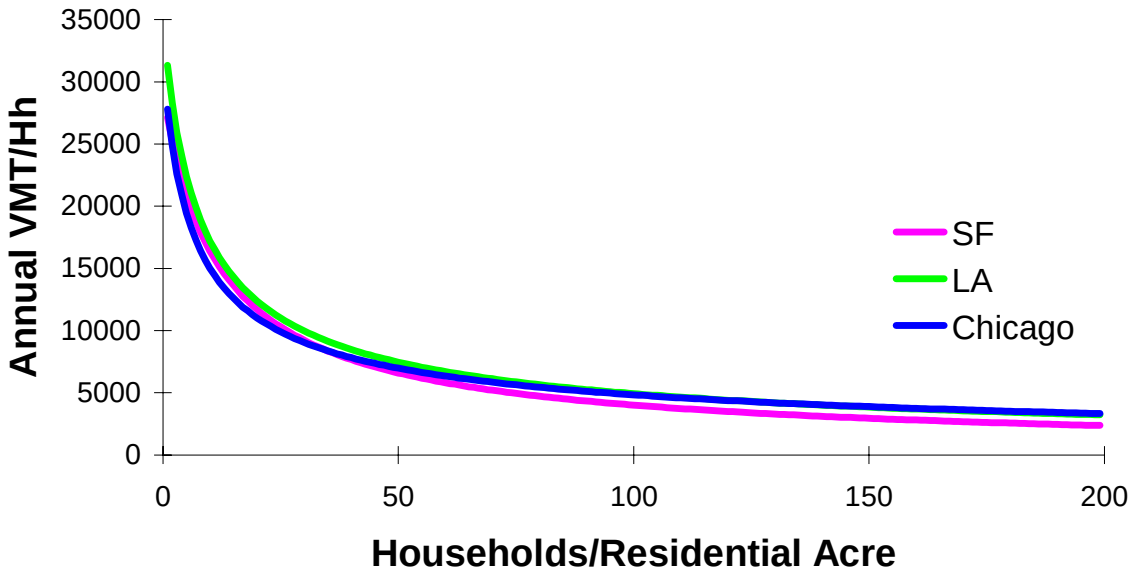
Second, these ranges of values were plugged into the formulas for the mitigation measures, and adjusted until the baseline values for each characteristic equaled the average ITE trip generation rates for each land use. For example, baseline density for Mid-Rise Apartments (64 units per residential acre) falls within the typical range observed from research of 45 to 125 units/acre, and when combined with other baseline characteristics for the land use, results in a 56.1% reduction in trip generation from the average rate for single family homes – the average reduction set forth in the ITE manual.

Finally, since the *Trip Generation* manual provides no daily trip generation rate for the "Mid-Rise Apartment" land use, we estimated a rate by extrapolating from the daily trip rate for the "High-Rise Apartment" land use type. The PM peak hour trip rate of 0.39 trips per unit for mid-rise apartments is 11.4% higher than the PM peak hour rate for high-rise apartments (0.35 trips/unit). Therefore, the daily trip rate for the "Mid-Rise Apartment" land use was estimated to be 4.68 trips per unit, or 11.4% higher than the daily trip for high-rise apartments (4.2 trips/unit).

Density

A considerable volume of research has investigated the links between density, particularly residential density, and travel behavior (for summaries, see Kuzmyak et. al, 2003; Boarnet & Crane, 2001). Overall, the conclusions can be summarized thus: there is a significant, quantifiable relationship between residential density and automobile use (see Figure 6), but there is uncertainty regarding the degree to which this effect is due to the inherent effects of density, as opposed to factors for which density serves as a proxy, such as parking price, local retail, transit service frequency and pedestrian friendliness.

Figure 6 Residential Density Vs. Vehicle Travel



Source: Holtzclaw et. al. (2002).

Fewer studies have attempted to disentangle the effects of density itself. Three of the main exceptions are:

- Typical elasticities for vehicular travel with respect to density are –0.1 to –0.04. These elasticities refer to the effect of density itself, isolated from variables that tend to be correlated with density such as transit frequency, and are additive to elasticities of other built environment factors. When these factors are not isolated, typical elasticities for VMT with respect to density are –0.22 to –0.27 (Kuzmyak et. al, 2003).
- The elasticity of density, when isolated from three other variables (diversity, design and destinations), is –0.043 with respect to vehicle trips, and – 0.035 with respect to VMT (Criterion and Fehr & Peers, 2001). However, this does not control for transit service levels.
- Cervero & Ewing (2001), in an update to this work, suggest a slightly higher elasticity of –0.05 with respect to both vehicle trips and VMT.

Note that density has been shown to have a nonlinear relationship with vehicle travel, with a threshold value of 25-30 units per acre below which the travel impacts of increased density are particularly large (Holtzclaw et. al, 2002). Holtzclaw et. al found that the best single variable equations to predict household vehicle travel (VMT per household, or

VMT/Hh) relied on Households per Residential Acre (Hh/RA). For the Los Angeles region, San Francisco and Chicago regions, these equations varied only slightly, producing the curves shown in Figure 6. For the Los Angeles region, this formula takes the form:

$$\frac{\text{VMT}}{\text{Hh}} = 19749\left(\frac{4.814 + \text{Hh/RA}}{4.814 + 7.140}\right)^{-0.639}$$

Based on this formula, the following elasticity formula is recommended for vehicle trips with respect to density. It is the same as Holtzclaw et. al' work, but reduced by 40% to take account of the fact that much of this impact will be realized through transit service, mix of uses and bicycle and pedestrian levels (which tends to correlate with density). The baseline assumed to correspond to a zero percent trip reduction is three units per acre, at which density the Holtzclaw formula results in 25,914 annual vehicle miles traveled per household. This translates into the following formula:

Trip reduction
= 0.6*(1-(19749*((4.814 + households per residential acre)/(4.814 + 7.14))$^{-0.639}$)/25914)

An apartment development of 16 units per residential acre, for example, would be estimated to generate 27.9% fewer trips than a three unit per acre project. The maximum allowable reduction recommended is 55% (equivalent to a 380 unit per acre development).

With this formula, "negative" reductions also apply, with less dense developments below the baseline level of three units per acre (for example large-lot housing) resulting in higher trip generation rates. (However, as long as the mitigation component is optional for developers or project proponents to complete, they will be unlikely to use it for projects whose overall score, for all components, will result in a finding to their disadvantage. For purposes of more accurately predicting vehicle trips and emissions, however, this negative reduction is useful and reflects the findings of the research literature.

Trip generation at the non-residential end is also influenced by density, but to a much lesser degree (Cervero, 1989, cited in Kuzmyak et. al, 2003). There are also far fewer studies investigating this relationship, and there is no comparable dataset to that for residential density. No reduction is recommended here.

Mix of Uses

Many references point to the impact of "diversity" or mix of uses on travel behavior. This is true both at the macro-scale, e.g. jobs-housing balance, and the micro-scale, e.g. the availability of services within walking distance. Key references, related to both the direction and magnitude of this relationship, include:

- Higher densities are most beneficial to transit ridership when they result in a mix of residential, commercial and office uses (Lund et. al., 2004).
- The elasticity of vehicle trips with respect to "diversity" is –0.051. The elasticity of VMT is –0.032. In this case, "diversity" is a measure of how the project affects regional population/employment balance. (Criterion and Fehr & Peers, 2001)
- Typical elasticities for vehicle trips with respect to local diversity (mix) are –0.03, and those for VMT are –0.05 (Ewing & Cervero, 2001).
- A balance of 1.5 jobs per household is estimated to produce a bus mode share 2 percentage points over the share for a single use area, although the degree of mix is not a useful estimating variable (Messenger & Ewing, 1996, cited in Kuzmyak et. al, 2003).
- Suburban activity centers with some on-site housing had 3-5% more transit, bike and walk commute trips (Cervero, 1989, cited in Kuzmyak et. al, 2003).
- The presence of retail reduces auto mode share by 2-5%, depending on neighborhood density. (Parsons Brinkerhoff, 1996, cited in Kuzmyak et. al, 2003).
- At suburban activity centers, the presence of retail in office buildings lowers vehicle trip rates by 6-8% (NTI, 2000, cited in Kuzmyak et. al, 2003).
- Employment sites with "good" nearby retail and commercial services have a vehicle trip rate 21.5% below the ambient rate. Sites with "fair" services showed an 8.3% reduction, and those with "poor" services a 5.3% reduction. This is attributed not just to the presence of these services, but the fact that they make TDM programs more likely to succeed (Comsis, 1994, cited in Kuzmyak et. al, 2003).

The analysis is complicated by the fact that some of the most beneficial developments from this perspective may be single-use, in an area where another use is predominant (e.g. residential in an employment area). To take this into account, the following procedure is proposed (adapted from Criteron and Fehr & Peers, 2001):

$$\text{Trip reduction} = (1- (\text{ABS} (1.5 * h – e) / (1.5 * h + e)) – 0.25) / 0.25 * 0.03$$

Where: h = study area households (or housing units)
e = study area employment

Negative reductions of up to 3% can result, and should be included.

This formula assumes an "ideal" housing balance of 1.5 jobs per household, based on Messenger & Ewing (1996), and a baseline diversity of 0.25. The maximum possible reduction using this formula is 9%.

This reduction takes into account overall jobs-population balance. The presence of local serving *retail* can be expected to bring further trip reduction benefits, and an additional reduction of 2% is recommended. This is towards the lower end of the values presented in the research discussed above, in order to avoid double counting with the diversity indicator.

Transit

The existing URBEMIS 2002 mitigation model places its primary emphasis on mode, i.e. whether service is provided by high-speed rail, commuter rail or bus. Within this framework, consideration is given to frequency (e.g. bus headways of 15 minutes or less score more highly than headways of 15-30 minutes).

For example, the current mitigation component would award the maximum score of 100 to a development 0.5 miles from a BART station, even if no other transit were available. A part of the city with several bus lines offering 10-minute service, in contrast, would score much lower, even though these transit lines would carry many more passengers.

Current transit planning thinking, however, emphasizes that frequency and speed are two of the most important factors determining mode choice, rather than whether the service is provided by bus, bus rapid transit, or rail. Researchers have found that there is no *inherent* preference for rail over bus, provided that the quality of service is the same (for example, Ben-Akiva & Morikawa, cited in Transportation & Land Use Coalition, 2002).

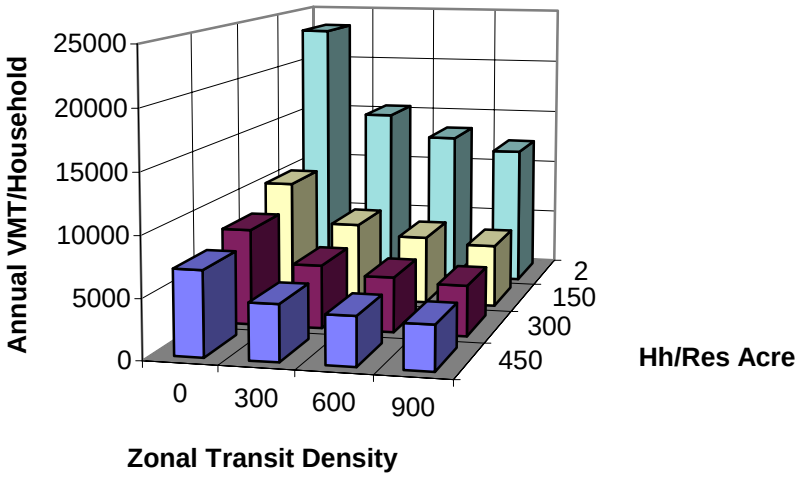
Key references include:

- The average elasticity of ridership with respect to frequency is +0.3 to +0.5. Higher elasticities of +1.0 have been observed in suburban systems, with the +0.3 value more typical of urban systems. (Kittselson & Associates et. al, 2003).
- Pratt et. al. (2003) suggest an elasticity of ridership with respect to service hours (i.e. a combined measure of frequency and service span) of +0.5. Ridership is most sensitive to frequency changes when the past service was infrequent.
- Modeling in Massachusetts suggests that halving transit service headways from 30 to 15 minutes leads to an 8% drop in vehicle trips. A further decrease to 5 minutes leads to a further 4% drop in vehicle trips (Pratt et. al., 2003).
- Holtzclaw et. al. (2002) show that vehicle travel falls as transit service levels increase, even when holding density constant (Figure 7). In the San Francisco Bay Area, a doubling of transit service from 300 to 600 (using the index described below) is associated with a 13% drop in VMT. An increase from 300 to 900 is associated with a 20% drop in VMT. In the Los Angeles region, the decreases in VMT are 12% and 18% respectively. However, the variable was omitted from the

vehicle travel model presented in this paper, since density was used as a proxy for transit service.

- The maximum distance that people are willing to walk to transit tends to be 0.25 miles for bus, and 0.5 miles for rail (and, presumably bus rapid transit). (Kittelson & Associates et. al, 2003). It is unclear whether there is a "distance decay" effect, whereas people are more likely to use transit at closer distances within this range (see Lund et. al, 2004).

Figure 7 VMT vs. Residential Density and Transit Use, San Francisco Bay Area



Source: Holtzclaw et. al. (2002).

Unfortunately, the elasticity of service with respect to transit ridership is difficult to convert to vehicle trip reduction, firstly because the baseline ridership needs to be known, and secondly because only a proportion (18-67% is cited by Pratt et. al., 2003) of new transit trips were formerly made by private auto. While it is clear that there is a direct correlation between transit service and vehicle trips, it is difficult to employ these elasticities directly. For this reason, the approach here is more in line with the existing mitigation component, which assumes a maximum percentage reduction for transit, and then reduces this based on a transit environment factor.

Various frequency-based transit service indices have been developed which have shown strong correlations with ridership. For example:

- In Los Angeles, the quality of four components of transit service (MTA rail, Rapid Bus, local bus and regional services) were rated on a scale of 0-3 for each community area, and then summed to provide the Transit Service Index on a scale of 0-12. (Nelson\Nygaard, 2002b).
- The studies by Holtzclaw et. al. (2002) used Zonal Transit Density, defined as the daily average number of buses or trains per hour times the fraction of the zone within 1/4 mile of the bus stop, or 1/2 mile of the rail station or ferry terminal, summed for all transit routes in or near the zone.

The Transit Service Index recommended here would combine the important features of all these approaches, with emphasis on frequency but with greater weighting given to rail services. Greater weight is also given to dedicated shuttles, in recognition of the fact that these are likely to be more closely targeted to the needs of the development. The Transit Service Index would be determined as follows:

- Number of average daily weekday buses stopping within 1/4 mile of the site; plus
- *Twice* the number of daily rail or bus rapid transit trips stopping within 1/2 mile of the site
- *Twice* the number of dedicated daily shuttle trips
- Divided by 900, the point at which the maximum benefits are assumed. (This equates to a BART station on a single line, plus four bus lines at 15-minute headways.)
- Developments that are larger than 0.5 miles across in any direction must be broken into smaller units for purposes of determining the transit service index. The average of all units would then be used.

Figure 8 shows some examples of how service frequencies translate into Transit Service Index scores (note these are additive, if a location has more than one component).

Figure 8 Example Transit Service Index Scores

Transit Service	Score	Assumptions
BART (single line)	0.33	150 trips per day (15-20 minute headways in each direction from 4 AM-12 AM)
15-minute bus, 5 AM – 12 AM	0.17	
30-minute bus, 5 AM – 7 PM	0.06	
Amtrak San Joaquin	0.03	6 trips per day in each direction
Dedicated commute shuttle	0.02	5 trips per commute period (single direction)

As well as existing service, planned and funded transit service would be included in the calculation. Purely demand responsive service would not be included.

A maximum trip reduction of 15% is recommended. This is the same as the existing URBEMIS 2002 trip reduction for existing and planned transit service.

In order to account for non-motorized access to transit, we also recommend that half the reduction be dependent on the pedestrian/bicycle friendliness score (calculated in the following section), similar to the approach taken in the existing mitigation component. This ensures that places with good pedestrian and bicycle access to transit are rewarded.

Trip reduction = t * 0.075 + t * ped/bike score * 0.075

Where t = transit service index

Bicycle and Pedestrian

Since bicycle mode share and pedestrian mode share depend on similar neighborhood characteristics, such as a fine-grained street grid, we recommend that a single factor be used to account for both modes. The bicycle and pedestrian components of the URBEMIS 2002 mitigation component are already well developed. However, the inputs are largely subjective, and there is still little evidence to justify the precise amount of credits for many of the individual mitigation measures (e.g. street trees).

Many street design factors have, however, been shown to promote walking and cycling. These include:

- Street connectivity, with traditional street networks that are more New Urbanist or grid-like, as opposed to the loops, lollipops and cul-de-sacs of most conventional subdivision. There are various measures of connectivity (summarized in Dill, 2003), such as:
    - Block length, size or density
    - Intersection density
    - Street density
    - Connected node ratio (number of street intersections divided by the number of intersections plus cul-de-sacs)
    - Link-node ratio (links are roadway or pathway segments between two nodes, which are intersections or cul-de-sac ends)
    - Grid pattern (percentage of intersections that are four- or more way).
    - Pedestrian Route Directness (ratio of route distance to straight line distance)
    - Effective Walking Area (% of parcels within 1/4 mile, that are also within 1/4 mile walking distance)

- Human-scale streetscapes with adequate pedestrian amenities, access to shopping and other amenities, and higher densities (Lund et. al., 2004)

Other relevant research includes:

- A composite indicator, the "Pedestrian Environment Factor," provides a statistically significant correlation with trip generation and VMT. It is comprised of four inputs (Parsons Brinkerhoff, 1993):
    - Ease of street crossings
    - Sidewalk continuity
    - Local street characteristics (grid vs. cul de sac)
    - Topography
- In Portland, OR, an increase in the PEF from "pedestrian hostile" to "almost average" reduces daily vehicle trips by 0.4 per household (7%). An increase from "almost average" to "fairly good" provides a daily reduction of 0.2 trips (Parsons Brinkerhoff, 1993, cited in Kuzmyak et. al, 2003).
- Sidewalk completeness, route directness and network density together have a vehicle trip elasticity of –0.05 (Ewing & Cervero, 2001).
- For a high degree of walkability, block lengths of approximately 300 feet are recommended. Short blocks provide more pedestrian crossing opportunities and direct walking routes, and mean that traffic is more likely to be dispersed. Downtown Los Angeles, for comparison, has about 150 intersections per square mile. (Ewing, 1999).

There is a strong tradeoff here between simplicity and low data requirements on the one hand, and robustness and accuracy on the other. Pedestrian and bicycle level of service work for the Florida Department of Transportation and FHWA, for example, has shown that there are numerous statistically significant factors that can be included to assess the quality of the bicycle and pedestrian environment. These include motor vehicle volumes and speeds, truck volumes, roadway widths, urban design, and lateral separation between pedestrians and motor vehicles (for example, FHWA, 1998; Landis et. al, 2001).

However, we recommend that in order to keep data requirements to a minimum, one or two of the street design indicators discussed by Dill (2003) and Ewing and Cervero (2001) be used, together with a single bicycle measure. Since route directness and network density measure similar characteristics, we recommend the use of one of these (network density, which is inversely related to block size) plus sidewalk completeness and bicycle network completeness. The pedestrian/bicycle factor would then be calculated as follows:

Ped/bike factor =
(network density + sidewalk completeness + bike lane completeness) / 3

Where:

Network density = intersections per square mile / 1300 (or 1.0, whichever is less)

Note: In most GIS applications, intersections are counted based on the number of line segment terminations, or each "valence." Intersections have a valence of 3 or higher – a valence of 3 is a "T" intersection, 4 is a four-way intersection, and so on.4 (Georgia Institute of Technology, 2002). Therefore, if intersections are counted manually on a map or project plan, care needs to be taken to distinguish between 3-, 4- and 5-way intersections, and factor them up accordingly. The 1,300 value roughly equates to a dense grid with four-way intersections every 300 feet, per the recommendation of Ewing (1999). Intersections with dedicated routes for pedestrians and/or bicyclists should be included in this calculation.

Sidewalk completeness =

% streets with sidewalks on both sides + 0.5 * % streets with sidewalk on one side

Bike lane completeness =

% arterials and collectors with bicycle lanes, or where suitable, direct parallel routes exist

A maximum reduction of 9% is proposed, based on the existing URBEMIS mitigation component.5 The trip reduction would then be calculated as:

Trip reduction = 9% * ped/bike factor

No reduction should be allowed if the entire area within a half-mile walk of the project center consists of a single use. (Note that this applies to a half-mile walk, rather than straight-line distance, to account for barriers such as freeways.) However, the ped/bike factor can still be used to calculate pedestrian access to transit, as part of the transit mitigation measure.

Affordable and Senior Housing

A significant amount of evidence points to the fact that lower-income households and senior citizens own fewer vehicles and drive less. Research includes:

4 A valence of 1 indicates that a line segment has terminated, e.g. in a cul-de-sac. A valence of 2 means that the street is continuing.

5 Note that this excludes the bicycle reduction in the current mitigation component. However, this compensates for the fact that the reductions recommended for the mixed use and density variables will be realized in practice through pedestrian and bicycle mode share.

- Russo (2001) cites evidence from the San Francisco Bay Area travel survey, which shows that households earning under $25,000 per year make 5.5 vehicle trips per day, compared to a regional average of 7.6. High income households (earning more than $75,000 per year) make an average of 10.5 trips. Note that this data does not control for other factors, such as density and transit access.
- In the San Francisco Bay Area, Los Angeles and Chicago, income was one of four variables with sufficient independent explanatory power to include in the model of VMT and vehicle ownership (Holtzclaw et. al., 2002).

Obviously, it is difficult if not impossible to account for the exact incomes of residents in URBEMIS, most obviously because the occupants are not known at the pre-development stage. However, the percentage of deed-restricted below-market-rate (BMR) housing does offer a way to incorporate this effect.

We recommend a 3% reduction in vehicle trips for each deed-restricted BMR unit.6 Thus, the total reduction is as follows:

Trip reduction = % units that are BMR * 0.04

A development with 20% BMR units would thus gain a 0.8% reduction. A development with 100% BMR units would gain a 4% reduction.

Parking Supply

Significant correlations between parking supply and employee mode split have been observed. For example, a study of the link between parking availability and transit use in eight Canadian downtowns found an extremely high elasticity of –0.77 (Morrall & Bolger, 1996, cited in Kuzmyak et. al., 2003b). In California, the number of parking spaces per worker was found to be one of the main two elements of a binomial logit model predicting transit mode share among TOD office workers (Lund et. al, 2004).

As with residential density, the extent to which parking supply itself is a causal factor is uncertain. In practice, it probably serves as a proxy for variables such as price, high quality public transit, mix of uses, and pedestrian friendliness (Kuzmyak et. al., 2003b). Indeed, in practice there is a two-way relationship between parking supply and mode split. Free parking, for example, can be seen as both a cause of high parking supply (more parking is

6 Calculated from Holtzclaw et. al. (2002), assuming 12,000 average annual VMT per vehicle, median per capita income of $33,000 (2002 figures per California State Department of Finance), and an average income in BMR units 25% below median. Holtzclaw calculate the coefficient of -0.0565. Therefore, expected VMT reduction can be calculated as 0.0565 * 33,000 * 0.25 / 12,000 = 4%

needed to satisfy the greater demand), and a consequence (the market price of parking is zero once an effectively unlimited supply is provided) (see, for example, Shoup, 1999).

Theoretically, it is possible to reduce parking provision to below the level of actual demand, should drivers park in neighboring lots or on-street in surrounding areas. However, planning approval is not likely to be granted for developments that significantly under-provide parking, unless complementary Residential Permit Parking programs or other measures to combat this type of overspill are introduced. Indeed, the main reason for minimum parking requirements levied by local jurisdictions is to address these overspill issues (Shoup, 1999).

Similarly, market realities are likely to prevent a developer from providing too little parking. The challenges in persuading lenders to finance developments that have below-code parking are difficult enough to overcome, even where there is clear, documented evidence to show that parking supply will be enough to meet demand (see for example, Parzen & Sigal, 2004). In contrast, the opposite tendency is likely to be apparent – that developments are prevented from taking full advantage of the opportunities to reduce parking supply by zoning codes (see, for example, Nelson\Nygaard, 2002).

The measure proposed here uses the Institute of Transportation Engineers' *Parking Generation* handbook as the baseline. This is assumed to equate to unconstrained demand. The trip reduction can therefore be calculated as follows:

Trip reduction = Actual parking provision / ITE Parking Generation rate

Since ITE parking generation rates use the same land use codes as the trip generation rates, these could be provided within the URBEMIS model itself. The user would only be required to enter the actual parking provision for each land use.

For land uses with rates for both weekday and weekend, the formula will use whichever rate is higher. The *Parking Generation* handbook covers most common land uses. For some land uses, however, no parking generation rates are available: in these cases, this particular mitigation measure may not be used.7 Those land uses without parking generation rates include:

- Single Family Detached Housing
- Mid-rise Apartments
- High-rise Condominium/Townhouse

7 The next edition of *Parking Generation,* currently under development by an ITE Task Force, is likely to provide date for some of these missing land uses. While it would be ideal to have parking generation data for every single land use before introducing this mitigation measure into URBEMIS, the data does not yet exist. Rather than abandoning this mitigation measure entirely until perfect data exists, we recommend allowing the measure to be used for the many land uses where reasonable data is available.

- Mobile Home Parks
- Residential Planned Unit Development (PUD)
- Day-care center
- Elementary school
- Junior High school
- Library
- City Park
- Discount Superstore
- Discount Club
- Electronic Superstore
- Home Improvement Superstore
- Gas/Service Station
- Pharmacy/Drugstore with and with/out Drive Through
- Medical Office Building
- General Heavy Industry

To avoid double counting with other trip reduction measures, the impacts of parking supply are proposed to be assessed in conjunction with all other non-residential trip reduction measures as follows:

- The total of all other non-residential trip reduction measures should be used if this is greater than or equal to the trip reduction from parking supply measures. For example, if parking supply is reduced 10% from ITE levels, and transit, mixed use and pedestrian/bicycle trip reductions amount to 20%, the 20% figure would be used.
- If the total of all other non-residential trip reduction measures (r_1) is less than the trip reduction from parking supply measures (r_2), the total trip reduction is as follows:

  $$r_1 + 0.5 * (r_2 - r_1)$$

  In effect, the parking supply reduction is only used if it is greater than the impact from other trip reduction measures, and the difference is discounted by 50%. For example, if parking supply is reduced 25% from ITE levels, and transit, mixed use and pedestrian/bicycle credits amount to 15%, the total reduction would be:

  $$15 + 0.5 * (25\text{-}15) = 20\%.$$

This reduction should only be granted if measures to control overspill are in place, such as Residential Permit Parking programs, time limits or meters.

Transportation Demand Management

Transportation Demand Management programs have been shown to have a major impact on travel behavior. Site-level employee vehicle trip reductions of up to 38% have been achieved, particularly for programs that have included parking pricing (Shoup & Willson, 1980; Comsis, 1993; Valk & Wasch, 1998; Pratt, 2000). Parking price elasticities of –0.1 to –0.3 have been reported (Pratt, 2000).

This component of the existing URBEMIS 2002 mitigation component is well developed. However, there is considerable scope to adapt it in two ways:

- Provide greater emphasis for the three elements that have the greatest impact on travel behavior – parking pricing/cash out; free transit passes; and telecommuting.
- Simplify the remaining elements, through offering broader options such as "major program", "minor program", and "no program," for elements that are likely to have a smaller trip reduction potential.

We recommend that none of these reductions be permitted, unless they form part of a legally enforceable agreement specifying, for example, minimum parking prices and other TDM measures. This might form part of a development agreement, be enforced through any TDM ordinance in the local jurisdiction, or consist of another mechanisms mutually agreed by the air district and project proponent. Otherwise, there is little to guarantee that some of the promised measures (e.g. parking pricing) will actually be implemented and maintained.

Parking Pricing and Cash Out

We recommend that a maximum trip reduction of 25% be applied to projects that commit to introducing parking pricing. This is based on the approximate midpoint of observed reductions, which range from 15% to 38% (Shoup & Willson, 1990; Comsis, 1993; Pratt, 2000). Note that most of these studies apply to before-after or with-without comparisons, with no increase in transit service or other measures to reduce vehicle trips. This maximum reduction should apply to prices of $6 per day or greater (in 2004 dollars).

The trip reduction will therefore be as follows:

Trip reduction = daily parking charge / 6 * 0.25

If the parking charge is more than $6, the 25% reduction is taken. If parking charges do not apply to all trips to a site (e.g. customers are exempt), the reduction is pro-rated by the percentage of trips that the charges apply to. If little or no on-site parking is provided, the parking charges should be those of surrounding public facilities.

Parking cash-out programs should be eligible for 50% of the reduction for direct parking charges, in recognition of the fact that their impacts tend to be significantly lower (Pratt, 2000). This is partly due to the fact that cash-out payments are a taxable benefit.

Free Transit Passes

Some California transit agencies, most notably VTA in Santa Clara County, have EcoPass or similar programs, whereby employers or property managers bulk-purchase transit passes for (free) distribution to their employees or tenants. Eco Pass programs have been shown to increase transit ridership by 50-79% (City of Boulder, undated; Caltrans, 2002), and reduce vehicle trips by 19% (Shoup, 1999). (Note that many of these new riders were making new trips, or ones previously made by walking or cycling.)

We therefore recommend that any project committing to providing free transit passes would receive an additional credit equivalent to 25% of the reduction granted for transit service. Thus, the credit is more valuable in places that have good transit service. This reduction would only apply to the portion of trips generated by those granted the free transit passes (e.g. residents and/or employees, but excluding shoppers and other visitors).

Telecommuting

We recommend the retention of the reductions granted for telecommuting and compressed work schedules in the existing mitigation component, with two clarifications:

- As with the reductions for other mitigation measures, there must be an enforceable commitment (e.g. development agreement), which covers both the take-up rate (employees actually telecommuting or using compressed work schedules) as well as the provision of the option.
- The percentage reduction should not be additive (in contrast to most other trip reduction measures). For example, if 20% of employees telecommute, and other trip reduction measures are estimated to reduce vehicle trips from 1,000 to 800 per day, the 20% reduction would apply to the 800 trips, not the original 1,000.

Other TDM Programs

Other TDM program elements, that do not include financial incentives, tend to have a smaller impact on travel behavior. We recommend that reductions be based on the number of the following elements incorporated into the program, per Figure 7:

- Secure bicycle parking (at least one space per 20 vehicle parking spaces)
- Showers/changing facilities
- Guaranteed Ride Home

- Car-sharing services
- Information on transportation alternatives, such as bus schedules and bike maps
- Dedicated employee transportation coordinator
- Carpool matching programs
- Preferential carpool/vanpool parking

The impact of a TDM program will also depend on the travel alternatives available. A program will have more impact if the site is served by frequent transit, for example (although note that a TDM program can do much to promote carpooling even in other locations). For this reason, we recommend that part of the TDM credit be used to adjust the credits granted for transit service and pedestrian/bicycle friendliness (see Figure 9).

Figure 9 Recommended TDM Program Reductions

Level	Number of Elements	Recommended Reduction
Major	At least 5 elements	2%, plus 10% of the credit for transit and pedestrian/bike friendliness
Minor	At least 3 elements	1%, plus 5% of the credit of transit and pedestrian/bike friendliness
No program	None	None

Examples

It is important to recognize that any type of calibration is beyond the scope of this analysis, which relies on existing references to build on the ranges established in the existing mitigation component. Figure 10, however, does provide some examples to indicate the trip reductions that would apply to specific places.

The data are drawn from the database compiled for the Location Efficient Mortgage program (for details, see Holtzclaw et. al., 2002), and from the San Francisco Bay Area Metropolitan Transportation Commission's TAZ files. For these reasons, the examples are limited to the San Francisco Bay Area. Transit service was estimated from schedules and route maps. Sidewalk and bike lane completeness were estimated based on local knowledge. For these reasons of limited data, the examples are intended as illustrations only, rather than to refer to a particular project.

The reductions are calculated for the physical and environmental factors only, for residential uses. They exclude any additional reductions from TDM programs and affordable housing.

The final column compares average vehicle miles traveled (no vehicle trip data were readily available) in these neighborhoods to the Brentwood baseline, as a rough

comparison to the reductions granted through the proposed trip reductions for URBEMIS. As can be seen, while there are significant discrepancies, the overall correspondence is acceptable for this type of sketch planning model.

Figure 10 Example Trip Reductions

								% Reduction in VMT from Brentwood
Example	TAZ	Residential Density	Mix of Uses	Local Retail	Transit	Ped/bike friendliness	Total Reduction	
Brentwood	899	1.4%	-3.0%	0.0%	0.1%	1.7%	0.3%	0.0%
Orinda	831	-9.5%	5.8%	0.0%	3.7%	1.4%	1.4%	5.6%
Pleasant Hill BART	806	14.4%	7.2%	3.0%	8.3%	3.3%	36.3%	40.2%
Emeryville	723	39.0%	1.7%	3.0%	4.4%	4.9%	53.1%	47.8%
Downtown Palo Alto	245	19.8%	4.4%	3.0%	6.1%	7.5%	40.8%	50.6%

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APPENDIX E

Cost Effectiveness Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

November 17, 2005

I. INTRODUCTION

California Health and Safety Code (CH&SC) Section 40920.6(a) requires the San Joaquin Valley Unified Air Pollution Control District (District) to conduct a cost effectiveness analysis of the proposed control options prior to the adoption of the proposed rules. The purpose of conducting a cost effectiveness analysis is the evaluation of the possible economic effect of the pollution control measures (rules). The analysis also serves a guideline in developing the control requirements for the rule.

II. SUMMARY AND CONCLUSION

The CH&SC section cited above requires a cost effectiveness analysis for the most likely compliance scenario, and an incremental cost effectiveness analysis on an alternative compliance scenario. Absolute cost effectiveness of a control option for traditional rules are typically determined by taking the added annual cost (in $/year) of the control technology or technique, divided by the emission reduction achieved (in tons/year). The costs can include capital equipment costs, engineering design costs, installation costs, and any cost savings, such as from decreased energy usage and decreased maintenance costs.

Rule 9510 would require developers to reduce the following project's operational and area source emissions: 33.3% of NOx emissions and 50% of the PM10 emissions, over a ten-year period. Rule 9510 would also require the developers to reduce emissions from equipment used during the construction phase by 20% for NOx and 45% for PM10 emissions compared to the statewide average. The construction emissions may be reduced on-site by using newer fleets than the statewide construction average, using add-on controls, and/or by using clean fuels. The rules are structured to allow flexibility in complying with the rule requirements due to various requirements and limitations imposed by local agencies in the projects' jurisdiction. Methods of compliance include the following: achieving the necessary reductions entirely through on-site emission reduction measures; reducing, in varying degrees, partially on-site and partially off-site through the off-site emission reduction fee; reducing entirely off-site through the payment of an off-site emission reduction fee. The fee for emissions not reduced in the design of the project or with equipment controls would fund off-site emission reduction projects. The fee for these off-site projects would be calculated by multiplying the required emission reductions by a cost effectiveness factor. This rule differs from traditional rules, in that a cost effectiveness value is predetermined and the control costs are based on that cost effectiveness value.

Cost effectiveness is a primary criterion for the District to fund emission reduction projects. Cost effectiveness of a off-site emission reduction project is based on the amount of pollution (per pound or ton of a pollutant) the project eliminates for each

dollar spent. There are different methodologies to determine cost effectiveness for different programs, but in general, cost effectiveness is determined by dividing the cost of the project by the amount of emissions reduced. Several factors are used to determine the emission reductions for a particular mitigation project, including: the age of the vehicle or engine being replaced, project life (how long in terms of time the emission reductions can be expected to be surplus), and activity level, which is usually represented in annual hours of operation or mileage. Project life allows the District to determine how many emission reductions can occur per year. This is important in determining timelines for emission reductions and will assist the District in attaining the ozone and PM10 standards.

To determine the cost effectiveness for the ISR Program, District staff identified NOx emission reduction projects that have previously been funded and the costs associated with each project. Table E–1*, Estimated NOx Emission Reductions from Current and Historical Grant Programs by the District* summarizes the grant programs.

Table E-1
Estimated NOx Emission Reductions from Current and Historical Grant Programs

	Emissions Tons	Emissions Pounds	Grant Funded Dollar Amounts	Cost Effectiveness* $/Pound	Cost Effectiveness* $/Ton
All External Projects					
1992 -1993	400	800,000	$3,665,200	$4.58	$9,163.00
1993 -1994	525	1,050,000	$4,773,814	$4.55	$9,092.98
1994 - 1995	590	1,180,000	$3,594,486	$3.05	$6,092.35
1995 - 1996	650	1,300,000	$3,688,311	$2.84	$5,674.32
1996 - 1998	885	1,770,000	$6,309,952	$3.56	$7,129.89
1998 - 2004	30,419	60,838,805	$60,798,609	$1.00	$1,998.68
Total	***33,469***	***66,938,805***	***$82,830,372***	***$3.26***	***$6,525.20***
REMOVE Program					
1992 - 1993 Phase I	400	800,000	$3,665,200	$4.58	$9,163.00
1993 - 1994 Phase II	525	1,050,000	$4,773,814	$4.55	$9,092.98
1994 - 1995 Phase III	590	1,180,000	$3,594,486	$3.05	$6,092.35
1995 - 1996 Phase IV	325	650,000	$2,688,311	$4.14	$8,271.73
1996 - 1998 Phase V	360	720,000	$5,309,952	$7.37	$14,749.87
1998 - 1999 Phase VI	104	208,247	$2,556,403	$12.28	$24,551.64
1999 - 2000 Phase VII	304	607,640	$2,422,741	$3.99	$7,974.26
2002 - 2003 Phase VIII	156	311,059	$1,210,648	$3.89	$7,784.04
Total	*2,608*	*5,526,946*	*$26,221,555*	*$5.48*	*$10,959.98*
Vehicle Buy-Back					
1995 - 1996	325	650,000	$1,000,000	$1.54	$3,076.92
1997 - 1998	525	1,050,000	$1,000,000	$0.95	$1,904.76
Total	*850*	*1,700,000*	*$2,000,000*	*$1.25*	*$2,490.84*
Heavy-Duty Program					
1997 - Jan 2004	29,811	59,622,859	$53,381,817	$2.28	$4,564.13
Lt. & Med.-Duty Vehicle Program					
2001 - Jan 2003	22	43,000	$750,000	$17.44	$34,883.72
1999 Lawnmower Replacement Program					
2001 - 2002	23	46,000	$477,000	$10.37	$20,739.13

Please note that beginning in 1995-96 vehicle buy-back was no longer included in the REMOVE Program. A separate program for heavy-duty vehicle projects was established beginning in 1997.

III. GRANT PROGRAMS

This section identifies the existing grant programs and different types of projects that are funded under those programs that are possible candidates for any off-site emission reduction fees collected under Rule 9510. In addition, this section identifies additional projects that may be funded through the ISR program. The District will also consider projects and programs for funding in addition to the ones discussed in this section, when other projects and programs are identified.

REMOVE/REMOVE II

The Reduce Motor Vehicle Emissions (REMOVE) Program was the first District grant program implemented in 1992 to fund projects that reduced emissions associated with motor vehicle trips. Due to the lengthy REMOVE evaluation committee process, the District's Governing Board approved the revised REMOVE II Program on March 13, 2005. The REMOVE II Program awards grant funding on a first-come, first-serve basis and consists of a broad range of mobile source incentive projects. The following separate components within the REMOVE II Program have established parameters and funding caps to achieve prudent cost effectiveness levels: E-Mobility (Telecommunications) Incentive Component; Public Transportation and Commuter Vanpool Passenger Subsidy Component Bicycle Infrastructure Component; Light and Medium Duty Incentive Component. The components establish guidelines to maximize the emission reduction potential for individual projects. The criterion for evaluating potential projects is ARB's methodology for calculating cost effectiveness and emission reductions. Additionally, the District has established requirements for applicants to validate the emission reductions generated by REMOVE II incentive program components.

The E-Mobility Component of the REMOVE II Program provides funding for the development or expansion of electronic telecommunications services in municipal government and public education. The electronic technology will serve as direct replacement of vehicle trips to public sites for conferencing, document transactions, general information, work functions, school instruction, and related applications. E-Mobility projects include: distance-learning technology, telecommute center equipment, teleconference systems, E-government technology, E-court technology and related electronic applications.

The Public Transportation and Commuter Vanpool Passenger Subsidy Component of the REMOVE II Program, provides funding to attract new participants to public transportation and commuter vanpools. The passenger subsidies will serve to attract new participants to public transportation and commuter vanpools as an alternative to single occupant vehicle (SOV) commutes. Passenger subsidy projects include: incentives for transit bus agencies, shuttles, commuter vanpools, rail, and park-and-ride lot construction.

The Bicycle Infrastructure Component of the REMOVE II Program will fund the development of a comprehensive bicycle transportation network. The component will

support the expansion and linkage of bicycle transportation facilities that promotes the practice of commuter bicycling as a safe and viable transportation alternative. Bicycle infrastructure projects may include the development of Class I Bicycle Paths (construction) and Class II Bicycle Lanes (striping).

The Light and Medium Duty Incentive Component of the REMOVE II Program will fund a portion of the purchase cost of low-emission light-duty and medium-duty motor vehicles for public agencies. The purpose for the component is to encourage and increase the introduction of reduced emission alternative fuel vehicles. Low-emission vehicles may include Zero Emission Vehicles, Super Ultra Low Emission Vehicles, Ultra Low Emission Vehicles, and Electric Bicycles based on ARB emission standards.

Heavy-Duty Program

The Heavy-Duty Engine Emission Reduction Incentive Program (Heavy-Duty Program) initially evolved from REMOVE in 1997 and the District continues to administer the program. The Heavy-Duty Program replaces older model high polluting engines with newer and cleaner burning engines. The Heavy-Duty Program also encourages the early introduction of on-road and off-road heavy-duty motor vehicles with engines that include reduced-emission technologies. Eligible project types funded under this program include: marine vessels, forklifts, agricultural pump engines, on-road and off road vehicles and equipment, agricultural harvesters, hay bailers, tractors, delivery trucks, sprayers, yard spotters, earthmovers, line haul trucks, back hoes, dump trucks, earth movers and drills, transit and school buses, and forklifts. This program has been expanded to assist in the development of alternative fuel infrastructure, particulate filters on eligible diesel school buses, and idle reduction technologies for heavy-duty vehicles.

Emission reductions are obtained when the project applicant purchases vehicles and engines that are cleaner than required by current emission standards or installs an emission certified retrofit kit on an existing engine. The District pays the differential cost of purchasing the lower emitting technology compared to conventional technology. Emission reduction, calculations, and horsepower categories are used to determine an incentive amount. Project monitoring is conducted to verify eligibility, to ensure proper use of public funds and to validate the emission reductions. Applicants are required to enter into contracts with the District and are required to submit annual usage reports for five years after the technology is purchased.

The Heavy Duty Program is primarily aimed at NOx reductions, but many projects also achieve particulate matter (PM10) reductions. Historically, this incentive program has been exceptionally cost effective, replacing approximately 4,484 engines[1].

[1] *SJVAPCD Heavy-Duty Engine Incentive Program Database*

PM10 Incentive Program

The District currently does not have an incentive program that primarily targets PM10 emissions reductions, however an incentive program will be needed for Rule 9510. Initially, District staff surveyed the PM10 emissions inventory to determine the largest sources of emissions and related factors, the extent of existing or planned control, and types of control options that are available. District staff identified unpaved traffic surfaces and unpaved shoulders as the most viable options for emission reduction projects. Other potential sources include the use of PM10-efficient street sweepers and fireplace retrofits/replacement. The District is proposing to develop an Unpaved Road and Traffic Surface Program that would fund or partially fund the treating or paving of unpaved roads or unpaved shoulders within the San Joaquin Valley Air Basin, in time to implement and achieve the reductions committed to for this rule. Once that program is established, the District will continue to explore and develop other PM10 incentive programs, such as PM10-efficient street sweepers, fireplace retrofits/replacement, and/or leaf blowers.

The duration of the contract will vary depending on the project. Some contracts will be completed upon installation, while others may require reporting for 5 years. For example, a road-paving project would have a contract that is completed upon installation, whereas an engine contract typically contains a 5-year reporting requirement. The staff report will be amended to include this information.

IV. RULE 9510 ESTIMATED COST EFFECTIVENESS

The District's future prospects for funding the most cost effective NOx reduction projects are currently declining. Many of engines that qualify for the Heavy-Duty Program incentive funds have been replaced or retrofitted. Diesel engines greater then 50 horsepower are being regulated by the State and the District resulting in cleaner operating engines with lower emissions. Consequently, the most cost-effective projects (e.g. diesel engines manufactured before 1996) have previously been funded resulting in projects that will cost more in the future to fund.

To determine future cost effectiveness for NOx emission reduction projects, staff reviewed previously funded projects' NOx cost effectiveness, the types of projects, and the future availability of those projects. Attachment 1 compiles the necessary information and determines the resulting cost effectiveness. The general concept for NOx projects in Attachment 1, is that the types of grant applications received will move from the heavy duty projects to lighter duty projects at a rate of 5% per year, and that the cost of heavy duty projects will increase approximately $2000 more per ton. Attachment 1, can be summarized as follows:

NOx Cost-Effectiveness

Year	Cost to Reduce One ton of NOx
2006	$4,650.00
2007	$7,100.00
2008 and beyond	$9,350.00

Presently, most of the Districts incentive funds have been used to fund NOx emission reductions. In order to determine future cost effectiveness for PM10 emission reduction projects, District staff researched PM10 emissions and reductions. Initially, the PM10 emissions inventory was surveyed to determine the largest sources of emission factors, the extent of existing or planned control, and types of control options that are available. District staff identified unpaved traffic surfaces and unpaved shoulders as the most viable options for emission reduction projects. Other potential sources include the use of PM10-efficient street sweepers and fireplace retrofits/replacement.

Once the sources were identified, each source was analyzed in terms of emission factors, thresholds, available control effectiveness, and costs of those controls. Attachment 1 also compiles the necessary information and determines the resulting cost effectiveness for PM10 projects. There are several concepts for PM10 projects that are incorporated in Attachment 1. Initially, the District is anticipating that it will receive a high number of applications to treat or pave unpaved roads, with the most cost effective projects coming in the first few years. The District is also expecting the cost to treat or pave unpaved roads to increase by 75% each year for each ton reduced. The District is anticipating receiving a higher number of applications for unpaved shoulders and street sweepers, each year. Attachment 1, can be summarized as follows for PM10:

PM10 Cost-Effectiveness

Year	Cost to Reduce One ton of PM10
2006	$2,907.00
2007	$5,594.00
2008 and beyond	$9,011.00

V. SOURCES OF COST DATA

District staff used cost effectiveness information derived from actual NOx emissions reduction projects administered by the District. This data is sent to the California Air

Resources Board (ARB) on an annual basis. The following data sources were used for the PM10 analysis:

1. Effectiveness Demonstration of Fugitive Dust Control Methods for Unpaved Roads and Unpaved Shoulders on Paved Roads
   DRI document No. 685-5200.1F1
   Desert Research Institute
   December 31, 1996

2. Methods to find Cost-effectiveness of Funding Air Quality Projects: For Evaluating Motor Vehicle Registration Fee Projects and Congestion Mitigation and Air Quality Improvement (CMAQ) Projects
   California Air Resources Board
   2003 Edition

3. Final BACM Technological and Economic Feasibility Analysis
   Sierra Research, Inc.
   Prepared for the SJVAPCD
   March 2003

4. Entrained Road Dust from Paved Road Travel: Emission Estimation Methodology, Background Document
   Section 7.9
   California Air Resources Board
   Updated July 1997

5. Unpaved Road Dust (non-farm roads, SJV only)
   Section 7.10 SJV
   California Air Resources Board
   Patrick Gaffney
   Updated May 2004

6. Spreadsheet used for San Joaquin Valley Air Pollution Control District PM10 SIP, 2003
   Spreadsheet, “Unpaved1999Mar_13_2003Final.xls”
   California Air Resources Board
   Patrick Gaffney

7. Conversations and E-mail correspondence with Mel Zeldin, consultant

Attachment 1
Anticipated Use of ISR Funds
for Determining Cost Effectiveness

For 2006					
	Projected % of Fund Use	**Cost Effectiveness ($/ton reduced)**			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	90%	$1,694	$15,000	$1,819	
Unpaved Shoulders	5%	$11,838	$15,000	$12,907	
Street Sweepers	5%	$10,000	$15,000	$12,500	
Overall PM10		**$1,694**	**$15,000**	**$9,075**	**$ 2,907**
NOx					
Heavy Duty Program	95%	$3,000	$5,000	$4,000	
REMOVE	5%	$14,000	$20,000	$17,000	
Overall NOx		**$3,000**	**$20,000**	**$10,500**	**$ 4,650**

For 2007					
	Projected % of Fund Use	**Cost Effectiveness ($/ton reduced)**			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	75%	$1,900	$15,000	$3,183	
Unpaved Shoulders	20%	$11,838	$15,000	$12,907	
Street Sweepers	5%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$9,530**	**$ 5,594**
NOx					
Heavy Duty Program	90%	$5,000	$7,000	$6,000	
REMOVE	10%	$14,000	$20,000	$17,000	
Overall NOx		**$5,000**	**$20,000**	**$11,500**	**$ 7,100**

Anticipated Use of ISR Funds for Determining Cost Effectiveness

For 2008					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	55%	$1,900	$15,000	$5,571	
Unpaved Shoulders	35%	$11,838	$15,000	$13,419	
Street Sweepers	10%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$10,497**	**$ 9,011**
NOx					
Heavy Duty Program	85%	$7,000	$9,000	$8,000	
REMOVE	15%	$14,000	$20,000	$17,000	
Overall NOx		**$7,000**	**$20,000**	**$12,500**	**$ 9,350**

For 2009					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	55%	$1,900	$15,000	$9,749	
Unpaved Shoulders	35%	$11,838	$15,000	$13,419	
Street Sweepers	10%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$11,889**	**$ 11,308**
NOx					
Heavy Duty Program	80%	$9,000	$12,000	$10,500	
REMOVE	20%	$14,000	$20,000	$17,000	
Overall NOx		**$9,000**	**$20,000**	**$13,750**	**$ 11,800**

Anticipated Use of ISR Funds
for Determining Cost Effectiveness

For 2010					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	45%	$1,900	$15,000	$14,682	
Unpaved Shoulders	40%	$11,838	$15,000	$13,419	
Street Sweepers	15%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$13,534**	**$ 13,850**
NOx					
Heavy Duty Program	75%	$11,000	$13,000	$12,000	
REMOVE	25%	$14,000	$20,000	$17,000	
Overall NOx		**$11,000**	**$20,000**	**$14,500**	**$ 13,250**

1 The cost effectiveness cap in this column represents the cap that this program would require, not necessarily the historical cap.

2 The representative cost effectiveness is the anticipated cost effectiveness for that year. This is based on district staff forecast.

APPENDIX E
Attachment 1

Project Spending Plan for Proposed Rule 9510 (Indirect Source Review)

November 17, 2005

I. INTRODUCTION

The purpose of this document is to demonstrate that any funds collected by the District will meet their intended purpose of reducing emissions caused by new development in the air basin. It provides a plan for spending any funds generated by the rule in a cost-effective and responsible manner.

Rule 9510 is projected to generate up to $103 million between 2006 and 2008. After 2008 the District will provide a new estimate based on experience with the program and the amount of development occurring in the San Joaquin Valley. The new estimates may be higher or lower than the amounts currently in the rule. To demonstrate the capability to distribute these funds to cost-effective projects, the District has analyzed the potential emission reduction projects available that meet requirements for being surplus, quantifiable, and enforceable. Once the potential projects were identified, staff performed additional research into the cost of individual projects and the potential for owners of the equipment, vehicles, etc. to take advantage of incentive funding.

The District plans on using existing grant programs that are available for immediate funding of projects and to develop new programs for non-traditional sources not eligible for other funding sources such as DMV Surcharge Fees and California Carl Moyer Program funds.

II. Existing Programs

The following existing programs and programs where the District has operated programs in the past are described in Appendix E.

- **Heavy-Duty Engine Incentive Program**
- **REMOVE II Program**
- **Lawnmower Buyback Program**
- **Light and Medium Duty Vehicle Program**
- **Voluntary Accelerated Vehicle Retirement**

The Heavy-Duty Engine Incentive Program and REMOVE II Program are currently in operation and can be used as an outlet for funds from ISR immediately. Other programs where the District has past experience can be implemented quickly.

III. New Programs

Stationary Source Incentive Program

Program concept: Some control options that are in excess of current rule requirements and best available control technology (BACT) thresholds can be implemented with the help of incentive funding. These options typically exceed BACT cost-effectiveness limits or were not required by the rule due to economic impacts; however, relatively cost-effective control options may be available in a variety of industries.

All projects would be required to demonstrate that they are:

- Surplus to all federal, state, and local requirements
- Quantifiable – emission reductions can be determined
- Enforceable – a mechanism is available to ensure that reductions occur
- Permanent – reductions are maintained for the life of the credit

There are several potential ways in which stationary source operators would be attracted to the incentive program:

- Applicant initiated - Applicant proposing expansion or equipment replacement approaches the District with equipment or control technologies in excess of requirements.

- District initiated - District permit engineers identify control technology in excess of BACT requirements and rule requirements during project review and suggest to applicant the potential for going beyond requirements with the help of incentive funding.

- Ongoing program - The District identifies specific equipment or technologies in excess of requirements in a grant program and open application process.

Stationary Source Project Review Process Outline:

1. For projects identified during BACT analysis required under Rule 2201, permit engineers identify potential control technology that exceeds BACT requirements and is surplus of all regulations.
2. The engineer contacts Emission Reduction Incentive Program (ERIP) staff to forward cost effectiveness analysis. *Note: the cost effectiveness performed for ERIP purposes is not the BACT cost effectiveness*.
3. ERIP determines whether project meets ISR funding criteria and contacts PSD and applicant.
4. If not, the project, as initially proposed, is processed by Permit Staff.
5. If yes, 3-parts meeting (ERIP, PSD, Applicant) to review feasible options (technical aspects and funding).

6. Project, as initially proposed, is on hold, waiting for ERIP and applicant final approval/decision.
7. Applicant determines whether the project would be feasible at their facility.
8. If not, the project, as initially proposed, is processed by Permit Staff.
9. If yes, ERIP staff initiates incentive funding application process.
10. For eligible projects, the applicant would complete an application providing contact information and complete project and cost information.
11. Initial project amended to incorporate new proposed control technology.
12. The application would be approved by ERIP and Permit Service Division (PSD).
13. ERIP staff would prepare a contract for the project between the applicant and the District.
14. PSD would incorporate the new controls and emission amounts into the applicant's permit application.
15. PSD issues an Authority to Construct (ATC) allowing the applicant to install the new control.
16. Compliance staff conducts an inspection, that may include a source test for some projects, to verify the emission reductions.
17. Compliance notifies PSD and ERIP that the installation is complete.
18. ERIP approves claim for payment for the contract.
19. Finance issues payment for the project to the applicant.
20. Long term monitoring and reporting is accomplished through the normal process for permitted equipment.
21. ERIP reports emission reductions in periodic reports to the Governing Board.

Projects may also enter the system that are initiated by operators of the permitted sources. In these cases, PSD will conduct an assessment to determine technological feasibility and if the project is surplus and enforceable. PSD would then turn the project over to ERIP for application processing and contracting. Project types that have the potential for large numbers of applications may become an ongoing program component with outreach to recruit applicants.

Example Projects

The following are examples of projects that illustrate the potential to obtain emission reductions through a stationary source incentive program. All projects listed would require additional research and analysis prior to offering incentives.

Example: Replace natural gas fired boilers/burners with cleaner model.

Under District Rule 4306, boilers rated from greater than 5 up to 20 MMBTU per hour are required to achieve a NOx emission rate of 15 ppm. If the applicant currently operated a 30 ppm boiler, when it comes time to replace the boiler, he would be required to install a 15 ppm boiler. Due to advances in technology there are now 9 ppm ultra-low NOx burners available. The cost is in excess of the District's BACT threshold, so the applicant is not required to purchase the 9 ppm boiler. The increment between

the 15 ppm boiler and the 9 ppm boiler are therefore surplus reductions. The incentive amount would be set to cover the extra cost of installing the cleaner boiler. There are approximately 420 units between 5 to 20 MMBTU per hour that are subject to Rule 4306. Complete new burner unit costs are in the range of $28,000 to $57,000 depending on size, based on contact with venders. The differential cost between low emitting and high emitting burners ranges from $5,000 to $7,000

Another possible source of surplus reductions may occur from boilers rated from 2 to 5 MMBTU per hour and subject to proposed Rule 4307, which has a NOx limit of 30 ppm. Some boilers that currently operate above 30 ppm may be exempt from rule retrofit requirements now under development, so the surplus reductions for those units may be calculated from the uncontrolled emissions of 55 ppm down to 9 ppm. The incentive would need to cover 100 percent of the cost of the installation. There are no increased operating costs expected with the 9 ppm burners. There could be more than 300 of these exempt units eligible for an incentive. Unit costs for 2.5 MMBtu/hr 9 ppm burners are about $41,000 based on contact with vendors.

Example: Electrification of stationary non-emergency IC engines.

Stationary engines are required to meet a NOx emission limit specified by Rule 4702. Installing an electric motor in place of the engine would result in a surplus reduction for the increment between the emission limit and the zero emission electric motor. Depending on the current electric rate and price of fuel, there may be a cost increase from changing to electric. The incentive would need to cover the cost of replacing the engine with an electric motor and increased operating costs. There are hundreds of units installed that could take advantage of this program with sufficient incentive amounts. Costs have not been researched.

Example: Install SCR at a flat glass melting furnace.

Glass melting furnaces are required to meet NOx emission limits specified in Rule 4354 when the furnace is next rebuilt. These furnaces are rebuilt approximately every 7 years. The rule requirements can be exceeded with installation of selected catalyst reduction. The surplus reductions can be achieved by using SCR instead of oxy fuel or in addition to oxy fuel in some cases. The cost of control may exceed $10 million per unit, but the large potential emission reductions result in relatively good cost-effectiveness. SCR has high operating costs and would most likely require incentives to cover increased operating costs. There are two potential candidates for this project in the San Joaquin Valley.

Example: Install plenum chambers or additional cyclone separators in cotton gins.

Cotton gins are required to reduce PM10 emissions produced during the ginning process under Rule 4204. Additional controls may be possible for some gins if an

incentive were provided. Installing a plenum chamber before the required cyclone separators may provide reductions if there is room for the equipment in the building. After the cyclone separators there may be potential to add either cyclone separators in or a bag house in series. Feasibility will depend on the gin configuration. There are increased operating costs with adding cyclone separators and bag houses that may impact cost-effectiveness of these options.

PM10 Public Agency Road and Unpaved Surface Program

The District has identified several sources of fugitive PM10 from paved and unpaved roads that provide significant emission reduction potential for the ISR rule. The most promising projects are:

- Paving unpaved roads
- Paving unpaved road shoulders
- Long-term contracts for chemical suppressants on unpaved roads
- Long-term contracts for chemical dust suppressants on unpaved road shoulders
- Purchase of PM10 Efficient Street Sweepers

Program Concept

The District envisions this program as a coordinated effort between the District, Valley Transportation Planning Agencies, city and county road agencies, and public works departments. The funds collected for PM10 will be spent in the county of origin to the extent possible.

The District will develop an application process and evaluation procedure for funding road projects. Some of the key features are outlined below:

General Program Features

1. Each county and the cities within each county will be competing for funds generated in the county
2. The Council of Governments/Transportation Planning Agencies may coordinate the process of identifying funding priorities among the local member jurisdictions.
3. The primary consideration in funding priorities is cost-effectiveness.
4. Projects must not supplant funding from any source.
5. A mix of projects with higher cost-effectiveness may be funded as long as the average cost-effectiveness for the year is consistent with the District's annual target.
6. Once a list of eligible projects is created and ranked, funding would be allocated twice each year as fees are collected by the District.

Unpaved Roads

1. Provide a list of unpaved road segments in descending average daily trip (ADT) sequence (same data used for compliance with Rule 8061).
2. Indicate road segments that will be paved or chemical treated in compliance with Rule 8061.
3. If economic hardship is claimed for Rule 8061, provide justification.
4. As a general rule, the highest ADT road segments should be paved or treated first.
5. Other factors to consider in scoring projects:
   Roads with significant truck traffic should receive added points
   Roads in or near to urban areas should receive added points
6. Payment will be made to the agency after the project is complete.
7. Suppressant projects would be paid annually under a continuing agreement.
8. A single project could be based on total miles of road segments from a jurisdiction so that different roads could be done under one contract.

Paved Road Shoulder Paving Projects

1. Provide a list of unpaved road shoulders in descending average daily trip (ADT) sequence (same list used for compliance with Rule 8061).
2. Indicate road shoulder segments that will be paved or chemical treated in compliance with Rule 8061.
3. Other criteria should be same as unpaved road projects

PM10 Efficient Street Sweepers

1. Provide a description of the existing street sweeping program if any, including sweeping schedule and types of sweepers (PM Efficient or Standard)
2. Demonstrate compliance with Rule 8061 sweeper purchase requirements or provide economic hardship justification.
3. Provide an estimate of the curb miles that will be swept by the new sweeper(s).
4. Projects proposing natural gas vehicles may be eligible for additional funding based on NOx and PM10 exhaust emission reductions.

Agricultural Project Incentive Program

The District has identified several potential projects for agricultural equipment and emission sources not currently eligible for other funding sources. The projects must be surplus to agricultural regulations and be able to demonstrate quantifiable emission reductions.

Program Concept: Although many agricultural sources are now regulated, there are some opportunities for early implementation of controls that are scheduled far enough in the future to result in surplus reductions. In some cases, it is possible to go beyond

current regulations. For example, measures in addition to those required by the Agricultural Conservation Management Program rule.

Agricultural Projects:

- ❖ Lower emitting almond harvester purchase
- ❖ Chippers and shredder purchases as alternative to burning

Project descriptions:

New almond harvesters that emit 35 to 70 percent less PM10 than older units are currently available. Field-testing results completed for the harvesters is currently under analysis by UC Davis. Early introduction of lower emitting almond harvesters will result in significant reductions.

Chipping and shredding wood waste in the orchard instead of burning results in substantial reductions of PM10, NOx, and ROG. Although Rule 4103 phases out most burning by 2010, some will be exempt due to lack of an economic alternative to burning. The District would purchase chippers and shredders for growers that were unable to implement an alternative to burning and had not selected this as a practice for their CMP Plan.

IV. Potential Projects Lists for NOx and PM10

The following tables list potential projects along with estimates of the number of potential projects, costs, emission reductions and cost-effectiveness for each type of project. The purpose of the list is to show that sufficient projects are available at a cost-effectiveness to achieve program goals. The list is not all inclusive. There are many Heavy-Duty Engine Incentive Program and REMOVE II eligible projects that could also be funded. New projects may also become available as retrofit devices are certified and new technologies are released to the market. The conclusion that can be drawn from this information is that projects well in excess of projected funding are available for the ISR program.

Tables are also provided for 2006, 2007, and 2008 containing a demonstration that the cost-effectiveness targets can be met with the types of projects that are available. This is not intended as a funding allocation system. Participation in grant programs is voluntary and on a first come, first served basis. The District may perform targeted outreach and may set up funding pots for the most cost-effective projects if necessary to achieve emission reduction commitments.

NOx Project Availability

	Individual Project Cost	Annual Reduction (t/y)	Project Life	Lifetime Reductions	Project CE $/ton	Projects Available	Total Cost	Cumulative Cost	Category Reductions Life (tons)	Total Reductions t/d	Cumulative Reductions tons	Cumulative CE
Marine Vessels (Harbor Craft) 04 repower	$197,850	7.6	16	121.6	1627.5	1	$197,850	$197,850	121.57	0.02	121.6	$1,627.46
Ag Irrigation Pump Electrification	$21,558	3.0	10	29.9	720.8	142	$3,061,273	$3,259,124	4247.22	0.58	4368.8	$746.00
Marine Vessels (Harbor Craft) 03 repower	$69,288	3.3	16	52.8	1313.3	1	$69,288	$3,328,412	52.8	0.01	4421.6	$752.77
Ag Irrigation Pumps Portable Diesel Repowers	$27,144	2.3	7	15.9	1705.0	50	$1,357,198	$4,685,610	796.0	0.11	5217.6	$898.05
HDD Trucks Idle Reduction	$9,883	0.6	5	3.0	3316.3	320	$3,162,411	$7,848,021	953.6	0.13	6171.2	$1,271.73
Open Burning Chippers Almond	$227,182	5.7	10	57.2	3971.7	1	$227,182	$8,075,203	57.2	0.01	6228.4	$1,296.52
Off-Road Vehicles/Equipment large ag	$48,382	1.7	7	11.8	4100.2	10	$483,820	$8,559,023	118.0	0.02	6346.4	$1,348.65
Auxiliary Power Units (Transportation Refridgeration Units)	$12,518	0.4	5	1.8	6878.1	294	$3,680,348	$12,239,371	535.1	0.07	6881.4	$1,778.61
Ag non self-propelled ICE	$9,200	0.1	7	1.0	8846.2	10	$92,000	$12,331,371	10.4	0.00	6891.8	$1,789.27
On-Road HD Vehicles - Fleet Modernization	$88,756	1.0	10	10.2	8744.4	1000	$88,755,962	$101,087,334	10150.0	1.39	17041.8	$5,931.72
Glass Melting Furnaces - SCR	$22,120,500	239.0	10	2390.0	9255.4	1	$22,120,500	$123,207,834	2390.0	0.33	19431.8	$6,340.52
Off-Road Vehicles/Equipment small ag repowers	$12,677	0.2	7	1.3	9981.9	20	$253,540	$123,461,374	25.4	0.00	19457.2	$6,345.27
Ag non self-propelled ICE - repowers	$15,500	0.2	7	1.5	10402.7	12	$186,000	$123,647,374	17.9	0.00	19475.1	$6,348.99
Small Boilers, Steam Generators, and Process Heaters - replacement	$13,000	0.1	10	1.2	10743.8	1207	$15,691,000	$139,338,374	1460.5	0.20	20935.6	$6,655.58
School Bus Replacement	$110,000	0.3	10	3.1	35483.9	1000	$110,000,000	$249,338,374	3100.0	0.42	24035.6	$10,373.72
Locomotives	$1,414,286	6.0	18.6	111.7	12664.7	10	$14,142,857	$263,481,231	1116.7	0.15	25152.3	$10,475.44
Small Boilers, Steam Generators, and Process Heaters - replacement	$6,000	0.0	10	0.3	18181.8	552	$3,312,000	$266,793,231	182.2	0.02	25334.5	$10,530.85
Forklifts (Electric, ICE, SI)	$44,457	0.4	5	2.0	22798.7	50	$2,222,873	$269,016,104	97.5	0.01	25432.0	$10,577.88
Airport Ground Support Equipment - Electric replacements	$27,889	0.2	5.0	1.1	24753.5	73	$2,035,889	$271,051,993	82.2	0.01	25514.2	$10,623.57
Open Burning Chippers Figs	$185,212	0.6	10	5.7	32379.7	12	$2,222,544	$273,274,537	68.6	0.01	25582.8	$10,681.95
Gross Polluter - VAVR	$3,000	0.1	1	0.08	37500.0	100	$300,000	$273,574,537	8.0	0.00	25590.8	$10,690.33
Old Vehicle - VAVR	$3,000	0.02	3	0.06	50000.0	5000	$15,000,000	$288,574,537	300.0	0.04	25890.8	$11,145.82
									25890.8	3.55		

PM10 Project Availability

	Individual Project Cost	Annual PM10 Reduction (t/y)	Project Life	Lifetime Reductions	Project CE $/ton	Projects Available	Total Cost	Cumulative Cost	Category Reductions Life (tons)	Total Reductions t/d	Cumulative Reductions tons	Cumulative CE
Unpaved Roads - City and County												
Paving 75 ADT roads	$290,000	27.1	20	542.0	535.1	10	$2,900,000	$2,900,000	5420	0.7	5420	$535.06
Paving 25 ADT roads	$290,000	9.0	20	180.7	1605.2	90	$26,100,000	$29,000,000	16260	2.2	21680	$1,337.64
Paving 10 ADT roads	$290,000	3.6	20	72.0	4027.8	100	$29,000,000	$58,000,000	7200	1.0	28880	$2,008.31
Suppressants 10 year contract	$140,080	3.5	10	35.0	4002.3	100	$14,008,000	$72,008,000	3500	1.0	32380	$2,223.84
Paved Roads											32380	
Paving Shoulders	$100,000	0.2	20	3.8	26315.8	500	$50,000,000	$122,008,000	1900	0.5	34280	$3,559.16
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	30231.3	500	$24,185,000	$146,193,000	800	0.2	35080	$4,167.42
PM Efficient Street Sweepers	$152,000	0.9	8	7.3	20821.9	15	$2,280,000	$148,473,000	109.5	0.0	35189.5	$4,219.24
Stationary Source Projects												
Cotton Gin - Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	460.1	12	$90,000	$148,563,000	195.6	0.0	35275.6	$4,211.49
Cotton Gin - Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	2173.9	12	$720,000	$149,283,000	331.2	0.0	35606.8	$4,192.54
Cotton Gin - Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	2536.2	12	$840,000	$150,123,000	331.2	0.1	35938	$4,177.28
Charbroiler Replacement	$6,600	0.2	10	2.4	2750.0	135.0	$891,000	$151,014,000	324	0.1	36262	$4,164.52
Other Ag Projects												
Almond Harvester Purchase	$145,000	3.6	10	35.7	4061.6	260	$37,700,000	$188,714,000	9282	2.5	45220	$4,173.24
										8.5		

NOx Cost-Effectiveness Demonstration

NOx Project Mix in 2006 to achieve an average cost effectiveness of $4650/ton with $6,006,379 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2006	Total cost	Total tons	Project CE $/ton
Ag Projects									
Ag Irrigation Pump Electrification	$21,558	3.0	10	29.9	142	20	$431,165	598.2	721
Ag Irrigation Pumps Portable Diesel Repowers	$27,144	2.3	7	15.9	50	10	$271,440	159.2	1,705
Off-Road Vehicles/Equipment large ag repowers	$48,382	1.7	7	11.8	10	4	$193,528	47.2	4,100
Ag non self-propelled ICE repowers hay bayler	$9,200	0.1	7	1.0	10	1	$9,200	1.0	8,846
Ag non self-propelled ICE repowers spray rig	$15,500	0.2	7	1.5	12	2	$31,000	3.0	10,403
Off-Road Vehicles/Equipment small ag repowers	$12,677	0.2	7	1.3	20	3	$38,031	3.8	9,982
Open Burning - Chipping Almonds	$227,182	5.7	4	22.9	1	1	$227,182	22.9	9,921
Open Burning - Chipping Figs	$185,212	0.6	4	2.28	12	1	$185,212	2.3	81,233
Marine Projects									
Marine Vessels (Harbor Craft) 03 repower	$69,288	3.3	16	52.8	1	1	$69,288	52.8	1,313
Marine Vessels (Harbor Craft) 04 repower	$197,850	7.6	16	121.6	1	1	$197,850	121.6	1,627
HD Truck/Bus Projects									
HDD Trucks Idle Reduction	$9,883	0.6	5	3.0	320	0	$0	0.0	#DIV/0!

NOx Cost-Effectiveness Demonstration

NOx Project Mix in 2006 to achieve an average cost effectiveness of $4650/ton with $6,006,379 available

HD Truck/Bus Projects *Cont*									
Auxiliary Power Units (Transportation Refridgeration Units) repowers	$12,518	0.4	5	1.8	294	20	$250,364	36.4	6,878
On-Road HD Vehicles Fleet Modernization	$88,756	1.0	10	10.2	1000	10	$887,560	101.5	8,744
School Bus Replacement	$110,000	0.3	10	3.1	1000	9	$990,000	27.9	35,484
Locomotives Tier 0 to Tier 2 or hybrid	$1,414,286	6.0	18.6	111.7	10	1	$1,414,286	111.7	12,665
Stationary Source Projects									
Glass Melting Furnaces	$22,120,500	239.0	10	2390.0	1	0	$0	0.0	#DIV/0!
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	$13,000	0.1	10	1.2	1207	1	$13,000	1.2	10,744
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	$6,000	0.0	10	0.33	552	12	$72,000	4.0	18,182
Off-Road Mobile									
Forklifts (Electric, ICE, SI)	$44,457	0.4	5	1.95	50	5	$222,287	9.8	22,799
Airport Ground Support Equipment - Electric	$27,889	0.2	5	1.13	73	3	$83,667	3.4	24,753
Other Mobile									
Gross Polluter - VAVR	$3,000	0.1	1	0.08	100	0	$0	0.0	#DIV/0!
Old Vehicle - VAVR	$3,000	0.02	3	0.06	5000	150	$450,000	9.0	50,000
				Overall cost and average CE for 2006			**$6,037,059**	**1316.7**	**4,585**

NOx Project Mix in 2007 to achieve an average cost effectiveness of $7100/ton with $14,407,974 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2007	Total cost	Total tons	Project CE $/ton
Ag Projects									
Ag Irrigation Pump Electrification	21,558	3.0	10	29.9	122	20	$431,165	598.2	721
Ag Irrigation Pumps Portable Diesel Repowers	27,144	2.3	7	15.9	40	20	$542,879	318.4	1,705
Off-Road Vehicles/Equipment large ag repowers	48,382	1.7	7	11.8	6	4	$193,528	47.2	4,100
Ag non self-propelled ICE repowers hay bayler	9,200	0.1	7	1.0	9	4	$36,800	4.2	8,846
Ag non self-propelled ICE repowers spray rig	15,500	0.2	7	1.5	10	4	$62,000	6.0	10,403
Off-Road Vehicles/Equipment small ag repowers	12,677	0.2	7	1.3	17	4	$50,708	5.1	9,982
Open Burning - Chipping Almonds	227,182	5.7	3	17.2	0	0	$0	0.0	#DIV/0!
Open Burning - Chipping Figs	185,212	0.6	3	1.71	11	0	$0	0.0	#DIV/0!
Marine Projects									
Marine Vessels (Harbor Craft) 03 repower	69,288	3.3	16	52.8	0	0	$0	0.0	#DIV/0!
Marine Vessels (Harbor Craft) 04 repower	197,850	7.6	16	121.6	0	0	$0	0.0	#DIV/0!
HD Truck/Bus Projects					0				
HDD Trucks Idle Reduction	9,883	0.6	5	3.0	320	0	$0	0.0	#DIV/0!
Auxiliary Power Units	12,518	0.4	5	1.8	274	40	$500,728	72.8	6,878

NOx Project Mix in 2007 to achieve an average cost effectiveness of $7100/ton with $14,407,974 available

HD Truck/Bus Projects *Cont.*									
On-Road HD Vehicles - Fleet Modernization	88,756	1.0	10	10.2	990	45	$3,994,018	456.8	8,744
School Bus Replacement	110,000	0.3	10	3.1	991	40	$4,400,000	124.0	35,484
Locomotives	1,414,286	6.0	18.6	111.7	9	2	$2,828,571	223.3	12,665
Stationary Source Projects					0				
Glass Melting Furnaces	22,120,500	239.0	10	2390.0	1	0	$0	0.0	#DIV/0!
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	13,000	0.1	10	1.2	1206	2	$26,000	2.4	10,744
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	6,000	0.0	10	0.33	540	6	$36,000	2.0	18,182
Off-Road Mobile									
Forklifts (Electric, ICE, SI)	44,457	0.4	5	1.95	45	3	$133,372	5.9	22,799
Airport Ground Support Equipment - Electric	27889	0.2	5.0	1.13	70	4	$111,556	4.5	24,753
Other Mobile									
Gross Polluter - VAVR	$3,000	0.1	1	0.08	100	5	$15,000	0.4	37,500
Old Vehicle - VAVR	$3,000	0.02	3	0.06	4850	350	$1,050,000	21.0	50,000
				Overall cost and average CE for 2007			**$14,412,326**	**1892.0**	**7,617**

NOx Project Mix in 2008 to achieve an average cost effectiveness of $9350/ton with $22,373,287 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2008	Total cost	Total tons	Project CE $/ton	Comments
Ag Projects										
Ag Irrigation Pump Electrification	21,558	3.0	10	29.9	102	18	$388,049	538.4	721	
Ag Irrigation Pumps Portable Diesel Repowers	27,144	2.3	7	15.9	20	10	$271,440	159.2	1,705	
Off-Road Vehicles/Equipment large ag repowers	48,382	1.7	7	11.8	2	2	$96,764	23.6	4,100	
Ag non self-propelled ICE repowers hay bayler	9,200	0.1	7	1.0	5	5	$46,000	5.2	8,846	
Ag non self-propelled ICE repowers spray rig	15,500	0.2	7	1.5	6	6	$93,000	8.9	10,403	
Off-Road Vehicles/Equipment small ag repowers	12,677	0.2	7	1.3	13	8	$101,416	10.2	9,982	
Open Burning - Chipping Almonds	227,182	5.6	2	11.1	1	1	$227,182	11.1	20,467	Rule 4103 2010 Implementation
Open Burning - Chipping Figs	185,212	0.6	2	1.14	11	0	$0	0.0	#DIV/0!	Rule 4103 2010 Implementation
Marine Projects										
Marine Vessels (Harbor Craft) 03 repower	69,288	3.3	16	52.8	0	0	$0	0.0	#DIV/0!	
Marine Vessels (Harbor Craft) 04 repower	197,850	7.6	16	121.6	0	0	$0	0.0	#DIV/0!	
HD Truck/Bus Projects					0					
HDD Trucks Idle Reduction	9,883	0.6	5	3.0	320	50	$494,127	149.0	3,316	Idle Aire req. min order of 50 units

NOx Project Mix in 2008 to achieve an average cost effectiveness of $9350/ton with $22,373,287 available

HD Truck/Bus Projects *Cont.*										
Auxiliary Power Units - Repower	12,518	0.4	5	1.8	234	40	$500,728	72.8	6,878	
On-Road HD Vehicles - Fleet Modernization	88,756	1.0	10	10.2	945	66	$5,857,894	669.9	8,744	
School Bus Replacement	110,000	0.3	10	3.1	951	50	$5,500,000	155.0	35,484	
Locomotives	1,414,286	6.0	18.6	111.7	7	4	$5,657,143	446.7	12,665	
Stationary Source Projects					0					
Glass Melting Furnaces	22,120,500	239.0	10	2390.0	1	0	$0	0.0	#DIV/0!	
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	13,000	0.1	10	1.2	1204	60	$780,000	72.6	10,744	
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	6,000	0.0	10	0.33	534	60	$360,000	19.8	18,182	
Off-Road Mobile					0					
Forklifts (Electric, ICE, SI)	44,457	0.4	5	1.95	42	5	$222,287	9.8	22,799	
Airport Ground Support Equipment - Electric	27889	0.2	5.0	1.13	10	5	$139,444	5.6	24,753	
Other Mobile					0					
Gross Polluter ID & Replace - VAVR	$3,000	0.1	1	0.08	95	50	$150,000	4.0	37,500	
Old Vehicle - VAVR	$3,000	0.02	3	0.06	4500	500	$1,500,000	30.0	50,000	
				Overall cost and average CE for 2008			**$22,385,473**	**2391.7**	**9,359**	

NOx Cost Effectiveness Demonstration

Year	Nox Projected Revenue	NOx CE $/ton
2006	$6,006,379	4,650
2007	$14,407,974	7,100
2008	$22,373,287	9,350
Total	$42,787,640	

PM10 Cost-Effectiveness Demonstration

Project Mix in 2006 to achieve an average cost effectiveness of $2907/ton with $5,941,908 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2006	Total cost	Total tons	Project CE $/ton
Unpaved Roads									
Paving 75 ADT roads	$290,000	27.1	20	542	10	2	$580,000	1084.0	535
Paving 25 ADT roads	$290,000	9.0	20	180.7	90	2	$580,000	361.3	1,605
Paving 10 ADT roads	$290,000	3.6	20	72.0	100	4	$1,160,000	288.0	4,028
Suppressants 10 year contract	$140,080	3.5	10	35.0	100	6	$840,480	210.0	4,002
Paved Roads									
Paving Shoulders	$100,000	0.2	20	3.8	500	14	$1,400,000	53.2	26,316
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	500	16	$773,920	25.6	30,231
PM Efficient Sweeper Purchase	$152,000	0.9	8	7.3	25	2	$304,000	14.6	20,879
Cotton Gins									
Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	12	2	$15,000	32.6	460
Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	12	2	$120,000	55.2	2,174
Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	12	2	$140,000	55.2	2,536
Other Ag Equipment									
Almond Harvester Purchase	$145,000	3.6	10	35.7	260	0	$0	0.0	#DIV/0!
Average CE in 2006						**Overall cost and CE for 2006**	**$5,913,400**	**2179.7**	**2,713**

Project Mix in 2007 to achieve an average cost effectiveness of $5594/ton with $20,861,575 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2007	Total cost	Total tons	Project CE $/ton
Unpaved Roads									
Paving 75 ADT roads	$290,000	27.1	20	542	8	0	$0	0.0	#DIV/0!
Paving 25 ADT roads	$290,000	9.0	20	180.7	88	5	$1,450,000	903.3	1,605
Paving 10 ADT roads	$290,000	3.6	20	72.0	96	22	$6,380,000	1584.0	4,028
Suppressants 10 year contract	$140,080	3.5	10	35.0	94	16	$2,241,280	560.0	4,002
Paved Roads					0				
Paving Shoulders	$100,000	0.2	20	3.8	486	55	$5,500,000	209.0	26,316
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	484	50	$2,418,500	80.0	30,231
PM Efficient Sweeper Purchase	$152,000	0.9	8	7.3	23	12	$1,824,000	87.4	20,879
Cotton Gins									
Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	10	2	$15,000	32.6	460
Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	10	2	$120,000	55.2	2,174
Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	10	2	$140,000	55.2	2,536
Other Ag Equipment									
Almond Harvester Purchase	$145,000	3.6	10	35.7	260	2	$290,000	71.4	4,062
Average CE in 2007						**Overall cost and CE for 2007**	**$20,378,780**	**3638.1**	**5,602**

Project Mix in 2008 to achieve an average cost effectiveness of $9011/ton with $33,883,309 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2008	Total cost	Total tons	Project CE $/ton
Unpaved Roads									
Paving 75 ADT roads	$290,000	27.1	20	542	8	1	$290,000	542.0	535
Paving 25 ADT roads	$290,000	9.0	20	180.7	83	5	$1,450,000	903.3	1,605
Paving 10 ADT roads	$290,000	3.6	20	72.0	74	10	$2,900,000	720.0	4,028
Suppressants 10 year contract	$140,080	3.5	10	35.0	78	5	$700,400	175.0	4,002
Paved Roads					0				
Paving Shoulders	$100,000	0.2	20	3.8	431	175	$17,500,000	665.0	26,316
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	434	160	$7,739,200	256.0	30,231
PM Efficient Sweeper Purchase	$152,000	0.9	8	7.3	11	11	$1,672,000	80.1	20,879
Cotton Gins					0				
Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	8	2	$15,000	32.6	460
Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	8	2	$120,000	55.2	2,174
Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	8	2	$140,000	55.2	2,536
Other Ag Equipment									
Almond Harvester Purchase	$145,000	3.6	10	35.7	258	6	$870,000	214.2	4,062
Average CE in 2008						**Overall cost and CE for 2008**	**$33,396,600**	**3698.6**	**9,029**

PM10 Cost-Effectiveness Demonstration

Year	PM10 Projected Revenue	PM10 CE $/ton
2006	$5,941,908	2,907
2007	$20,306,433	5,594
2008	$33,883,309	9,011
Total	$60,131,650	

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APPENDIX F

Socioeconomic Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

November 17, 2005

SOCIOECONOMIC ANALYSIS PROPOSED INDIRECT SOURCE RULE: DRAFT RULES 9510 AND 3180

4 November 2005

Prepared for

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1. EXECUTIVE SUMMARY

The San Joaquin Valley Unified Air Pollution Control District ("District") seeks to adopt New Rule 9510 and 3180 to meet certain United States Environmental Protection Agency (US EPA) mandates and timelines with regards to improved air quality in the region. This section of the report summarizes the findings of the socioeconomic analysis of Rules 9510 and 3180.

The analysis indicates that while the worst-case residential fee that a typical residential development would pay under Draft Rule 9510 and 3180 can increase the amount of household income required to finance the purchase of a new home, the estimated increase represents a small fraction of the original household income required to finance a new home in the event no air quality fees were in place. The affect of the fees on rents is similarly small.

The analysis also examines the question of housing affordability from the vantage point of low- and moderate-income households. The analysis demonstrates that, even before the imposition of an air quality fees, most low-income and households in the Central Valley are priced out of newly constructed multifamily unit market, the rents for which need to be at levels that account for price of land, development costs, developer fees, and an adequate level of profit, among other things. The analysis discusses how public subsidies can assist in enhancing the financial feasibility of a real estate project in which a certain portion of units are set-aside as below-market rental units.

The analysis also examines the impacts of proposed worst-case off-site emission reduction fees on commercial, industrial and institutional projects. While a typical non-residential development can absorb the 2006 and 2008 fees, projects will have to recover the cost of the fee over a period of time.

It is important to note that any fee identified in the report is the estimated maximum fee in the worst-case scenario for a typical development project, with the understanding that the

actual fee will vary with the particulars of any project. Any fee in the report is presented for the purposes of analyzing potential impacts given costs associated with reducing quantifiable emissions resulting from what constitutes typical residential, commercial and industrial developments. It is also important to note that the developer may reduce fees by incorporating on-site emission reduction measures into the projects. There may or may not be costs associated with on-site measures. In any event, it is anticipated that the developer will choose the least costly option.

2. INTRODUCTION

This report describes the socioeconomic impacts of Rule 9510 (Indirect Source Review – ISR) and 3180 (Administrative Fees for Indirect Source Review). Following this introduction, the report summarizes the proposed amendments and describes the methodology for the socioeconomic analysis. In Section 5, the report describes the economic characteristics of sources affected by Rule 9510 and 3180. The sixth section analyzes the socioeconomic impacts of compliance costs on the regional economy.

The report is prepared pursuant to the provisions of AB2051 (Section 40728.5 of the California Health and Safety Code), which requires an assessment of socioeconomic impacts of proposed air quality rules. The findings in this report can assist District staff in understanding the socioeconomic impacts of Rules 9510 and 3180, and can assist staff in preparing a refined version of the rule. A final report will be presented at the Governing Board hearing by District staff in December 2005. Figure 1 is a map of the eight-county region that comprises the San Joaquin Valley Air Basin. As indicated in the map, Kern County is not completely in the District.

FIGURE 1
San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) Air Basin



3. DESCRIPTION OF NEW RULES 9510 & 3180

The San Joaquin Valley Air Basin (SJVAB) is classified as a nonattainment area for the state and federal health based ambient ozone and PM 10 standards by the California Air Resources Board (ARB) and the U.S. Environmental Protection Agency (EPA). The SJVAB is currently classified as serious nonattainment for the 24-hour and annual National Ambient Air Quality Standards (NAAQS) for particulate matter 10 microns in size and smaller (PM10), extreme nonattainment for the federal 1-hour ozone standard, serious nonattainment for the new federal 8-hour ozone standard, and severe nonattainment for the 1-hour state ozone standard.

The San Joaquin Valley Unified Air Pollution Control District's (District) adopted 2003 PM10 Plan projects attainment of NAAQS for PM10 at the earliest practicable date of December 31, 2010. The Indirect Source Rule[1] (ISR) is one of the commitments contained in the 2003 PM10 Plan to achieve these emissions reductions. The ISR commitment will be implemented through Rules 9510 and 3180. The purpose of Draft Rule 9510 is to reduce emissions of NOx and PM10 from new development projects. The purpose of Draft Rule 3180 is to recover the costs of administering Draft Rule 9510. Implementation of these draft rules is expected to reduce NOx and PM10 emissions by 5.4 and 5.8 tons per day respectively.

The District identified several examples of air pollution agencies in California that are currently reviewing land use projects for indirect source impacts and/or collecting mitigation fees in their districts. District staff reviewed programs being implemented by the Mendocino County and Shasta County Air Quality Management Districts and the Great Basin, Colusa County, and Placer County Air Pollution Control Districts. District staff also considered a number of

[1] Indirect Sources are land uses that attract or generate motor vehicle trips.

program types including District permitting, city/county review, District review, and simple fee.

Despite significant air pollution reductions from both mobile and stationary sources, the District exceeds state and federal air quality standards for ozone and PM10. Although today's new cars pollute about 90 percent less than models produced 25 years ago (due to California's strict vehicle emissions standards), large increases in population and driving partially offset the benefits these cleaner-burning vehicles provide. The District's total population increased by 22 percent between 1990 and 2000; and, California's Department of Finance projects that the SJVAB's population will increase by 24 percent between 2000 and 2010. With increased population, there is an increase in emissions from area sources, such as consumer products, fuel combustion, landscape maintenance equipment, etc.

The total number of vehicle miles traveled (VMT) in the District has increased at a rate faster than population growth. The district witnessed a nine percent increase between 1999 and 2002, and is expecting a 27 percent increase from 2002 to 2010. Entrained and re-entrained paved road dust and corresponding PM10 emissions increase as VMT increases.

To reduce emissions of NOx and PM10, Draft Rule 9510 would apply to development projects that will seek to gain a discretionary approval for projects that, upon full build-out will include any one of the following: 50 residential units, 2,000 square feet of commercial space, 25,000 square feet of industrial space, 20,000 square feet of medical office space, 39,000 square feet of general office space, 9,000 square feet of educational space, 10,000 square feet of government space, 20,000 square feet of recreational space, or 9,000 square feet of unidentified space. Certain transportation projects, transit projects, reconstruction projects that result from a natural disaster, and development projects whose primary source of emissions are subject to District Rule 2201 or 2010 would be exempt from this Draft Rule. Also, development projects that have a mitigated baseline below two tons per year for each pollutant would be exempt from the emission reduction requirements of the rule.

Draft Rule 9510 would require new development project applicants to submit an Air Impact Assessment application to the District prior to or at application for a project's final discretionary approval with a public agency. The application would include an assessment, project location and description, an on-site emission reduction checklist, a proposed Monitoring and Reporting Schedule (MRS), and a fee deferral agreement if necessary. The District would have 10 days to determine whether or not the application is complete. After deeming an application complete, the district would have 30 days to approve the application and notify the applicant of the fee amounts.

Draft Rule 9510 would require developers to reduce cumulative NOx emissions in excess of 50 percent of the project's first-year operational baseline emissions until the emissions reach 50 percent of the first-year baseline emissions (approximately 10 years). Developers would be required to reduce PM10 emissions equal to half of the first-year emissions after build-out for the same time period required for NOx reductions. Developers would also be required to reduce emissions from construction equipment NOx by 20%, and PM10 by 45% compared to the statewide fleet average. Emissions could be reduced through on-site emission reduction measures, by paying the District a fee to fund emission reduction projects off-site, or through a combination of the two.

To recover the costs of administering Draft Rule 9510, Draft Rule 3180 would include a non-refundable application filing fee to be paid when an application is submitted to the District. Once an application and application fee are received, District staff would log the total staff hours spent on the project. So that only the cost of the actual hours spent on the project is recovered, the cost of the hours spent on the project (hours multiplied by a weighted average labor rate) would be subtracted from the application fee. Draft Rule 3180 would also contain a fee, payable when the off-site emission reduction fees are collected, equal to four percent of the off-site fees to recover the cost of administering off-site emission reduction projects.

4. METHODOLOGY

The socioeconomic analysis involves the use of information provided directly by affected sources, as well as secondary data used to describe the industries affected by the proposed provisions of Rule 9510 and 3180. The approach is briefly described below.

This report relies heavily on the most current data available from a variety of sources. For commercial-industrial prices, this report relies on Dataquick, Loopnet.com and Realtor.com. For construction trends, this report relied on the Construction Industry Research Board. When estimating cost of construction, we used "Commercial Square Foot Building Costs: 2004", by Deloitte Saylor Publication, as well as per square foot cost of construction estimates used by many cities when estimating the value of a project. For purposes of estimating profits, ADE relied on Dun and Bradstreet, as well as corporate reports of major home builders and developers of commercial-industrial space operating in California and the Central Valley.

With the above information, ADE was able to estimate profit ratios for sources affected by the draft rule. ADE calculated ratios of profit per dollar of revenue for affected industries. The result of the socioeconomic analysis shows what proportion of profits the compliance costs represent. Based on assumed thresholds of significance, ADE discusses in the report whether the affected sources are likely to pass on costs to consumers or to reduce jobs as a means of recouping the cost of rule compliance or as a result of reducing business operations. To the extent that such job losses appear likely, the indirect multiplier effects of the jobs losses are estimated using a regional IMPLAN input-output model.

When analyzing the socioeconomic impacts of proposed new rules and amendments, ADE works closely within the parameters of accepted methodologies discussed in a 1995 California Air Resources Board report called "Development of a Methodology to Assess the Economic Impact Required by SB513/AB969" (by Peter Berck, PhD, UC Berkeley

Department of Agricultural and Resources Economics, Contract No. 93-314, August, 1995). The author of this report reviewed a methodology to assess the impact that California Environmental Protection Agency proposed regulations would have on the ability of California businesses to compete. The California Air Resources Board (ARB) has incorporated the methodologies described in this report in its own assessment of socioeconomic impacts of rules generated by ARB. One methodology relates to determining a level above or below which a rule and its associated costs is deemed to have significant impacts. When analyzing the degree to which its rules are significant or insignificant, ARB employs a threshold of significance that ADE follows. Berck reviewed the threshold in his analysis and wrote, "The Air Resources Board's (ARB) use of a 10 percent change in [Return on Equity] ROE (i.e. a change in ROE from 10 percent to a ROE of 9 percent) as a threshold for a finding of no significant, adverse impact on either competitiveness or jobs seems reasonable or even conservative."

5. IMPACT INDUSTRIES SUBJECT TO NEW RULES 9510 & 3180 (INDIRECT SOURCE RULE)

This section of the socioeconomic analysis describes demographic and economic trends in the San Joaquin Valley region. The first part of this section compares the San Joaquin Valley region against California as a whole, and provides a context for understanding demographic and economic changes that occurred within the San Joaquin Valley region between 1998 and 2003. Starting with sub-section 5.2, the second part of this section narrows the focus of the socioeconomic analysis to industries affected by New Rules 9510 and 3180. The second part of this section describes the economic characteristics of potentially impacted industries that might be subject to Rules 9510 and 3180.

In this report, the San Joaquin Valley region is defined as Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare counties. Data for Kern County in Tables 1 and 2 are for all of Kern County, although Kern County is only partially in the San Joaquin Valley Air Basin. Starting with Table 3, data for Kern County are for the part of Kern County that is in the San Joaquin Valley Air Basin.

5.1 REGIONAL DEMOGRAPHIC AND ECONOMIC TRENDS

REGIONAL DEMOGRAPHIC TRENDS

The San Joaquin Valley region experienced tremendous population growth during the 1990s. Many came to this area because of affordable housing. As a result, population increased significantly. The eight-county region's population increased by 22 percent (or approximately 2.0 percent annually), from 2.9 million in 1993 to 3.6 million in 2003. While the State of California's population increased by 15 percent (or approximately 1 percent annually), all the counties in the region experienced faster rates of growth, and two counties grew at rates that were triple the State's growth rate, as Table 1 shows. While by many standards Madera County continues to be a small county– at 135,262 residents

according to the Department of Finance–it still experienced a 35 percent growth in population during the last decade (or three percent annually). Kings County also grew by three percent per year. As demonstrated in the following section on regional economic trends, the demographic changes that occurred in the San Joaquin Valley region during the 1990s significantly influenced the economy of this eight-county region.

TABLE 1
Population Growth: San Joaquin Valley Region, 1993 - 2003

	1993	1998	2003	Distribution, 2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	31,303,452	32,670,019	36,144,267		1%	2%	1%
SJV Region	2,959,911	3,192,439	3,615,696	10%	2%	3%	2%
Fresno	722,608	781,936	862,642	24%	2%	2%	2%
Kern	593,087	637,227	724,883	20%	1%	3%	2%
Kings	109,648	120,957	141,434	4%	2%	3%	3%
Madera	100,297	114,137	135,262	4%	3%	3%	3%
Merced	191,883	203,181	232,141	6%	1%	3%	2%
San Joaquin	507,170	546,852	630,577	17%	2%	3%	2%
Stanislaus	400,417	428,272	491,929	14%	1%	3%	2%
Tulare	334,801	359,877	396,828	11%	1%	2%	2%

Source: Applied Development Economics, based on California Department of Finance

Housing construction in the San Joaquin Valley Air Basin has paralleled this increase in population. Low interest and the availability of land at prices lower than in coastal areas of California has fueled construction activity in the Central Valley. Tables 2 and 3 track building permits for single-family and multi-family homes. According to the California Construction Industry Research Board, home-builders typically take out building permits only when they are ready to construct housing. Thus, building permits is a good indicator of housing production. As Table 2 shows, the amount of single-family building permits increased by 14 percent annually between 1998 and 2003 in the Central Valley, easily surpassing the statewide annual rate of eight percent. Almost forty percent of all single family building permits was for projects in San Joaquin and Stanislaus County in 2003. As the tables below show, the amount of new construction for single-family homes greatly exceeds new

construction for multi-family housing, for reasons related to market demand, availability of land, and historically low-interest rates, among other reasons.

TABLE 2
Single-Family Residential Building Permit Trends:
San Joaquin Valley, 1993-2003

	---------- SFU Building permits ----------						
	1993	1998	2003	Distribution, 2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	69,901	94,298	138,762		6%	8%	7%
SJV Region	15,055	14,280	27,080	20%	-1%	14%	6%
Fresno	3,743	2,742	4,479	17%	-6%	10%	2%
Kern	3,082	3,025	5,529	20%	0%	13%	6%
Kings	530	526	835	3%	0%	10%	5%
Madera	694	473	1,144	4%	-7%	19%	5%
Merced	1,087	960	2,489	9%	-2%	21%	9%
San Joaquin	2,545	3,170	6,727	25%	4%	16%	10%
Stanislaus	1,835	1,997	3,884	14%	2%	14%	8%
Tulare	1,539	1,387	1,993	7%	-2%	8%	3%

Source: Applied Development Economics, based on Construction Industry Research Board

TABLE 3
Multi-Family Residential Building Permit Trends: San Joaquin Valley, 1993-2003

	---------- MFU Building permits ----------						
	1993	1998	2003	Distribution, 2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	14,755	31,409	56,920		16%	13%	14%
SJV Region	1,309	1,403	3,699	6%	1%	21%	11%
Fresno	404	292	1,520	41%	-6%	39%	14%
Kern	314	428	583	16%	6%	6%	6%
Kings	13	231	143	4%	78%	-9%	27%
Madera	105	160	90	2%	9%	-11%	-2%
Merced	20	72	457	12%	29%	45%	37%
San Joaquin	83	59	225	6%	-7%	31%	10%
Stanislaus	148	93	284	8%	-9%	25%	7%
Tulare	222	68	397	11%	-21%	42%	6%

Source: Applied Development Economics, based on Construction Industry Research Board

While the value of single-family unit building permits in the Central Valley is lower by almost $40,000 than the value of single family building permits for the state as a whole, it is worth noting that between 1998 and 2003 average values rose

faster in the region as compared to the state (see Table 4). Using average construction cost figures adjusted for regional and historical variations, local officials estimate the value of single-family, multi-family and commercial and industrial building permits for reasons related to calculating fees and maintaining departmental budgets. The actual price of housing on the market is typically higher than the estimated value of the building permit, though changes in the value of building permits are a good indication as to the trajectory of change in the actual housing market.

TABLE 4
Average Value of Single-Family Unit Building Permit, San Joaquin Valley

	---------- Average Value ----------					
	1993	1998	2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	$183,559	$218,055	$217,271	4%	0%	2%
SJV Region	$130,879	$141,956	$170,604	2%	4%	3%
Fresno	$135,736	$150,044	$183,122	2%	4%	3%
Kern	$130,191	$130,167	$149,816	0%	3%	1%
Kings	$141,740	$136,190	$119,485	-1%	-3%	-2%
Madera	$100,791	$102,214	$150,562	0%	8%	4%
Merced	$135,439	$140,674	$153,139	1%	2%	1%
San Joaquin	$143,809	$161,303	$197,209	2%	4%	3%
Stanislaus	$119,981	$143,309	$176,566	4%	4%	4%
Tulare	$118,658	$122,141	$153,456	1%	5%	3%

Source: Applied Development Economics, based on Construction Industry Research Board

Table 5 below identifies the median price for for-sale owner-occupied housing in the Central Valley. The data comes from Dataquick. In the last two years, the median selling price of homes sold on the market has increased substantially. Dataquick's median housing price data cover transactions involving newly built homes, reselling of older homes, and condominiums and townhouses. At almost $300,000 the median price of a home in Madera County is almost twice what is was in July 2003.

TABLE 5
Median Home Sale Prices: San Joaquin Valley, 2003-2005 ($2005)

	July 2003	July 2004	July 2005	03-04	04-05
Fresno County	$171,220	$220,955	$265,000	29%	20%
Kern County	$136,353	$176,041	$236,500	29%	34%
Madera County	$151,811	$242,638	$299,500	60%	23%
Merced County	$207,151	$242,638	$335,000	17%	38%
San Joaquin County	$247,295	$320,075	$403,000	29%	26%
Stanislaus County	$245,165	$278,775	$360,000	14%	29%
Tulare County	$131,494	$159,005	$215,500	21%	36%
	$184,356	$234,304	$302,071	27%	29%

Source: Applied Development Economics, based on Dataquick

REGIONAL ECONOMIC TRENDS

The influx of people moving into the region in search of homes that are more affordable than homes in the San Francisco Bay Area affects more than the housing market. The affect of more people in the San Joaquin Valley region can also be seen in the changing economic profile of the region.

Economic development practitioners and planners have traditionally divided economies into two broad industrial categories—the economic base and local support industries. Economic base industries are the drivers of local and regional economies in that these industries draw income into a local economy by selling products outside of the local economy, much like the export industries of a national economy. Accrued earnings then circulate throughout the local area in the form of wages and salaries, investments, purchases of fixed assets, and goods and services, generating more jobs and wealth.

The economic base is typically comprised of industries within the manufacturing, minerals-resource extraction, and agricultural sectors. There are also the "local support industries" such as retail or service sectors, the progress of which is a function of the economic base and demographic changes, and more so the latter than the former. As population increases in a given area, demand for services–such as realtors, teachers, and healthcare–increases, as does

demand for basic retail items like groceries, gas for commuting, or clothing at the local apparel shops.

Agriculture is the economic base of the San Joaquin Valley region by virtue of the amount of goods this sector produces and exports throughout the nation and the globe. Fourteen percent of all workers in the region are employed by industries within agriculture, as Table 2 shows. However, in 1998 the proportion of workers in agriculture was 18 percent. In fact, over the five-year period between 1998 and 2003, employment in agriculture declined by three percent per year, or by 15 percent over five years.

Between 1998 and 2003, local support industries gained in prominence within the San Joaquin Valley region. Service-rendering industries employed the most workers as a proportion of total employment in the region. As Table 2 shows, excluding wholesale, retail and transportation, service-rendering industries comprise the largest employment sector in the region, at 647,100 or 53 percent of all jobs. With retail, transportation and wholesale, services accounts for slightly over 70 percent of all jobs. In 1998, service-rendering industries represented 50 percent of all jobs, and when including retail, wholesale and transportation in the mix, 67 percent.

Increases in employment in service-rendering industries are consistent with regional population growth. In the region, local support industries of construction, education and health, financial activities, and government increased annually by six percent, four percent, three percent and three percent respectively between 1998 and 2003.

TABLE 6
Employment Profile Of The San Joaquin Valley Region 1998 – 2003

MAJOR SECTORS	San Joaquin Valley Region Employment 1998	San Joaquin Valley Region Employment 2003	San Joaquin Valley Region Employment Distribution, 2003	Annual Percent Change 1998 to 2003	California Employment Distribution, 2003	Annual Percent Change 1998 to 2003
Agriculture	204,200	174,900	14%	-3%	3%	-2%
Resources, Mining and Construction	57,400	78,100	6%	6%	5%	5%
Manufacturing	114,300	110,300	9%	-1%	10%	-4%
Wholesale	34,400	39,000	3%	3%	4%	1%
Retail	121,400	133,200	11%	2%	11%	2%
Transportation/Warehousing/Utilities	37,600	45,700	4%	4%	3%	-1%
Information	15,000	14,200	1%	-1%	3%	-0.5%
Financial Activities	40,400	46,600	4%	3%	6%	3%
Professional and Business Services	88,000	95,100	8%	2%	14%	1%
Educational and Health Services	101,500	122,200	10%	4%	10%	3%
Leisure, Hospitality and Other Srvcs	112,500	116,400	9%	1%	13%	2%
Government	221,200	252,600	21%	3%	16%	2%
Total Employment	**1,147,900**	**1,228,300**	**100%**	**1%**	**100%**	**1%**

Source: Applied Development Economics, based on data from California Employment Development Department LMID

The emergence of local support industries in the San Joaquin Valley region mirrors and leads statewide trends, as Table 6 shows. In the region, construction, health-education, and government increased annually by six percent, four percent and three percent, whereas, statewide, these industries grew by five percent, three percent and two percent per year between 1998 and 2003. In short, while agriculture remains the leading edge of the economy, the San Joaquin Valley region's economy has become more diverse, with the growth occurring within population-driven local support industries rather than the export-focused economic base industries of manufacturing and agriculture.

5.2 *DESCRIPTION OF AFFECTED INDUSTRIES*

The analysis below examines trends of industries that will be likely affected by Draft Rules 9510 and 3180. According to the rule, developers of applicable development projects will have to pay a fee to reduce emissions related to the project that are not reduced on-site. The analysis below seeks to understand the possible impact of the fee on the economics of a development project, particularly with respect to project profitability and with respect to impacts on the final user,

which, in the case of housing, is the homebuyer or renter. The report takes into consideration existing fees that are already in place, meaning that the analysis is on the incremental impact of the new fee on top of existing fees.

The following section reviews residential and commercial-industrial trends in certain number of cities in the eight-county region. The report focuses on 27 cities in the region. Table 7 below organizes the 27 cities into different typologies. The consultant obtained information regarding existing fees on residential and commercial development from many of these jurisdictions. In addition, the report references a report issued by State of California's Housing and Community Development Department, called "Pay to Play." This report also tracks residential development fees for many cities in the Central Valley.

TABLE 7
Select Central Valley Cities By Type

Type	Cities
Large Urban	Fresno, Bakersfield
Bay Area Commuter Shed	Stockton, Modesto, Manteca, Lodi, Tracy
Medium	Visalia, Clovis, Merced, Turlock, Hanford, Porterville, Tulare
Small/Med Bedroom Community	Ceres, Sanger, Atwater, Selma, Linden
Small Rural/Farming	Mendota, Wasco, Firebaugh, Avenal, Taft, Orange Cove, Oakhurst, Shafter

Source: San Joaquin Valley Unified Air Pollution Control District

HOUSING TRENDS IN SELECT CITIES

Table 8 below identifies the population for the 27 cities that are the focus of this analysis. These cities consist of over 2 million residents, or 55 percent of all people in the eight-county San Joaquin Valley region. Between 1998 and 2003, population in these cities grew by three percent annually, which is consistent with annual population growth rates for the region as a whole (see Table 1).

TABLE 8
Population Trends of Select Cities in the San Joaquin Valley Region, 1993-2003

			------ Population ------				
	City	**County**	**1993**	**1998**	**2003**	**1993-1998**	**1998-2003**
Large Urban	Bakersfield	Kern	192,351	220,771	268,914	3%	4%
	Fresno	Fresno	385,914	409,070	450,614	1%	2%
			578,265	**629,841**	**719,528**	**2%**	**3%**
Bay Area Commuter Shed	Lodi	San Joaquin	52,936	55,844	60,317	1%	2%
	Manteca	San Joaquin	42,833	47,256	57,485	2%	4%
	Modesto	Stanislaus	176,241	182,929	203,498	1%	2%
	Stockton	San Joaquin	222,992	241,777	262,553	2%	2%
	Tracy	San Joaquin	39,913	47,687	69,987	4%	8%
			534,915	**575,493**	**653,840**	**1%**	**3%**
Medium	Clovis	Fresno	57,036	67,291	76,545	3%	3%
	Hanford	Kings	33,892	39,012	44,833	3%	3%
	Merced	Merced	59,270	61,705	68,155	1%	2%
	Porterville	Tulare	32,310	36,286	42,181	2%	3%
	Tulare	Tulare	37,342	40,848	46,538	2%	3%
	Turlock	Stanislaus	46,481	50,958	62,256	2%	4%
	Visalia	Tulare	84,725	93,856	99,460	2%	1%
			351,056	**389,956**	**439,968**	**2%**	**2%**
Small/Med Bedroom Community	Atwater	Merced	22,528	22,944	26,216	0.4%	3%
	Ceres	Stanislaus	29,331	32,289	36,449	2%	2%
	Linden	San Joaquin	1,090	1,068	1,046	-0.4%	-0.4%
	Mendota	Fresno	7,287	7,521	8,203	1%	2%
	Sanger	Fresno	17,927	18,557	19,993	0.7%	2%
	Selma	Fresno	16,462	17,937	21,003	2%	3%
			94,625	**100,316**	**112,910**	**1%**	**2%**
Small Rural/Farming	Avenal	Kings	11,459	12,178	15,428	1%	5%
	Firebaugh	Fresno	5,031	5,565	6,201	2%	2%
	Oakhurst	Madera	2,570	2,519	2,833	0%	2%
	Orange Cove	Fresno	5,709	7,095	8,782	4%	4%
	Shafter	Kern	10,771	11,182	13,443	0.8%	4%
	Taft	Kern	6,508	7,375	9,027	3%	4%
	Wasco	Kern	17,212	20,083	22,400	3%	2%
			59,260	**65,996**	**78,114**	**2%**	**3%**
San Joaquin Valley Air Basin			**1,618,121**	**1,761,601**	**2,004,360**	**2%**	**3%**

Source: Applied Development Economics, based on California Department of Finance and US Census

Table 9 identifies the number of single-family dwelling unit building permits issued by the 27 cities. As the table shows, the cities issued 17,641 single-family building permits in 2003, which represents almost two-thirds of all single-family building permits issued in the eight-county region as a whole. Table 10 identifies the number of multi-family dwelling units issued by the 27 cities. The amount of these permits represents almost 80 percent of all multi-family building permits issued in the region as a whole in 2003. For these reasons, the cities are representative of the larger region.

TABLE 9 Single-Family Dwelling Units Building Construction Permits, San Joaquin Valley Region 2000-2003

	2000		2001		2002		2003		2000 - 2003	
	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Annual Change in Permits	Annual Change in Avg. Value
01 Large Urban	3,381	$132,038	4019	$132,089	4083	$137,988	5162	$152,257	15%	5%
02 Bay Area Commuter Shed	6,223	$161,757	4699	$172,165	6084	$172,996	6208	$176,852	-0.1%	3%
03 Medium	2,705	$125,488	3585	$141,040	4178	$153,806	5218	$156,243	24%	8%
04 Small/Med Bedroom Community	365	$105,702	542	$112,427	651	$118,285	801	$128,044	30%	7%
05 Small Rural/Farming	190	$83,956	262	$87,732	314	$85,667	252	$98,046	10%	5%
	12,864	$143,580	13107	$147,205	15310	$154,305	17641	$160,217	11%	4%

TABLE 10 Multi-Family Dwelling Units Building Construction Permits, San Joaquin Valley Region 2000-2003

	2000		2001		2002		2003		2000 - 2003	
	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Annual Change in Permits	Annual Change in Avg. Value
01 Large Urban	177	$67,079	182	$73,639	454	$61,259	1150	$67,333	87%	0%
02 Bay Area Commuter Shed	84	$56,183	368	$59,905	514	$65,380	275	$69,075	48.5%	7%
03 Medium	206	$63,512	27	$64,680	155	$76,627	1119	$77,362	76%	7%
04 Small/Med Bedroom Community	51	$48,135	7	$38,617	71	0	162	$22,627	47%	-22%
05 Small Rural/Farming	83	$40,584	135	$36,997	4	$48,978	194	$56,369	33%	12%
	601	$59,067	719	$59,052	1,198	$61,344	2900	$68,137	69%	5%

Source: Applied Development Economics, based on Construction Industry Research Board

Table 11 identifies the average selling price of a new 3 to 4 bedroom home in the select cities. As expected, housing prices in the Bay Area Commuter Shed tend to be higher, in large part because of the close proximity to the San Francisco Bay Area housing market. Prices there are on average $402,644 per 3-4 bedroom unit, versus almost $250,000 for new units in Small/rural farming communities such as Avenal (Kings County) or Orange Cove (Fresno County).

TABLE 11 Average Selling Price of New Single-Family and Multi-Family Housing San Joaquin Valley Region 2005

	------ Single-Family Units ------				------ Multi-Family Units ------		
	Avg 3-4 BR SFU Values	Avg 3-4 BR SFU Size	Lot Size 3-4 BR SFU	Value Per SQFT	Average MFU Values	Average MFU Size	Value Per SQFT
01 Large Urban	$338,047	1,893	5,407	$179	$146,914	1,071	$137
02 Bay Area Commuter Shed	$402,664	2,112	6,034	$191	$180,603	1,071	$169
03 Medium	$296,428	1,779	5,083	$167	$137,357	1,071	$128
04 Small/Med Bedroom Community	$314,030	1,883	5,379	$167	$136,062	1,071	$127
05 Small Rural/Farming	$247,836	1,644	4,697	$151	$125,482	1,071	$117
	$323,966	1,862	5,320	$171	$145,283	1,071	$136

Source: Applied Development Economics, based on Realtor.com, Dataquick, and California Housing and Community Development, "Pay to Play"

Table 12 identifies existing fees on residential development in the 27 cities. As the table shows, fees amount to approximately five to six percent of values for single- and multi-family units. Data for fees comes from a variety of sources, including local jurisdictions and the California Department of Housing and Community Development (HCD), which issued a detailed report on residential developer fees of many cities throughout California. In using the HCD figures, this report adjusted the amount for general inflation and housing price inflation.

TABLE 12 Existing Fees On A Per Unit Basis

	Existing Fees On 3-4 BR SFU Unit	All Fees As Percent of Value	Existing Fees On MFU Unit	All Fees As Percent of Value
01 Large Urban	$17,796	5%	$6,149	4%
02 Bay Area Commuter Shed	$24,576	6%	$8,093	4%
03 Medium	$19,266	6%	$7,355	5%
04 Small/Med Bedroom Community	$21,162	7%	$11,883	9%
05 Small Rural/Farming	$12,689	5%	$5,969	5%
	$18,552	6%	$7,890	5%

Source: Applied Development Economics, based on Realtor.com, Dataquick, and California Housing and Community Development, "Pay to Play"

Tables 13 and 14 compare existing fees against other development costs, including the price of land, to estimate profit and a profit rate. The profit rates calculated below are similar to what would be found in corporate reports of national homebuilders, particularly Centex Homes, Kaufman and Broad, Lennar, and Pulte Homes, whose combined average profit rate is approximately eight percent.[2]

TABLE 13 Home Prices, Construction Costs, Fees and Profit: Single Family Housing

Community Types	Avg 3-4 BR SFU Values	Land Value Per 3-4 BR SFU Unit	All Fees Per 3-4 BR SFU Unit	Site Development Cost Per 3-4 BR Unit	Building Construction Costs Per 3-4 BR Unit	TOTAL COSTS	Profit per Unit	Profit as % Value
Large Urban	$338,047	$77,124	$21,759	$40,233	$167,600	**$306,716**	$31,330	9%
Bay Area Commuter Shed	$402,664	$93,015	$26,957	$46,410	$200,828	**$367,210**	$35,454	9%
Medium-Sized Cities	$296,428	$50,069	$19,266	$37,346	$159,484	**$266,165**	$30,263	10%
Small\Medium Bedroom Communities	$314,030	$74,468	$21,162	$34,570	$157,136	**$287,336**	$26,694	9%
Small Rural\Farming Communities	$247,836	$47,847	$12,689	$28,825	$131,024	**$220,386**	$27,450	11%
	$323,966	$68,505	$20,367	$38,373	$166,739	**$293,983**	$29,982	9%

[2] www.sec.gov see Form 10-K

TABLE 14 Home Prices, Construction Costs, Fees and Profit: Multi-Family Housing

Community Types	Avg MFU Values	Land Value Per MFU Unit	All Fees Per MFU Unit	Site Development Cost Per MFU Unit	Building Construction Costs Per MFU Unit	TOTAL COSTS	Profit per Unit	Profit as % Value
Large Urban	$146,914	$12,999	$6,149	$20,324	$81,295	**$120,767**	$26,147	18%
Bay Area Commuter Shed	$180,603	$14,794	$8,093	$23,116	$92,464	**$138,467**	$42,136	23%
Medium-Sized Cities	$137,357	$10,831	$7,355	$19,519	$80,260	**$117,964**	$19,393	14%
Small\Medium Bedroom Communities	$136,062	$12,868	$11,883	$19,435	$80,926	**$125,113**	$10,949	8%
Small Rural\Farming Communities	$125,482	$10,955	$5,969	$17,085	$77,658	**$111,666**	$13,815	11%
	$145,283	$12,489	$7,890	$20,140	$83,179	**$123,698**	$21,585	15%

Commercial-Industrial Trends

Table 15 below estimates the value, costs and profit associated with developing one acre of commercial, industrial and office development. Information for the table comes from a variety of sources, including Realtor.com and Loopnet.com for current price of new industrial and commercial projects in the Central Valley. When estimating cost of construction, we used "Commercial Square Foot Building Costs: 2004", by Deloitte Saylor Publication, as well as per square foot cost of construction estimates used by many cities when estimating the value of a project. In determining the amount of fees on a commercial-industrial development, we asked building officials in five cities to calculate the amount of fees that would be generated by a 10,000 square feet light industrial development on a 2.5-acre parcel and by a 10,000 square feet retail project on a similarly-sized piece of land. We converted the fees into a per acre amount. The per acre values in the table below were calculated after having calculated the development costs, based on a profit of ten percent, and these values were checked against what we found on Loopnet.com and Realtor.com. The 10 percent profit is based on a review of Deloitte-Saylor's "Commercial Square Foot Building Costs: 2004." It is also based on a review of corporate reports of Catellus (industrial developer) and ProLogis (warehouse

distribution developer). It should be noted that while data in the residential section above represents trends in 27 cities in the Central Valley, information in this section is for five cities that fit the different city types.

As Table 15 shows, existing fees on commercial and office developments are significantly higher than on industrial projects. This is so because of the traffic generated by retail and office is much higher than traffic generated by industrial users, which then requires a corresponding amount of reduction via fees.

TABLE 15 Commercial-Industrial Trends: San Joaquin Valley Region, 2005

		Avg. Value Per Acre (Land and Building)	Unimproved Land Value Per Acre	Fees Per Acre	Site Development Cost Per Acre	Building Construction Costs Per Acre	TOTAL Costs per Acre	Est. Profit Per Acre	Profit As percent of Value
Large Urban									
	Industrial	$1,594,742	$157,518	$14,726	$60,768	$1,202,256	$1,435,268	$159,474	10%
	Commercial	$1,910,201	$546,032	$35,306	$45,576	$1,092,267	$1,719,181	$191,020	10%
	Office	$2,828,107	$546,032	$35,306	$45,576	$1,918,382	$2,545,296	$282,811	10%
Bay Area Commuter Shed									
	Industrial	$1,679,815	$200,905	$47,904	$60,768	$1,202,256	$1,511,833	$167,981	10%
	Commercial	$2,011,879	$522,536	$150,312	$45,576	$1,092,267	$1,810,692	$201,188	10%
	Office	$2,929,785	$522,536	$150,312	$45,576	$1,918,382	$2,636,807	$292,979	10%
Medium-sized Cities									
	Industrial	$1,546,952	$100,000	$29,233	$60,768	$1,202,256	$1,392,257	$154,695	10%
	Commercial	$1,748,583	$303,178	$132,704	$45,576	$1,092,267	$1,573,724	$174,858	10%
	Office	$2,666,489	$303,178	$132,704	$45,576	$1,918,382	$2,399,840	$266,649	10%
Small/Medium Bedroom Community									
	Industrial	$1,631,301	$130,700	$74,447	$60,768	$1,202,256	$1,468,171	$163,130	10%
	Commercial	$1,668,338	$280,576	$83,085	$45,576	$1,092,267	$1,501,504	$166,834	10%
	Office	$2,586,244	$280,576	$83,085	$45,576	$1,918,382	$2,327,619	$258,624	10%
Small Rural\Farming Communities									
	Industrial	$1,877,846	$350,642	$76,395	$60,768	$1,202,256	$1,690,061	$187,785	10%
	Commercial	$1,653,475	$217,800	$136,292	$41,769	$1,092,267	$1,488,127	$165,347	10%
	Office	$2,567,106	$217,800	$132,444	$41,769	$1,918,382	$2,310,395	$256,711	10%

6. SOCIOECONOMIC IMPACTS

This section of the report compares the economic characteristics of affected industries against the possible Rule 9150 and 3180 air quality fees. The first part of this section discusses annual compliance cost. Section 6.2 discusses general business responses to compliance costs. Section 6.3 analyzes the socioeconomic impacts of Draft Rules 9510 and 3180.

6.1 NEW RULE 9510 AND 3180 FEE

Tables 16 through 18 identify the worst-case fees associated with New Rules 9510 and 3180. To reduce emissions of NOx and PM10, Draft Rule 9510 would apply to development projects that will seek to gain a final discretionary approval for projects that, upon full build-out will include any one of the following: 50 residential units, 2,000 square feet of commercial space, 25,000 square feet of industrial space, 20,000 square feet of medical office space, 39,000 square feet of general office space, 9,000 square feet of educational space, 10,000 square feet of government space, 20,000 square feet of recreational space, or 9,000 square feet of unidentified space. Certain transportation projects, transit projects, reconstruction projects that result from a natural disaster, and development projects whose primary source of emissions are subject to District Rule 2201 or 2010 would be exempt from this Draft Rule. Also, development projects that have a mitigated baseline below two tons per year for each pollutant would be exempt from the emission reduction requirements of the rule.

It is important to note that any fee identified below are the estimated maximum fee in the worst case scenario for a typical residential, commercial and or industrial development, with the understanding that the actual fee will vary with the particulars of any project. Any fee below is presented for the purposes of analyzing potential impacts given costs associated with reducing quantifiable emissions resulting from what constitutes typical applicable developments. The fee amounts

identified include all off-site emission reduction fees and all administrative fees.

In the worst case, the fee that a typical residential development will pay is estimated at $784 per unit starting in 2006, climb to $1,268 the following year, and above $1,772 in the years starting in 2008. The fee could be lower depending on the strategies that a developer employs to reduce emissions.

TABLE 16
Worst Case Estimate: Fee That Corresponds to A Typical Residential Development

Year	Per Unit
2006	$784.12
2007	$1,268.09
2008	$1,772

TABLE 17
Worst Case Estimate: Fee That Corresponds To The Typical Industrial Development

Use	Average Acres	Corresponding Fee Total
2006		
Heavy Industrial	300.0	$357,394.75
Light Industrial	75.0	$240,508.75
Warehouses	25.0	$83,645.68
Misc. Industrial (industrial park)	39.0	$143.797.05
2008		
Heavy Industrial	300.0	$747,626
Light Industrial	75.0	$518,237
Warehouses	25.0	$179,956
Misc. Industrial	39.0	$309,965

TABLE 18
Worst Case Estimate: Fee That Corresponds To a Typical Commercial Development

TYPE OF SHOPPING CENTERS	SIZE RANGE	TYPICAL SIZE (sq ft)	Corresponding Fee Total
	2006		
convenience shopping center	up to 30,000	20,000	$24,524.94
neighborhood shopping center	30,000 to 100,000	50,000	$61,599.54
community shopping center	100,000 to 450,000	150,000	$184,647.45
super community shopping center	200,000 to 300,000	250,000	$403,546.91
regional shopping center	300,000 to 700,000	450,000	$626,791.07
superregional shopping center	500,000 to 2 million	900,000	$1,253,582.15
	2008		
convenience shopping center	up to 30,000	20,000	$52,971.24
neighborhood shopping center	30,000 to 100,000	50,000	$131,689.99
community shopping center	100,000 to 450,000	150,000	$397,483.34
super community shopping center	200,000 to 300,000	250,000	$872,322.57
regional shopping center	300,000 to 700,000	450,000	$1,353,824.12
superregional shopping center	500,000 to 2 million	900,000	$2,708,116.82

6.2 BUSINESS RESPONSES TO PROPOSED FEES

Industries impacted by the proposed new rule may respond in a variety of ways when faced with new regulatory costs. These responses may range from simply absorbing the costs and accepting a lower rate of return, to shutting down the affected business operation altogether and, where practical, shift from lower-value to higher-value product. Affected sources may also seek to renew efforts to increase productivity and reduce costs elsewhere in their operation in order to recoup the regulatory costs and maintain profit levels. Based on the discussion during a focus group meeting held in July, 2005, industries impacted by the new rules will in all likelihood seek to pass the costs on to homebuyers and renters in the case of residential fees, to the extent that the market allows.

6.3 IMPACTS ON AFFECTED INDUSTRIES

This section of the report analyzes revenues and profits of affected industries against anticipated costs associated with

implementation of the draft rule. The analysis first examines impacts on builders of single-family homes. Then, it analyzes impacts on builders of multi-family units. In addition to impacts on homebuilders, the section analyzes how changes in price affect prospective homebuyers and renters. Finally, the section below examines impacts on non-residential developments, particularly commercial retail, industrial, and office projects.

Single-Family Dwelling Units

Tables 19 through 21 compare the fee that a typical residential development would pay in the year 2006, 2007 and 2008, or $784, $1,268 and $1,772, against estimated profits. In calculating the impacts of the fee, we have included the additional $400 administrative cost associated with Rule 3180. As Tables 19, 20 and 21 show, the fees do not significantly impact affected builders of single-family homes in a negative manner. The fee amounts to approximately three, four and six percent of estimated net profits, meaning that affected stakeholders would still garner between 94 sand 97 percent of their original profit. Moreover, the impact is below the ten percent significance threshold employed in this analysis.

TABLE 19 Impact Analysis of 2006 Air Quality Fee on Typical Single-Family Development: $784 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $.421/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Home Value @ 5.85%, 30 yrs and 20% down	(7) Home Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Initial Home Value @ 6.85%, 30 yrs and 20% down	(9) Home Value @ 6.85%, 30 yrs and 20% down: With Air Fee	(10) Affect of Fee	(11) Affect of 1% Change in Interest Rate
Large Urban	11.5%	$797	-2.1%	<significant	11.3%	$93,624	$93,846	$101,737	$101,979	$223	$8,113
Bay Area Commuter Shed	10.8%	$889	-2.1%	<significant	10.6%	$111,520	$111,768	$121,184	$121,454	$248	$9,664
Medium-Sized Cities	8.3%	$749	-3.1%	<significant	8.0%	$82,097	$82,307	$89,212	$89,439	$209	$7,114
Small\Medium Bedroom Communities	8.5%	$793	-3.0%	<significant	8.2%	$86,972	$87,194	$94,509	$94,750	$221	$7,537
Small Rural\Farming Communities	10.6%	$692	-2.7%	<significant	10.3%	$68,639	$68,833	$74,587	$74,798	$193	$5,948
All Select Cities Average	9.3%	$784	-2.6%	<significant	9.0%	$89,724	$89,943	$97,499	$97,737	$219	$7,775

TABLE 20 Impact Analysis of 2007 Air Quality Fee on Typical Single-Family Development: $1,268 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $.681/sqft	(3) Profit as % Value	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Home Value @ 5.85%, 30 yrs and 20% down	(7) Home Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Initial Home Value @ 6.85%, 30 yrs and 20% down	(9) Home Value @ 6.85%, 30 yrs and 20% down: With Air Fee	(10) Affect of Fee	(11) Affect of 1% Change in Interest Rate
Large Urban	11.5%	$1,289	-3.3%	<significant	11.2%	$93,624	$93,983	$101,737	$102,127	$359	$8,113
Bay Area Commuter Shed	10.8%	$1,438	-3.3%	<significant	10.5%	$111,520	$111,920	$121,184	$121,619	$400	$9,664
Medium-Sized Cities	8.3%	$1,212	-5.0%	<significant	7.9%	$82,097	$82,435	$89,212	$89,578	$337	$7,114
Small\Medium Bedroom Communities	8.5%	$1,282	-4.8%	<significant	8.1%	$86,972	$87,329	$94,509	$94,897	$357	$7,537
Small Rural\Farming Communities	10.6%	$1,120	-4,3%	<significant	10.2%	$68,639	$68,951	$74,587	$74,925	$312	$5,948
All Select Cities Average	9.3%	$1,268	-4.3%	<significant	8.9%	$89,724	$90,007	$97,499	$97,883	$353	$7,775

TABLE 21 Impact Analysis of 2008 Air Quality Fee on Typical Single-Family Development: $1,772 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $.952/sqft	(3) Profit as % Value	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Home Value @ 5.85%, 30 yrs and 20% down	(7) Home Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Initial Home Value @ 6.85%, 30 yrs and 20% down	(9) Home Value @ 6.85%, 30 yrs and 20% down: With Air Fee	(10) Affect of Fee	(11) Affect of 1% Change in Interest Rate
Large Urban	11.5%	1,802	-4.6	<significant	11.0%	$93,624	$94,125	$101,737	$102,281	$501	$8,113
Bay Area Commuter Shed	10.8%	2,011	-4.6	<significant	10.3%	$111,520	$112,079	$121,184	$121,791	$559	$9,664
Medium-Sized Cities	8.3%	1,694	-6.9	<significant	7.7%	$82,097	$82,568	$89,212	$89,723	$471	$7,114
Small\Medium Bedroom Communities	8.5%	1,792	-6.7	<significant	7.9%	$86,972	$87,471	$94,509	$95,050	$498	$7,537
Small Rural\Farming Communities	10.6%	1,565	-6.0	<significant	10.0%	$68,639	$69,074	$74,587	$75,060	$435	$5,948
All Select Cities Average	9.3%	1,773	-5.9	<significant	8.7%	$89,724	$90,217	$97,499	$98,035	$493	$7,775

TABLE 22 Median Home Sale Prices in Small to Medium Communities, 2003-2005

		July 2003	July 2004	July 2005	03-04 Change	04-05 Change	03-04 Per Chg	04-05 Per Chg
Medium	Merced (Merced)	$204,341	$226,741	$322,500	$22,400	$95,759	11%	42%
	Tulare (Tulare)	$125,379	$161,146	$204,000	$35,767	$42,854	29%	27%
	Turlock (Stanislaus)	$240,088	$284,330	$369,500	$44,242	$85,170	18%	30%
	Visalia (Tulare)	$154,723	$185,938	$270,000	$31,215	$84,062	20%	45%
Small/Medium Bedroom Community	Atwater (Merced)	$207,009	$232,422	$324,250	$25,413	$91,828	12%	40%
	Mendota (Fresno)		$77,438	$120,000		$42,563		55%
	Sanger (Fresno)	$161,659	$171,734	$276,500	$10,075	$104,766	6%	61%
	Selma (Fresno)	$123,245	$177,158	$249,250	$53,912	$72,092	44%	41%
Small Rural/Farming	Oakhurst (Madera)	$209,143	$273,742	$306,000	$64,599	$32,258	31%	12%
	Taft (Kern)	$82,697	$77,474	$110,000	-$5,223	$32,526	-6%	42%
	Wasco (Kern)	$93,101	$103,299	$132,000	$10,198	$28,701	11%	28%
		$160,139	$179,220	$244,000	$19,082	$64,780	12%	36%

Source: Applied Development Economics, based on Dataquick

A close review of Tables 19 through 21 reveals that the fees under consideration could potentially impacts different community types in different ways. For Medium-sized communities, Small\medium bedroom communities, and Small rural\farming communities, the impact of the possible fee on profits is slightly higher than impact to home builders operating in the large urban and Bay Area Commuter Shed markets. This is so because prices of new homes are higher in the latter markets. To understand the influence of the $784, 1,268 or $1,772 fee on home prices in the Medium-sized cities, Small\medium bedroom communities, and Small rural\farming communities, it is worthwhile to compare the fees against recent changes in home prices in cities in these three community types.

Table 22 above includes recent data from Dataquick. Among other things, it shows that between July 2003 and July 2004 and July 2004 and July 2005, median prices of homes increased by $19,000 and $65,000 in specific cities in Medium-sized cities, Small\medium bedroom communities, and Small rural\farming communities. Table 22 includes all homes sold, not just newly constructed three-to-four bedroom homes. While the fee could raise home prices by $784 to $1,772, it is apparent that larger market forces are the primary culprit behind the increase in housing prices in these three community types. The fee associated with Draft Rules 9510 and 3180 would amount to, at most, three percent of recent change in housing prices in these three community types (or $1,772 divided by $65,000).

Tables 19 through 21 above also include an analysis on how the $784, $1,268 or $1,772 fee would impact potential homebuyers. In other words, we assume that the homebuilder will pass this cost on to homebuyers to the fullest extent possible allowed by the market. As Table 11 above previously showed, the price of a new three-to-four bedroom home in the San Joaquin Valley region is approximately $324,000. In large urban areas of Bakersfield and Fresno, the average price of a new three-to-four bedroom home is $338,000, while in the Bay Area Commuter Shed, it is even higher at $402,700. Housing is more affordable in rural communities such as Avenal, where the

average price of a new home is $247,800 (see Table 11 above).

In Column Six of Tables 19 though 21, we estimate the minimum household income required to qualify for conventional financing for new three-to-four bedroom homes in the different market types. We assume that the potential homebuyer is a first-time homebuyer, meaning that there are no proceeds from the sale of a previous home to put towards the purchase of the new home. We assume that the potential homebuyer will have a downpayment equal to 20 percent of the market value of the unit. We also factor in a 5.85 interest rate, monthly bills, homeowners insurance, and property taxes when calculating the minimum household income needed to qualify for a new three-to-four bedroom home in the San Joaquin Valley.

To qualify for financing for a $324,000 home in the Central Valley, a prospective first-time home buying household would need to earn approximately $89,724 annually. Columns Seven and Ten to the tables above show the extent to which the different fees raise the minimum qualifying household income. As a result of the $784, $1,268 and $1,772 fees, minimum qualifying incomes for the region as a whole would rise, on average, by $219, $353, and $493 respectively. The $219 to $493 amount is less than one percent of the original income needed to qualify for a new three-to-four bedroom home in the Central Valley.

For comparative purposes, Tables 19 through 21 include Columns Eight and Eleven, which show what would happen if interest rates rose from 5.85 percent to 6.85 percent. If this occurred, the minimum qualifying income would rise from $89,724 to $97,499, or by $7,775. In other words, while the fees have the potential to increase the amount of income required to qualify for financing, larger market forces such as interest rates and market-driven price fluctuations play a significantly greater role in determining the income level needed to qualify for a new three-to-four bedroom home.

Multi-Family Dwelling Units

Tables 23 through 25 show the affects of the fees on construction of multi-family dwelling units. Small\medium

bedroom communities and Small rural\farming communities are affected negatively more so than the other communities, because the price of multi-family dwelling units elsewhere are higher than in these community types. Columns Six and Seven in each of the tables below estimate the minimum income required to purchase a multi-family unit such as a condominium or townhouse, and the extent to which the impact fee could raise this amount, in the event developers of multi-family units pass costs onto the consumers. The fee could raise the minimum income needed to qualify for financing for the purchase of a condominium or townhouse valued at $145,300 (see Table 14 above), from $40,237 to $40,455 ($784 fee), $40,589 ($1,268 fee) or at most $40,696 ($1,772 fee), which represent at most a one percent change. Tables 23 through 25 below show that the fee would only slightly affect rents, in the event units were rented out as opposed to sold.

TABLE 23 Impact Analysis of 2006 Fee on Typical Multi-Family Housing Development: $784 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ .732/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down	(7) Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Minimum Rent without Air Fee	(9) Minimum Rent with Air Fee	(10) Qualifying Rental Household without Air Fee	(11) Qualifying Rental Household with Air Fee
Large Urban	17.7%	$788	-3.0%	<significant	17.3%	$40,689	$40,907	$1,150	$1,157	$41,453	$41,675
Bay Area Commuter Shed	23.3%	$788	-1.9%	<significant	22.9%	$50,019	$50,237	$1,414	$1,420	$50,958	$51,180
Medium	14.1%	$788	-4.1%	<significant	13.5%	$38,042	$38,260	$1,076	$1,082	$38,756	$38,978
Small/Med Bedroom Community	8.0%	$788	-7.2%	<significant	7.5%	$37,683	$37,901	$1,065	$1,072	$38,391	$38,613
Small Rural/Farming	11.0%	$788	-5.7%	<significant	10.4%	$34,753	$34,971	$983	$989	$35,405	$35,628
All Select Cities Average	14.9%	$788	-3.6%	<significant	14.3%	$40,237	$40,455	$1,138	$1,144	$40,992	$41,215

TABLE 24 Impact Analysis of 2007 Fee on Typical Multi-Family Housing Development: $1,268 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $1.184/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down	(7) Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Minimum Rent without Air Fee	(9) Minimum Rent with Air Fee	(10) Qualifying Rental Household without Air Fee	(11) Qualifying Rental Household with Air Fee
Large Urban	17.7%	$1,268	-4.9%	<significant	16.9%	$40,689	$41,041	$1,150	$1,160	$41,453	$41,812
Bay Area Commuter Shed	23.3%	$1,268	-3.0%	<significant	22.6%	$50,019	$50,371	$1,414	$1,424	$50,958	$51,317
Medium	14.1%	$1,268	-6.6%	<significant	13.2%	$38,042	$38,394	$1,076	$1,086	$38,756	$39,115
Small/Med Bedroom Community	8.0%	$1,268	-11.6%	significant	7.1%	$37,683	$38,035	$1,065	$1,075	$38,391	$38,749
Small Rural/Farming	11.0%	$1,268	-9.2%	<significant	10.0%	$34,753	$35,105	$983	$993	$35,405	$35,764
All Select Cities Average	14.9%	$1,268	-5.9%	<significant	14.0%	$40,237	$40,589	$1,138	$1,148	$40,992	$41,351

TABLE 25 Impact Analysis of 2008Fee on Typical Multi-Family Housing Development: $1,772 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ 1.655/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down	(7) Condo-Townhouse Value @ 5.*5%, 30 yrs and 20% down: With Air Fee	(8) Minimum Rent without Air Fee	(9) Minimum Rent with Air Fee	(10) Qualifying Rental Household without Air Fee	(11) Qualifying Rental Household with Air Fee
Large Urban	17.7%	$1,657	-6.3%	<significant	16.7%	$40,689	$41,148	$1,150	$1,150	$41,453	$41,920
Bay Area Commuter Shed	23.3%	$1,657	-3.9%	<significant	22.4%	$50,019	$50,478	$1,414	$1,427	$50,958	$51,426
Medium	14.1%	$1,657	-8.5%	<significant	12.9%	$38,042	$38,501	$1,076	$1,089	$38,756	$39,224
Small/Med Bedroom Community	8.0%	$1,657	-15.1%	significant	6.8%	$37,683	$38,142	$1,065	$1,078	$38,391	$38,858
Small Rural/Farming	11.0%	$1,657	-12.0%	significant	9.7%	$34,753	$35,212	$983	$996	$35,405	$35,873
All Select Cities Average	14.9%	$1,657	-7.7%	<significant	13.7%	$40,237	$40,696	$1,138	$1,151	$40,992	$41,460

Affordable Housing For Low-and Moderate Income Households

The discussion above focused on how fees would affect first-time homebuyers of single-family and multi-family units, as well as potential renters. In that context, housing affordability refers to the minimum income required to qualify for either a mortgage or the minimum income needed to pay a certain rent, with the understanding that the annual housing payment must not exceed one-third of annual household income. The federal agency called the Department of Housing and Urban Development (HUD) and private lenders use the one-third threshold as a way to gauge housing affordability. Anyone paying more than one-third of his or her income on housing is living in an unaffordable situation.

Affordable housing also refers to the extent to which low-income and moderate-income households can access housing at affordable rents. Every year, the federal government issues guidelines as to what constitutes low-income and moderate-income households, particularly for the purposes of qualifying households for federal housing programs such as Section 8 or the Low-Income Housing Tax Credit program. In turn, state and local agencies adopt these guidelines when carrying out their respective housing programs.

Table 26 below identifies the federal Housing and Urban Development's (HUD) 2005 income guideline for most of the Central Valley, and this guideline adjusts for number of people in a household. A single individual earning no more than $27,500 is a low-income individual, while a single individual make $27,502 would be a moderate-income person.

TABLE 26 HUD Income Guidelines, 2005

	Low Income		Moderate	
	Minimum	Maximum	Minimum	Maximum
1 person	$0	$27,500	$27,501	$41,250
2 persons	$0	$31,400	$31,401	$47,100
3 persons	$0	$35,350	$35,351	$53,025
4 persons	$0	$39,300	$39,301	$58,950
5 persons	$0	$42,400	$42,401	$63,600
6 persons	$0	$45,550	$45,551	$68,325
7 persons	$0	$48,700	$48,701	$73,050
8 or more persons	$0	$51,850	$51,851	$77,775

Source: Applied Development Economics, based on Department of Housing and Urban Development

More importantly for the purposes of this analysis, a single person making no more than $27,500 a year and who, at the same time, pays a rent that does not exceed one-third of her or his income lives in an affordable situation. Conversely, a single individual making no more than $27,500 who is paying a rent that exceeds one-third of his or her income is living in an unaffordable situation. Table 27 below calculates the rents that would be affordable to low- and moderate-income households. For the most part, rents that low-income households should pay are substantially below the rents that typical new multi-family units constructed in the region should command, even before the imposition of the air fee. For example, 2-person low-income households should pay no more than $785 on rent. As Tables 23 through 25 showed, rent for a newly constructed apartment unit should be $1,138, which is unaffordable to 2-person low-income households by standards established by HUD. On the other hand, a two-person moderate-income household that paid the $1,138 would be living in an affordable situation, since the maximum rent for purposes of calculating affordability is $1,178. A one-person moderate-income household should pay no more than $1,031 toward rent; thus the $1,138 rent calculated in Table 23 through 25 would constitute unaffordable housing.

TABLE 27 Affordable Monthly Rents

	Affordable Rent: Low Income		Affordable Rent: Moderate Income	
	Minimum	Maximum	Minimum	Maximum
1 person	$0	$688	$689	$1,031
2 persons	$0	$785	$786	$1,178
3 persons	$0	$884	$885	$1,326
4 persons	$0	$983	$984	$1,474
5 persons	$0	$1,060	$1,061	$1,590
6 persons	$0	$1,139	$1,140	$1,708
7 persons	$0	$1,218	$1,219	$1,826
8 or more persons	$0	$1,296	$1,297	$1,944

Without public subsidies to either the renting households or to housing developers, most low-income households in the Central Valley are priced out of newly constructed multifamily units, the rents for which need to be at a level to take into account price of land, development costs, developer fees, and an adequate level of profit, among other things. For the region as a whole, the market rate rent for a typical multi-family unit is calculated at $1,138, though rents are higher or lower depending on the community type, with Large Urban communities and the Bay Area Commuter Shed requiring higher rents (see Tables 23 through 25 Column Eight). Moderate-income households consisting of no more than three persons should be able to afford newly constructed multi-family units with monthly rents at or about $1,138, although the same cannot be said for moderate-income households consisting of four or more persons, who will need higher-priced living quarter with additional rooms.

There are a number of housing programs and policies that can assist low- and moderate-income households to live in market rate housing. Federal housing programs such as Section 8 provide the difference between the amount[3] that a low-income household can pay and the actual rent for an apartment in the private sector that is willing to accept Section 8. However, local governments receive only a limited number of Section 8 vouchers from the federal government,

[3] The amount that a Section 8 tenant contributes toward rent on an out of pocket basis must not exceed one-third of the tenant's annual income.

resulting in waiting lists consisting of many households waiting a relatively long time. Other public subsidies are aimed at encouraging the private sector to set-aside some, if not all, newly constructed housing as affordable to low- and moderate-income households. The federal Low-Income Housing Tax Credit (LIHTC) or, at the local level, the twenty percent housing redevelopment tax increment set-aside are just two revenue sources that can increase the feasibility of setting aside units at below market rents for low- and moderate-income households. Like the Section 8 program, there are some inherent limitations to the LIHTC and the tax increment set-aside programs. The financing via the federal LIHTC program is not readily available as it is accessed on a competitive basis. Not all cities have redevelopment agencies, and, of those with such agencies, it takes some time to generate the necessary amount of revenues (also known as tax increment) for a successful housing set-aside program.

Some cities have what are called "inclusionary housing" policies, meaning that in order to obtain approval for this or that housing project, the developer must guarantee that a certain portion (typically 15 percent) is reserved for low- and moderate-income households. Some cities sweeten their inclusionary policies with public financing, and some do not. It is argued that "inclusionary housing" policies without public subsidies result in overall higher rents or home prices, as developers required to set-aside housing at below-market levels for some units make up the difference by driving up the price of rest of the bulk of the units in a project.[4]

Non-Residential Development

Table 28 below analyzes the impacts of the Draft Rule 9510 and 3180 commercial and industrial fees on a per acre basis. In 2006, the fee on a typical retail and office development will amount to $15,286 and $7,914 per acre respectively. In the year 2008, fees on a per acre basis are expected to increase to $33,008 (retail) and $17,099 (office). As the table shows, in

4 Home Builders Association of Northern California - HBA News, (www.hbanc.org/ news2000/ JulAug2001/ JulAug01feat2.html) / "The Inclusionary Housing Debate - Who Really Pays for Affordable ..." (www.realtor.org/sg3.nsf/Pages/housingdebatepays?OpenDocument)

the year 2006 possible off-site emission reduction fees on new typically-sized commercial and office developments will not exceed the threshold of significance. The possible off-site fee amounts to an estimated 21 percent of profits in the year 2006. In 2008, the possible air off-site fees on new typically-sized commercial retail developments will exceed the threshold of significance by six to ten percent, depending on the community in which development occurs. The dollar amount in excess of the threshold in the year 2008 ranges from $12,889 to $16,324 per acre for commercial developments.

TABLE 28 Impact Analysis of 2006 and 2008 Fee on Typical Commercial-Industrial Project

	Avg. Value Per Acre	Est. Profit Per Acre	Profit as percent of Value	Est. Fees Per Acre		Est. Fees As % of Profit		Percent Above Significance Threshold		Dollar Amount Above Significance Threshold	
				2006	2008	2006	2008	2006	2008	2006	2008
Large Urban											
Industrial	$1,594,742	$159,474	10%	$1,880	$4,000	1%	3%	< sig.	< sig.		
Commercial	$1,910,201	$191,020	10%	$15,286	$33,008	8%	17%	< sig.	7%		$13,906
Office	$2,828,107	$282,811	10%	$7,914	$17,099	3%	6%	< sig.	< sig.		
Bay Area Commuter Shed											
Industrial	$1,679,815	$167,981	10%	$1,880	$4,000	1%	2%	< sig.	< sig.		
Commercial	$2,011,879	$201,188	10%	$15,286	$33,008	8%	16%	< sig.	6%		$12,889
Office	$2,929,785	$292,979	10%	$7,914	$17,099	3%	6%	< sig.	< sig.		
Medium-sized Cities											
Industrial	$1,546,952	$154,695	10%	$1,880	$4,000	1%	3%	< sig.	< sig.		
Commercial	$1,748,583	$174,858	10%	$15,286	$33,008	9%	19%	< sig.	9%		$15,522
Office	$2,666,489	$266,649	10%	$7,914	$17,099	3%	6%	< sig.	< sig.		
Small/Medium Bedroom Community											
Industrial	$1,631,301	$163,130	10%	$1,880	$4,000	1%	2%	< sig.	< sig.		
Commercial	$1,668,338	$166,834	10%	$15,286	$33,008	9%	20%	< sig.	10%		$16,324
Office	$2,586,244	$258,624	10%	$7,914	$17,099	3%	7%	< sig.	< sig.		
Small Rural\Farming Communities											
Industrial	$1,877,846	$187,785	10%	$1,880	$4,000	1%	2%	not sig.	not sig.		
Commercial	$1,653,475	$165,347	10%	$15,286	$33,008	9%	20%	not sig.	10%		
Office	$2,567,106	$256,711	10%	$7,914	$17,099	3%	7%	not sig.	not sig.		

It is not clear how the development community will adjust to the additional costs. Rather than absorb the costs, the developer (or a subsequent owner of an affected project site) might seek to pass costs onto commercial tenants in the form of rent increases. Table 29 translates the amount of the total fee into a per square foot rent for significantly impacted commercial uses. While the 2006 fee does not significantly impact developers of commercial uses, the 2008 fee significantly impacts these developers to the tune of $13,905. This amounts to almost one cent per square foot, which developers will pass onto future commercial tenant.

It is worth noting that the 2006 and 2008 fee, in effect, sets the bar slightly higher with respect to lease rates on all new commercial developments in the region. Comparable office developments that have been in place prior to the new fees could conceivably raise monthly rents by one cent. In addition, comparable retail sites in place prior to the new fees could conceivably raise rents by two cents in 2008.

TABLE 29
2006 and 2008 Fee on Typical Commercial-Industrial Project: Affect of Fee on Monthly Rent

	2006 Dollar Amount Significance Threshold	Fee as a Percent of Profit	Amount Above Significance Threshold	2006 Fee Per SqFt	2006 Per Sqft Fee As Monthly Rent Increase Over Typical Amortization Period (15 years)	2008 Dollar Amount Significance Threshold	Fee as a Percent of Profit	Amount Above Significance Threshold	2008 Fee Per SqFt	2008 Per Sqft Fee As Monthly Rent Increase Over Typical Amortization Period (15 years)
Large Urban										
Industrial	< sig.	1%	< sig.			< sig.	3%	< sig.		
Commercial	< sig.	8%	< sig.			$13,906	17%	7%	$1.28	$0.007
Office	< sig.	3%	< sig.			< sig.	6%	< sig.		
Bay Area Commuter Shed										
Industrial	< sig.	1%	< sig.			< sig.	2%	< sig.		
Commercial	< sig.	8%	< sig.			$12,889	16%	6%	$1.18	$0.007
Office	< sig.	3%	< sig.			< sig.	6%	< sig.		
Medium-sized Cities										
Industrial	< sig.	1%	< sig.			< sig.	3%	< sig.		
Commercial	< sig.	9%	< sig.			$15,522	19%	9%	$1.43	$0.008
Office	< sig.	3%	< sig.			< sig.	6%	< sig.		
Small/Medium Bedroom Community										
Industrial	< sig.	1%	< sig.			< sig.	2%	< sig.		
Commercial	< sig.	9%	< sig.			$16,324	20%	10%	$1.50	$0.008
Office	< sig.	3%	< sig.			< sig.	7%	< sig.		
Small Rural\Farming Communities										
Industrial	< sig.	1%	< sig.			< sig.	2%	< sig.		
Commercial	< sig.	9%	< sig.			$16,473	20%	10%	$1.51	$0.008
Office	< sig.	3%	< sig.			< sig.	7%	< sig.		

6.4 IMPACT ON SMALL BUSINESSES

In addition to analyzing the various impacts of the Proposed Indirect Source Rule (Draft Rules 9510 and 3180) that are discussed above, state legislation requires that the socioeconomic analysis assess whether small businesses are disproportionately affected by air quality rules. This section discusses how fees that are assessed on developers of residential and commercial projects are typically passed onto the consumer. Because of the additional costs associated with the proposed off-site emission reduction fee, prospective buyers must either increase their respective household incomes or produce a downpayment that is larger than the typical 20 percent. Thus, prospective homebuyers may have to delay purchasing goods and services as a result of the need to raise additional downpayment, resulting in impacts to local stores, particularly small businesses. This section discusses potential small business impacts resulting from Draft Rule 9510 and 3180.

Off-Site Emission Reduction Fees, Minimum Household Income, and the Downpayment

As the analysis above demonstrated, the 2006, 2007 and 2008 off-site emission reduction fee under consideration could slightly raise the minimum qualifying incomes for obtaining a conventional loan by, on average, $219, $353, and $493. In other words, to finance a new three to four bedroom home valued at $323,966 in the region, a first-time homeowner would need an income of at least $89,724.[5] The 2006 fee could raise this minimum by a slight $219, to $90,217

What if a lender is inflexible and will not extend a loan to household that is $219 to $493 short of the minimum income needed to qualify for financing? In cases such as this, the prospective homeowner will have to produce a larger downpayment or pay a higher interest rate. The table below identifies the amount of additional downpayment above the

[5] This minimum will change depending on the housing market, with households in Large Urban and Bay Area Commuter Shed communities needing more income than households in other part of the region.

amount generated by the typical 20 percent downpayment rate.

As Table 30 shows, in the region in general, a household with at least $89,724 in income can afford to purchase a newly constructed three to four bedroom unit priced at $323,966 so long it has a downpayment in the amount of $64,793, or 20 percent of the value of the home. In general, the 2006 through 2008 off-site emission reduction fees will require prospective homeowners to produce an additional $970 to $2,147 that will go towards the downpayment, in the event a lender is unwilling to exercise flexibility with respect to minimum income needed to qualify for a loan. The amount of additional downpayment differs between housing markets, with households in the Large Urban communities and the Bay Area Commuter Shed having to pay more.

Table 30 Potential Per Household Impact of Off-Site Emission Reduction Fees On Downpayment: Single Family Unit

	Initial Qualifying Household Income Prior to Fee: SFU	Initial Downpayment	Additional Downpayment (2006 fee: $784)	Additional Downpayment (2007 fee: $1,268)	Additional Downpayment (2008 fee: $1,772)
Large Urban	$93,624	$67,609	$1,008	$1,616	$2,231
Bay Area Commuter Shed	$111,520	$80,533	$1,188	$1,906	$2,629
Medium-Sized Cities	$82,097	$59,286	$894	$1,434	$1,980
Small\Medium Bedroom Communities	$86,972	$62,806	$947	$1,519	$2,097
Small Rural\Farming Communities	$68,639	$49,567	$761	$1,221	$1,686
All Select Cities Average	$89,724	$64,793	$970	$1,556	$2,147

Table 31 is similar to Table 30, although it focuses on the additional amount of downpayment required of prospective buyers of townhouses and condominiums. In general, the 2006 through 2008 off-site emission reduction fees will require prospective homeowners to produce an additional downpayment ranging from $932 to $1,948.

Table 31 Potential Per Household Impact of Off-Site Emission Reduction Fees On Downpayment: Multi-Family Unit

	Initial Qualifying Household Income Prior to Fee: MFU	Initial Downpayment	Additional Downpayment (2006 fee: $784)	Additional Downpayment (2007 fee: $1,268)	Additional Downpayment (2008 fee: $1,772)
Large Urban	$40,907	$29,383	$940	$1,529	$1,966
Bay Area Commuter Shed	$50,237	$36,121	$1,119	$1,818	$2,336
Medium-Sized Cities	$38,260	$27,471	$890	$1,447	$1,860
Small\Medium Bedroom Communities	$37,901	$27,212	$883	$1,435	$1,846
Small Rural\Farming Communities	$34,971	$25,096	$827	$1,344	$1,730
All Select Cities Average	$40,455	$29,057	$932	$1,515	$1,948

Prospective Homebuyers and Small Business Disproportionate Impact Analysis

Faced with the need to increase the amount of downpayment, a household will have to save by cutting back on expenditures, which could result in a decline in purchases of discretionary items from local retail and services establishments. Consumers may stop spending altogether, or shift their spending toward lower-priced goods and services. As we shall see, there is ample reason to believe that impacts associated with the decline in spending that corresponds to the 2006, 2007 and 2008 fees will be temporary. Before engaging in that discussion, below is a brief summary of what constitutes a small business for the purposes of analysis.

For purposes of qualifying small businesses for bid preferences on state contracts and other benefits, the State of California defines small businesses in the following manner[6]. To be eligible for small business certification, a business:

- Must be independently owned and operated;
- Cannot be dominant in its field of operation;
- Must have its principal office located in California

[6] State of California. Department of General Services. "California Small Business Certification" (http: www.pd.dgs.ca.gov/smbus/sbcert.htm)

- Must have its owners (or officers in the case of a corporation) domiciled in California; and
- Together with its affiliates, be either:
  - A business with 100 or fewer employees, and an average gross receipts of $10 million or less over the previous tax years, or
  - A manufacturer with 100 or fewer employees

Data is available as to the number of retail and services establishments in the eight-county region, and with this data we can estimate sales by stores with 100 or fewer employees. Table 32 below provides an estimate on the number of retail, accommodations-food services, and arts-entertainment-recreation establishments in the region, including estimates on their respective sales. Data comes from the County Business Patterns and the US Economics Census.

TABLE 32
Number of Commercial Establishments That Sell Goods and Select Discretionary Services: San Joaquin Valley Air Basin, 2002

	Total Establishments	Sales	Total Nos. Small Businesses	Sales By Small Businesses
Commercial				
Retail*	8,792	$21,790,159,759	8,601	$14,971,588,578
Accommodations and Food Services	627	$532,590,300	615	$365,953,623
Arts, Entertainment and Recreations	5,139	$3,048,315,000	5,108	$2,809,025,816
Gasoline stations	1,044	$2,909,895,000	1,044	$2,909,895,000
	15,602	$28,280,960,059	15,368	$21,056,463,017

* Apparel, groceries, home improvement, specialty retail, auto (except gas stations)

As Table 32 shows, in 2002 there were 15,602 stores that sold consumer goods and select number of discretionary services (such as entertainment venues and restaurants) and, of these, 15,368 employed less than 100 workers. These small stores generated approximately $21.1 billion in sales. Based on a review of ten-year's worth of data from Dun and Bradstreet, we estimate that retail generates after tax net profits that amount to 2.2 percent of sales, while both accommodations-

food services and arts-entertainment-recreations generate returns of 5.1 percent of sales. Combined, these industries generated an estimated $548.6 million in net profits.

Table 33 estimates the aggregate amount of additional dollars that households will have to set aside as a result of the 2006, 2007 and 2008 off-site emission reduction fees. The additional downpayment per household is multiplied against the number of new single-family units that are built in the region. According to the California Department of Finance, the eight-county region grew by an average of 15,000 single-family units per year between 1995 and 2005. This amount is somewhat consistent with data in Table 2, which shows that between 1993 and 2003, homebuilders took out building permits to construct 15,000 and 27,000 single-family homes in those years, for an annual average of 18,800 single-family homes. In calculating the aggregate amount of additional dollars that all households will need to set aside because of the air quality fees, we adjusted for the fact that not all are first-time homebuyers.[7]

TABLE 33
Aggregate Amount of Dollars All Households Will Need to Set Aside As A Result of Off-Site Emission Reduction Fees

		Additional Downpayment (2006 fee)	Additional Downpayment (2007 fee)	Additional Downpayment (2008 fee)
		$970	**$1,556**	**$2,147**
Scenario 1: Low	15,000 units	$5,820,000	$9,336,000	$12,882,000
Scenario 2: Mid	19,000 units	$7,760,000	$12,448,000	$17,176,000
Scenario 3: High	30,000 units	$11,640,000	$18,672,000	$25,764,000

If 15,000 newly constructed single-family units are sold in 2006, then the aggregate additional downpayment amount attributable to first-time homebuyers will equal $5.8 million, as Table 33 shows. If the number of units goes as high as 30,000, then the additional downpayment will equal $11.6 million. In the highest scenario in year 2008, the aggregate

[7] Scenario 1 2006 fee = (15,000 x 40% rate of rentership) x $970 = $5,820,000

amount of additional downpayment could equal $25.8 million. Thus, local retail and services establishments, particularly small businesses, could lose anywhere between $5.8 million to $25.8 million.

Table 34 below compares the amounts in Table 33 against the estimated net profits of retail and services establishments that employ less than 100 workers. As the table shows, the aggregate amount of additional dollars that households will need to set aside as a result of the off-site emission reduction fee amounts to one to five percent of net profits of small retail and select services establishments. These impacts are below the ten percent threshold of significance employed in this and other socioeconomic analyses for the purposes of evaluating proposed air quality rules.[8] It is worth noting that the analysis assumes that all of the dollars in Table 33 are spent at small business establishments, which, in reality, would not be the case. As a result, the table below overstates impacts on small businesses. Thus, the proposed rule does not disproportionately impact small businesses.

TABLE 34
Impact on Net Profits of Small Business Retail and Select Services Establishments

		Additional Downpayment (2006 fee)	Additional Downpayment (2007 fee)	Additional Downpayment (2008 fee)
		$970	**$1,556**	**$2,147**
Scenario 1: Low	15,000 units	1%	2%	2%
Scenario 2: Mid	19,000 units	1%	2%	3%
Scenario 3: High	30,000 units	2%	3%	5%

In all likelihood, the impacts identified in Table 34 are temporary. More than likely, the purchase of a new home will spur additional spending at retail and services establishments in excess of what is shown in Table 33. A

[8] It should be noted that the report does not include a corresponding analysis for multi-family units because the impacts on net profits were significantly less than one percent, in large part because the number of newly constructed and sold new townhouses in the eight-county region is so low, ranging from 50 to 100 units per year.

recent Pittsburgh Post-Gazette newspaper article on spending habits of new homeowners quotes the web-site of a marketing data company, which indicated that "New homeowners are golden opportunities for the enterprising businessman. These prospects are full of hope and ready to spend money."[9] Clickdata.com reports that many new homeowners purchase a new car within the first year at their new address.[10]

New homeowners are in a spending mood not simply because of the number of new credit cards and or other financing instruments that lenders eagerly extend to households that have demonstrated the financial wherewithal to purchase something as significant as a new home. For some, a new home represents a new phase in the life cycle of a household, including the addition of new family members such as children or a spouse. Others simply need bigger and better space. Inevitably, the new stage in the life cycle involves corresponding needs for goods and services from retail and service establishments, including small businesses.

Small Business Disproportionate Impact Analysis and Non-Residential Developments

The section directly above examined potential impacts on small businesses that sell retail items to consumers, particularly as the impacts relate to how households shift from funds from spending to saving. The section concludes that impacts will be temporary and more than compensated for when a household purchases a home. New Rule 9510 and 3180 could potentially impact small businesses in other ways as well. In particular, small business may not be able to absorb rent increases contemplated in Section 6.3 above.

This section evaluates the impacts of rent increases discussed in Section 6.3 on small businesses, particularly those that occupy commercial developments. As Section 6.3 demonstrated, new commercial development and are potentially significantly impacted by the proposed new rule.

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[9]Caitlin Cleary, "New homeowners welcomes with onslaught of new mail" (Pittsburgh Post-Gazette), 10-15-05

[10]www.clickdata.com/consumer/newequity.asp

For purposes of analysis, commercial development refers to retailers, restaurants, and entertainment and recreation venues.

The analysis below examines how all commercial small businesses are impacted, not just new ones. As Section 6.3 noted, comparable commercial developments that have been in place prior to the new fees could conceivably have their monthly rents raised by one cent per square foot starting in 2008.

If small businesses cannot pass costs onto consumers, and if they are unable to increase sales, then these businesses will have to absorb the additional rent, resulting in a decline in net profits. Lease rates for new and older but well-maintained commercial space is approximately $1.50 per square foot in the San Joaquin Valley region. Scant data on arts and entertainment space suggest these areas go for $1.25 per square foot a month.[11] Older buildings away from busy commercial corridors will in all likelihood command less than the $1.50 that new buildings in busy areas command. Thus, in using the $1.50 (retail and restaurants), $1.10 (gas stations) and $1.25 (arts and entertainment), we will overstate the cost in relation to net profits.

Table 35 shows that the 2008 fee will impact net profits of commercial small businesses by 1.5 percent. The bulk of impacts are borne by small businesses because these entities comprise almost 98 percent of commercial businesses and gas stations in the region.[12] However, the impacts are less than significant. Thus, small businesses are not disproportionately impacted by the rule.

[11] For the purposes of analysis, we assume that all commercial spaces pay these rents. Similar to the analysis directly above, commercial space refers to retail and select services such as restaurants and arts and entertainment venues. Select services exclude office space for industries such as accounting, medical, legal assistance, etc., because office uses are significantly impacted by the rule, as shows in Section 6.3.

[12] 15,368dividedby15,602 = 98%

TABLE 35
Small Business Impact of Additional Rent Resulting From Proposed Air Quality Mitigation Fee

Total Number of Retail and Select Services Establishments	15,602
Total Number of Small Business Retail and Select Services Establishments	14,324
Total Number of Small Business Retail and Select Services: Sales	$18,146,568,017
Total Number of Small Business Retail and Select Services: Net Profits	$485,376,512
Dollar Amount of One Cent Rent Increase (2008 fee: commercial)	$7,230,586
Impact of One Cent Rent Increase on Net Profit of commercial uses (2008 fee)	1.5%
Impact of One Cent Rent Increase on Net Profit of commercial uses (2008 fee)	Less than significant

APPENDIX A: ECONOMIC BENEFITS ASSOCIATED WITH DRAFT RULE 9510 AND 3180

The San Joaquin Valley Air Pollution Control District (SJVUAPCD) will use the Off-Site Emission Reduction Fees will be used to fund off-site emission reduction projects located within the San Joaquin Valley. Besides providing a health benefit to all Valley residents by reducing overall emissions in the air basin, the funding projects would benefit the Valley's economy. Potential projects for funding through this program are numerous and varied ranging from public works construction project such as road paving, procuring cleaner vehicles and equipment for businesses and local government agencies, to school bus upgrades. If all projects that go through the ISR program only reduce emissions through the off-site fee, the District may receive approximately $11 million dollars in 2006 and approximately $56 million in 2008 (allowing for fee deferrals) for use in the off-site emission reduction program. All of the money received as an off-site fee will be spent on projects within the region that make the air cleaner. The program would benefit the economy through three beneficial impacts:

LOCAL PURCHASES

Projects that require a purchase of equipment, materials, or services will result in money being re-circulated into the regional economy. The District cannot guarantee that the manufacturer or provider would be located within the Valley, but it can be expected that the majority will be Valley businesses that benefit. For example, road-paving projects would require asphalt and similar materials that would be provided by Valley businesses. A project that buys a cleaner engine would benefit the Valley engine dealer that sells the engine.

LOCAL PROJECTS

It has already been stated that the program would fund local projects. This means that the school, city, industry or private group that receives the funding for an emission reduction

project would benefit economically from the program. For example, a school district may receive a new, cleaner school bus. A manufacturing facility may receive assistance in procuring a new, cleaner piece of equipment or pollution control device not required by District rules and regulations. A city or county would receive money that makes a road-paving project possible or enables their fleets to operate cleaner new vehicles.

JOB CREATION

The off-site funding program made possible by the ISR Program may also lead to short-term and perhaps long-term job creation. For a financially strapped company or public agency, the funding allows for the purchase and installation or construction of the item (be it a school bus or road project). The installation and construction aspects of the program may benefit the local economy through short-term job creation. Since the ISR program will provide ongoing funding as development occurs over time, it is expected to continue to provide this type of benefit while the rule is in effect. In addition, more efficient equipment may reduce costs and may allow for later expansion that can create long-term jobs.

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APPENDIX G

Rule Consistency Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

November 17, 2005

RULE CONSISTENCY ANALYSIS FOR DRAFT RULE 9510 (INDIRECT SOURCE REVIEW) AND RULE 3180 (ADMINISTRATIVE FEES FOR AIR IMPACT ASSESSMENT APPLICATIONS)

I. REQUIREMENTS OF ANALYSIS

Pursuant to Section 40727.2 of the California Health and Safety Code, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of draft Rules 3180 and 9510 with the corresponding elements of existing or proposed District and United States Environmental Protection Agency (US EPA) rules, regulations, and guidelines that apply to the same source category.

For this analysis, the comparison with other District and US EPA rules and guidelines mainly cover the rules' purpose and applicability. Unlike other District prohibitory rules, Rule 9510 reduces emissions from area sources, not from distinct units considered as point sources that are amenable to analysis in terms of emissions limits, source testing, or recordkeeping requirements. This approach analyzes whether Rule 9510 is in conflict or is redundant with the purpose of other District or federal rules and guidelines already in place, and it also clarifies the applicability of other rules relevant to the development projects covered by Rule 9510.

II. RESULTS OF ANALYSIS

A. District Rules

Consistency with District Fee Rules

The stated purpose of Rule 3180 is to recover District cost for administering the requirements of Rule 9510 and the applicability of Rule 3180 is specific to developments projects subject to the requirements of Rule 9510. There are no other District fee rules with a similar purpose and applicability. The fee requirements stated in District Rule 3100 (California Environmental Quality Act Fee) is specifically for permitted sources subject to District rules and regulations and does not apply to development projects subject to Rule 9510. The process for Rule 9510 is different from the District Permit Program---development projects are required to submit an Air Impact Assessment application, which the District evaluates and approves, and assesses a off-site emission reduction fee if emissions are not reduced on-site. The exact role Rule 9510 in the CEQA process will be determined when the District revises its Guidelines for Assessing and Mitigating the Air Quality Impacts (GAMAQI) document.

Consistency with Rule 2010 (Permits Required)

The applicability of Rule 9510 concerns development projects that have not been traditionally under the purview of District Permit Requirements. In lieu of permitting requirements, development projects covered by Rule 9510 are required to submit an Air Impact Assessment application, which the District evaluates and approves, and assesses a off-site emission reduction fee if emissions are not reduced on-site. There may be some new developments that could be subject to Rule 2010 for particular piece(s) of equipment, however, Rule 9510 will only apply to the area and operational (motor vehicle) emissions, and will not apply to the stationary sources of emissions from a particular development. Therefore, Rule 9510 requirements will not duplicate the requirements in Rule 2010.

Consistency with Rule 9110 (General Conformity)

Proposed Rule 9510 is designed to reduce emissions of PM10 and PM10 precursors and fulfills commitments in the 2003 PM10 Plan, which has been SIP-approved. After Rule 9510 is adopted, it will be submitted for SIP approval. With the approval of Rule 9510 into the SIP, District Rule 9110 (General Conformity) is triggered. The District's Rule 9110 adopted by reference the federal conformity rule which states that (40 CFR 51.850): "No department, agency or instrumentality of the Federal Government shall engage in, support in any way or provide financial assistance for, license or permit, or approve any activity which does not conform to an applicable implementation plan." Therefore any development project subject to Rule 9110 (General Conformity) must make a determination of conformity with the District's SIP-approved rules and regulations, including Rule 9510. A federal actions that result in direct and indirect emissions equal to or exceeding 10 tons of ozone precursors (VOCs or NOx) in extreme nonattainment areas or 70 tons of PM10 in serious nonattainment areas is required to perform conformity determination (40 CFR 51.853).

There is no provision in Rule 9510 exempting federal actions in total. Federally sanctioned actions subject to Rule 9110 are exempt from the requirements of Rule 9510 if they fall under any of the following categories: (1) transportation projects that meet specific conditions, (2) transit projects, (3) reconstruction of any development project that is damaged or destroyed and is rebuilt to essentially the same use, or (4) a development project whose primary emission source are from stationary sources subject to Rule 2201 (New and Modified Stationary Source Review) and Rule 2010 (Permits Required). In the event that a project that is subject to Rule 9110 and 9510, any action or emissions used to demonstrate general conformity, can also be used as credit towards the required emission reductions, as long as they meet the requirements in Rule 9510. In the event that there is a shortfall in meeting the emission reduction requirements, the project will need to reduce the remaining emissions either with additional on-site measures or with off-site measures to be in full compliance with the requirements of Rule 9510.

Consistency with Regulation VIII Rules

The baseline emissions for construction, as used in this rule's emission reduction analysis, do not include emissions from fugitive dust, as required by Regulation VIII. However, any control technique performed for purposes of complying with Regulation VIII that reduces the project's construction equipment exhaust emissions will reduce the required reduction and the corresponding fee amount required under Rule 9510.

Consistency with Other District Rules

The baseline emissions attributed to sources subject to Rule 9510 include emissions from area sources that are assumed to be already in compliance with the requirements of other District rules (for residential sources) such as: Rule 4601 (Architectural Coatings), Rule 4901 (Wood Burning Fireplaces and Wood Burning Heaters), Rule 4902 (Residential Water Heaters), and Proposed Rule 4905 (Residential Central-Heating Furnaces). These rules don't require permits for affected units, and the enforcement mechanism is through certification by manufacturers or distributors prior to the sale and installation of these units within the San Joaquin Valley. Other District rules, which regulate non-residential sources and apply to and control specific stationary or area source emissions that are assumed to be already in compliance with other District rules requirements, are not included in the emissions baseline for Rule 9510. These include but may not be limited to: Rule 4351, 4305, 4306 (Boilers, Steam Generators, and Process Heaters), Rule 4622 (Gasoline Transfer into Motor Vehicle Fuel Tanks), Rule 4672 (Petroleum Solvent Dry Cleaning Operations), Rule 4692 (Commercial Charbroiling), and other process-specific District rules.

Consistency with Rule 1070

Rule 1070 provides the basis of authority for the District enforcement activities such as site inspections to verify compliance with mitigation measures.

B. US EPA RULES AND GUIDELINES

There are no specific federal guidelines applying to development projects as a source of NOx, PM10, or PM10 precursors in terms of New Source Performance Standards (NSPS), Control Technique Guidelines (CTG), Maximum Achievable Control Technology (MACT) and National Emission Standards for Hazardous Pollutants (NESHAP).

As previously mentioned, District's Rule 9110 adopted by reference the federal conformity rule which states that (40 CFR 51.850): "No department, agency or instrumentality of the Federal Government shall engage in, support in any way or provide financial assistance for, license or permit, or approve any activity which does not conform to an applicable implementation plan." Its relationship to Rule 9501 is discussed above.

BEFORE THE GOVERNING BOARD OF THE
SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

IN THE MATTER OF: PROPOSED RULE 9510 (Indirect Source Review) and PROPOSED RULE 3180 (Administrative Fees for Indirect Source Review)) **RESOLUTION NO.** 05-12-16

WHEREAS, the San Joaquin Valley Unified Air Pollution Control District (District) is a duly constituted unified district, as provided in California Health and Safety Code (CH&SC) Sections 41050 to 40161; and

WHEREAS, said District is authorized by CH&SC Section 40702 to make and enforce all necessary and proper orders, rules, and regulations to accomplish the purpose of Division 26 of the CH&SC; and

WHEREAS, Section 40716 of the CH&SC authorizes the District to adopt and implement regulations to reduce or mitigate emissions from indirect and areawide sources of pollution; and

WHEREAS, Section 42311(g) of the CH&SC authorizes districts to adopt a schedule of fees on areawide or indirect sources which are regulated, but for which permits are not issued, to cover the costs of District programs related to this source; and

WHEREAS, Section 40604 of the CH&SC (SB 709), directs the San Joaquin Valley Unified Air Pollution Control District to adopt a schedule of fees to be assessed on areawide or indirect sources of emission; and

WHEREAS, pursuant to Section 107 of the Clean Air Act and pursuant to Section 39608 of the CH&SC, the San Joaquin Valley Air Basin has been classified as a nonattainment area for the national and state health based ambient ozone and particulate matter 10 microns in size and smaller (PM10); and

WHEREAS, the District's 2004 Extreme Ozone Attainment Demonstration Plan as amended by the Governing Board on October 20, 2005 and the District's 2003 PM10 Plan as amended by the Governing Board on December 18, 2003 and May 19, 2005 commits the District to adopt and implement control measures to reach attainment; and

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WHEREAS, the Indirect Source Program is a control strategy contained in both the District's 2004 Extreme Ozone Attainment Demonstration Plan and 2003 PM10 Plan to be implemented through Rule 9510 (Indirect Source Review), and Rule 3180 (Administrative Fees for Indirect Source Review); and

WHEREAS, a public hearing for adopting Rule 9510 and Rule 3180 was duly noticed for public hearing on November 3, 2005 in accordance with CH&SC Sections 40725 and 40727.2.

NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:

1. The Governing Board hereby adopts Rule 9510 (Indirect Source Review), and Rule 3180 (Administrative Fees for Indirect Source Review) as set forth in the attached hereto and incorporated herein by this reference. Said rules shall become effective on December 15, 2005.

2. The Governing Board hereby finds, based on the evidence and information presented at the hearing upon which its decision is based, all notices required to be given by law have been duly given in accordance with CH&SC Section 40725, Section 42311(e) and Section 40727.2, and the Board has allowed public testimony in accordance with CH&SC Section 40726.

3. In connection with the proposed requirements of said rules, the Board makes the following findings as required by CH&SC Section 40727:

a. **NECESSITY.** The Governing Board finds, based on the staff report, public and industry testimony on the record for this rulemaking proceeding, that a need exists for the adoption of Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Indirect Source Review). Said action is necessary to meet the commitments of the submitted State Implementation Plan and requirements of the federal Clean Air Act.

b. **AUTHORITY.** The Governing Board finds that it has the legal authority to adopt said rules under the California Health & Safety Code Sections 40000 and 40001.

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c. **CLARITY.** The Governing Board finds that said rules are written or displayed so that their meaning can be easily understood by those persons or industries directly affected by them.

d. **CONSISTENCY.** The Governing Board finds that said rules are in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

e. **NONDUPLICATION.** The Governing Board finds that said rules do not impose the same requirements as any existing state or federal regulation.

f. **REFERENCE.** The Governing Board finds that said rulemakings implement Section 40604 of the California Health and Safety Code.

4. The Governing Board hereby finds that the requirements of the California Health and Safety Code Section 40728.5 have been satisfied to the greatest extent possible, and that the Governing Board has actively considered and made a good faith effort to minimize any adverse socioeconomic impacts associated with the proposed rulemakings.

5. The District has completed an Initial Study for said rules that indicate that the project will not result in any significant adverse effects to the environment, and a Proposed Negative Declaration has been prepared and properly noticed pursuant to the California Environmental Quality Act Guidelines (CEQA). The Governing Board of the District has duly considered said Initial Study and Proposed Negative Declaration. Accordingly, the Governing Board of the District (a) certifies that the Initial Study and Negative Declaration reflect the independent judgment of the District; (b) finds that the above-described project will have a de minimis impact on fish and wildlife resources; and (c) approves and adopts a Negative Declaration for said rulemaking effort pursuant to CEQA requirements. In accordance with the provisions of Section 15075 of the *California Environmental Quality Act Guidelines*, the Executive Director/Air Pollution Control Officer is hereby directed to cause to be

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filed a Notice Determination with the County Clerks of each of the counties in the District.

6. To the maximum extent feasible, the offsite emission reduction fees collected by the District shall be expended in a manner that provides for localized air quality benefits commensurate with the emissions from the new development projects.

7. The District shall explore support of legislative initiatives that provide appropriate litigation relief on air quality issues in conjunction with the California Environmental Quality Act (CEQA) process for new development projects that satisfy the District emission reduction requirements of Rule 9510 or more stringent standards set by local communities and land use agencies.

8. No later than December 31, 2010, and after holding at least one series of public workshops, the Air Pollution Control Officer shall submit Rules 9510 and 3180 to the District Governing Board for reevaluation and reauthorization.

9. The District shall prepare an annual report that will be available to the public regarding the expenditure of offsite fee funds, and shall include the following: total amount of offsite fees received; total monies spent; total monies remaining; any refunds distributed; a list of all projects funded; total emissions reductions realized, and; the overall cost-effectiveness factor for the projects funded.

10. The Executive Director/Air Pollution Control Officer is directed to file with all appropriate agencies certified copies of this resolution and the rules adopted herein and is directed to maintain a record of this rulemaking proceeding in accordance with CH&SC Section 40728.

11. The Air Pollution Control Officer is directed to transit Rule 9510 (Indirect Source Review) to the California Air Resources Board for incorporation in the State Implementation Plan.

12. The Governing Board authorizes the Air Pollution Control Officer to

///

include in the submittal or subsequent documentation any technical corrections, clarifications, or additions that may be needed to secure EPA approval, provided such changes do not alter the substantive requirements of the approved rule.

THE FOREGOING was passed by the following vote of the Governing Board of the San Joaquin Valley Unified Air Pollution Control District this 15th day of December 2005, to wit:

AYES: Patrick, Anderson, Worthley, Barba, Nelson, Dominici, Sieglock, Prince, Maggard and Mayfield.

NOES: None.

ABSENT: Armentrout.

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

By: _____
Thomas W. Mayfield, Chair
Governing Board

ATTEST:

By: _____
Sissy Smith

Appendix C

Biological Resources Technical Documentation

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C.1 Biological Analysis Report

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BIOLOGICAL ANALYSIS REPORT

CALIFORNIA RESOURCES CORPORATION

CARBON TERRAVAULT 1



MARCH 2023

BIOLOGIAL ANALYSIS REPORT

CARBON TERRAVAULT 1 – CARBON CAPTURE AND SEQUESTRATION PROJECT

Prepared for:

California Resources Corporation, LLC.
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March 2023

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Project #220067

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ACRONYMS AND ABBREVIATIONS

AMSL	Above Mean Sea Level
BAR	Biological Analysis Report
BIOS	Biogeography Information and Observation System
BMPs	Best Management Practices
BSA	Biological Study Area
CDFW	California Department of Fish and Wildlife
CEQA	California Environmental Quality Act
CESA	California Endangered Species Act
CFGC	California Fish and Game Code
CNDDB	California Natural Diversity Database
CNPS	California Native Plant Society
CO2	Carbon dioxide
CRC	California Resources Corporation, LLC
CRPR	California Rare Plant Rank
CWHR	California Wildlife Habitat Relationships
EIR	Environmental Impact Report
FEMA	Federal Emergency Management Agency
FESA	Federal Endangered Species Act
IPaC	Information for Planning and Consultation
HCP	Habitat Conservation Plan
MBTA	Migratory Bird Treaty Act
NEPA	National Environmental Policy Act
NHD	National Hydrography Dataset
NRCS	Natural Resources Conservation Service
NWI	National Wetlands Inventory
RWQCB	Regional Water Quality Control Board
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey

EXECUTIVE SUMMARY

The Biological Analysis Report (BAR) evaluates the potential for sensitive biological resources to be impacted by the proposed California Resources Corporation, LLC (CRC) Carbon TerraVault 1 – Carbon Capture and Sequestration Project (Project). The proposed project involves transporting "local industrial sources" of carbon dioxide ("CO2") to four to six injection wells in the Elk Hills oilfield that have the capacity to store 48 million metric tons of CO2 at a rate of more than 1.5 million metric tons per year. The proposed project would take local industrial sources of CO2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project. The CO2 would then be injected into identified geographically confined reservoirs for storage in perpetuity. This area has been identified as a location suitable for such storage and a potential to provide a contribution to the goals of California for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air.

Database reviews were conducted to determine the potential for special-status species and other sensitive biological resources to occur on-site that may be impacted by the Project. These reviews resulted in 23 special-status plant species and 40 special-status wildlife species having the potential to be on or near the Project.

Based on these database reviews, QK field surveys in 2022, and environmental conditions such as soil types, elevation, historical range, and other factors, it was determined that ten special-status plant species have the potential to occur onsite; heartscale (*Atriplex cordulata* var. *cordulata*), Lost Hills crownscale (*Atriplex coronata* var. vallicola), California jewelflower (Caulanthus californicus), recurved larkspur (Delphinium *recurvatum*), Kern mallow (*Eremalche parryi* ssp. *kernensis*), Temblor buckwheat (*Eriogonum temblorense*), Tejon poppy (*Eschscholzia lemmonii* ssp. *kernensis*), showy golden madia (*Madia radiata*), San Joaquin woollythreads (*Monolopia congdonii*), and oil neststraw (*Stylocline citroleum*).

Based on the database reviews and QK field surveys, it was determined that 17 special-status wildlife species have the potential to occur on-site; Crotch bumblebee (*Bombus crotchii*), California glossy snake (*Arizona elegans occidentalis*), blunt-nosed leopard lizard (*Gambelia sila*) a State and federal endangered species, San Joaquin coachwhip (*Masticophis flagellum ruddocki*), coast horned lizard (*Phrynosoma blainvillii*), burrowing owl (*Athene cunicularia*), Swainson's hawk (*Buteo swainsoni*) a State threatened species, prairie falcon (*Falco mexicanus*), loggerhead shrike (*Lanius ludovicianus*), Nelson's (=San Joaquin) antelope squirrel (*Ammospermophilus nelsoni*) a State threatened species, LeConte's thrasher (*Toxostoma lecontei),* giant kangaroo rat (*Dipodomys ingens*) a State and federal endangered species, short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*), Tulare grasshopper mouse (*Onychomys torridus tularensis*), San Joaquin pocket mouse (*Perognathus inornatus*), American badger (*Taxidea taxus*), and San Joaquin kit fox (*Vulpes macrotis mutica*) a State threatened and federal endangered species. Migratory birds have been observed and are likely to nest on or near the Project site during the nesting season.

QK biologists conducted general reconnaissance surveys in the fall and winter of 2022. These surveys were conducted to document site conditions, evaluate biological resources on-site, and determine the suitability of the existing habitat to support special-status plant and wildlife species described in the database search that may occur on or near the Project site. Direct observations of burrowing owl and San Joaquin antelope squirrels occurred during the surveys.

SECTION 1 - INTRODUCTION

QK prepared this Biological Analysis Report (BAR) to evaluate the potential for sensitive biological resources to be impacted by the proposed Carbon TerraVault 1 Project (Project). The Project, as proposed by California Resources Corporation, LLC (CRC), would include the construction of a captured carbon dioxide (CO2) compression and pumping facility, construction and modifications of injection well sites, conversion of existing well sites, and installation of approximately 14- miles of associated pipelines. Existing roads and pipeline routes will be utilized to the maximum extent possible though some may require maintenance or widening within the Elk Hills Oil Field in Kern County, California. The Project would inject the captured C02 into these well sites for sequestration into the ground for importunity as part of the goal to reduce C02 emissions for the State of California.

1.1 - Project Location

The Project area is located generally within western Kern County, California (Figure 1-1). It is entirely within the boundary of the Elk Hills Oil Field, an approximately 75-square mile complex with surface and mineral rights privately held by CRC, in the San Joaquin Valley of unincorporated Kern County. The Project area extends east of the intersection of Skyline Road and Elk Hills Road approximately 0.50 miles and west of the intersection approximately 5.5 miles. The majority of the Project area follows existing and maintained pipeline rights-of-way. The Project area is approximately 12.75 miles west of Interstate 5 and five miles south of State Route 58. It can be accessed via CRC's gated and guarded entrance to the oil field located at the western intersection of Skyline Road and Elk Hills Road (Figure 1-2).

The Project area is bordered on all sides by existing oil and gas exploration and production. Existing land use in the outside of the Project area generally includes agricultural lands, current, past and abandoned oil and gas exploration and production land and undeveloped land owned by CRC and other oil and gas operators. The City of McKittrick is approximately four miles west of the Project area and the City of Taft is approximately nine miles to the south. The Project area is located within two U.S. Geological Survey (USGS) 7.5-minute topographic quadrangles (see Table 1-1). All the Sections, Townships, and Ranges are in the Mount Diablo Base Meridian.

Table 1-1
U.S. Geological Survey 7.5-Minute Topographic Quadrangles
Within Project Site, Carbo TerraVault 1 Project, Kern County, California

Quadrangle	Township/ Range	Section (s)
East Elk Hills	30 South 23 East	26, 27, 34, 35, 36
West Elk Hills	30 South 22 East	13, 14
	30 South 23 East	7, 18, 19, 27, 28, 29,30

1.2 - Project Description

The Project will facilitate construction of a CO2 compression and pumping facility and associated pipelines. Construction of six new wells and conversion of 15 existing wells to injector or monitoring wells will also be required. New pipeline will be installed primarily above ground, with the exception of road crossings, which will be trenched using traditional cut and cover techniques. The majority of the new pipeline will be collocated with existing pipelines along established rights-of-way. In sections that will not be collocated, new existing sleepers will be installed prior to pipe placement. New sleeper locations will require boreholes of approximately eight inches in diameter. Drainages intersecting the pipeline route will be spanned. All pipelines will be covered in cathodic protection to prevent corrosion. After installation, the pipeline will be hydrotested to verify its integrity.

The Project also includes establishing and utilizing a temporary construction corridor and temporary storage and laydown areas. The temporary construction corridor right of way (ROW), of up to approximately 12-feet in width, will be established along areas of the pipeline route not accessible via established roads or other existing cleared areas to allow for off-road construction equipment and a travel path. Temporary storage and laydown areas outside of the ROW will be used to store equipment, pipe, and materials, and to stage construction activities. Laydown areas are designed to minimize new disturbance by utilizing existing, cleared areas such as fields, parking lots, or other developed areas. After completion of construction, all laydown areas will be returned to pre-Project contours and revegetated to native habitat conditions.

The CO2 compression and pumping facility site will be located within a fenced area measuring 460 feet by 300 feet, an area of 3.17 acres. The facility will include the following components: CO2 compressor packages, CO2 compressor auxiliary area containing compressor piping, tanks, vessels, pumps, and other equipment, CO2 pumps, chiller system, heat exchanger, electrical substation area, electrical equipment area, control room, parking area, lighting, signage, and access road(s). The facility will be accessed via existing surfaced roads northward from Skyline Road within the CRC Elk Hills Oil Field, west of Gate 4. Currently the proposed facility site is accessed via dirt roads from the ends of surfaced roads as part of the Project, these dirt roads will be paved, thus extending the surfaced roads.

During construction water will be used for dust suppression, fire protection, and pipeline hydrotesting. Construction activities will generally occur during daylight hours but limited nightwork could potentially include, but are not limited to, pipeline tie-in connections, refuelling equipment, staging equipment and material for the following day's construction activities, quality assurance/control, and commissioning. All lighting utilized during nightwork will be situated to avoid lighting impacts on the surrounding area by directing lights downward to the work area and only for durations necessary to safely complete the task. Traffic control will be provided for street encroachments and crossings as necessary.

Project construction will result in temporary disturbance associated with the pipeline construction corridor and temporary construction storage and laydown areas, and limited

permanent disturbance associated with new pipeline sleeper installation sites and the CO2 compression and pumping facility.

Construction Schedule:
Project construction is expected take two to three months. Pipeline construction will be implemented and once it is complete, crews will install the associated structures at facilities. There may be some overlap of phase construction work where facility work may be continuing while pipeline construction may begin on a subsequent phase. Idling and purging will occur after the new pipeline for each phase of construction is operational. Construction duration may vary based on factors such as weather, seasonal environmental constraints, resource availability, number of contractor spreads, permit acquisition, site conditions and other issues encountered in the field.

- Implementation of the project would require permits from the Federal Environmental Protection Agency (EPA) for four (4) to six (6) Class VI injection wells in compliance with the UIC program Class VI geologic sequestration regulations. Location of the proposed Class VI injection wells will be within the proposed CUP boundary of 5,332.34 acres. All employee facilities needed to manage the project will be provided by the existing Elk Hills oil field facilities. Implementation of the project as proposed includes the following requests: Zone Change Case (ZCC No. 5, Map No. 118; ZCC No. 5, Map No. 119; ZCC No 4, Map No. 120); : From A-1 (Limited Agriculture) to A (Exclusive Agriculture) on approximately 3,208 acres; and

- Issuance of three (3) Conditional Use Permits (CUP No. 13, Map No. 118; CUP No. 5, Map 119; CUP No. 3, Map No. 120) to allow for the construction and operation of a 5,332.34-acre carbon capture and sequestration field and accessory infrastructure with a CO2 storage capacity of 48 million metric tons, within the A (Exclusive Agriculture) Zone District. Carbon Capture and Sequestration (CCS) has been determined to be a storage operation and not a manufacturing operation and under the Kern County Zoning Ordinance, Section 19.08.085. And under the authority of Section 19.06.020. Storage of CCS in either existing formations or tanks is an allowed use with a Conditional Use Permit (CUP) in the following districts: A District (Exclusive Agriculture), M-2 District (Medium Industrial) and M-3 (Heavy Industrial).

Restoration:
Pre-construction conditions will dictate post-construction restoration activities along the construction corridor. Restoration methods may include broadcast reseeding or hydroseeding with a mix of native grass and forb seed in undeveloped natural areas (e.g., Valley Scrub). Best management practices (BMPs) will be followed to prevent soil erosion and off-site sediment transport until vegetation is re-established.

1.3 - Purpose, Goals, and Objectives

The purpose of this BAR is to identify where potential special-status biological resources may occur within the Project site, determine how those resources may be impacted by the proposed Project, and recommend avoidance, minimization, and mitigation measures to reduce the potential for impact to a less than significant level. This BAR has been prepared to support an analysis of biological conditions as required by the California Environmental Quality Act (CEQA). Information contained in this BAR would, at least partially, support an analysis of project effects required by the National Environmental Policy Act (NEPA) and to support regulatory permit applications, if needed.

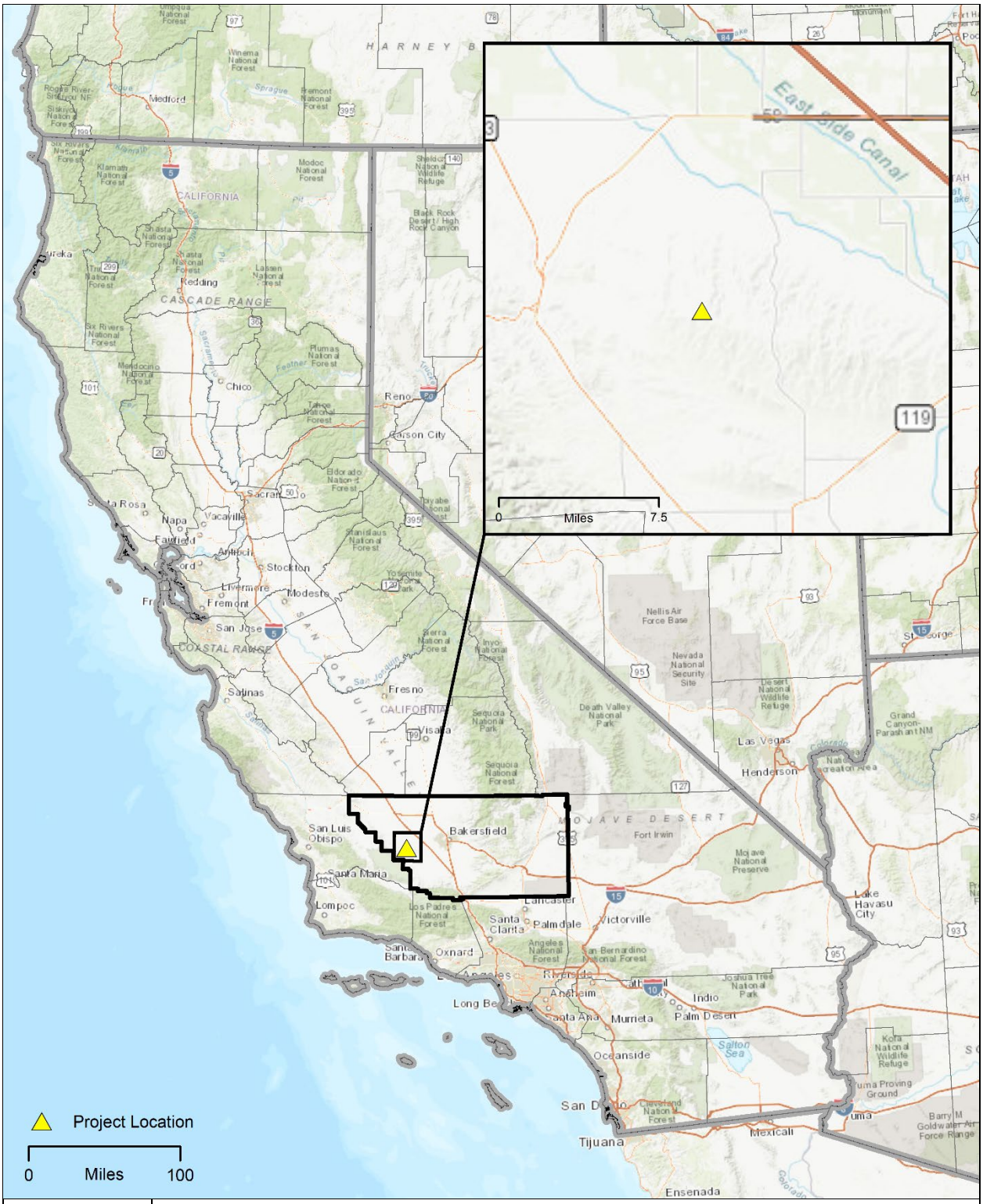

Figure 1-1
Regional Map
Carbon TerraVault 1 Project, Kern County, California

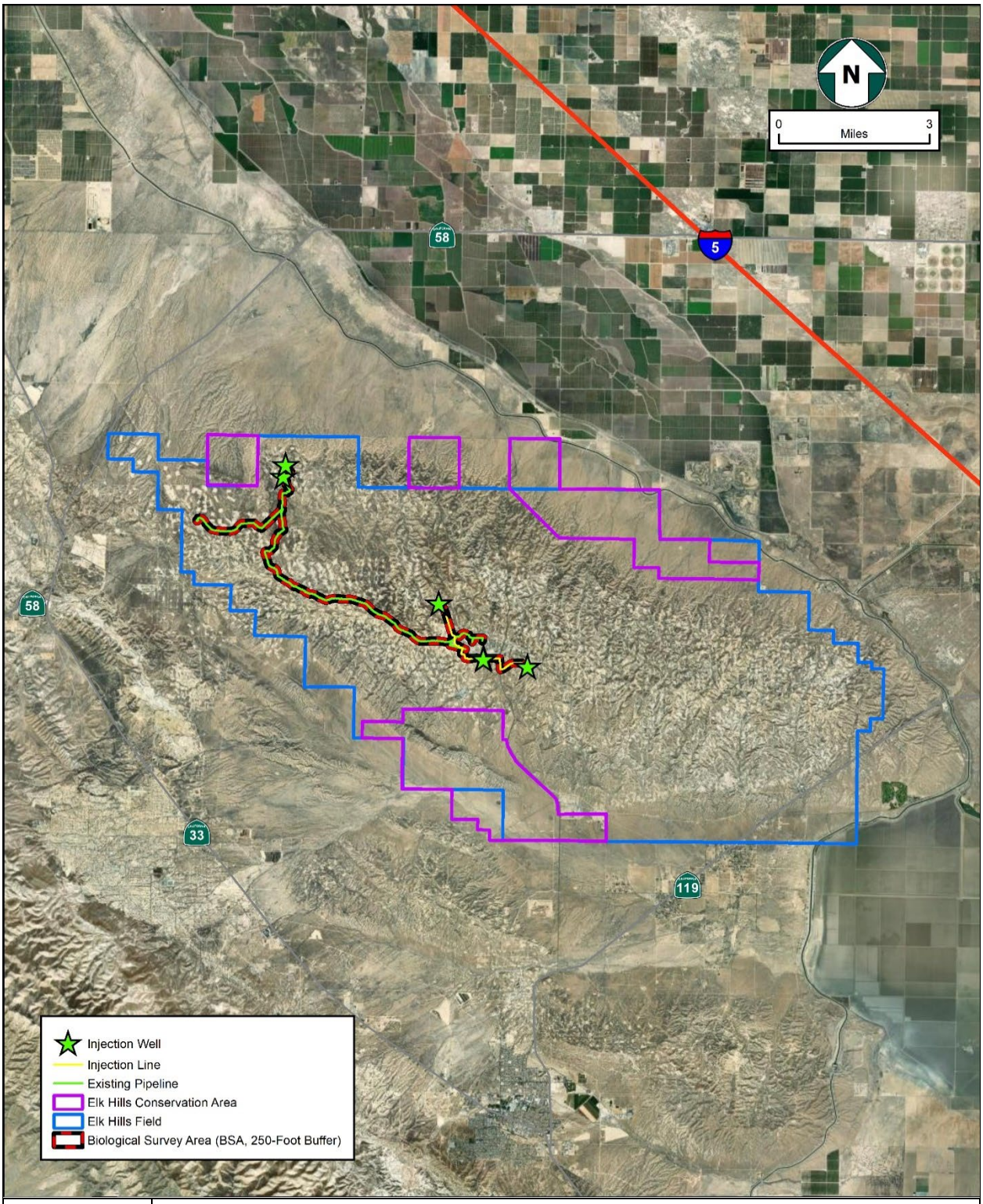

Figure 1-2
Project Area
Carbon TerraVault 1 Project, Kern County, California

SECTION 2 - METHODS

2.1 - Definition of Biological Study Area

The Biological Study Area (BSA) used for this BAR includes everything within the limits of the Project boundaries and a 250-foot survey buffer, where feasible (Figure 2-1).

2.2 - Definition of Special-Status Species

For the purpose of this report, special-status species include:

- Species listed as threatened or endangered under the Federal Endangered Species Act (FESA); species that are under review may be included if there is a reasonable expectation of listing within the life of the project,
- Species listed as candidate, threatened, or endangered under the California Endangered Species Act (CESA),
- Species designated as Fully Protected, Species of Special Concern, or Watch List by the California Department of Fish and Wildlife (CDFW),
- Other species included on the CDFW's Special Animals List,
- Plant species with a California Rare Plant Rank (CRPR) in categories 1 or 2,
- Species designated as locally important by the Local Agency and/or otherwise protected through ordinance or local policy.

The potential for each special-status species to occur in the study area was evaluated according to the following criteria:

- **No Potential**. Habitat on and adjacent to the Project is clearly unsuitable to meet the needs of the species (foraging, breeding, cover, substrate, elevation, hydrology, plant community, site history, disturbance regime), and species would have been identifiable on-site if present.

- **Potential**. Conditions on the Project may, in some way, support a portion of the species ecology (foraging, reproduction, movement/migration). Negative survey results do not exclude the potential for a species to occur.

- **Present**. Species or diagnostic sign of the species was observed on the Project or has been recorded (e.g., databases, other reports) on the Project recently (within the last five years).

2.3 - Literature Review and Database Analysis

The following sources were reviewed for information on sensitive biological resources in the project vicinity:

- CDFW's California Natural Diversity Database (CNDDB; CDFW 2023a; CDFW 2023b).
- CDFW's Biogeographic Information and Observation System (BIOS; CDFW 2023c).

- CDFW's California Wildlife Habitat Relationships (CWHR) System (Mayer and Laudenslayer 1988).
- California Native Plant Society (CNPS) Inventory of Rare and Endangered Plants of California (CNPS 2023).
- Calflora (Calflora 2023).
- U.S. Fish and Wildlife Service's (USFWS) Information for Planning and Consultation (IPaC) system (USFWS 2023a).
- USFWS Critical Habitat Mapper (USFWS 2023b).
- USFWS National Wetlands Inventory (NWI; USFWS 2023c).
- United States Geological Survey (USGS) National Hydrography Dataset (NHD; USGS 2023).
- Federal Emergency Management Agency (FEMA) flood zone maps (FEMA 2023).
- U.S. Department of Agriculture, Natural Resources Conservation Service (NRCS) Web Soil Survey (NRCS 2023a).
- NRCS Lists of Hydric Soils (NRCS 2023b).
- eBird Explore (eBird 2023).
- VertNet (VertNet 2023).
- Current and historical aerial imagery from Google Earth (Google LLC 2023).

All State and federal data sources listed above focused on the California USGS 7.5-minute quadrangles *East Elk Hills* and *West Elk Hills*, in which the Project is located, and the surrounding ten quadrangles: *Belridge*, *Lokern*, *Buttonwillow*, *Rio Bravo*, *Tupman*, *Mouth of Kern*, *Taft*, *Fellows*, *Panorama Hills*, and *Reward*.

The CNDDB provides element spatial information on individually documented occurrence of special-status species and sensitive natural communities. Some of the information available for review in the CNDDB is still undergoing review the CDFW, these records are identified as unprocessed data. The CNPS database and Calflora provide similar information as the CNDDB but at a much lower spatial resolution. Much of the information in these databases is obtained opportunistically and is often focused on protected lands or on lands where development has been proposed. Neither database represents a comprehensive survey for special-status resources in the region. As such, the absence of recorded occurrence in these databases at any specific location does not preclude the possibility that a special-status resource may be present, which is why site-specific surveys were undertaken. The IPaC and CDFW's Special-status animals list provide only lists of species that could occur in the region, with no specific records of occurrence. The NWI, NDH, and Web Soil Survey provide comprehensive spatial data but at a low resolution that requires confirmation in the field.

The results of the database inquiries were reviewed to develop a comprehensive list of sensitive biological resources that may be present on or in the vicinity of the Project site (see Table A-1 in Appendix A). This list was then evaluated against existing site conditions observed during the biological field surveys of the BSA to determine which special-status resources have the potential to occur and then the potential for impacts to those resources as a result of the implementation of the Project.

2.4 - Reconnaissance-Level Field Surveys

Reconnaissance surveys of the BSA were conducted from September 20 to December 15, 2022, by QK Biologists (Table 2-2). The surveys consisted of walking meandering pedestrian transects spaced 50 to 100 feet apart throughout the BSA. One hundred percent survey coverage of the BSA was achieved. No protocol surveys were conducted for this report.

Tasks completed during the survey included developing an inventory of plant and wildlife species observed, characterizing vegetation associations and habitat conditions, assessing the potential for federally and State listed special-status plant and wildlife species to occur, assessing potential for bat usage habitat, and assessing the potential for migratory bird and raptor nesting within the BSA. All locational data were recorded using ESRI Collector for ArcGIS software installed on an iPad, and site conditions were documented with representative photographs.

Table 2-1
Field Survey Personnel and Dates

Date	Personnel	Time	Weather		
			Condition	Temperature (F)	Wind Speed (mph)
09/20/2022	CC, EM, LF, MW	0800 -1400	clear	65 - 84	0 - 5
09/21/2022	EM, JE, KD, MW, CC, LF	0800 -1400	clear	65 - 84	0 - 5
10/03/2022	CC, JE, LF, MW	0845 -1400	clear	64 - 82	0 - 5
10/11/2022	CC, EM, LF, MW	0730 -1245	clear	70 - 84	0 - 1
10/12/2022	CC, EM, LF, MW	0730 -1335	clear	69 - 84	0 - 5
12/14/2022	EM, JE	1000 - 1340	clear	47 - 54	0 - 2
12/15/2022	EM, JE	0900 - 1320	overcast	46 - 52	0 - 1

Surveyors: CC = Courtney Chaney; EM = Eric Madueno; JE = Jeffrey Erway; KD = Karissa Denney; LF = Lauren Fah; MW = Mitch Wayman

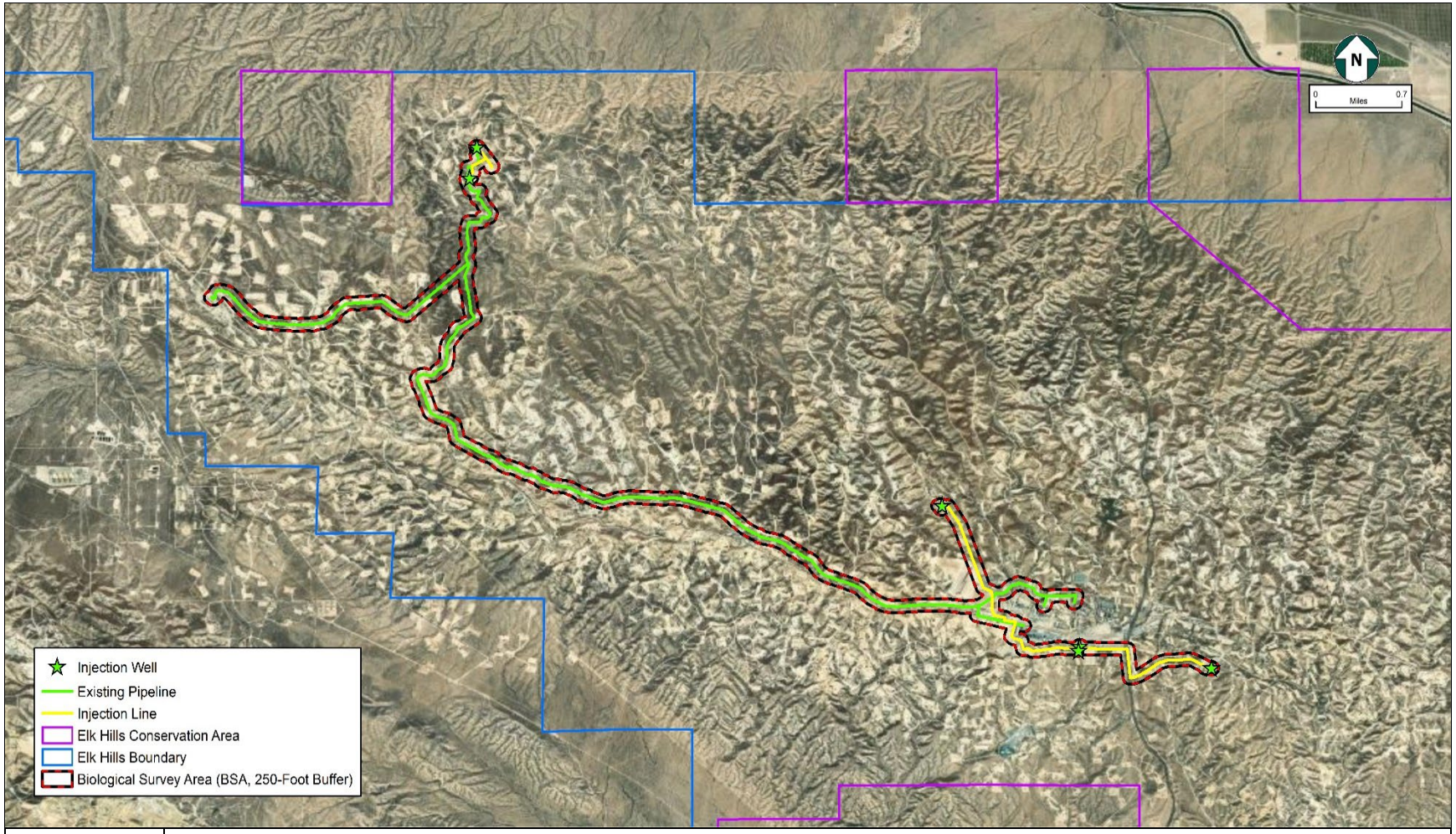

Figure 2-1
Biological Study Area
Carbon TerraVault 1 Project, Kern County, California

SECTION 3 - REGULATORY SETTING

Regulated or sensitive resources that were studied and analyzed include special-status plant and animal species, nesting birds and raptors, sensitive plant communities, jurisdictional waters and wetlands, wildlife movement areas, and locally protected resources such as protected trees. Regulatory authority over biological resources is shared by federal, State, and local authorities. Primary authority for regulation of general biological resources lies within the land use control and planning authority of local jurisdictions (in this instance, the Kern County General Plan and the Kern County Oil and Gas Environmental Impact Report (Kern County, 2021).

Regulation of biological resources on the site derives from the following list of statutes. Summaries of these statutes are provided in Appendix B. The significance of impacts to biological resources for purposes of CEQA was determined in the context of the Public Resources Code Sections 21000 et seq.

- California Environmental Quality Act (CEQA)
- Federal Endangered Species Act (FESA)
- California Endangered Species Act (CESA)
- Federal Clean Water Act
- California Fish and Game Code (CFGC)
- Migratory Bird Treaty Act (MBTA)
- The Bald and Golden Eagle Protection Act
- Porter-Cologne Water Quality Control Act
- San Joaquin Valley Upland Species Recovery Plan
- Kern County General Plan
- Kern County Oil and Gas Environmental Impact Report (EIR)

SECTION 4 - ENVIRONMENTAL SETTING

This section identifies the regional and local environmental setting of the Project and describes existing baseline conditions. The environmental setting of the Project area was obtained from various sources of literature, databases, and aerial photographs. Site conditions were verified and refined based on observations made during the biological surveys described in Section 3.

4.1 - Physical Characteristics

This section identifies the regional environmental setting of the Project and describes baseline conditions. Representative photographs of the Project area are included in Appendix C.

4.1.1 - TOPOGRAPHY

The Project is situated in the eastern section of Kern County near the floor of the San Joaquin Valley. The southern Sierra Nevada foothills are east of the Project, while the Temblor Range of the Southern Coast Range lies to the west. The topography of the Project area consists of variable terrain from gentle slopes to steep hill slopes. Elevations range from 750 feet above mean sea level (AMSL) to 1,550 feet AMSL.

4.1.2 - CLIMATE

The region in which the Project is located is characterized by a typical Mediterranean climate of hot summers and mild, wet winters. Average high temperatures range from 57°F in January to 100°F in July, with daily temperatures exceeding 100°F several days in the summer (WWRC 2023). Average low temperatures range from 41°F in December to 67°F in July. Precipitation occurs primarily as rain, most of which falls from December to April, with an average of 5.4 inches of rainfall per year. Precipitation may also occur as a dense fog known as Tule fog during the winter months. Rain rarely falls during the summer months.

4.1.3 - LAND USE

The entirety of the Project area lies within the Elk Hills Oil Field. The Project area is characterized by heavy oil and gas exploration and production including existing well pads, processing facilities, pipeline routes, and access roads. Most of the Project new pipeline infrastructure follows established pipeline routes. Development in the surrounding area is predominantly oil and gas production, agricultural, and municipalities such as the towns of McKittrick, Tupman, Taft, and Buttonwillow.

The Project area boundaries encompass a mix of parcels that have been owned and used for oil and gas production or on which leases have been acquired by the Project proponent.

4.1.4 - SOILS

Habitat types and special-status plant species are partially dependent on soil types. The BSA is underlain by five (5) soil types: Elkhills sandy loam, Kimberlina sandy loam, and three variations of the Elkhills-Torriorthents stratified complex (NRCS 2023a). The most prevalent soil type within the BSA is Elkhills-Torriorthents stratified, eroded complex (Table 4-1).

Table 4-1
Soil Types Occurring Within the BSA

Soil Type	Acreage
Elkhills sandy loam, 9 to 50 percent slopes, eroded	107.5
Elkhills- Torriorthents stratified complex, 9 to 15 percent slopes	88.1
Elkhills-Torriorthents stratified, eroded complex, 15 to 50 percent slopes	536.8
Kimberlina sandy loam, 5 to 9 percent slopes	2.5
Torriorthents stratified, eroded-Elkhills complex, 9 to 50 percent slopes	47.6

4.1.5 - HYDROLOGY

A query of the NHD and NWI databases indicated seven wetland features may intersect the BSA (Figure 4-1). No formal wetland delineations were conducted for this BAR; however, many of the identified water features appeared to be ephemeral drainages during the site surveys. Federal Emergency Management Agency flood zones for which the BSA is within are shown in Figure 4-2.

4.2 - Vegetation and Other Land Cover

Based on descriptions of the habitat classification system in the CWHR (Mayer and Laudenslayer, 1988), two habitat types, Valley Saltbush Scrub and Urban, were present within the BSA (Table 4-2, Figure 4-3). The most prevalent habitat type within the BSA was Valley Saltbush Scrub. The Valley Saltbush Scrub habitat was comprised of isolated fragments of *Atriplex polycarpa* and *A. spinifera* shrubs, with an understory of forbs and non-native grasses, interspersed with dirt access roads, established pipeline routes, and well pads. The urban habitat is restricted to the southeastern end of the BSA and is comprised of oil and gas facilities and associated paved areas. A complete list of plant species observed during the reconnaissance surveys is included in Appendix D.

The habitats observed on-site have been described in the context of the CWHR (Mayer and Laundeslayer, 1988). Note in some areas the Valley Saltbush Scrub habitat was intermixed with annual grassland habitat at a scale too small to capture via mapping and so a description of that habitat type has also been included below for reference.

Table 4-2
Habitat Acreages Observed On-Site

Habitat Type	BSA (acres)
Valley Saltbush Scrub	642.15
Urban	140.33

4.2.1 - VALLEY SALTBUSH SCRUB

This community consists of open, gray or blue-green chenopod scrubs, usually over a low herbaceous annual understory. Areas dominated by *Atriplex polycarpa* or *A. spinifera* may be differentiable from one another. Typically found on sandy to loamy soils without surface alkalinity, largely on rolling, dissected alluvial fans. Found in areas with long, arid summers and short, damp winters, and tule fog is often present during the winters.

4.2.2 - URBAN

The structure of urban vegetation varies, with five types of vegetative structure defined: tree grove, street strip, shade tree/lawn, lawn, and shrub cover. Tree groves, common in city parks, green belts, and cemeteries, vary in height, tree spacing, crown shape, and understory conditions, depending upon the species planted and the planting design. Shade trees and lawns are typical of residential areas and reminiscent of natural savannas. Species composition in urban habitats varies with planting design and climate. Monoculture is commonly observed in tree groves and street tree strips. A distinguishing feature of the urban wildlife habitat is the mixture of native and exotic species. Both native and exotic species are valuable, with exotic species providing a good source of additional food in the form of fruits and berries. For the purposes of the Urban habitat type for this analysis, Urban is bare ground on well pads and roads, no green belts other than ruderal grasses and forbs and no planted vegetation.

4.3 - General Wildlife Observations

Wildlife occurring within the Project area was typical of developed oilfields of western Kern County. Bird species included common raven (*Corvus corax*), white-crowned sparrow (*Zonotrichia leucophrys*), and red-tailed hawk (*Buteo jamaicensis*). Reptile species included common side-blotched lizard (*Uta stansburiana*) and coastal whiptail (*Aspidoscelis tigris*). Mammal species included San Joaquin antelope squirrel (*Ammospermophilus nelsoni*), black-tailed jackrabbit (*Lepus californicus*), and coyote (*Canis latrans*). A complete list of wildlife observed is included in Appendix D.

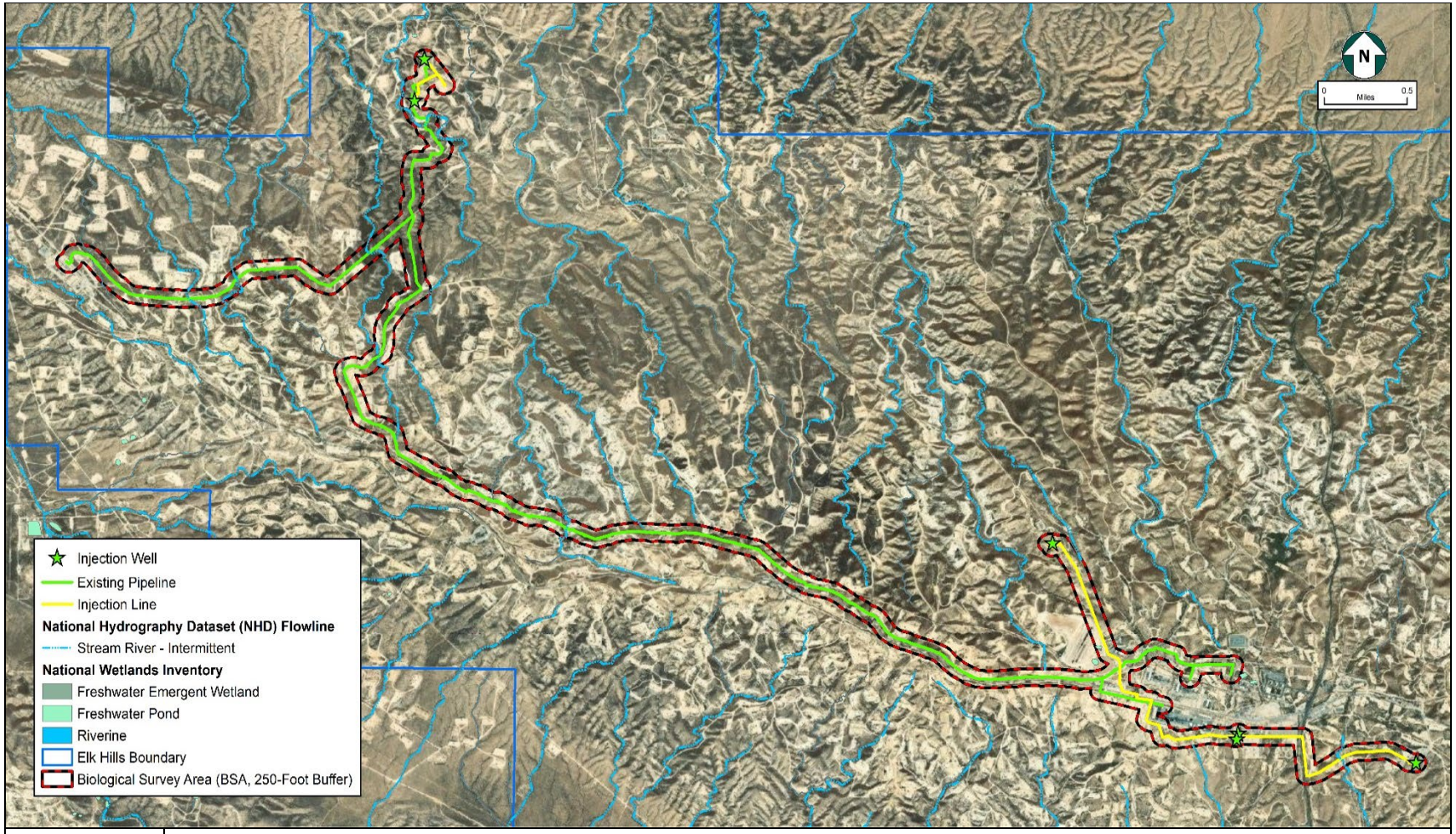

Figure 4-1
NWI and NHD Records of Aquatic Resources
Carbon TerraVault 1 Project, Kern County, California

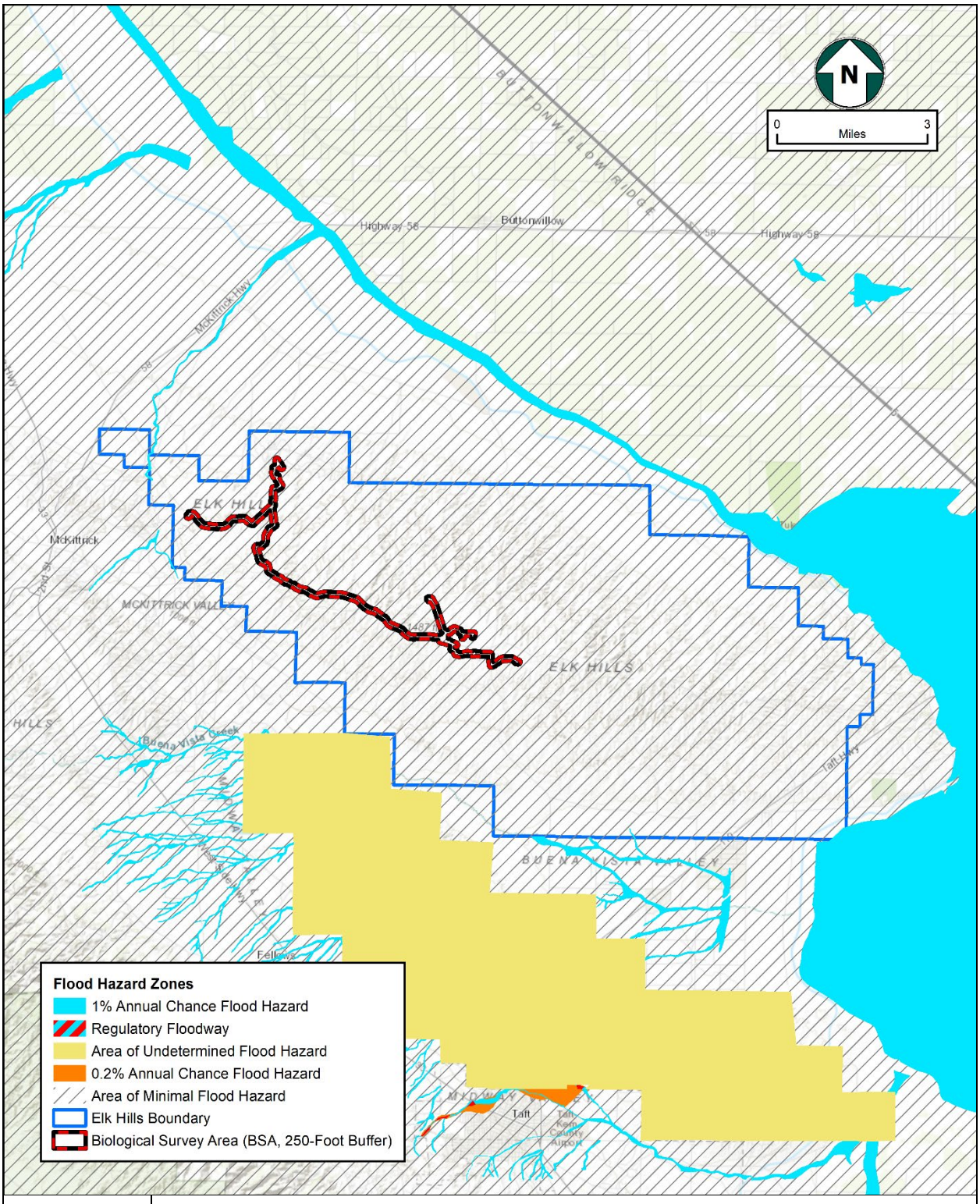

Figure 4-2
FEMA Flood Zone Map
Carbon TerraVault 1 Project, Kern County, California

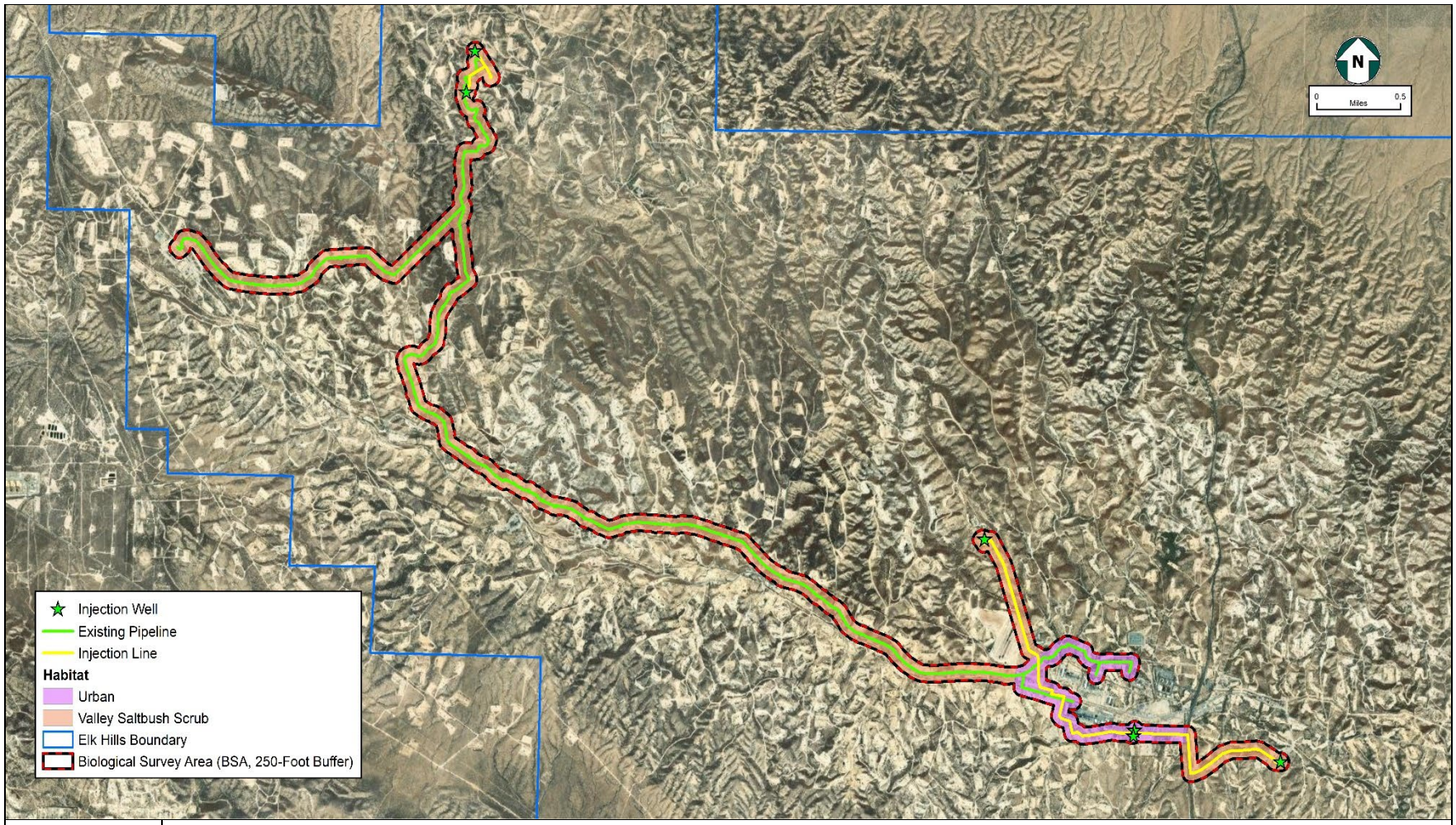

Figure 4-3
Vegetation Communities within the BSA
Carbon TerraVault 1 Project, Kern County, California

SECTION 5 - SENSITIVE BIOLOGICAL RESOURCES

Local, State, and federal agencies regulate special-status species and other sensitive biological resources and require an assessment of their presence or potential for presence to be on-site prior to the approval of proposed development on a property. This section discusses sensitive biological resources observed within the BSA and evaluates the potential for the BSA to support other sensitive biological resources. Assessments for the potential occurrence of special-status species are based upon known ranges, species habitat preferences, species occurrence records from the CNDDB, CNPS, IPaC, eBird, VertNet, and species occurrence records from other studies in the survey area, and the results of the surveys of the BSA.

5.1 - Special-Status Species

There were 27 special-status plant and animal species determined to have potential to occur on-site and potentially be affected by the Project (Table 5-1). The complete list of species evaluated for this Project is included in Appendix A. Each species with potential to occur on the site is further discussed in the subsections below.

Table 5-1
Special-Status Species with Potential to Occur On-Site

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Potentially Affected by Project? Yes/No	Viability Threat? Yes/No
Plants			
Atriplex cordulata var. *cordulata* Heartscale	-/- 1B.2/-	Yes	No
Atriplex coronate var. *vallicola* Lost Hills crownscale	-/- 1B.2/-	Yes	No
Caulanthus californicus California jewelflower	FE/SE 1B.1/-	Yes	No
Delphinium recurvatum recurved larkspur	-/- 1B.2/-	Yes	No
Eremalche parryi ssp. *kernensis* Kern mallow	FE/- 1B.2/-	Yes	No
Eriogonum temblorense Temblor buckwheat	-/- 1B.2/-	Yes	No
Eschscholzia lemmonii ssp. *kernensis* Tejon poppy	-/- 1B.1/-	Yes	No
Madia radiata showy golden madia	-/- 1B.1/-	Yes	No
Monolopia congdonii San Joaquin woollythreads	FE/- 1B.2/-	Yes	No
Stylocline citroleum oil neststraw	-/- 1B.1/-	Yes	No
Invertebrates			
Bombus crotchii Crotch bumble bee	-/SCE -/-	Yes	No
Reptiles			

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Potentially Affected by Project? Yes/No	Viability Threat? Yes/No
Arizona elegans occidentalis California glossy snake	-/- -/SSC	Yes	No
Gambelia sila blunt-nosed leopard lizard	FE/SE -/SFP	Yes	No
Masticophis flagellum ruddocki San Joaquin coachwhip	-/- -/SSC	Yes	No
Phrynosoma blainvillii coast horned lizard	-/- -/SSC	Yes	No
Birds			
Athene cunicularia burrowing owl	-/- SSC	Yes	No
Buteo swainsoni Swainson's hawk	-/ST -/-	Yes	No
Falco mexicanus *prairie falcon*	-/- -/WL	Yes	No
Lanius ludovicianus loggerhead shrike	-/- -/SSC	Yes	No
Toxostoma lecontei Le Conte's thrasher	-/- -/SSC	Yes	No
Mammals			
Ammospermophilus nelsoni Nelson's (=San Joaquin) antelope squirrel	-/ST -/-	Yes	No
Dipodomys ingens giant kangaroo rat	FE/SE -/-	Yes	No
Dipodomys nitratoides brevinasus short-nosed kangaroo rat	-/- -/SSC	Yes	No
Onychomys torridus tularensis Tulare grasshopper mouse	-/- -/SSC	Yes	No
Perognathus inornatus San Joaquin pocket mouse	-/- -/-	Yes	No
Taxidea taxus American badger	-/- -/SSC	Yes	No
Vulpes macrotis mutica San Joaquin kit fox	FE/ST -/-	Yes	No

CRPR (California Rare Plant Rank):
- 1A Presumed Extinct in California
- 1B Rare, Threatened, or Endangered in California and elsewhere
- 2A Plants presumed extirpated in California, but more common elsewhere
- 2B Plants Rare, Threatened, or Endangered in California, but more common elsewhere

CRPR Threat Code Extension:
- .1 Seriously endangered in California (over 80% of occurrences threatened / high degree and immediacy of threat)
- .2 Fairly endangered in California (20-80% occurrences threatened)
- .3 Not very endangered in California (<20% of occurrences threatened)

Federal Ranking
- FE Federally Endangered
- FT Federally Threatened

State Ranking
- SE State Endangered
- ST State Threatened
- SCE State Candidate Endangered
- SFP State Fully Protected
- SSC State Species of Special Concern

5.1.1 - SPECIAL-STATUS PLANT SPECIES

The literature and database review identified 23 special-status plant species known or with potential to occur in the vicinity of the Project (see the evaluation table in Appendix A). Ten of these species were determined to have potential to occur on the Project site (see Table 5-1) because the Project supports suitable habitat, is located within the species' known range, and/or the species is documented in or near the Project. One species, *Hoover's eriastrum*, was excluded from consideration as it has since been delisted. A description of the species that may occur on the Project site are described below.

Heartscale

ATRIPLEX CORDULATA VAR. CORDULATA

Status: CRPR 1B.2

Heartscale is an annual herb endemic to California that blooms from April to October. It is found in saline and alkaline soils, chenopod scrub, meadows and seeps, and sandy soils in valley foothill grassland habitats. It occurs at elevations ranging from sea level to approximately 1,835 feet and is known to occur in Alameda, Butte, Contra Costa, Colusa, Fresno, Glenn, Kern, Madera, Merced, San Joaquin, Solano, Stanislaus, Tulare, and Yolo counties. This species is threatened by competition from non-native plants and possibly threated by trampling

The Project is within known range of the species and suitable habitat, saltbush scrub and annual grassland, is present throughout the BSA. There are five CNDDB occurrences within ten miles of the BSA, though none are from within the last decade. The most recent occurrence (EONDX 54759) is from 2003 and located approximately six miles southeast of the BSA where the species was observed in habitat along State Route 119.

Lost Hills Crownscale

ATRIPLEX CORONATE VAR. VALLICOLA

Status: CRPR 1B.2

Lost Hills crownscale is an annual herb endemic to California that blooms between April and September. It is found in dry beds of alkaline pools in chenopod scrub, valley and foothill grassland, and vernal pools. It is also found on exposed slopes rich in gypsum. It occurs at elevations ranging from 165 to 2,085 feet. It has been documented on the valley floors and lower foothills of the western Central Valley in Fresno, Kings, Kern, Merced, San Benito, San Luis Obispo, and Tulare counties. This species is threatened by grazing, vehicles, and development.

The Project is within known range of the species and suitable habitat, saltbush scrub and annual grassland, is present throughout the BSA. There are multiple CNDDB records within ten miles of the BSA, the nearest (EONDX 58368) is from 2000 and located approximately

1.30 miles southeast of the BSA, where the species was observed in saltbush scrub habitat within the Elk Hills Oil Field.

California Jewelflower

CAULANTHUS CALIFORNICUS

Status: Federally Endangered, State Endangered, CRPR 1B.1

California jewelflower is an annual herb that blooms between February and May. It is found in slightly alkaline sandy soils in chenopod scrub, valley and foothill grassland, and pinyon and juniper woodland, typically at elevations from approximately 200 to 3,280 feet. It occurs in the San Joaquin Valley, Carrizo Plain, and Cuyama Valley from Fresno County south to Santa Barbara County and many occurrences are presumed extirpated. This species is threatened by development, grazing, and competition from non-native plants.

The Project is within known range of the species and suitable habitat, saltbush scrub and annual grassland, is present throughout the BSA. There are two CNDDB occurrences (EONDX 20294 and 23135) within ten miles of the BSA, although both are presumed extirpated, and neither are from within the last decade. The occurrences are approximately 8.60 miles northwest and 4.75 miles southeast of the BSA, respectively. As the BSA contains similar habitat to the nearby records (prior to their extirpation) there is potential for the species to occur.

Recurved Larkspur

DELPHINIUM RECURVATUM

Status: CRPR 1B.2

Recurved larkspur is a perennial herb that blooms between March and June. It occurs in alkaline conditions in chenopod scrub, cismontane woodland, and valley and foothill grassland. It occurs at elevations ranging from approximately 10 to 2,590 feet. This species is endemic to California. It occurs throughout the Central Valley and Coast Ranges from Butte County south. Few occurrences are in the Antelope Valley. This species is threatened by agriculture and competition from non-native plants.

The Project is within the known range of the species and suitable habitat, saltbush scrub and annual grassland, is present throughout sections of the BSA. There are multiple CNDDB occurrences within ten miles of the BSA, one of which (EONDX 83186) overlaps the northern terminus of the BSA. This occurrence is from 1995 when the species was observed within the Elk Hills Oil Field.

Kern Mallow

ASTRAGALUS HORNII VAR. HORNII

Status: CRPR 1B.1

Ken mallow is an annual herb that starts to bloom in January, sometimes February or March, until May. It is found on dry, open sandy to clay soils, often at the edges of balds in chenopod scrub, pinyon and juniper woodland, and valley and foothill grassland. It occurs at elevations

ranging from approximately 230 to 4,230 feet. It has been documented in the southern San Joaquin Valley, including Buena Vista Valley, Elk Hills, Lost Hills, McKittrick Hills, Stockdale Highway, and the Temblor Range, and Carrizo Plain. This species is threatened by agriculture and development, and possibly non-native plants.

The Project is within the known range of the species and suitable habitat, saltbush scrub and annual grassland, is present throughout the BSA. There are multiple CNDDB occurrences from the last decade within ten miles of the BSA. The most recent occurrence (EONDX 120309) is from 2020 where the species was observed within the Elk Hills Oil Field approximately 2.78 miles northeast of the southern terminus of the BSA.

Temblor Buckwheat

ERIOGONUM TEMBLORENSE

Status: CRPR 1B.2

Temblor buckwheat is an annual herb that typically blooms from May to September, but sometimes as early as April. It occurs in clay and sandstone substrate in valley and foothill grassland habitats. It occurs at elevations from approximately 98 to 3,280 feet and is only known in the Temblor Range from Fresno to Kern and San Luis Obispo counties. This species is threatened by energy development.

The Project near the known range of the species and suitable habitat, annual grassland, is present in limited areas within the BSA. There are two CNDDB occurrences within ten miles of the BSA, the nearest of which (EONDX 104358) is from 2011 and located approximately 0.85 mile north of the northern terminus of the BSA. Due to the proximity of the BSA to the known range of the species and the recent CNDDB occurrence within one mile of the BSA, this species was considered to have potential to occur.

Tejon Poppy

ESCHSCHOLZIA LEMMONII SSP. KERNENSIS

Status: CRPR 1B.1

Tejon poppy is an annual herb that blooms in March, sometimes as early as February, to May. It is found in open valley and foothill grasslands and chenopod scrub at elevations from approximately 450 to 4,500 feet. It is distinguished from the more common California poppy (*E. californica*) by its calyx. This species is possibly threatened by grazing and non-native plants.

The Project is within the known range for the species and suitable habitat, saltbush scrub and annual grassland, is present throughout the BSA. There are multiple CNDDB occurrences within ten miles of the BSA, several of which are from within the last decade and one of which

overlaps the BSA. The overlapping CNDDB occurrence (EONDX 21454) is from 1998 and located approximately midway along the proposed Project route.

Showy Golden Madia

MADIA RADIATA

Status: CRPR 1B.1

Showy golden madia is an annual herb endemic to California that blooms between March and May. It is found in cismontane woodland and valley and foothill grassland habitats with grassy or open slopes, usually on adobe or gypseous clay soils, at elevations from approximately 80 to 3,985 feet. Known occurrences are scattered throughout the mountains and foothills along the west side of the Central Valley from Contra Costa County south to Santa Barbara County. This species is threatened by grazing and non-native plants.

The Project is within the known range of the species and suitable habitat, annual grassland, is present in limited areas within the BSA. There are two CNDDB occurrences (EONDX 2732 and 7469) within ten miles of the BSA, both are from 1992 and located approximately 5.32-miles north of the BSA, where the species was observed adjacent to the California aqueduct within disturbed saltbush scrub habitat.

San Joaquin Woollythreads

MONOLOPIA CONGDONII

Status: Federally Endangered, CRPR 1B.2

San Joaquin woollythreads is an annual herb endemic to California that blooms from February to May. It is found in chenopod scrub and on sandy soils in valley and foothill grassland. It occurs at elevations from approximately 196 to 2,624 feet. Approximately half of the historical occurrences are expected to be extirpated and the known populations occur in Carrizo Plain Natural Area, Lost Hills, Kettleman Hills, Jacalitos hills, Panoche Hills, and Cuyama Valley. This species is seriously threatened by agricultural conversion, energy development, urbanization, grazing, trampling, and vehicles.

The Project is within the known range for the species and suitable habitat, saltbush scrub and annual grassland, is present throughout the BSA. There are four CNDDB occurrences within ten miles of the BSA, the nearest of which (EONDX 115497) is from 1988 and located 3.42-miles southwest of the BSA, where the species was observed within an oil field in saltbush scrub habitat.

Oil Neststraw

STYLOCLINE CITROLEUM

Status: CRPR 1B.1

Oil nestraw is an annual herb endemic to California that blooms from March to April. It is found on clay substrates in chenopod and coastal scrub, and valley and foothill grasslands. It occurs at elevations from approximately 164 to 1,312 feet and is possibly threatened by energy development and urbanization.

The Project is within the known range for the species and suitable habitat, saltbush scrub and annual grassland, is present throughout the BSA. There are multiple CNDDB occurrences within ten miles of the BSA, two of which (EONDX 58077 and 58095) overlap the BSA. Both overlapping CNDDB records are from 2001 when the species was observed within saltbush scrub habitat.

5.1.2 - Special-Status Animal Species

The literature and database review identified 40 special-status animal species known or with potential to occur in the vicinity of the Project (see the evaluation table in Appendix A). Seventeen of these species were determined to have potential to occur on-site (see Table 5-1) because the BSA supports suitable habitat, is located within the species' known range, and/or the species is documented in or near the BSA.

Crotch Bumblebee

Bombus crotchii

Status: State Candidate Endangered

The Crotch bumblebee occurs in relatively warm and dry environments, including the inner Coast Range of California and the margins of the Mojave Desert. It inhabits grassland and scrub habitats, where it nests in abandoned rodent burrows, occasionally nesting above ground in tufts of grass, rock piles, or cavities in dead trees. This species is classified as a short-tongued species, whose food plants include *Asclepias*, *Chaenactis*, *Lupinus*, *Medicago*, *Phacelia*, and *Salvia*. The species is threatened by habitat loss and degradation, including agricultural intensification and rapid urbanization.

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species and suitable habitat, abandoned rodent burrows within scrub habitat, is present. There are three CNDDB occurrences within ten miles of the BSA, the nearest of which (EONDX 98854) overlaps the southern end of the BSA, although it is from 1957 and mapped generally. A Calflora query for occurrences of suitable host plants, within the genera *Asclepias*, *Chaenactis*, *Lupinus*, *Medicago*, *Phacelia*, or *Salvia*, resulted in six documented occurrences within the vicinity of the BSA, none of which were observed within the last 40 years.

California Glossy Snake

Arizona elegans occidentalis

Status: Species of Special Concern

This subspecies of glossy snake occurs from the eastern part of the San Francisco Bay south to northwestern Baja, California. It appears to prefer microhabitats of open areas with soil loose enough for easy burrowing. It inhabits arid scrub, rocky washes, grasslands, and chaparral. This species is nocturnal and hides under rocks, in existing burrows, or creates its own burrow during daylight hours. It is usually active from late February until November.

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species and suitable habitat is present. There are seven CNDDB occurrences of this species within ten miles of the BSA. The nearest occurrence (EONDX 104923) is from 2015 and is located approximately 2.46-miles west of the BSA, where the species was observed within habitat adjacent to State Route 58.

Blunt-nosed Leopard Lizard

GAMBELIA SILA

Status: Federally Endangered, State Endangered, Fully Protected

The blunt-nosed leopard lizard is a large lizard that occurs in semiarid habitats within the southern Central Valley, Cuyama Valley, and Panoche Valley, at elevations between 100 and 2,400 feet. Preferred habitats are typically flat, sparsely vegetated grasslands with large open areas with scattered shrubs for cover, and sandy washes. The species spends most of the year underground in abandoned small mammal burrows, with adults surfacing in the spring and early summer to breed and feed. Young hatch in July and August, and both adults and young recede to refugia between August and November. Individuals feed primarily on grasshoppers and smaller lizards. The species is threatened mainly by habitat loss and fragmentation.

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within ten miles of the BSA, although non overlap the BSA. The nearest CNDDB occurrence (EONDX 119287) is from 2017 and is located approximately 0.65-mile northwest of the BSA where the species was observed in saltbush scrub habitat.

San Joaquin Coachwhip

MASTICOPHIS FLAGELLUM RUDDOCKI

Status: Species of Special Concern

San Joaquin coachwhip is a non-poisonous, slender, fast-moving snake with smooth scales and coloring ranging from a tan to pinkish brown (Brattstrom and Warren 2000-2018). This species is endemic to California, ranging from Colusa County in the Sacramento Valley southward to the Grapevine in the Kern County portion of the San Joaquin valley and westward into the inner South Coast Ranges (Brattstrom and Warren 2000-2018). The San Joaquin coachwhip occurs in open, dry, treeless areas with little or no cover, including valley grassland and saltbush scrub, desert scrub, chaparral, pasture, and open pine and oak woodlands, and avoids areas of dense vegetation where their mobility can be hindered. San Joaquin coachwhips are found below 7,700 feet in elevation (Zeiner et al 1988).

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species and suitable habitat is present. There are seven CNDDB occurrences within ten miles of the BSA. The nearest CNDDB occurrence (EONDX 113180) to the BSA is from 2017 and is located approximately 0.93-mile to the west where the species was observed at an oil field sump site.

Coast Horned Lizard

PHRYNOSOMA BLAINVILLII

Status: Species of Special Concern

This cryptic lizard prefers sandy, loose soils in grasslands, forests, woodlands, and open chaparral. Individuals are often found along sandy washes and dirt roads with scattered shrubs for cover. This species feeds almost exclusively on ants. It is found in coastal California from Baja California north to the Bay Area, southeastern desert regions, southern Central Valley flats and foothills and the surrounding mountains on drier, warmer slopes, at elevations up to 8,000 feet. The species is threatened by habitat loss and fragmentation and the spread of invasive ant species displacing native prey.

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species and suitable habitat is present. This species was observed within 5 miles of the Project site during a survey within Elk Hills by QK in 2022. However, there are no CNDDB records within ten miles of the BSA.

Burrowing Owl

ATHENE CUNICULARIA

Status: Species of Special Concern

The western burrowing owl is a broadly distributed, small ground-dwelling owl that can be found throughout western North American, Florida, Central and South America, Hispaniola, Cub, and northern Lesser Antilles, and the Bahamas (Shuford and Gardali 2008). Typically, this species can be found in a variety of habitat types including grasslands, deserts, or other open habitats where food resources are available and contain treeless areas with low vegetation cover and gently sloping terrain (Rodewald 2015).

Burrowing owls utilize earthen burrows, typically relying on other fossorial mammals to construct their burrows, such as prairie dog (*Cynomys* ssp.) or American badger (USFWS 1998a). In Florida, burrowing owls are capable of digging their own burrows (Poulin 2011). In California, they are associated with California ground squirrels (Winchell 1994). They use a burrow throughout the year for temperature regulation, offspring rearing, shelter, and escape from predators. While burrows are most often earthen, they have been documented using atypical burrows such as pipes, culverts, and other man-made structures as burrows, most often as shelter (Shuford and Gardali 2008). Burrowing owls can have several burrows close to one other that they may use frequently to avoid predators.

The Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within ten miles of the BSA, the nearest (EONDX 45077) is from 2000 and located approximately 2.10-miles southeast of the southern terminus of the BSA, where an adult was observed at a burrow site within the Elk Hills Oil Field. While no burrowing owl individuals were observed during reconnaissance surveys, two burrows displaying diagnostic sign (white-wash, pellets, feathers) were observed at the northern end of the BSA.

Swainson's Hawk

BUTEO SWAINSONI

Status: State Threatened

Swainson's hawks occur in grassland, desert, and agricultural landscapes throughout the Central Valley and Antelope Valley (Bechard et al. 2010, Zeiner et al. 1988). Some hawks may be resident, especially in the southern portion of their range, while others may migrate between winter and breeding habitats. They prefer larger isolated trees or small woodlots for nesting, usually with grassland or dry-land grain fields nearby for foraging and have been known to nest in large eucalyptus trees (*Eucalyptus* sp.) along heavily traveled freeway corridors. Swainson's hawks forage in grassland, open scrub, pasture, and dryland grain agricultural habitats, primarily for rodents. Swainson's hawks exhibit a moderate to high nest site fidelity for successful nest sites.

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species. No suitable nesting sites were observed within the BSA during site surveys, but inactive stick nests capable of supporting the species were observed nearby, and areas of open saltbush scrub within the BSA could provide foraging opportunities for the species. There are six CNDDB occurrences within ten miles of the BSA, the nearest (EONDX 91375) is from 2017 and is located approximately 4.37-miles north of the BSA where a nest was observed in a large tamarisk tree.

Prairie Falcon

FALCO MEXICANUS

Status: State Watch List

The prairie falcon is a widely distributed species that occurs all over the world. It breeds in open landscapes with cliffs or skyscrapers for nest sites. It nests at elevations up to 12,000 feet, as well as along rivers, coastlines, cities, transmission towers, silos, quarries, and bridges. This falcon primarily preys on other bird species and occasionally pirate prey from other raptors.

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species, and while no suitable nesting sites were observed within the BSA, suitable foraging habitat was observed. There is a single CNDDB occurrence (EONDX 18211), which is from 1989 and overlaps the BSA, although it is mapped generally as the exact location has been suppressed from the record.

Loggerhead Shrike

LANIUS LUDOVICIANUS

Status: Species of Special Concern

The loggerhead shrike is a common resident in lowlands and foothills throughout California. It prefers open grassland and pasture habitats with scattered trees, fence posts, utility lines, shrubs, and other perches. This species primarily consumes large insects but will prey upon

other small animals. It nests in densely foliaged and/or thorny shrubs and trees less than 50 feet above the ground.

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species and both suitable nesting and foraging habitat is present. There is a single CNDDB occurrence (EONDX 66869) within ten miles of the BSA, which is from 1999 when six adults and two juveniles were observed within saltbush scrub habitat. The CNDDB occurrence is located approximately 2.32 miles southwest of the northern terminus of the BSA.

Le Conte's Thrasher

TOXOSTOMA LECONTEI

Status: Species of Special Concern

Le Conte's thrasher is an uncommon-to-rare local resident in southern California deserts. It occurs in open desert wash, desert scrub, alkali desert scrub, desert succulent scrub, and Joshua tree habitat with scattered shrubs. It occurs from Mono County south to the Mexican border and in western and southern San Joaquin Valley. It has rarely been recorded north of Kern County after the 1950s. It feeds on insects and occasionally on seeds, small lizards, and other small vertebrates. This species is threatened by loss of habitat due to oil and gas production, overgrazing, and pesticides (DDT).

Although the species was not observed during reconnaissance surveys, the Project is located within the known range of the species and both suitable nesting and foraging habitat is present. There are multiple CNDDB occurrences within ten miles of the BSA, the nearest (EONDX 41609) is from 1999 and is located approximately 1.50-miles west of the northern terminus of the BSA where two adults were observed in saltbush scrub habitat within oil and gas development.

Nesting Birds

Habitat within the BSA supports nesting native bird species, which are protected by the federal MBTA and the CFGC. The reconnaissance surveys were conducted outside of the nesting bird season (February 1 to September 15); however, numerous bird species were observed during the surveys indicating there is a high potential for migratory birds and raptors to nest in the vicinity of the Project. Various species of birds will construct nests in a variety of substrates and structures, and nests may be found in trees or shrubs, in manmade structures, and directly on the ground. The Project supports several types of habitats, substrates, and structures suitable for nesting birds, and birds will likely nest on the Project during the breeding season.

While no nesting birds were observed during site reconnaissance surveys and no active nests were observed within the BSA; there were inactive snick nests noted in close proximity to the BSA in structures such as utility poles and the heads of abandoned pumpjacks (Figure 5-1).

San Joaquin Antelope Squirrel

AMMOSPERMOPHILUS NELSONI

Status: State Threatened

San Joaquin antelope squirrels occurs in saltbush scrub and grassland habitats and prefers washes and open shrub areas with sandy soils. Known populations occur in Lokern Natural Area, Elk Hills Carrizo and Elkhorn Plains, Temblor Range and foothills and interior valleys of the Diablo Range and as far north as Merced and San Benito counties. It feeds primarily on insects, green vegetation, seeds, and occasionally on small vertebrates. This species can excavate burrows or use kangaroo rat burrows for temperature regulation, litter-rearing, shelter, and escape from predators. The species is threatened by habitat loss and population fragmentation from agricultural development, urbanization, petroleum extraction, and excessive cattle grazing.

The Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within ten miles of the BSA, two of which overlap the BSA. The most recent overlapping CNDDB occurrence (EONDX 114570) is from 2018 when both adults and juveniles were observed in saltbush scrub habitat. Multiple individuals were observed during the reconnaissance surveys throughout the BSA, apart from the highly urbanized area in the southern section (Figure 5-2).

Giant Kangaroo Rat

DIPODOMYS INGENS

Status: Federally Endangered, State Endangered

Giant kangaroo rats occur in native annual grassland and shrubland habitats with vegetated annual grass and forbs and scattered desert shrubs. It is known only to six major geographic units: Panoche Region, Kettleman Hills, San Juan Creek Valley, western Kern County (Lokern, Elk Hills, McKittrick, Taft, and Maricopa), Carrizo Plain Natural Area, and Cuyama Valley and occurs at elevations between 280 to 2,800 feet. It excavates burrows on level or gentle slopes with friable, sandy, well-drained soils and is a nocturnal foraging species. It is threatened by habitat loss, fragmentation, and degradation, and drought and also by land conversions to agricultural, industrial, and urban developments.

Focused trapping surveys for this species were not conducted as part of this analysis; however, the Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within close proximity of the BSA, one of which overlaps the BSA. The overlapping CNDDB occurrence (EONDX 65314) is from 1987 in saltbush scrub habitat. This species was not observed during the reconnaissance surveys

Short-nosed Kangaroo Rat

DIPODOMYS NITRATOIDES BREVINASUS

Status: Species of Special Concern

The short-nosed kangaroo rat is a subspecies of the San Joaquin kangaroo rat (*Dipodomys nitratoides*) that occurs on friable soils on flat or gentle slops within grassland or desert

scrub habitat. The current range is unknown but there are fragmented populations in Pleasant Valley, Kettleman and Lost Hills, Lokern, Elk Hills, San Emigdio, Wheler Ridge, Carrizo Plain Natural Area, and Caliente Mountains. It excavates burrows on higher ground and is a nocturnal foraging species. The species is threatened by random catastrophic events (i.e., drought, flooding, fire), overgrazing of rangeland, and extensive land conversion to agriculture from the 1960s through 1970s.

Focused trapping surveys for this species were not conducted as part of this analysis; however, the Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within close proximity of the BSA, one of which overlaps the BSA. The overlapping CNDDB occurrence (EONDX 33137) is from 1990 in saltbush scrub habitat. This species was not observed during the reconnaissance surveys, however, suitable burrows with diagnostic sign of kangaroo rat were observed.

Tulare Grasshopper Mouse

ONYCHOMYS TORRIDUS TULARENSIS

Status: Species of Special Concern

The Tulare grasshopper mouse occurs in shrubland communities in hot, arid grassland and shrubland associations. These include blue oak woodlands, upper Sonoran subshrub scrub, alkali sink and mesquite associations on the Valley Floor, and grasslands associations on the sloping margins of the San Joaquin Valley and Carrizo Plain region. This subspecies occupies burrows and feeds primarily on invertebrates but may supplement its diet with seeds and other small mammals.

Focused trapping surveys for this species were not conducted as part of this BAR; however, the Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within ten miles of the BSA. The nearest CNDDB occurrence (EONDX 23826) is from 1957 and located approximately 0.75 mile north of the BSA. This species was not observed during the reconnaissance surveys, however potentially suitable burrows were observed within the BSA.

San Joaquin Pocket Mouse

PEROGNATHUS INORNATUS

Status: None

The San Joaquin pocket mouse is a nocturnal species found in dry, open grasslands and scrublands on fine-textured soils in the Central (mostly west side) and Salinas valleys at elevations from 1,100 to 2,000 feet. It digs its own burrows for cover, breeding, and seed caching.

Focused trapping surveys for this species were not conducted as part of this analysis; however, the Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within ten miles of the BSA, one of which overlaps the BSA. The overlapping CNDDB occurrence (EONDX 65635) is from 1991 when there were 172 captures resulting from four trapping periods throughout the year. This

species was not observed during the reconnaissance surveys, however potentially suitable burrows were observed within the BSA.

American Badger

TAXIDEA TAXUS

Status: Species of Special Concern

The American badger is an uncommon permanent resident at lower elevations throughout California except for the northern North Coast (CDFG 1995). They can typically be found in grasslands, deserts, and drier habitats. Badgers are typically nocturnal and hunt or forage at night while spending daylight hours below ground. Normally, they have a single den entrance that is approximately 8 to 12 inches in width, in an elliptical or half-moon shape, similar to their body shape. Dens are usually found in friable soils, which are easier to dig in. American badgers spend most of their time near a den; however, they many have multiple dens in an area that can be used at the same time. American badgers are known to be able to dig a new den each night. During cooler nights the entrance to the den may be partially plugged with soil to help regulate temperatures.

The Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within ten miles of the BSA, the nearest (EONDX 49676) is from 1999 and located approximately one-mile northwest of the BSA. The species was not observed during reconnaissance surveys, although dens displaying sign consistent with use by badger and characteristic badger exploratory digs were observed, indicating they may be present within the BSA.

San Joaquin Kit Fox

VULPES MACROTIS MUTICA

Status: Federally Endangered, State Threatened

The San Joaquin kit fox (SJKF) is a subspecies of kit fox that is endemic to the Central Valley of California (USFWS 1998a, 2011). Individuals of this subspecies are found primarily in the San Joaquin Valley, Carrizo Plain, and Cuyama Valley, as well as other small valleys in the western foothills of the Central valley. They are only found west of the Sierra Nevada crest. They occupy arid to semi-arid grasslands, open shrublands, savannahs, and grazed lands with loose-textured soils. SJKF are well-stablished in some urban areas and are highly adaptable to human-altered landscapes, and while they may occasionally forage in agricultural habitats, they generally avoid intensively maintained agricultural land due to repeated ground disturbance. SJKF use subterranean dens year-round for shelter and pup-rearing. They are nocturnally active but may be visible above ground near their dens during the day, particularly in the spring. They feed primarily on small mammals, but will consume a variety of prey, and will scavenge for human food.

The Project is located within the known range of the species and suitable habitat is present. There are multiple CNDDB occurrences within close proximity of the BSA, four of which overlap the BSA. The most recent overlapping CNDDB occurrence (EONDX 46017) is from 2001 when one individual was observed. San Joaquin kit fox was not observed during

reconnaissance surveys; however, several dens displaying diagnostic sign including scat and tracks were observed during the surveys (Figure 5-2).

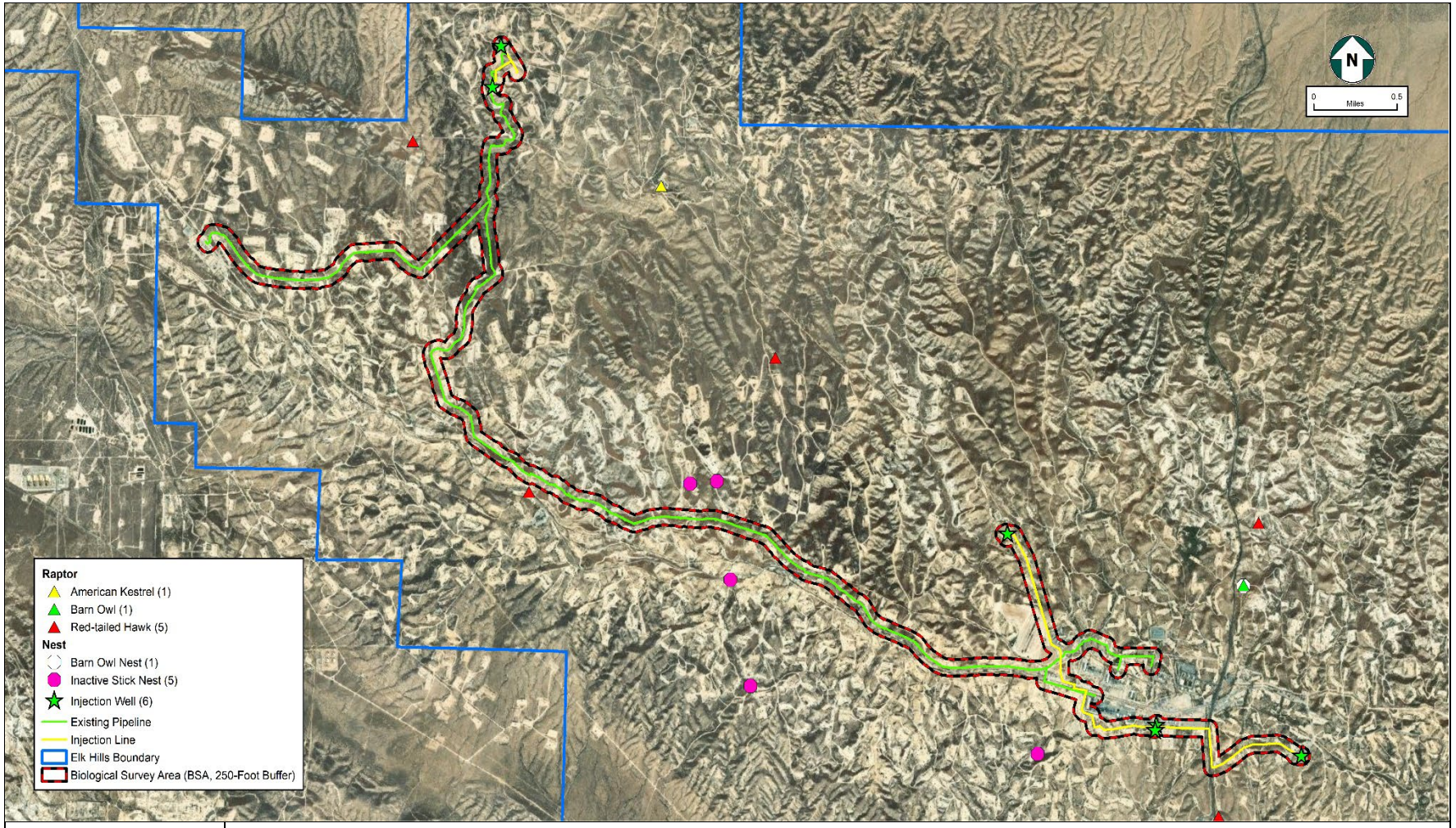

Figure 5-1
Raptors and Nests Observed within the BSA
Carbon TerraVault 1 Project, Kern County, California

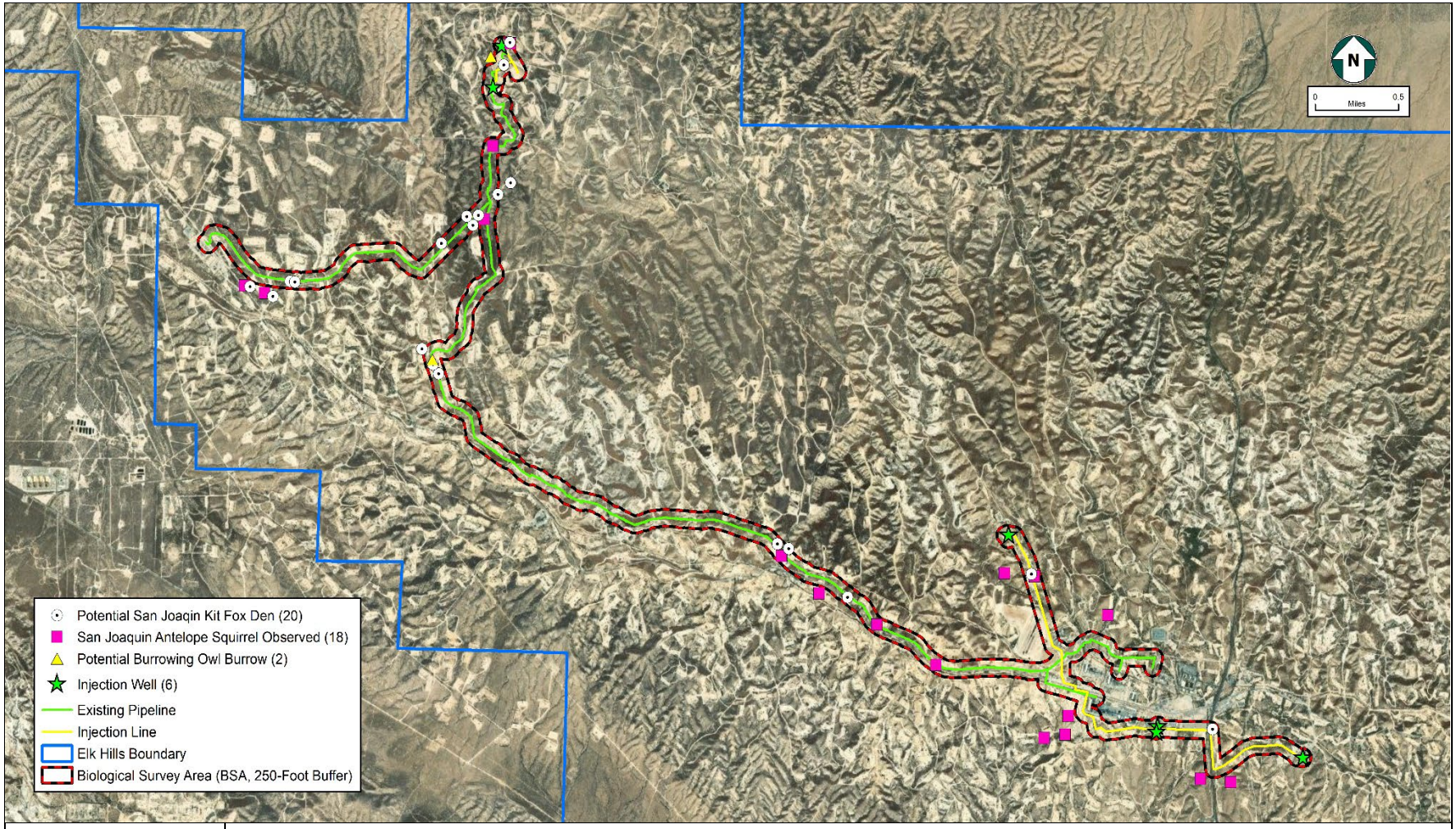

Figure 5-2
Special-Status Resources Observed within the BSA
Carbon TerraVault 1 Project, Kern County, California

5.2 - Sensitive Natural Communities

5.2.1 - SENSITIVE PLANT COMMUNITIES

The database and literature review identified three sensitive plant communities that are known to occur or with the potential to occur within the vicinity of the Project: Valley Saltbush Scrub, Great Valley Mesquite Scrub, and Valley Sink Scrub. One of these plant communities, Valley Saltbush Scrub, was observed on-site during the reconnaissance surveys.

There were no mesquite (*Prosopis glandulosa torreyana*) trees/shrubs, and thus Great Valley Mesquite Scrub, observed within the BSA during reconnaissance surveys. Similarly, alkali tolerant plant species characteristic of Valley Sink Scrub were not observed within the BSA. Valley Saltbush Scrub was observed throughout the BSA, predominantly as highly isolated fragments amongst the previously disturbed pipeline route within the oil and gas development.

5.2.2 - CRITICAL HABITATS

The Project does not overlap with any federally designated critical habitat (Figure 5-3, USFWS 2023b). The nearest Critical Habitat is for the Buena Vista ornate shrew approximately 10 miles to the east.

5.3 - Jurisdictional Aquatic Resources

A query of the NHD and NWI databases indicated that seven riverine water features might intersect the Project area (Figure 4-2). Formal jurisdictional delineations of potential waters were not conducted for this BAR; however, water features observed during field reconnaissance surveys were all ephemeral drainages, many of which have been impacted by surrounding development.

5.4 - Wildlife Movement

Wildlife movement corridors, also referred to as dispersal corridors or landscape linkages, are generally defined as linear features along which animals can travel from one habitat or resource area to another. Wildlife movement corridors can be large tracts of land that connect regionally important habitats that support wildlife in general, such as stop-over habitat that supports migrating birds or large contiguous natural habitats that support animals with very large home ranges (e.g., coyotes [*Canis latrans*], mule deer [*Odocoileus hemionus californicus*]). They can also be small scale movement corridors, such as riparian zones, that provide connectivity and cover to support movement at a local scale.

The Project is situated within two identified connectivity corridors, the Essential Connectivity Area, and Core Area (Figure 5-4). Specifically, the Project falls within the 'Elk Hills – Carrizo Plain/Temblor Range' and 'Ten Section Oil Field – Elk Hills' Essential Connectivity areas.

5.5 - Resources Protected by Local Policies and Ordinances

The County of Kern General Plan contains policies aimed at the preservation of biological resources and promotes coordination with federal and State resource agencies. These policies are listed in Appendix A. The General Plan also outlines a work plan with implementation measures by which to uphold these policies, including a biological resource review for proposed projects and development of mitigation measures for these projects.

The Kern County Oil and Gas EIR outlines a mitigation measure and reporting program with applicable measures that would reduce potential environmental impacts to a less than significant level. These mitigation measures are outlined below in section 6.

5.6 - Habitat Conservation Plans

California Resources Corporation has a habitat conservation program, which is certified by the Wildlife Habitat Council, in place. It includes operating practices to protect unique plant and animal species and cultural resources at Elk Hills and western Kern County.

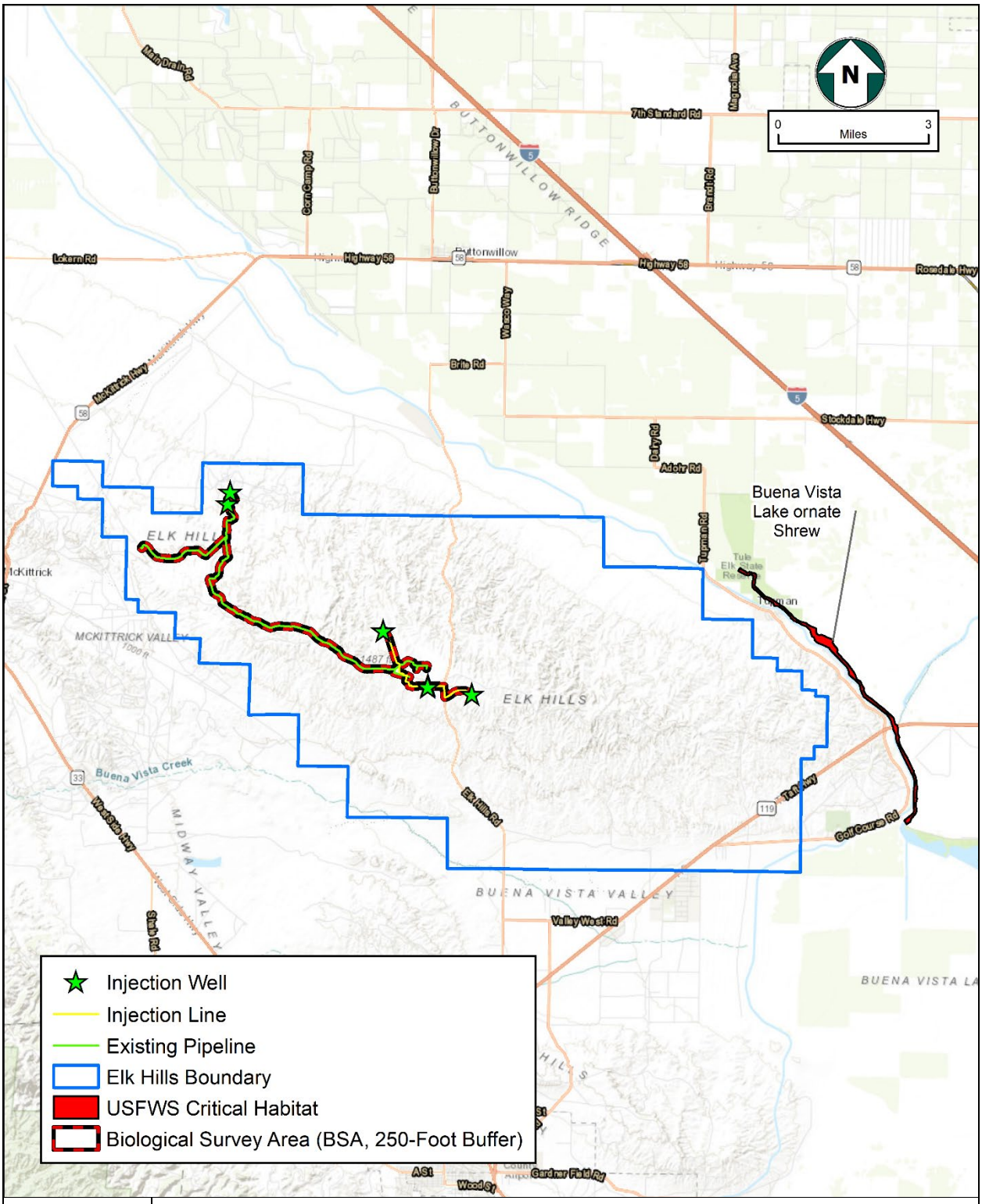

Figure 5-3
Critical Habitat in the Project Vicinity
Carbon TerraVault 1 Project, Kern County, California

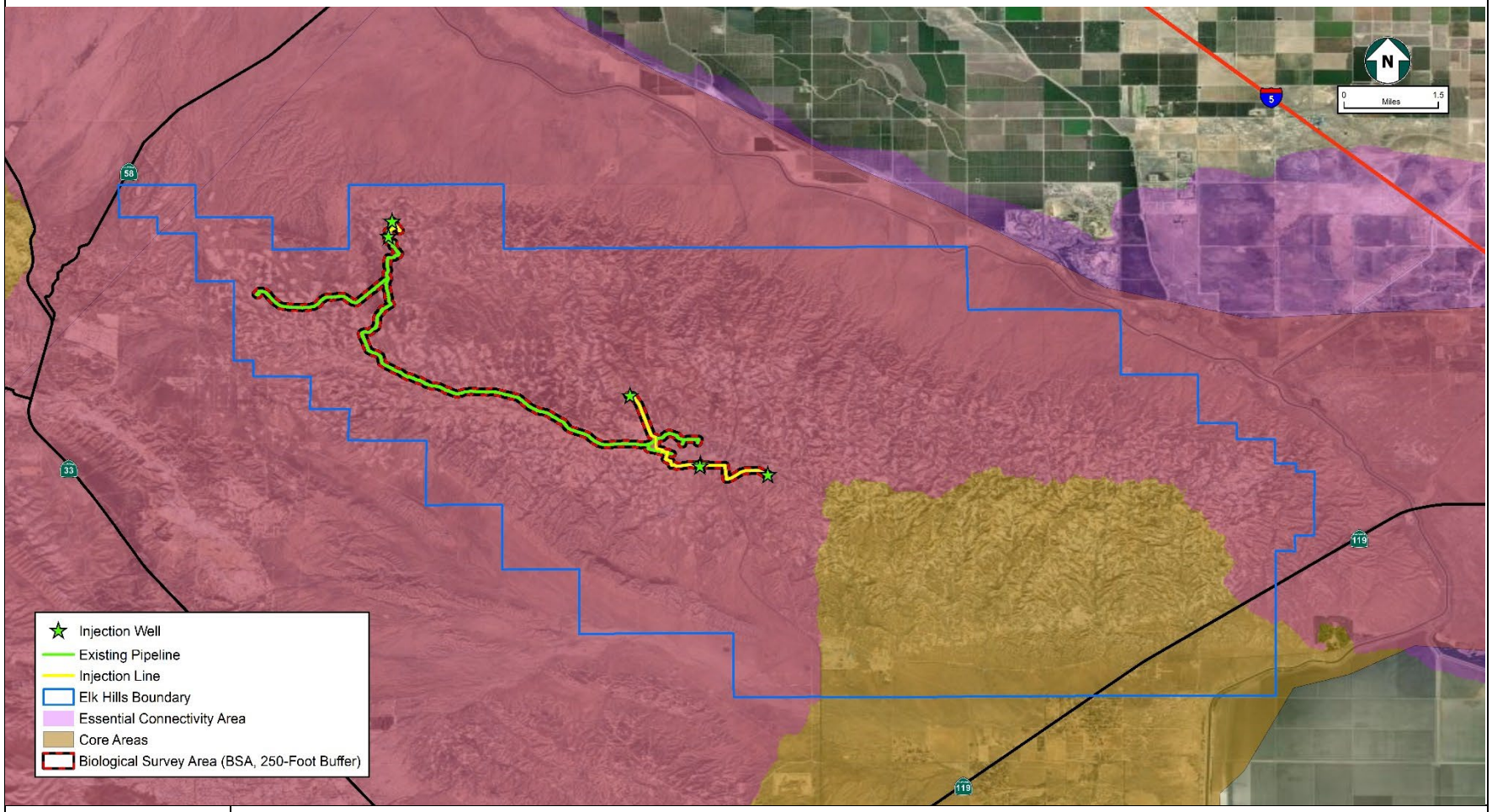

Figure 5-4
Movement Corridors and Linkages
Carbon TerraVault 1 Project, Kern County, California

SECTION 6 - IMPACT ANALYSIS AND RECOMMENDED MITIGATION MEASURES

This section provides an analysis of the potential for sensitive biological resources to be impacted by the Project. This section also provides avoidance and minimization measures to prevent and/or reduce Project impacts to sensitive biological resources. These measures were determined using the Kern County Oil and Gas EIR Mitigation Monitoring and Reporting Program. The impact analysis focuses on the construction phase of the Project.

6.1 - Special-Status Species

In accordance with Appendix G of the CEQA Guidelines, the proposed Project would have a significant effect on biological resources if it would:

a) *Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Wildlife or U.S. Fish and Wildlife Service.*

Avoidance and minimization measures are designed to reduce or eliminate impacts to special-status species through Project construction, operation, and decommissioning. Detailed specific measures are outlined below for each special-status species that may occur on the Project Site or within potential alternative routes.

6.1.1 - PROJECT IMPACTS TO SPECIAL-STATUS PLANT SPECIES

Special-Status Plant Species

Heartscale

Heartscale was not observed within the BSA during the surveys. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of Valley saltbush scrub habitat.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

There is no evidence this species is present in the BSA, and it is unlikely that the Project will result in direct or indirect impacts to this species. If present, implementation of Measures BIO-1 through BIO-4, listed below, would reduce impacts to this species to a less-than-significant level. It is assumed there would be no impacts to this species during the operational phase.

Lost Hills Crownscale

Lost Hills crownscale was not observed within the BSA during the surveys. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

There is no evidence this species is present in the BSA, and it is unlikely that the Project will result in direct or indirect impacts to this species. If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level. It is assumed there would be no impacts to this species during the operational phase.

California Jewelflower

Surveys were conducted outside of the optimal blooming period, February to May, of California jewelflower. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level.

Recurved Larkspur

Surveys were conducted outside of the optimal blooming period, March to June, of recurved larkspur. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level.

Kern Mallow

Surveys were conducted outside of the optimal blooming period, February to May, of Kern mallow. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level.

Temblor Buckwheat

Temblor buckwheat was not observed within the BSA during the surveys. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat intermixed with annual grassland within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

There is no evidence this species is present in the BSA, and it is unlikely that the Project will result in direct or indirect impacts to this species. If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level. It is assumed there would be no impacts to this species during the operational phase.

Tejon Poppy

Surveys were conducted outside of the optimal blooming period, February to May, of Tejon poppy. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat intermixed with annual grassland within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of

non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level.

Showy Golden Madia

Surveys were conducted outside of the optimal blooming period, March to May, of showy golden madia. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat intermixed with annual grassland within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level.

San Joaquin Woollythreads

Surveys were conducted outside of the optimal blooming period, February to May, of San Joaquin woollythreads. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level.

Oil Neststraw

Surveys were conducted outside of the optimal blooming period, March to April, of oil nestraw. However, the BSA is within the known range for the species and the species could potentially be present within the fragments of saltbush scrub habitat within the BSA.

Direct impacts from construction activities could include the destruction or injury of individual plants if present. During the growth and blooming period, the spread of dust during construction could cause an indirect impact on the species, as could the spread of

non-native or invasive species caused by Project activities. Competition with invasive plants would have an indirect impact on this species.

If present, implementation of Measures BIO-1 through BIO-3, listed below, would reduce impacts to this species to a less-than-significant level.

Avoidance and Minimization Measures

Implementation of the Avoidance and Minimization Measures listed below would reduce Project impacts to special-status plant species to a level that would be less-than-significant. The following measures are recommended to avoid and minimize impacts to the special-status species with the potential to occur within the Project area. These Avoidance and Minimization Measures were adapted from the 'Kern County Oil and Gas Mitigation and Reporting Program – August 23, 2022'.

BIO-1: Special-Status Plant Surveys. Plant surveys for Protected Species and Sensitive Species must be completed by a qualified biologist during the appropriate blooming periods for species identification and detection (see Table 6-1). Plant surveys shall be conducted in accordance with all applicable protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife for particular plant species ("Plant Survey Protocol") and shall extend 50 feet from areas where any new disturbance would occur unless a greater survey distance is specified in the species.

Table 6-1
Blooming Period of Special-status Plants with Potential to Occur

Special-Status Plant Species	Optimal Blooming Period
Atriplex cordulata var. *cordulata* heartscale	April – October
Atriplex coronata var. *vallicola* Lost Hills crownscale	April – September
Caulanthus californicus California jewelflower	February – May
Delphinium recurvatum recurved larkspur	March – June
Eremalche parryi ssp. *kernensis* Kern mallow	February/March – May
Eriogonum temblorense Temblor buckwheat	April/May - September
Eschscholzia lemmonii ssp. kernensis Tejon poppy	February/March - May
Madia radiata Showy golden madia	March - May
Monolopia congdonii San Joaquin woollythreads	February – May

Special-Status Plant Species	Optimal Blooming Period
Stylocline citroleum Oil neststraw	March – April

BIO-2 Avoidance of Listed Special-Status Plants. No incidental take or relocation of any plant listed under the federal Endangered Species Act, the California Endangered Species Act, or the California Native Plant Protection Act may occur unless the incidental take is authorized by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife in a permit or other authorization. If focused plant surveys detect the presence of any listed plant, the plant populations shall be buffered from disturbance activities by implementing applicable impact avoidance protocols established by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife unless incidental take authority is obtained. Projects covered under incidental take authority shall conduct activities in accordance with the take authorization. The California Department of Fish and Wildlife may be contacted to determine the appropriate buffer required to prevent incidental take of a listed plant if avoidance protocols have not been established for the species. The qualified biologist shall confirm that all applicable listed plant buffers have been implemented prior to the commencement of any disturbance activity.

BIO-3 Avoidance of Non-Listed Special-Status Plants. Sensitive species plant populations which are not Protected Species that may be impacted by new ground disturbing activities must be avoided by a 50-foot buffer, as delineated and implemented by a qualified biologist used by the applicant. These species of individuals or populations may be avoided by spanning or by rerouting new pipeline or roadway routes to avoid disturbance and minimize impacts to the plant populations from any construction activities.

6.1.2 - PROJECT IMPACTS TO SPECIAL-STATUS ANIMAL SPECIES

Crotch Bumble Bee

The Crotch bumblebee was not observed during reconnaissance surveys. Known host plants of the species (*Chaenactis, Lupinus, Medicago, Phacelia,* and Salvia) were also not observed, though the surveys were conducted outside of the optimal blooming period. There are only six Calflora records of potential host plant occurrences within the BSA, ranging from between 1937 and 1992. However, the BSA is within the known range for the species, and suitable habitat is present.

Direct impacts to the Crotch bumblebee could include mortality or injury caused by Project construction activities. The Project could also result in loss of suitable habitat.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-16, and BIO-17 would reduce impacts to the species.

California Glossy Snake

The San Joaquin coachwhip was not observed during reconnaissance surveys. However, the BSA is within the known range for the species and suitable habitat is present.

This species is nocturnal, so impacts of construction activities are expected to be limited. Direct impacts to California glossy snake could include mortality or injury caused by Project construction activities. Noise, vibration, and increased human activity could alter the normal behaviors of the lizard. The Project could also result in the loss of suitable habitat.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17 would reduce impacts to the species.

Blunt-nosed Leopard Lizard

The blunt-nosed leopard lizard was not observed during reconnaissance surveys. However, the BSA is within the known range for the species, suitable habitat is present, and there is a recent CNDDB record of the species within one mile of the BSA.

Without appropriate avoidance and minimization measures for BNLL, potentially significant impacts associated with ground-disturbing activities include habitat loss, burrow collapse, reduced reproductive success, or direct mortality. If there is an active burrow within land adjacent to the Project Site or proposed alternative routes, noise and vibration from construction activities could alter the daily behaviors of individuals and affect foraging activity and reproductive success during the short-term construction period. Habitat loss could result in indirect impacts through increased competition for limited resources over the long-term.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-15, BIO-16, and BIO-17 listed below would avoid direct impacts to the species.

San Joaquin Coachwhip

The San Joaquin coachwhip was not observed during reconnaissance surveys. However, the BSA is within the known range for the species, suitable habitat is present, and there is a recent CNDDB record of the species within one mile of the BSA.

Direct impacts to the San Joaquin coachwhip could include mortality or injury caused by Project construction activities. Noise, vibration, and increased human activity could alter the normal behaviors of the lizard. The Project could also result in the loss of suitable habitat.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17 would reduce impacts to the species.

Coast Horned Lizard

The coast horned lizard was not observed during reconnaissance surveys. However, the BSA is within the known range for the species and suitable habitat is present.

Direct impacts to the coast horned lizard could include mortality or injury caused by Project construction activities. Noise, vibration, and increased human activity could alter the normal behaviors of the lizard. The Project could also result in loss of suitable habitat.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17 would reduce impacts to the species.

Burrowing Owl

Burrowing owl was not directly observed during reconnaissance surveys. However, burrows displaying diagnostic sign of the species (white-wash, pellets, feathers) were observed within the BSA, the BSA is within the known range for the species, and suitable habitat is present.

Direct and/or indirect impacts to burrowing owl could occur if there is an active burrow within the Project area during the period of construction activities. Construction activities could result in crushing or destroying a burrow, with or without a burrowing owl inside. Noise, vibration, and increased human activity resulting from Project construction activities could alter the daily behaviors of individual owls and affect foraging success, displace owls from their burrows, or lead to nest failure. Operational activities have the potential to impact burrowing owls in the same way but to a lesser degree than construction activities. Suitable nesting and foraging habitat would be lost as a result of the Project.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-11, BIO-16, and BIO-17, listed below, would reduce impacts to the species.

Swainson's Hawk

Swainson's hawk was not observed during reconnaissance surveys. However, the BSA is within the known range for the species and suitable habitat for foraging is present.

Direct impacts to Swainson's hawks could occur if construction activities occur near an active nest or in foraging habitat during the nesting season. Complete tree removal, noise, and vibration from construction of the Project, plus the presence of construction workers, could alter the normal behaviors of nesting adults, resulting in harm or death to eggs or nestlings.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-14, BIO-16, and BIO-17 would reduce impacts to the species.

Prairie Falcon

Prairie falcon was not observed during reconnaissance surveys. However, the BSA is within the known range for the species and suitable habitat for foraging is present.

Direct impacts to the prairie falcon could include mortality or injury caused by Project construction activities. Noise, vibration, and increased human activity could alter normal behaviors resulting in reduced foraging success and displacing individuals from established territories. Loss of suitable habitat could impact the species.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-14, BIO-16, and BIO-17 would reduce impacts to the species.

Loggerhead Shrike

There were no observations of loggerhead shrike during reconnaissance surveys. Open areas of scrub habitat within the BSA provide suitable nesting and foraging habitat for loggerhead shrike. The species may use fence posts, utility lines, or scrubs within the BSA as perches and nest in areas of dense foliage.

Direct impacts to this species could include the destruction of active nests resulting from Project construction activities. Noise, vibration, and increased human activity could alter normal behaviors resulting in nest failure, reducing foraging success, and displacing individuals from established territories. Loss of suitable habitat could impact the species.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-14, BIO-16, and BIO-17 would reduce impacts to the species.

Le Conte's Thrasher

There were no observations of Le Conte's thrasher during reconnaissance surveys. The BSA provides suitable nesting and foraging habitat. The species may forage in areas of saltbush habitat and use saltbushes as nesting sites.

Direct impacts to this species could include the destruction of active nests resulting from Project construction activities. Noise, vibration, and increased human activity could alter normal behaviors resulting in nest failure, reducing foraging success, and displacing individuals from established territories. Loss of suitable habitat could impact the species.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-14, BIO-16, and BIO-17 would reduce impacts to the species.

San Joaquin Antelope Squirrel

Multiple San Joaquin antelope squirrel observations were made throughout the BSA during reconnaissance surveys (Figure 5-2). Suitable habitat for this species containing suitable burrows is present within the BSA.

Direct impacts to this species could include mortality or injury caused by entrapment or crushing individuals within burrows or from vehicle strikes during construction. Indirect impacts caused by noise, vibration, and the presence of construction workers could alter the normal behaviors of San Joaquin antelope squirrel, which could affect reproductive success, foraging success, or displacement from active burrows. Loss of foraging habitat could impact the species. Loss of suitable habitat could cause indirect impacts on the species, but impacts would be minimal given the amount of suitable foraging habitat throughout the region.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17, listed below, would reduce impacts to the species.

Giant Kangaroo Rat

Giant kangaroo rat was not observed during reconnaissance surveys. However, the BSA is within the known range of the species, suitable habitat is present.

Direct impacts to this species could include mortality or injury caused by entrapment or crushing individuals within burrows or from vehicle strikes during construction. Indirect impacts caused by noise, vibration, and the presence of construction workers could alter the normal behaviors of giant kangaroo rat, which could affect reproductive success, foraging success, or displacement from active burrows. Loss of foraging habitat could impact the species.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17, listed below, would reduce impacts to the species.

Short-nosed Kangaroo Rat

The short-nosed kangaroo rat was not observed during reconnaissance surveys. However, the BSA is within the known range of the species, suitable habitat is present, and potentially suitable burrows fitting the size characteristics of kangaroo rats and displaying sign consistent with use by the species (tail-drags) were observed.

Direct impacts to this species could include mortality or injury caused by entrapment or crushing individuals within burrows or from vehicle strikes during construction. Indirect impacts caused by noise, vibration, and the presence of construction workers could alter the normal behaviors of short-nosed kangaroo rat, which could affect reproductive success, foraging success, or displacement from active burrows. Loss of foraging habitat could impact the species.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17, listed below, would reduce impacts to the species.

Tulare Grasshopper Mouse

The Tulare grasshopper mouse was not observed during reconnaissance surveys. However, the BSA is within the known range of the species, suitable habitat is present, and potentially suitable burrows fitting the size characteristics of the species were observed.

Direct impacts to this species could include mortality or injury caused by entrapment or crushing individuals within burrows or from vehicle strikes during construction. Indirect impacts caused by noise, vibration, and the presence of construction workers could alter the normal behaviors of Tulare grasshopper mouse, which could affect reproductive success, foraging success, or displacement from active burrows. Loss of foraging habitat could impact the species.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17, listed below, would reduce impacts to the species.

San Joaquin Pocket Mouse

The San Joaquin pocket mouse was not observed during reconnaissance surveys. However, the BSA is within the known range of the species, suitable habitat is present, and potentially suitable burrows fitting the size characteristics of the species were observed.

Direct impacts to this species could include mortality or injury caused by entrapment or crushing individuals within burrows or from vehicle strikes during construction. Indirect impacts caused by noise, vibration, and the presence of construction workers could alter the normal behaviors of San Joaquin pocket mouse, which could affect reproductive success, foraging success, or displacement from active burrows. Loss of foraging habitat could impact the species.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-16, and BIO-17, listed below, would reduce impacts to the species.

American Badger

The American badger was not observed during reconnaissance surveys. However, suitable denning and foraging habitat is present within the BSA, and potentially suitable dens and sign of badger were observed during surveys.

Direct impacts to this species could include mortality or injury caused by entrapment or crushing individuals within dens and vehicle strikes. Indirect impacts to the species could be caused by noise, vibration, and the presence of construction workers that could alter normal behaviors, which could affect reproductive success, foraging success, or displacement from active dens if they were present within or adjacent to the Project area during construction. Operational activities could impact the species in many of these same ways because it is assumed that this species could be present from time to time during the operational phase of the Project.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-13, BIO-16, and BIO-17, listed below, would reduce impacts to the species.

San Joaquin Kit Fox

No San Joaquin kit fox were observed during reconnaissance surveys. However, potentially suitable dens, some including diagnostic sign such as scat and track, were observed throughout the BSA. San Joaquin den in a variety of areas, such as rights-of-way and vacant lands, and may be attracted to the Project area due to the type and level of ground-disturbing activities and the loose, friable soils resulting from intensive ground disturbance.

Since this species is highly mobile, foxes could be injured or killed if they disperse through the Project area during construction or operations activities. Direct impacts could also include entrapment in trenches or pipes during construction. If there is an active den within the Project Footprint during construction activities, noise and vibration from construction activities could alter the daily behaviors of individuals and affect foraging activity, or dens could be subject to collapse. Mortalities from vehicle strikes are possible but the proposed Project would not cause an appreciable increase in traffic at night when the species is most active.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-12, BIO-16, and BIO-17, listed below would avoid direct impacts to the species.

Nesting Birds

The entire Project area contains habitat suitable to support a wide variety of nesting native and non-native bird species. Depending on the timing of construction, eggs, and nestlings of bird species with small, well-hidden nests could be subject to loss. This action would result primarily during habitat clearing, earth removal, grading, digging, and equipment movement. If nesting occurs on the Project area during construction, an Environmentally Sensitive Area (ESA) may be established to reduce or eliminate potential impacts to nesting birds, eggs, and nestlings.

Noise, vibration, and increased human activity resulting from Project construction activities could alter the daily behaviors of individuals and affect foraging success or lead to nest failure. Access roads will be utilized during the construction phase, and there exists a potential for mortality due to vehicle collisions, although this risk is minimal as highly mobile species like birds are expected to disperse to nearby habitat.

Implementation of Avoidance and Minimization Measures BIO-7, BIO-9, BIO-10, BIO-14, BIO-16, and BIO-17 would reduce impacts to nesting birds.

Avoidance and Minimization Measures

Implementation of the avoidance and minimization listed below would reduce Project impacts to special-status wildlife species to levels that would be less than significant. The following measures are recommended to avoid and minimize impacts to, Crotch bumblebee,

California glossy snake, blunt-nosed leopard lizard, San Joaquin coachwhip, coast horned lizard, burrowing owl, Swainson's hawk, prairie falcon, loggerhead shrike, LeConte's thrasher, San Joaquin antelope squirrel, giant kangaroo rat, short-nosed kangaroo rat, Tulare grasshopper mouse, San Joaquin pocket mouse, American badger, San Joaquin kit fox, nesting birds, and wintering migratory birds and raptors. These Avoidance and Minimization Measures were adapted from the 'Kern County Oil and Gas Mitigation and Reporting Program – August 23, 2022' (Kern County 2022).

BIO-4: Qualified Biologist. A qualified biologist will be used for all preparation of reporting for submission of any application of an Incidental Take Permit if needed. The qualified biologist must have a Bachelor of Science Degree or Bachelor of Arts Degree in biology or related environmental science, have demonstrated familiarity with the natural history, habitat affinities and identification of Covered Species of the San Joaquin Valley and have conducted work in California for at least one (1) year of field level reconnaissance survey work. The resume of the biologist preparing any report submitted for permits shall be included in the report. Lack of these specific qualifications will result in immediate rejection of the report without further review.

Bio-5: Incidental Take Avoidance. No incidental take of any species listed as threatened or endangered under the federal Endangered Species Act, threatened or endangered under the California Endangered Species Act, rare or endangered in the California Native Plant Protection Act, or designated as fully-protected in the California Fish and Game Code (Protected Species) may occur unless the incidental take is authorized by applicable state and federal wildlife agencies in the form of a permit or other written authorization

BIO-6: Biological Reconnaissance Surveys. A qualified biologist shall conduct a biological reconnaissance survey in potential special-status species habitat to advise the project proponent of potential project impacts, potential surveying needs, and advise on the need for focused special status surveys. Early consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife will also inform project proponents of additional recommendations.

BIO-7: Pre-Disturbance Surveys. Within 30 days before any ground-disturbing activities in special-status species habitat, the qualified biologist shall conduct a pre-disturbance survey to record existing conditions of the site, determine if conditions have changed since the reconnaissance or focused/protocol surveys were conducted, and to determine where sensitive species avoidance buffers will be established.

BIO-8: Focused/Protocol Surveys. Based on the information gathered from the biological reconnaissance survey and any informal consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife and if required, focused/protocol surveys shall be conducted by a qualified biologist consistent with protocol study timelines in advance of submittal of the permit application to determine the presence/absence of sensitive species protected by state and federal Endangered Species Acts and potential project impacts to those species. The survey shall be conducted in accordance with the most

current standard protocol of the United States Fish and Wildlife Service and California Department of Fish and Wildlife.

a. The purpose of focused/protocol surveys is to confirm the presence or absence of any species listed as threatened or endangered under the federal Endangered Species Act, threatened or endangered under the California Endangered Species Act, rare or endangered in the California Native Plant Protection Act or designated as fully-protected in the California Fish and Game Code (collectively, "Protected Species"), and to confirm the presence or absence of any other species considered "sensitive" under California Environmental Quality Act ("Sensitive Species"), and to identify and implement avoidance and minimization measures for such species.
b. The surveys shall be conducted in accordance with all currently-applicable presence and absence survey and/or species protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife ("Species Protocols").
c. In the absence of any approved protocols, the survey shall extend for a minimum of 250 feet from all areas where any ground disturbance activities would occur, provided that permission to access has been obtained.
d. As an alternative to individual pre-disturbance surveys for each application, and after consultation with and concurrence by the California Department of Fish and 'Wildlife and the United States Fish and Wildlife Service, multiple parcels or areas of oil and gas production lands (including lands which may have multiple surface or mineral ownership) may be consolidated for the purpose of more efficiently managing pre-disturbance surveys and determinations regarding the absence of protected species in areas of proposed new ground disturbance activities.

BIO-9: Biological Monitoring. A biological monitor with the same qualifications as a qualified biologist shall be present during initial ground-disturbing activities in project locations that have special-status species habitat or are adjacent to potential special-status species habitat.

Bio-10: Protected Species Avoidance Buffers. Protective buffers shall be used, where effective in the opinion of the qualified biologist, to avoid any unauthorized incidental take of Protected Species, and to minimize any incidental take of Sensitive Species, by separating the planned disturbance area from any locations where the qualified biologist has detected the presence of Protected Species or Sensitive Species. Protective buffers shall be delineated using brightly colored stakes and/or flagging or similar materials and remain until construction activities are complete, at which time of completion the buffers must be removed. Protective buffers shall be established around active dens and/or burrows of special-status animal species, or populations of special-status plant species to avoid unauthorized take of protected species as listed in the table below. The protective buffer distance shall be increased if required to avoid unauthorized incidental take of any Protected Species as determined by a qualified biologist. Protective buffer distances and other avoidance measures that may be implemented to avoid impacts to Protected Species or Sensitive Species must be consistent with the United States Fish and Wildlife Service and/or

the California Department of Fish and Wildlife requirements and shall be implemented and overseen by the qualified biologist.

Table 6-2
Disturbance Buffers for Sensitive Resources

Sensitive Resource	Buffer Zone from Disturbance (feet)
Potential San Joaquin kit fox den	50
Known San Joaquin kit fox den	100
Natal San Joaquin kit fox den	500
Atypical San Joaquin kit fox den	50
Rodent burrows	50
Listed bird species active nests	500 feet to 0.5 mile dependent on species and sight line
Burrowing owl burrow (breeding and non-breeding season)	Pursuant to CDFW guidelines (see table 6-3)
San Joaquin coachwhip, all legless lizard species, coast horned lizard, and California glossy snake	30
American badger: Non-maternity dens	50
American badger: Maternity dens	200
Special-status plants	50

Bio-11: Burrowing Owl Avoidance. Occupied burrowing owl burrows shall not be disturbed during the species nesting season (February 1 through August 31). The following distances shall be maintained between all disturbance areas and burrowing owl nesting sites (Table 6-3).

Table 6-3
Setback Distances for Burrowing Owl Nesting Sites by Level of Proposed Project Impacts

Location		
Nesting sites	Nesting sites	Nesting sites
Time of Year		
April 1-Aug 15	Aug16- Oct 15	Oct 16- March 31
Project Impact Level		
Low		
656 feet (200 meters)	656 feet (200 meters)	164 feet (50 meters)
Medium		
1,640 feet (500 meters)	656 feet (200 meters)	328 feet (100 meters)
High		
1,640 feet (500 meters)	1,640 feet (500 meters)	1,640 feet (500 meters)

Burrowing owls present in proposed disturbance areas or within 500 feet or as specified under an approved Habitat Conservation Plan (as identified during pre-disturbance surveys) outside of the breeding season (between September 1 and January 31) may be moved away from the disturbance area using passive relocation techniques approved by the California Department of Fish and Wildlife. Passive relocation techniques in the California Department of Fish and Wildlife Staff Report on Burrowing Owl Mitigation Guidelines (California Department of Fish and Game 2012) include installing one-way doors in burrow entrances for 48 hours, to ensure the owl(s) have left the burrow, daily monitoring during the passive relocation period, and collapsing existing burrows to prevent reoccupation. A minimum of one or more weeks will be required to relocate the owl(s) and allow for acclimatization to alternate off-site burrows. Prior to burrow exclusion or eviction, a burrowing owl management plan shall be prepared and approved by the California Department of Fish and Wildlife. Destruction of burrows shall occur only pursuant to a management plan for the species approved by the California Department of Fish and Wildlife; burrow excavation shall be conducted by hand whenever possible.

As an alternative to passive relocation, occupied burrows identified off-site within 500 feet of construction activities may be buffered with hay bales, fencing (e.g., sheltering in place), or as directed by the qualified biologist and the California Department of Fish and Wildlife, to avoid disturbance of burrows.

BIO-12: Standard Avoidance and Minimization Measures for the Protection of SJKF. Any potential San Joaquin kit fox dens (as defined in United States Fish and Wildlife Service 2011a) detected during reconnaissance or focused/protocol surveys shall be reevaluated by the qualified biologist for species activity no more than 30 days prior to the commencement of ground disturbance in the required pre-construction survey. Potential kit fox dens shall be marked, and a 50-foot avoidance buffer shall be delineated using brightly colored stakes and flagging or similar materials to prevent inadvertent damage to the potential den. If the qualified biologist determines that an unoccupied potential den cannot be avoided, the den may be hand excavated in accordance with the United States Fish and Wildlife Service Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance (United States Fish and Wildlife Service 2011). If species activity is detected, the location shall be identified as a "known" kit fox den in accordance with the U.S. Fish and Wildlife Service species guidelines (United States Fish and Wildlife Service 2011). A minimum 100-foot buffer from any disturbance area shall be maintained for known dens and a minimum 500-foot buffer from any disturbance area shall be maintained for natal dens. No excavation of a known or natal den shall occur without prior authorization from the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. For activities occurring on land covered under an approved federal and/or State incidental take authorization, the requirements set forth in those documents shall be implemented. Other standard measures to protect San Joaquin kit fox, including capping pipes, covering trenches, adding exit ramps to excavated areas, shall be implemented in accordance with BIO-17.

BIO-13: Avoidance and Minimization Measures for the Protection of American badger. Occupied American badger dens detected during pre-disturbance surveys shall be flagged

and ground-disturbing activities avoided within 50 feet of the den. Maternity dens shall be avoided and a minimum 200-foot buffer from disturbance shall be maintained during pup-rearing season (February 15 through July 1). Maternity dens must be avoided to the maximum extent feasible in the opinion of the qualified biologist. If an active maternity den is proposed to be disturbed, the qualified biologist, shall consult with the California Department of Fish and Wildlife to identify any appropriate additional minimization measures which the qualified biologist determines, with the wildlife agencies, can actually be implemented based on field conditions. All such measures must be implemented for project activities.

BIO-14: Pre-activity Surveys for Nesting Birds. Pre-disturbance surveys for active bird nests must be conducted no more than 10 days prior to the commencement of disturbance. Surveys shall follow United States Fish and Wildlife and California Department of Fish and Wildlife guidance and/or protocols, as applicable. If no active nests or nesting birds are identified, then Project construction activities may proceed and no further mitigation measures for nesting birds are required. If active nest(s) are identified, the active nest(s) should be continuously surveyed for the first 24 hours after detection, to establish a behavioral baseline prior to any construction-related activities.

Once construction commences, all nests shall be continuously monitored to detect any behavioral changes as a result of the Project (i.e., nest avoidance or abandonment). If behavioral changes are observed, the work causing that change shall cease until the applicant qualified biologist consults with the California Department of Fish and Wildlife and the United States Fish and Wildlife and the qualified biologist used by the applicant implements the recommended measures. During such times as the qualified biological monitor is not onsite while construction workers are onsite, a minimum non disturbance buffer of 250 feet shall be established around active nests and a 500-foot no-disturbance buffer around the nests of raptors until the breeding season has ended, or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or parental care for survival, and any adult birds are no longer occupying the nest. Deviations from these no disturbance buffers may be implemented if the qualified biologist concludes that work within the buffer area would not cause nest avoidance or abandonment (e.g., when the disturbance area would be concealed from a nest site by topography) provided that notification of this determination of a deviation in the no-disturbance buffer is provided by the qualified biologist no less than 15 days in advance to the California Department of Fish and Wildlife and the United States Fish and Wildlife.

BIO-15: Avoidance of Blunt-nosed Leopard Lizard. The following measures will be implemented to avoid take of blunt-nosed leopard lizard and to ensure protection of these animals during Project activities:

a. Project activities will avoid all potential burrows that may be occupied by blunt-nosed leopard lizards. Suitable burrows within and adjacent to potential habitat for the species should be avoided by a minimum distance of 50-feet in all areas where ground-disturbing Project activities will occur.

b. No more than one year prior to ground disturbing activities, focused surveys following current California Department of Fish and Wildlife and United States Fish and Wildlife protocols for detection of this species or other methods approved by both agencies shall be conducted in all potential blunt-nosed leopard lizard habitat within the work site and a 250-foot buffer area. If no individual blunt-nosed leopard lizards are observed during focused surveys, and surveys are current (e.g., completed in the same calendar year), then Project activities may proceed.

c. If blunt-nosed leopard lizards are detected during focused surveys, a blunt-nosed leopard lizard avoidance plan shall be prepared for the Project that will result in avoidance of incidental take of this species unless take is separately authorized under a Natural Communities Conservation Plan and appropriate federal authorization is obtained. At a minimum, the blunt-nosed leopard lizard avoidance plan shall be provided to the California Department of Fish and Wildlife and the County, and shall contain the following elements:

    1. A Worker Environmental Awareness Program shall be implemented for all construction personnel before construction begins (see BIO-16).

    2. During periods that are optimal for blunt-nosed leopard lizard activity (early spring through late fall), a qualified biologist will be present during all ground disturbing activities. The qualified biologist will check the Project site(s) and access route(s) daily during the blunt-nosed leopard lizard active season to determine presence or absence of lizards in or near the work areas. Monitoring by a qualified biologist is not required during periods of inactivity (the winter season).

    3. All open trenches or excavations shall be covered at the end of each workday or protected with the use of exclusion fencing to prevent wildlife entrapment. If an excavation is too large to cover, escape ramps shall be installed at an incline ratio of no greater than 2:1. All trenches and pipes shall be inspected for the presence of wildlife each day prior to the commencement of work. If blunt-nosed leopard lizards are observed at the work site during construction, construction shall cease within a 250-foot radius and the United States Fish and Wildlife Service, and the California Department of Fish and Wildlife shall be consulted to determine what additional measures would be necessary to prevent take of this species.

    4. Offsite locations where blunt-nosed leopard lizards have been observed or are likely to occur shall be clearly marked to prevent workers from driving off the road and to prevent inadvertent destruction of burrows. Barriers, such as exclusionary fencing may be installed. All construction equipment and construction personnel vehicles will be checked prior to moving to ensure no blunt-nosed leopard lizard are under equipment/vehicles.

    5. A speed limit of 10 miles per hour shall be posted and observed within 0.25 miles of any reported blunt-nosed leopard lizard observation.

6. Construction activities shall avoid burrows that may be used by blunt-nosed leopard lizards. Any location of proposed construction activity with potential to collapse or block burrows (i.e., stockpile storage, parking areas, staging areas, trenches) will be identified prior to construction in the blunt-nosed leopard lizard avoidance plan and approved by the qualified biologist. The qualified biologist may allow certain activities in burrow areas if the combination of soil hardness and activity impact is not expected to collapse burrows and no blunt-nosed leopard lizards have been found during pre-Project surveys in the impact area.

7. All individual blunt-nosed leopard lizards observed above-ground will be avoided. Any individual blunt-nosed leopard lizard that may enter the Project site(s) would be allowed to leave unobstructed, and on its own accord. If a blunt-nosed leopard lizard is detected during biological monitoring or observed at any other point, the California Department of Fish and Wildlife and the United States Fish and Wildlife Service shall be notified to determine what additional measures would be necessary to prevent take of the species.

BIO-16: Worker Environmental Awareness Program. A Worker Environmental Awareness Program shall be developed and implemented for all personnel that could access the site prior to commencing any disturbance activities. The program shall consist of an on-site or center presentation that will describe the locations and types of sensitive plant, wildlife, and sensitive natural communities (collectively, "Biological Resources") on and near the site, an overview of the laws and regulations governing the protection of Biological Resources, the reasons for protecting the Biological Resources, the specific protection and avoidance measures that are applicable to the site, and the identity of designated points of contact should questions or issues arise, including the qualified biologist. The program shall provide training to recognize, avoid and report to applicable qualified biologists any Biological Resources on the site.

a. The Worker Environmental Awareness Program shall emphasize the need to avoid contact with onsite wildlife and avoid entry into areas where Biological Resources have been identified based on pre-disturbance field surveys and to implement the buffer avoidance or other protection measures established by the United States Fish and Wildlife Service shall be identified California Department of Fish and Wildlife or required by the Biological Resource mitigation measures. The training shall emphasize the importance of not feeding or domesticating wildlife and the need to avoid any trash, microtrash, or potential food disposal onsite except in animal-proof containers emptied daily to avoid attracting or causing adverse impacts to special status wildlife.

b. All onsite personnel must sign a statement verifying that they have completed the Worker Environmental Awareness Program, and that they understand and agree to implement the biological requirements for the worksite. If signed employee statements are not available, documentation may be provided by Worker Environmental Awareness Program training records, which shall be kept by the Applicant for a minimum of 5 years. Each Applicant shall maintain a list of all persons

who have completed the training program and shall provide the list to the County or to state and federal wildlife agency representatives upon request.

BIO-17: General Measures. The following additional measures shall be implemented to avoid and minimize potential significant adverse impacts to Protected and Sensitive Species:

a. All vehicles shall observe a 20-mile-per-hour speed limit in all areas of disturbance and on unpaved roads unless otherwise posted. Off-road traffic outside of designated access routes is prohibited. Speed limit signs shall be posted in visible locations at the point of site entry and at regular intervals on all unpaved access roads.

b. All disturbance activities, except emergency situations or drilling that may require continuous operations, shall only occur during daylight hours. Nighttime disturbance activity for drilling purposes shall use directed lighting, shielding methods, and comply with applicable lighting mitigation measures.

c. All food-related trash items and all forms of microtrash, such as wrappers, cans, bottles, bottle tops, and food scraps shall be disposed of in closed, animal proof containers and removed daily from the site.

d. Excavations, spoils piles, access roadways, and parking and staging areas shall subject to dust control as set forth in the dust control mitigation measures.

e. The use of herbicides for vegetation control shall be restricted to those approved by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. No rodenticides shall be used on any site unless approved by the United States Fish and Wildlife Service, and the California Department of Fish and Wildlife, and shall observe label and other restrictions mandated by the United States Environmental Protection Agency, California Department of Food and Agriculture, and state and federal laws and regulations. For split estates, no herbicides for vegetation control may occur in Tier 2 areas without surface owner approval.

f. No plants or wildlife shall be collected, taken, or removed from the site or any adjacent locations except as necessary for Project-related vegetation removal or wildlife relocation by a qualified biologist and subject to all applicable permits and authorizations.

g. All open trenches or excavations shall be covered at the end of each workday to prevent wildlife entrapment. If an excavation is too large to cover, escape ramps shall be installed at an incline ratio of no greater than 2:1. All trenches and pipes shall be inspected for the presence of wildlife each day prior to the commencement of work.

h. To enable San Joaquin kit foxes and other wildlife to pass through the Project site, any perimeter fencing shall include a 4- to 8-inch opening between the fence mesh and the ground, or the fence shall be raised 4 inches above the ground except blunt-nosed leopard lizard exclusion fencing. The bottom of the fence fabric shall be knuckled (wrapped back to form a smooth edge) to protect wildlife.

i. All vertical tubes used in Project construction and chain link fencing poles, shall be temporarily or permanently capped to avoid the entrapment and death of special-status wildlife and birds. All pipes 1.5 inches or greater in diameter stored overnight on a project location must have end caps or other physical barriers that prevent wildlife from entering the pipe.

j. All dead or injured special status wildlife shall be left in place and reported to the United States Fish and Wildlife Service and the California Department of Fish and Wildlife within 48 hours of discovery for rescue or salvage. Discovery of state or federal listed species that are injured, or dead shall also be managed consistent with regulatory requirements, including being reported immediately via telephone and within 24 hours in writing, and with a copy to Kern County Planning and Natural Resources.

k. All drilling installations and operations will comply at all times with the applicable federal, State, county, and local law ordinances, and regulations.

l. During pre-construction surveys, the qualified biologist shall delineate previously disturbed areas to be used by the applicant to minimize the amount of new disturbance.

m. All concrete and asphalt debris should be removed from the site for recycling or disposal at an authorized, permitted facility.

n. No vehicles or construction equipment shall be parked within a wetland or waterbody/dry wash.

o. Tracked vehicles and other construction equipment must be washed or maintained to be weed-free prior to entering and working within areas of new disturbance.

p. All washing of trucks, paint, equipment, or similar activities should occur in areas where runoff is fully contained for collection and offsite disposal. Wash water may not be discharged from the site and shall be located at least 100 feet from any water body, or sensitive Biological Resources.

q. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from wetland boundaries or waterbody, except where the adjacent upland consists of cultivated or rotated cropland or other disturbed land.

r. All areas that must be avoided as result of the pre-disturbance surveys, and areas where new disturbance will occur, shall be clearly delineated by fencing or staking and flagging and/or rope or cord.

s. No firearms shall be allowed on any site.

t. No pets shall be allowed on any site.

u. No smoking may occur except in designated areas.

v. If ground disturbance is intended to be temporary and does not occur on cultivated and crop lands, perform topsoil segregation during construction activities to preserve the seed bank for restoration efforts. Store the segregated topsoil separate from the subsoil and restore segregated topsoil to its original location.

BIO- 18: Compensation. Any new ground disturbance shall be mitigated at a 1.0 to 1.0 ratio (one-acre of new disturbance shall require one-acre of mitigation) except in Tier 1 areas that contain existing disturbance of 70% or greater which shall be mitigated at a 1.0 to 0.5 ratio (one-acre of new disturbance shall require one-half acre of mitigation), for the land included in the Site Plan. This compensatory mitigation requirement does not apply to construction on ground for which compensatory mitigation has already been provided, or on ground that has been previously disturbed (e.g., cleared of vegetation for other oil and gas extraction uses, existing unpaved roads, and existing unvegetated well pads). Ground disturbance activities that are authorized by permits or other written authorizations approved by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife, which include avoidance and compensatory mitigation acreage requirements, may be used to satisfy this County compensatory mitigation ratio. Compensatory mitigation shall be required for the actual acreage of ground disturbance documented during the site plan review and completion process. New disturbance mitigation may be satisfied by one or a combination of the following measures:

a. The recordation of a conservation easement or similar permanent, long-term conservation management agreement in a form acceptable to the County for land within the Project Area on land that has mitigation value. The easement lands may be owned by an Applicant or a third party under contract with an Applicant. Larger land areas may be placed under a conservation easement or similar agreement, and an Applicant may "draw down" the conserved land as needed to satisfy the acreage mitigation requirements for multiple site plan review conformity permits or other authorizations from the County for oil and gas activities.

b. Acquisition of land preservation credits from a mitigation bank located within the Project area, which is owned by the County, on other lands approved by the County, or on lands approved for mitigation or conservation purposes by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife.

c. Removal of legacy oil and gas equipment, inclusive of compliance with applicable legal requirements (e.g., well plugging and abandonment requirements under state or federal regulations), restoration of the surface grade to be consistent with surrounding lands, complete a reseeding effort using native species, and notification of the site owner (if not the Applicant) of the completion of the removal and grading restoration work.

d. Enhancement or restoration of existing habitat on lands already subject to a conservation easement or similar agreement, or which become subject to a

conservation easement or similar agreement subsequent to the certification of this Environmental Impact Report, provided that such activities are covered in a permit or authorization, conservation plan, Habitat Conservation Plan, or Natural Community Conservation Plan, approved by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife.

e. Payment of a biological resources' mitigation fee for the acquisition and management of mitigation lands, legacy equipment removal, and/or land enhancement already subject to conservation easements or a similar agreement under the terms of any biological resource mitigation program that is adopted by Kern County and approved by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife. The County shall coordinate with the United States Fish and Wildlife Service or the California Department of Fish and Wildlife to identify priority conservation areas and potential conservation partners and funding sources to increase the efficiency and effectiveness of mitigation fee expenditures.

6.2 - Sensitive Natural Communities and Critical Habitat

The proposed project would have a significant effect on biological resources if it would:

b) Have a substantial adverse impact on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, regulations or by the California Department of Fish and Wildlife or US Fish and Wildlife Service.

The Project area does not overlap any USFWS designated critical habitat.

One sensitive plant community, Valley Saltbush Scrub, is expected to be impacted by Project activities. As the existing Valley Saltbush Scrub habitat consists of highly isolated fragments surrounded by existing oil and gas disturbance and the Project area largely follows established pipeline rights-of-way the impact to this habitat is expected to be less than significant.

6.3 - Jurisdictional Aquatic Resources

The proposed project would have a significant effect on biological resources if it would:

c) Have a substantial adverse effect on state or federally protected wetlands (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means.

Formal delineation of the NHD and NWI identified water features was not conducted for the proposed Project. It is not anticipated jurisdictional aquatic resources will be directly impacted and the Project will avoid these features to the extent feasible, such as spanning drainages along the Project route. However, if avoidance is impractical, to minimize impact to potential waters of the State and fulfill the regulatory requirements associated with discharges to waters of the State, the following measure should be implemented should the

Project design impact the existing riverine features. If the riverine feature is not determined to be Waters of the State or under the jurisdiction of any agency, the following measures would not be warranted.

Avoidance and Minimization Measures

BIO-19: If construction activities will alter federal jurisdictional waters, project applicants shall comply with the federal Clean Water Act Section 404 and Section 401 permitting and certification requirements. If construction activities will alter state waters, project applicants shall comply with California Department of Fish and Wildlife Streambed Alteration requirements.

6.4 - Wildlife Movement

The proposed project would have a significant effect on biological resources if it would:

d) Interfere substantially with the movement of any resident or migratory fish or wildlife species or with established resident or migratory wildlife corridors or impede the use of wildlife nursery sites.

The Project area is located within an Essential Connectivity Area and Core Area. Implementation of the Biological Resources mitigation measures would reduce wildlife movement impacts to less than significant.

6.5 - Local Policies and Ordinances

The proposed project would have a significant effect on biological resources if it would:

e) Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance.

The Project does not conflict with the County of Kern General Plan and is not subject to any local ordinances. Therefore, there are no impacts with respect to local policies and ordinance and no measures are warranted.

6.6 - Adopted or Approved Plans

The proposed project would have a significant effect on biological resources if it would:

f) Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Conservation Community Plan, or other approved local, regional, or state habitat conservation plan.

The Project does not conflict with any adopted Habitat Conservation Plans, Natural Conservation Community Plan, or other approved conservation plan. Therefore, there are no impacts with respect to local policies and ordinance and no measures are warranted.

SECTION 7 - LIMITATIONS, ASSUMPTIONS, AND USE RELIANCE

This Biological Analysis Report has been performed in accordance with professionally accepted biological investigation practices conducted at this time and in this geographic area. The findings and opinions conveyed in this report are based upon on-site field examinations, jurisdictional areas, and specified historical and literature sources. The biological investigation is limited by the scope of work performed. Biological surveys conducted as part of this assessment may not have been performed during a particular blooming period, nesting period, or particular portion of the season when positive identification of certain taxa would be expected if present, and therefore cannot be considered definitive. The biological surveys are limited also by the environmental conditions present at the time of the surveys. In addition, general biological (or protocol) surveys do not guarantee that the organisms are not present and will not be discovered in the future within the site. In particular, mobile animal species could occupy the site on a transient basis or re-establish populations in the future. No other guarantees or warranties, expressed or implied, are provided.

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APPENDIX A

SPECIAL-STATUS SPECIES EVALUATION TABLE

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Sensitive Natural Communities				
Great Valley Mesquite Scrub	-/- -/-	This community is composed of an open woodland or savanna dominated by *Prosopis glandulosa* torreyana and *Atriplex polycarpa*. Understories are grassy in good rainfall years, though usually dominated by introduced annuals. This community is found in sandy loams of alluvial origin, often with wind-modified microtopography. Mesquite requires a high-water table. Sierran snowmelt provided the necessary groundwater for the perennial phreatophytes.	No Potential	Western honey mesquite was not present within the BSA.
Valley Saltbush Scrub	-/- -/-	This community consists of open, gray or blue-green chenopod scrubs, usually over a low herbaceous annual understory. Areas dominated by *Atriplex polycarpa* or *A. spinifera* may be differentiable from one another. Typically found on sandy to loamy soils without surface alkalinity, largely on rolling, dissected alluvial fans. Found in areas with long, arid summers and short, damp winters, and tule fog is often present during the winters.	Present	This habitat was observed, with varying degrees of disturbance, throughout the BSA. Much of the habitat within the BSA has been extremely fragmented due to oil and gas development.
Valley Sink Scrub	-/- -/-	This community consists of low, open to dense succulent shrublands dominated by alkali tolerant Chenopodiaceae, especially *Allenrolfea occidentalis* or several Suaeda species. Understories usually are lacking, though sparse herbaceous cover dominated by *Bromus rubens* develop occasionally. Also consists of saline or alkaline clays. Heavy, saline and/or alkaline clays of lakebeds or playas with *Allenrolfea*, salt grass, *Lasthenia*, etc.	No Potential	Characteristic alkali tolerant plant communities were not present within the BSA. The nearest CNDDB occurrence (EONDX 9786) of this habitat is located five mile north of the northern terminus of the BSA, east of the California aqueduct.
Plants				

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Astragalus hornii var. *hornii* Horn's milk-vetch	-/- 1B.1/-	This is a perennial herb that blooms between May and October. It occurs in meadows and seeps, alkali playas, wetlands, salty flats, and along lake margins. It occurs at elevations ranging from approximately 200 to 1,000 feet and is known to occur in Inyo, Kern, San Bernardino, and possibly Tulare counties.	No Potential	Suitable habitat is absent from the BSA. There are two CNDDB records within ten miles of the BSA, neither is from within the last decade. The nearest CNDDB record (EONDX 70410) is from 1988 and is approximately five miles southwest of the BSA.
Atriplex cordulata var. *cordulata* heartscale	-/- 1B.2/-	This is an annual herb that is endemic to California and blooms from April to October. It occurs in saline and alkaline soils, chenopod scrub, meadows and seeps, and sandy soils in valley foothill grassland habitats. It occurs at elevations ranging from sea level to approximately 1,835 feet and is known to occur in Alameda, Butte, Contra Costa, Colusa, Fresno, Glenn, Kern, Madera, Merced, San Joaquin, Solano, Stanislaus, Tulare, and Yolo counties. This species is threatened by competition from non-native plants and possibly threated by trampling.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. There several CNDDB records within ten miles of the BSA, while none are from the last decade, they occur in habitat similar to that present within the BSA.
Atriplex cordulata var. *erecticaulis* Earlimart orache	-/- 1B.2/-	This is an annual herb that is endemic to California and blooms from August to September, sometimes as late as November. It occurs in low-lying, sparsely vegetated valley and foothill grasslands and on mounds between vernal pools. It occurs at elevations ranging from 130 to 330 feet and is known primarily from the valley floor in Kings, Kern, and Tulare counties. It is threatened by vehicles and possibly development and competition from non-native plants.	No Potential	The BSA is above the known elevational range of the species. There are no CNDDB records of the species within ten miles of the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Atriplex coronata var. *vallicola* Lost Hills crownscale	-/- 1B.2/-	This is an annual herb that is endemic to California and blooms between April and August. It occurs in dry beds of alkaline pools in chenopod scrub, valley and foothill grassland, and vernal pools. It is also found on exposed slopes rich in gypsum. It occurs at elevations ranging from 165 to 2,085 feet. It has been documented on the valley floors and lower foothills of the western Central Valley in Fresno, Kings, Kern, Merced, San Benito, San Luis Obispo, and Tulare counties. It is threatened by grazing, vehicles, and development.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. Multiple CNDDB records are within ten miles of the BSA, the nearest (EONDX 58368) is from 2000 and located approximately 1.30 miles southeast of the BSA, where the species was observed within saltbush scrub habitat.
Atriplex flavida Carrizo Plain crownscale	-/- 1B.3/-	This annual herb is endemic to California, specifically to the Carrizo Plain of eastern San Luis Obispo County, and blooms from March to July. This species was formally included in *Atriplex coronata* var. *vallicola* and has been recently differentiated from *A. coronata* species by its overall yellow-green color (as opposed to gray-green), fewer number of stamens, and longer fruiting bracts. It occurs in a semi-arid region of sodic, alkaline soils in chenopod scrub, valley and foothill grassland, and vernal pool habitat. It is ground at elevations ranging from 1,920 to 1,985 feet and is limited to the Carrizo Plain of San Luis Obispo County. Potential threats include agricultural development, grazing, introduction of non-native plants, and road construction.	No Potential	The BSA is outside of the known geographic range of the species. There are no CNDDB records of the species within ten miles of the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Atriplex minuscula lesser saltscale	-/- 1B.1/-	This is an annual herb that is endemic to California and blooms between May and October. It occurs on alkaline and sandy soils in chenopod scrub, playas, and valley and foothill grassland. It occurs at elevations ranging from 50 to 655 feet and is known to occur in Alameda, Butte, Fresno, Kings, Kern, Madera, Merced, Stanislaus, and Tulare counties. It is threatened by agriculture and solar energy development; documented primarily on Central Valley floor with some lower foothill occurrences.	No Potential	The BSA is above the know elevational range of the species. There are no CNDDB records of the species within ten miles of the BSA.
Atriplex subtilis subtle orache	-/- 1B.2/-	This is an annual herb that is endemic to California and blooms between June and September, possibly as late as October. It occurs on alkaline soils in valley and foothill grassland habitats. It occurs at elevations ranging from approximately 130 to 330 feet and is known to occur in Butte, Fresno, Kings, Kern, Madera, Merced, Stanislaus, and Tulare Counties. This species is threatened by agriculture and possibly solar energy development and is documented primarily on Central Valley floor.	No Potential	The BSA is above the know elevational range of the species. There are no CNDDB records of the species within ten miles of the BSA.
Caulanthus californicus California jewelflower	FE/SE 1B.1/-	This is an annual herb that blooms between February and May. It occurs in slightly alkaline sandy soils in chenopod scrub, valley and foothill grassland, and pinyon and juniper woodland, typically at elevations from approximately 200 to 3,280 feet. It occurs in the San Joaquin Valley, Carrizo Plain, and Cuyama Valley from Fresno County south to Santa Barbara County and many occurrences are presumed extirpated. It is threatened by development, grazing, and competition from non-native plants.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. There are two CNDDB records (EONDX 20294 and 23135) within ten miles of the BSA, although both are presumed extirpated. As the BSA contains similar habitat to the nearby records (prior to their extirpation) there is potential for the species to occur.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Caulanthus lemmonii Lemmon's jewelflower	-/- 1B.2/-	This is an annual herb that blooms from February through May. It occurs in pinyon and juniper woodland and valley and foothill grassland. It occurs at elevations ranging from approximately 260 to 5185 feet. This species is documented in lower foothills and mountains in the Coast Ranges on the west side of the Central Valley from Alameda and San Joaquin counties to Ventura County. It is threatened by development, grazing, and vehicles.	No Potential	The BSA is outside of the known geographic range of the species. There are no CNDDB records of the species within ten miles of the BSA.
Cirsium crassicaule slough thistle	-/- 1B.1/-	This is an annual or perennial herb that blooms from May to August. It occurs in fresh water in chenopod scrub, marshes, and swamps (sloughs), and riparian scrub. It occurs at elevations ranging from approximately 9 to 330 feet. This species has been documented on western alluvial plains of Central Valley in Kings, Kern and San Joaquin counties. It is threatened by agriculture and non-native plants. Population sizes can vary widely from year to year.	No Potential	The BSA lacks wetland habitat suitable of supporting this species.
Delphinium recurvatum recurved larkspur	-/- 1B.2/-	This is a perennial herb that blooms between March and June. It occurs in alkaline conditions in chenopod scrub, cismontane woodland, and valley and foothill grassland. It occurs at elevations ranging from approximately 10 to 2,590 feet. This species is endemic to California. It occurs throughout the Central Valley and Coast Ranges from Butte County south. Few occurrences are in the Antelope Valley. This species is threatened by agriculture and competition from non-native plants.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. There are multiple CNDDB records within ten miles of the BSA, one of which (EONDX 83186) overlaps the northern terminus of the BSA. This record is from 1995 when the species was observed within the Elk Hills Oilfield.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Eremalche parryi ssp. *kernensis* Kern mallow	FE/- 1B.2/-	This is an annual herb that starts to bloom in January, sometimes February or March, until May. It occurs on dry, open sandy to clay soils, often at the edges of balds in chenopod scrub, pinyon and juniper woodland, and valley and foothill grassland. It occurs at elevations ranging from approximately 230 to 4,230 feet. It has been documented in the southern San Joaquin Valley and Carrizo Plain and surrounding foothills and mountains. This species is threatened by agriculture and development, and possibly non-native plants.	Potential	The BSA is near the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. There are multiple CNDDB records from within the last decade in the vicinity of the BSA. The most recent record (EONDX 120309) is from 2020 and located approximately 2.78-miles northeast of the southern terminus of the BSA, where the species was observed within the Elk Hills Oilfield.
Eriogonum temblorense Temblor buckwheat	-/- 1B.2/-	This is an annual herb that typically blooms from May to September, but sometimes as early as April. It occurs in clay and sandstone substrate in valley and foothill grassland habitats. It occurs at elevations from approximately 98 to 3,280 feet and is only known in the Temblor Range from Fresno to Kern and San Luis Obispo counties. It is threatened by energy development.	Potential	The BSA is near the known range for the species, and suitable habitat including annual grassland is present. There are two CNDDB records within close proximity of the BSA. The nearest record (EONDX 104358) is from 2011 and is located approximately 0.85-mile north of the northern terminus of the BSA.
Eschscholzia lemmonii ssp. *kernensis* Tejon poppy	-/- 1B.1/-	This is an annual herb that blooms in March, sometimes as early as February, to May. It is found in open valley and foothill grasslands and chenopod scrub at elevations from approximately 450 to 4,500 feet. It is distinguished from the more common California poppy (*E. californica*) by its calyx. It is possibly threatened by grazing and non-native plants.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. There are multiple CNDDB records within close proximity to the BSA, several of which are from within the last decade. The nearest record (EONDX 21454) is from 1998 and overlaps the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Lasthenia chrysantha alkali-sink goldfields	-/- 1B.1/-	This California endemic annual herb blooms between February and June. It occurs on alkaline soils in vernal pools and on wet saline flats at elevations of 655 feet and lower. It has been documented in the Central Valley from Sacramento south to Bakersfield and in the foothills on the western margin of the Valley. Threats to the species include habitat loss, agriculture, urbanization, and development.	No Potential	The BSA lacks suitable habitat for the species and is above the known elevational range of the species. There is a single CNDDB record within ten miles of the BSA (EONDX 118438) it is from an unknown date and is located approximately 5.34-miles east of the BSA within the Tule Elk State Nature Reserve.
Lasthenia glabrata ssp. *coulteri* Coulter's goldfields	-/- 1B.1/-	This is an annual herb that blooms between February and June. It occurs in coastal salt marshes and swamps, playas, and vernal pools in the interior of California. It occurs at elevations from sea level to 4,000 feet. It is seriously threatened by urbanization and agricultural development and road maintenance and is potentially threatened by foot traffic and drought.	No Potential	The BSA lacks habitat capable of supporting this species. The nearest CNDDB record (EONDX 98968) is from 2010 and is approximately 9.31-miles north of the BSA where it was observed in alkali sink habitat.
Layia heterotricha pale-yellow layia	-/- 1B.1/-	This is an annual herb endemic to California that blooms between March and June. It occurs on alkaline and clay soils in cismontane woodland, coastal scrub, pinyon and juniper woodland, and valley and foothill grassland. It occurs at elevations from approximately 980 to 5,595 feet and is mainly found in western mountains and foothills of the San Joaquin Valley from Fresno and San Benito Counties south to Ventura and possibly Los Angeles Counties and also in Tehachapi Mountains. It is threatened by agriculture, vehicles, and competition from non-native plants.	No Potential	The BSA is outside of the known geographic range of this species, specifically the western mountains and foothills of the San Joaquin Valley. All CNDDB records of this species are west of the BSA within the foothills of the Temblor Range in juniper woodland habitat except one (EONDX 101475), which was observed 3.12-mile west of the BSA in 1905. The exact location of the CNDDB record from 1905 is unknown and the record notes it may have been located further west on the ridge of the Temblor range with the other CNDDB records.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Lepidium jaredii ssp. *jaredii* Jared's pepper-grass	-/- 1B.2/-	This is an annual herb endemic to California that blooms from March to May. It occurs in alkaline and adobe substrate within valley and foothill grassland. It is found only from Soda Lake in the Carrizo Plain and Devil's Den. It occurs at elevations from approximately 1,099 to 3,297 feet and is threatened by solar energy development and grazing.	No Potential	The BSA is outside of the know geographic range of the species. There are no CNDDB records of the species within ten miles of the BSA.
Madia radiata showy golden madia	-/- 1B.1/-	This is an annual herb endemic to California that blooms between March and May. It occurs in cismontane woodland and valley and foothill grassland at elevations from approximately 80 to 3,985 feet. Known occurrences are scattered throughout the mountains and foothills along the west side of the Central Valley from Contra Costa County south to Santa Barbara County. It is threatened by grazing and non-native plants.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland is present. There are two CNDDB records (EONDX 2732 and 7469) within ten miles of the BSA, both are from 1992 and located approximately 5.32-miles north of the BSA, where the species was observed adjacent to the California aqueduct within disturbed saltbush scrub habitat.
Monolopia congdonii San Joaquin woollythreads	FE/- 1B.2/-	This is an annual herb endemic to California that blooms from February to May. It occurs in chenopod scrub and on sandy soils in valley and foothill grassland. It occurs at elevations from approximately 196 to 2,624 feet. Approximately half of the historical occurrences are expected to be extirpated and the known populations occur in Carrizo Plain Natural Area, Lost Hills, Kettleman Hills, Jacalitos hills, Panoche Hills, and Cuyama Valley. It is seriously threatened by agricultural conversion, energy development, urbanization, grazing, trampling, and vehicles.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. The nearest CNDDB record (EONDX 115497) is from 1988 and located 3.42-miles southwest of the BSA, where the species was observed within an oil field in saltbush scrub habitat.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Puccinellia simplex California alkali grass	-/- 1B.2/-	This is an annual grass that blooms between March and May. It usually occurs on sinks, flats, and lake margins in vernally moist, alkaline conditions of chenopod scrub, meadows and seeps, valley and foothill grassland, and vernal pools. It occurs at elevations from approximately 5 to 3,050 feet. It is threatened by hydrological alterations, urbanization, agricultural conversion, development, and habitat fragmentation, disturbance alteration and loss. It is potentially threatened by solar energy development and is possibly threatened by grazing and proximity to roads.	No Potential	Sufficiently moist habitat capable of supporting this species was not observed within the BSA. There are two CNDDB records within ten miles of the BSA, both of which are associated with alkaline vernal pools and neither of which is from within the last decade.
Senecio aphanactis chaparral ragwort	-/- 2B.2/-	This is an annual herb that typically blooms from January to April but can bloom as late as May. It sometimes grows in alkaline conditions in chaparral, cismontane woodland, and coastal scrub. It occurs at elevations from approximately 49 to 2,624 feet. It is threatened by development and is rare in Los Angeles, Orange, and Riverside counties.	No Potential	The BSA lacks habitat capable of supporting this species. There are no CNDDB records of the species within ten miles of the BSA.
Stylocline citroleum oil neststraw	-/- 1B.1/-	This is an annual herb endemic to California that blooms from March to April. It occurs on clay substrates in chenopod and coastal scrub, and valley and foothill grasslands. It occurs at elevations from approximately 164 to 1,312 feet and is possibly threatened by energy development and urbanization.	Potential	The BSA is within the known range for the species, and suitable habitat including annual grassland and saltbush scrub is present. There are numerous CNDDB records within close proximity to the BSA and several that overlap the BSA. The most recent CNDDB records are from 2013.
Invertebrates				

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Bombus crotchii Crotch bumble bee	-/SCE -/-	This bee occurs in relatively warm and dry environments, including the inner Coast Range of California and the margins of the Mojave Desert. It inhabits grassland and scrub habitats, where it nests in abandoned rodent burrows, occasionally nesting above ground in tufts of grass, rock piles, or cavities in dead trees. This species is classified as a short-tongued species, whose food plants include *Asclepias, Chaenactis, Lupinus, Medicago, Phacelia, and Salvia*. The species is threatened by habitat loss and degradation, including agricultural intensification and rapid urbanization.	Potential	Suitable habitat is present within the BSA, although preferred food sources are scarce. The nearest CNDDB record (EONDX 98854) overlaps the southern end of the BSA, although it is from 1957 and mapped generally. This species was not observed during reconnaissance surveys.
Branchinecta lynchi vernal pool fairy shrimp	FT/- -/-	This species occurs in a variety of vernal pool habitats that range from small, clear sandstone rock pools to large, turbid, alkaline, grassland valley floor pools. It occurs more commonly in pools less than 0.05 acre, typically as part of larger vernal pool complexes. Adults are active from early December to early May. Pools must hold water for at least 18 days, the minimum to complete the life cycle if temperatures are optimal. Eggs are laid in spring and persist through dry season as cysts. The current California distribution includes the Central Valley and coast ranges. This species is threatened by habitat loss, degradation, fragmentation, and interference with vernal pool hydrology.	No Potential	No vernal pools were observed within the BSA. This species was not observed during reconnaissance surveys, and it is not expected to occur within the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Danaus plexippus plexippus monarch - California overwintering population	FC/- -/-	This butterfly species occurs in various open habitats including fields, meadows, weedy areas, marshes, and roadsides. Adults make massive migrations from August to October, flying thousands of miles south to hibernate along the California coast and in central Mexico. Eggs are laid and larvae feed on plants in the milkweed family, primarily *Asclepias* sp., but also other genera including *Calotropis*, *Cynanchum*, *Gonolobus*, and *Sarcostemma*. Adult butterflies typically live from two to six weeks, but overwintering individuals may live as long as nine months. Overwintering migratory adults will roost in large colonies in forested sites in California and Mexico, which must provide protection from the elements and assist with thermoregulation.	No Potential	Although the species could potentially disperse through the BSA, suitable overwintering roosting habitat is absent and preferred plants were not observed. The species was not observed during surveys.
Lytta hoppingi Hopping's blister beetle	-/- -/-	This beetle species occurs in the foothills of the southern end of the Central Valley. Adults have often been found on flowers and have been collected from late March through June. Like other members of the *Lytta* genus, females excavate shallow burrows to oviposit. *Lytta* larvae are nest parasites of solitary bees.	No Potential	This species was not observed during site reconnaissance surveys. There is a single CNDDB record (EONDX 14398) approximately eight miles south of the BSA, it from 1978 and mapped generally to the city of Taft.
Protodufourea zavortinki Zavortink's protodufourea bee	-/- -/-	A species of sweat bees that are associated with Phacelia species for foraging purposes. This species has been documented in Kern and San Luis Obispo County.	No Potential	Neither this species nor its' associated host plant was observed during reconnaissance surveys. There is a single CNDDB record (EONDX 59989) approximately 2.5-miles west of the BSA, it from 1978 and mapped generally to the city of McKittrick.
Fish				

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Hypomesus transpacificus Delta smelt	FT/SE -/-	This is a small fish species endemic to the San Francisco Estuary and the larger Sacramento-San Joaquin Delta. It moves between freshwater and low salinity water throughout the year and most spawning happens in tidally influenced backwater sloughs and channel edge waters. It occurs primarily in main water bodies and sloughs of the Delta and Suisun Bay and is not directly associated with small stream systems. This species historical distribution does not extend beyond Mossdale on the San Joaquin River and Sacramento on the Sacramento River.	No Potential	The BSA lacks aquatic habitat capable of supporting this species and is outside of the known range.
Amphibians				
Spea hammondii western spadefoot	-/- -/SSC	This species relies on vernal pools for breeding where predators cannot become established. It occurs in open areas with sand or gravelly soils in a variety of habitats: grasslands, coastal scrub, woodlands, chaparral, sandy washes, lowland river floodplains, alkali flats, foothills, and mountains. This species is endemic to California and northern Baja California with a distribution from Redding south throughout Central Valley and foothills, throughout the South Coast mountain range into coastal southern California to Transverse mountains and Peninsular mountains. This species occurs at elevations ranging from sea level to 4,500 feet.	No Potential	There is no suitable breeding habitat, vernal pools, present within the BSA. The nearest CNDDB records of the species are located approximately three to five miles east of the BSA and are all adjacent to the California aqueduct.
Reptiles				

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Anniella alexanderae Temblor legless lizard	-/SC -/SSC	These lizards are only found in two sites, separated by continuous suitable habitat west of Highway 33, within the Temblor Range. The two sites are in areas of sandy soil at the southeast base of the Temblor Range between McKittrick and Taft on the west side of the Southern San Joaquin Valley in Kern County. They occur in moist warm loose soil with vegetation cover on beach dunes, chaparral, pine-oak woodlands, desert scrub, sandy washes, and stream terraces with sycamores, cottonwoods, or oaks. They can be found under rocks, boards, driftwood, logs, and leaf litter under bushes and trees. Breeding occurs between early spring and July with the young born between September and November.	No Potential	The BSA is outside of the current known range of the species, which is west of Highway 33 between Taft and McKittrick. Additionally, due to ongoing drought conditions, moist soil is absent from the BSA and therefore suitable habitat to support this species is absent. This species was not observed during reconnaissance surveys.
Anniella grinnelli Bakersfield legless lizard	-/- -/SSC	This species occurs in moist warm loose soil with sparsely vegetated areas of beach dunes, chaparral, pine-oak woodlands, desert scrub, sandy washes, and stream terraces with sycamores, cottonwoods, or oaks. It can be found under leaf litter from trees and bushes or under objects such as rocks, boards, driftwood, and logs. This species requires moisture in the soil. Breeding occurs between early spring and July with young born between September and November.	No Potential	Due to ongoing drought conditions moist soil, and therefore suitable habitat, is absent from the BSA. There is a single CNDDB record of this species (EONDX 121126) within ten miles of the BSA, it is from 2020 and is located approximately 8.75-miles northeast of the BSA in the city of Bakersfield where the species was observed adjacent to a canal. This species was not observed during reconnaissance surveys.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Anniella spp. California legless lizard	-/- -/SSC	This species occurs in moist, loose soils with sparsely vegetated areas of beach dunes, chaparral, pine-oak woodlands, desert scrub, sandy washes, and stream terraces with sycamores, cottonwoods, or oaks. It can be found under leaf litter from trees and bushes or under objects such as rocks, boards, driftwood, and logs. This species requires moisture in the soil. Breeding occurs between early spring and July with young born between September and November.	No Potential	Due to ongoing drought conditions moist soil, and therefore suitable habitat, is absent from the BSA. There are two CNDDB records of the species within ten miles of the BSA. The nearest (EONDX 106983) is from 2015 and is located approximately 3.70-miles west of the BSA, but it is noted as possibly extirpated due to development. This species was not observed during reconnaissance surveys.
Arizona elegans occidentalis California glossy snake	-/- -/SSC	This subspecies of glossy snake occurs from the eastern part of the San Francisco Bay south to northwestern Baja, California. It appears to prefer microhabitats of open areas with soil loose enough for easy burrowing. It inhabits arid scrub, rocky washes, grasslands, and chaparral. This species is nocturnal and hides under rocks, in existing burrows, or creates its own burrow during daylight hours. It is usually active from late February until November.	Potential	Suitable habitat including arid scrub and grassland is present within the BSA. There are multiple CNDDB records of this species within close proximity to the BSA. The nearest record (EONDX 104923) is from 2015 and is located approximately 2.46-miles west of the BSA, where the species was observed within habitat adjacent to State Route 58.
Emys marmorata western pond turtle	-/- -/SSC	This species is highly aquatic and diurnally active. It is found in ponds, lakes, rivers, streams, creeks, marshes, and irrigation ditches with vegetation and rocky or muddy bottoms in a wide variety of habitats. It needs basking areas near water (logs, rocks, vegetation mats, banks). This species may enter brackish water and even seawater and it digs a nest on land near water. It ranges from north of the San Francisco Bay area south, including the Central Valley.	No Potential	There were no perennial water sources to support this species observed within the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Gambelia sila blunt-nosed leopard lizard	FE/SE -/FP	This large lizard occurs in semiarid habitats within the southern Central Valley, Cuyama Valley, and Panoche Valley, at elevations between 100 and 2,400 feet. Preferred habitats are typically flat, sparsely vegetated grasslands with large open areas with scattered shrubs for cover, and sandy washes. The species spends most of the year underground in abandoned small mammal burrows, with adults surfacing in the spring and early summer to breed and feed. Young hatch in July and August, and both adults and young recede to refugia between August and November. Individuals feed primarily on grasshoppers and smaller lizards. The species is threatened mainly by habitat loss and fragmentation.	Potential	Suitable habitat is present within the BSA and there are multiple CNDBB records within close proximity, although none overlap. The nearest CNDDB record (EONDX 119287) is from 2017 and is located approximately 0.65-mile northwest of the BSA where the species was observed in saltbush scrub habitat. This species was not observed during reconnaissance surveys.
Masticophis flagellum ruddocki San Joaquin coachwhip	-/- -/SSC	This species occurs in open, dry, treeless areas with little or no cover. They are found in valley grassland and saltbush scrub habitats and avoid areas that are densely vegetated. They are found from the Sacramento Valley in Colusa County southward to the Grapevine in Kern County and westward to the inner South Coast Ranges. They are threatened by habitat loss and fragmentation, conversion of large suitable habitats to agricultural use in the San Joaquin Valley and urban development in the inner Coast Ranges.	Potential	Suitable habitat including open grassland and saltbush scrub is present within the BSA. The nearest CNDDB record (EONDX 113180) to the BSA is from 2017 and is located approximately 0.93-mile to the west where the species was observed at an oil field sump site. This species was not observed during reconnaissance surveys.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Phrynosoma blainvillii coast horned lizard	-/- -/SSC	This cryptic lizard prefers sandy, loose soils in grasslands, forests, woodlands, and open chaparral. Individuals are often found along sandy washes and dirt roads with scattered shrubs for cover. This species feeds almost exclusively on ants. It is found in coastal California from Baja California north to the Bay Area, southeastern desert regions, southern Central Valley flats and foothills and the surrounding mountains on drier, warmer slopes, at elevations up to 8,000 feet. The species is threatened by habitat loss and fragmentation and the spread of invasive ant species displacing native prey.	Potential	Marginally suitable habitat consisting of sandy, loose soils within grassland, as well as dirt roads occur within the BSA. However, this species was not observed during reconnaissance surveys and there are no CNDDB records within ten miles of the BSA and so potential for it to occur within the BSA is low.
Thamnophis gigas giant gartersnake	FT/ST -/-	This is a highly aquatic snake found in marshes and sloughs, drainage canals, and irrigation ditches and prefers sloughs to be flooded in summer and dry in winter. It prefers vegetation close to water for basking and typically does not venture more than 200 feet from aquatic habitat. It ranges in elevation from sea level to 400 feet. It is endemic to California and currently ranges from Glenn County to southern edge of San Francisco Bay Delta, and from Merced County to northern Fresno County.	No Potential	There were no suitable water sources, such as pools or creeks, observed within the BSA. This species was not observed during reconnaissance surveys and is not expected to occur within the BSA.
Birds				
Agelaius tricolor tricolored blackbird	-/ST -/-	This species is a year-round resident that is a colonial breeder. It occurs in freshwater, emergent wetlands with tall, dense cattails or tule, but also thickets of willow, blackberry, wild rose, and tall herbs. Breeding colonies consist of a minimum of approximately 50 pairs. This species forages for mostly insects and spiders and less often seeds and cultivated	No Potential	The BSA lacks aquatic habitat, and therefore habitat capable of supporting this species.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
		grains in pastures, grain fields, cropland, and similar habitats near breeding areas.		
Athene cunicularia burrowing owl	-/- -/SSC	This species occupies a variety of open, semi-arid to arid habitats throughout Central and Southern California, including desert regions. It prefers open habitats with few shrubs or trees and low-growing vegetation. It is most active around sunrise and sunset and utilizes burrows constructed by mammals year-round for shelter and nesting. This species is well documented in urban areas where patches of undeveloped areas are present (e.g., canals, airports, drainage basins), and in areas of dense agricultural development, particularly where canals provide burrow habitat. It forages primarily for rodents and insects within several miles of its burrow, usually in open grassy habitats if available. It has been observed hunting bats and insects around parking lot lights. Threats to this species include development resulting in habitat loss/fragmentation.	Present	Suitable habitat for foraging and burrowing is present within the BSA. There were no burrowing owls observed during the reconnaissance surveys, but multiple burrows showing diagnostic sign (whitewash, pellets, feathers) were observed. There are multiple CNDDB records within close proximity of the BSA, the nearest (EONDX 45077) is from 2000 and located approximately 2.10-miles southeast of the southern terminus.
Buteo swainsoni Swainson's hawk	-/ST -/-	This species occurs in grassland, desert and agricultural landscapes in the Central Valley and Antelope Valley. These hawks may be resident or migrant, and nest and breed in stands with few trees in juniper-sage flats, riparian areas, and oak savannah habitats. This species has also been observed nesting and breeding in large eucalyptus trees along freeways and in trees over rural residences surrounded by agriculture. Nests are a platform of sticks, bark, and fresh leaves at or near the top of trees. This species breeds from late	Foraging: Potential Nesting: No Potential	The BSA lacks suitable nesting habitat such as large trees but supports suitable foraging habitat and the species may occur as a transient. The nearest CNDDB record (EONDX 91375) is from 2017 and is located approximately 4.37-miles north of the BSA where a nest was observed in a large tamarisk tree.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
		March to late August. It forages in grassland, open scrub, and grain fields, primarily for rodents.		
Charadrius montanus mountain plover	-/- -/SSC	This terrestrial plover does not breed in California but is a winter resident and migrant between September and March, when it often forms large overwintering flocks. Preferred habitats include grasslands, open sagebrush, and plowed and grazed fields throughout central and southern California. Mountain plovers feed on large insects, especially grasshoppers.	No Potential	This species does not breed in California and the BSA does not support preferred winter habitat, such as plowed and grazed fields. The nearest CNDDB record (EONDX 40902) is from 1990 and located approximately 6.06-miles east of the BSA where the species was observed within the Tule Elk State Natural Reserve.
Charadrius nivosus nivosus western snowy plover	FT/- -/SSC	This is a ground nesting bird that occurs along sandy beaches, salt pond levees and shores of large alkali lakes. It prefers to nest on open bare ground in loose colonies or isolated pairs. It builds nests on a natural or shallow scrape in the ground and lined with bits of debris, pebbles, grass, and shell fragments. This species primarily feeds on terrestrial and aquatic invertebrates.	No Potential	The BSA lacks wetland habitat, and therefore habitat capable of supporting this species.
Coccyzus americanus occidentalis western yellow-billed cuckoo	FT/SE -/-	This migratory species nests in open riparian woodlands along broad lower flood bottoms of larger river systems. It prefers willows, often mixed with cottonwood, with understory of blackberry, nettles or wild grape. Its nest is most often placed in willows with cottonwoods used extensively for foraging and also occasionally nests in orchards adjacent to river bottoms.	No Potential	The BSA lacks riparian habitat, and therefore habitat capable of supporting this species.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Dendrocygna bicolor fulvous whistling-duck	-/- -/SSC	This duck occupies freshwater wetlands including marshes, marshy ponds, and flooded rice fields. It breeds from March to September in dense floating or flooded emergent vegetation. It is threatened by irregular species movements, pesticide contamination, habitat loss and degradation, agricultural and hunting disturbances.	No Potential	The BSA lacks wetland habitat, and therefore habitat capable of supporting this species.
Falco mexicanus prairie falcon	-/- -/WL	This falcon is primarily found in annual grasslands, savannahs, rangeland, some agricultural fields, and desert scrub. It breeds throughout the open county in the West. Nests are built on bluffs and cliffs at elevations ranging from alpine habitat to 11,000 feet. Breeding occurs in grasslands, areas of fixed shrubs, or alpine tundra. It is threatened by pesticides (reproduction failure), and degradation of habitat due to agricultural development.	Foraging: Potential Nesting: No Potential	The BSA lacks suitable nesting habitat such as bluffs and cliffs but supports suitable foraging habitat and the species may occur as a transient. The single CNDDB record (EONDX 18211) within ten miles overlaps the BSA and is from 1989, although it is mapped generally, and the exact location has been suppressed.
Gymnogyps californianus California condor	FE/SE -/FP	This condor has been documented in southern and northern California, northern Baja California, Oregon, southern British Columbia, and Arizona, Utah, and Nevada where the three states come together. It is a rare visitor to the San Joaquin Valley, found at elevation ranges from sea level to 9,000 feet. Their main characteristics sought for a nest site are 1) partially sheltered from the weather and 2) located on a cliff, steep slope, or tall trees. Nests are located between 2,000 to 6,500 feet in elevation. They are threatened by lead poisoning, micro trash ingestion, collisions, electrocution by powerlines, drownings, and predation. More recent threats have been from shootings.	No Potential	The BSA is below the known breeding range of the species and is not within habitat designated as critical to the species. There is a low potential the species may forage and disperse through the BSA, but no suitable nesting habitat is present, and the species is not anticipated to occur.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Lanius ludovicianus loggerhead shrike	-/- -/SSC	This species is a common resident in lowlands and foothills throughout California. It prefers open grassland and pasture habitats with scattered trees, fence posts, utility lines, shrubs, and other perches. This species primarily consumes large insects but will prey upon other small animals. It nests in densely foliaged and/or thorny shrubs and trees less than 50 feet above the ground.	Potential	Suitable foraging and nesting habitat is present in the BSA, although the species was not observed during site reconnaissance surveys. The nearest CNDDB record (EONDX 66869) is from 1999 and is located approximately 2.32-miles southwest of the northern terminus of the BSA.
Plegadis chihi white-faced ibis	-/- -/SSC	This bird occurs in freshwater wetlands, especially cattail and bulrush marshes. It rarely breeds in California and is an uncommon summer resident at some southern California localities. It nests in several marshes in the western United States and the Great Basin. This species forages in flooded hay meadows, agricultural fields, and estuarine wetlands. Its primary prey are insects, crustaceans, and earthworms.	No Potential	The BSA lacks wetland habitat, and therefore habitat capable of supporting this species.
Toxostoma lecontei Le Conte's thrasher	-/- -/SSC	This species is an uncommon-to-rare local resident in southern California deserts. It occurs in open desert wash, desert scrub, alkali desert scrub, desert succulent scrub, and Joshua tree habitat with scattered shrubs. It occurs from Mono County south to the Mexican border and in western and southern San Joaquin Valley. It has rarely been recorded north of Kern County after the 1950s. It feeds on insects and occasionally on seeds, small lizards, and other small vertebrates. It is threatened by loss of habitat due to oil and gas production, overgrazing, and pesticides (DDT).	Potential	Suitable foraging and nesting habitat is present in the BSA, although the species was not observed during site reconnaissance surveys. The nearest CNDDB record (EONDX 41609) is from 1999 and is located approximately 1.50-miles west of the northern terminus of the BSA where two adults were observed within saltbush scrub habitat within oil and gas development.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Vireo bellii pusillus least Bell's vireo	FE/SE -/-	This migratory species is a locally common summer resident ranging from coastal southern California through the Sacramento and San Joaquin valleys as far north as Red Bluff in Tehama County. It can also occur in the Sierra Nevada and Coast ranges, Owens and Death Valley and scattered locations within the Mojave Desert. It typically occurs at low elevation, riparian habitats with dense shrub understory. Nests are typically constructed in willows but mulefat, California wild rose, poison oak, mugwort, and cottonwoods may also be used. This species occurs below 2,000 feet in elevation. It primarily feeds on insects and is threatened by habitat loss and brood parasitism by the brown-headed cowbird.	No Potential	The BSA lacks riparian habitat, and therefore habitat capable of supporting this species.
Xanthocephalus xanthocephalus yellow-headed blackbird	-/- -/SSC	This species is a migratory and summer resident in Central Valley from mid-April to late July. It occurs in marshes and pockets of habitat along rivers and tributaries, typically with tall emergent vegetation. Nearby water levels in nesting habitat are approximately 2.0 to 4.0 feet deep. This species forages on seeds and cultivated grain but during the breeding season they may eat insects. It is susceptible to pesticide and threatened by loss due to wetland drainage for irrigation, flood control, or water diversions.	No Potential	The BSA lacks riparian habitat, and therefore habitat capable of supporting this species.
Mammals				

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Ammospermophilus nelsoni Nelson's (=San Joaquin) antelope squirrel	-/ST -/-	This species occurs in saltbush scrub and grassland habitats and prefers washes and open shrub areas with sandy soils. Known populations occur in Lokern Natural Area, Elk Hills Carrizo and Elkhorn Plains, Temblor Range and foothills and interior valleys of the Diablo Range and as far north as Merced and San Benito counties. It feeds primarily on insects, green vegetation, seeds, and occasionally on small vertebrates. This species can excavate burrows or use kangaroo rat burrows for temperature regulation, litter-rearing, shelter, and escape from predators. It is threatened by habitat loss and population fragmentation from agricultural development, urbanization, petroleum extraction, and excessive cattle grazing.	Present	Multiple observations of this species were made during site reconnaissance surveys and suitable habitat is present within the BSA. There are numerous CNDDB record surrounding the BSA, several of which are overlapping. The most recent record (EONDX 114570) overlapping the BSA is from 2018.
Dipodomys ingens giant kangaroo rat	FE/SE -/-	This species occurs in native annual grassland and shrubland habitats with vegetated annual grass and forbs and scattered desert shrubs. It is known only to six major geographic units: Panoche Region, Kettleman Hills, San Juan Creek Valley, western Kern County (Lokern, Elk Hills, McKittrick, Taft, and Maricopa), Carrizo Plain Natural Area, and Cuyama Valley and occurs at elevations between 280 to 2,800 feet. It excavates burrows on level or gentle slopes with friable, sandy, well-drained soils and is a nocturnal foraging species. It is threatened by habitat loss, fragmentation, and degradation, and drought and also by land conversions to agricultural, industrial, and urban developments.	Potential	This species was not observed during site reconnaissance surveys, but appropriately sized burrows displaying sign consistent with use by kangaroo rat were observed throughout sections of the BSA within suitable habitat. Suitable habitat is present within the BSA and there are multiple CNDDB records in close proximity to the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Dipodomys nitratoides brevinasus short-nosed kangaroo rat	-/- -/SSC	This is a subspecies of the San Joaquin kangaroo rat (Dipodomys nitratoides) that occurs on friable soils on flat or gentle slops within grassland or desert scrub habitat. The current range is unknown but there are fragmented populations in Pleasant Valley, Kettleman and Lost Hills, Lokern, Elk Hills, San Emigdio, Wheler Ridge, Carrizo Plain Natural Area, and Caliente Mountains. It excavates burrows on higher ground and is a nocturnal foraging species. It is threatened by random catastrophic events (i.e., drought, flooding, fire), overgrazing of rangeland, and extensive land conversion to agriculture from the 1960s through 1970s.	Potential	This species was not observed during site reconnaissance surveys, but appropriately sized burrows displaying sign consistent with use by kangaroo rat were observed throughout sections of the BSA within suitable habitat. Suitable habitat is present within the BSA, there are multiple CNDDB records in close proximity to the BSA, and several records that overlap the BSA.
Dipodomys nitratoides nitratoides Tipton kangaroo rat	FE/SE -/-	This is a subspecies of the San Joaquin kangaroo rat (Dipodomys nitratoides) that occurs in valley saltbush scrub, valley sink scrub, and grasslands. It is historically known to occur in the southern San Joaquin Valley from southern margins on Tulare Lakebed near Lemoore and Hanford, and on the valley floor in Tulare and Kern counties but now is found only east of the California Aqueduct. Population distribution is not continuous and occurs only in small, isolated patches. It is a nocturnal foraging species that excavates burrows for temperature regulation, litter-rearing, shelter, and escape from predators. This species is threatened by habitat loss, fragmentation, degradation and by land conversions to agricultural, industrial, and urban developments, but it can quickly inhabit fallow agricultural fields if a source population is nearby.	No Potential	The BSA is outside of the known geographic range (east of the California aqueduct) of the species.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Eumops perotis californicus western mastiff bat	-/- -/SSC	This species occurs in open, semi-arid to arid habitats throughout southeastern San Joaquin Valley and Coast Ranges from Monterey County southward. It can also occur in urban areas. It feeds on insects captured in flight and roosts in cliff faces, high buildings, trees, and tunnels. The maternity season begins in March with young typically volant by September. Nursery roosts most often occur in tight rock crevices or crevices in buildings.	No Potential	No suitable roosting habitat (cliff faces, high buildings, trees, or tunnels) was observed within the BSA. There are four CNDDB records within ten miles of the BSA, all are from the 1950's and mapped generally as the exact location is unknown. The nearest record (EONDX 66382) is form 1959 and located approximately 4.65-miles southwest of the BSA near the city of Derby Acres. Based on the lack of nearby roosting sites, this species is not expected to be encountered within the BSA.
Onychomys torridus tularensis Tulare grasshopper mouse	-/- -/SSC	This subspecies occurs in shrubland communities in hot, arid grassland and shrubland associations. These include blue oak woodlands, upper Sonoran subshrub scrub, alkali sink and mesquite associations on the Valley Floor, and grasslands associations on the sloping margins of the San Joaquin Valley and Carrizo Plain region. This subspecies occupies burrows and feeds primarily on invertebrates but may supplement its diet with seeds and other small mammals.	Potential	This species was not observed during site reconnaissance surveys; however, potentially suitable burrows were observed within areas of suitable habitat (undisturbed grassland and saltbush scrub) during the site survey. The nearest CNDDB record (EONDX 23826) is from 1957 and located approximately 0.75 mile north of the BSA.
Perognathus inornatus San Joaquin pocket mouse	-/- -/-	This nocturnal species is found in dry, open grasslands and scrublands on fine-textured soils in the Central (mostly west side) and Salinas valleys at elevations from 1,100 to 2,000 feet. It digs its own burrows for cover, breeding, and seed caching.	Potential	This species was not observed during site reconnaissance surveys; however, potentially suitable burrows were observed within areas of suitable habitat (undisturbed grassland and saltbush scrub) during the site survey. The nearest CNDDB record (EONDX 65635) is from 1991 and overlaps the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
Sorex ornatus relictus Buena Vista Lake ornate shrew	FE/- -/SSC	This shrew species occurs in moist soil conditions in marsh habitat with dense emergent vegetation and/or leaf litter and is often associated with cottonwoods, willows, alkali heath, wild rye grass, and Baltic rush. Historically, this species occurred in and around the Buena Vista Lake and Tulare Lake Basins and was once thought to be extinct but was rediscovered at Kern Lake Preserve in 1986. It is primarily insectivorous. Reproduction typically occurs from late February to September or early October and the litter size varies.	No Potential	The BSA lacks habitat capable of supporting this species.
Taxidea taxus American badger	-/- -/SSC	This species occurs mostly in open, drier stages of shrub, forest, and herbaceous habitats, with friable soils. It feeds mostly on fossorial rodents. It digs burrows for cover and reproduction and can dig a new den each night. Litters are typically born in March and April. This species can be somewhat tolerant of human activities but generally avoids cultivated agricultural habitats.	Potential	This species was not observed during site reconnaissance surveys; however, suitable habitat is present within the BSA, and potential dens were observed during site surveys. The nearest CNDDB record (EONDX 49676) is from 1999 and located approximately one mile northwest of the BSA.
Vulpes macrotis mutica San Joaquin kit fox	FE/ST -/-	This fox species is endemic to the Central Valley and primarily occurs in arid to semi-arid grasslands, open shrublands, savannahs, and grazed lands with loose-textured soils within the San Joaquin Valley, Carrizo Plain, Salinas Valley, Cuyama Valley, and other small valleys in western foothills. Intensively maintained agricultural areas are typically avoided. It is highly adaptable and documented in urban developed areas. It uses burrows year-round for shelter, escape from predators, and rearing young and it will use man-made structures, such as pipes, for denning. Kit fox feed	Potential	This species was not observed during site reconnaissance surveys; however, suitable habitat is present within the BSA, and potential dens were observed during site surveys. There are numerous CNDDB records of the species in the vicinity of the BSA, several of which overlap the BSA.

Scientific Name Common Name	Status Fed/State ESA CRPR/CDFW	Habitat Requirements	Potential to Occur	Rationale
		primarily on small mammals, but will also consume birds, reptiles, insects, and scavenge for human food. It is threatened by habitat loss and fragmentation, vehicle strikes, and disease such as the current mange outbreak in urban population in Bakersfield and in nearby natural areas.		

APPENDIX B

REGULATORY SETTING

Regulatory Setting

Federal Laws and Regulations

Federal Endangered Species Act of 1973 (USC, Title 16, Sections 1531 -1543)

The federal Endangered Species Act (FESA) and subsequent amendments provide guidance for the conservation of endangered and threatened species and the ecosystems upon which they depend. The FESA defines species as threatened or endangered and provides regulatory protection for listed species. The FESA provides a program for the conservation and recovery of threatened and endangered species as well as the protection of designated critical habitat that USFWS determines is required for the survival and recovery of listed species.

Section 9 lists actions that are prohibited under the FESA. Although take of a listed species is prohibited, it is allowed when it is incidental to an otherwise legal activity. Section 9 prohibits take of listed species of fish, wildlife, and plants without special exemption. The definition of "harm" includes significant habitat modification or degradation that results in death or injury to listed species by significantly impairing behavioral patterns related to breeding, feeding, or shelter. "Harass" is defined as actions that create the likelihood of injury to listed species by disrupting normal behavioral patterns related to breeding, feeding, and shelter significantly.

Section 7 of the FESA requires federal agencies, in consultation with and assistance from the Secretary of the Interior or the Secretary of Commerce, as appropriate, to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of threatened or endangered species or result in the destruction of adverse modification of critical habitat for these species. The USFWS and National Marine Fisheries Service (NMFS) share responsibilities for administering the FESA. Regulations governing interagency cooperation under Section 7 are found in California Code of Regulations (CCR) Title 50, Part 402. If an activity could result in "take" of a listed species as an incident of an otherwise lawful activity, then a biological opinion can be issued with an incidental take statement that exempts the activity from FESA's take prohibitions.

Section 10 provides a means whereby a nonfederal action with the potential to result in take of a listed species can be allowed under an incidental take permit. Application procedures are found at CFR Title 50, Sections 13 and 17 for species under the jurisdiction of USFWS and CFR, Title 50, Sections 217, 220, and 222 for species under the jurisdiction of NMFS. Section 10 would apply to the Project if take of a species (as defined in Section 9) were determined to occur.

Section 4(a)(3) and (b)(2) of the FESA requires the designation of critical habitat to the maximum extent possible and prudent based on the best available scientific data and after considering the economic impacts of any designations. Critical habitat is defined in section 3(5)(A) of the FESA: 1) areas within the geographic range of a species that are occupied by individuals of that species and contain the primary constituent elements (physical and biological features) essential to the conservation of the species, thus warranting special

management consideration or protection; and 2) areas outside of the geographic range of a species at the time of listing but that are considered essential to the conservation of the species.

MIGRATORY BIRD TREATY ACT (USC, TITLE 16, SECTIONS 703 - 711)

The MBTA, first enacted in 1918, is a series of treaties that the United State has with Great Britain (on behalf of Canada), Mexico, Japan, and the former Soviet Union that provide for international migratory bird protection. The MBTA authorizes the Secretary of the Interior to regulate the taking of migratory birds. The act provides that it shall be unlawful, except as permitted by regulations, "to pursue, take, or kill any migratory bird, or any part, nest or egg of any such bird" (U.S. Code Title 16, Section 703). The MBTA currently includes several hundred species and includes all native birds.

BALD AND GOLDEN EAGLE PROTECTION ACT OF 1940 (USC, TITLE 16, SECTION 668)

The Bald and Golden Eagle Protection Act (BGEPA) of 1940 protects bald eagles (*Haliaeetus leucoephalus*) and golden eagle (*Aquila chrysaetos*) by prohibiting the taking, possession, and commerce of these species and established civil penalties for violation of this act. Take of bald and golden eagles includes to "pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb." To disturb means to agitate or bother a bald or golden eagle to a degree that causes, or is likely to cause, based on the best scientific information available, 1) injury to an eagle, 2) a decrease in its productivity, by substantially interfering with normal breeding, feeding, or sheltering behavior, or 3) nest abandonment, by substantially inferring with normal breeding, feeding, or sheltering behavior. (Federal Register [FR], volume 72, page 31132; 50 CFR 22.3).

FEDERAL CLEAN WATER ACT (USC, TITLE 33, SECTIONS 1521 - 1376)

The Federal Clean Water Act (CWA) provides guidance for the restoration and maintenance of the chemical, physical, and biological integrity of the nation's waters. Section 401 requires that a Project applicant that is pursuing a federal license or permit allowing a discharge to waters of the U.S. to obtain State Certification of Water Quality, thereby ensuring that the discharge will comply with provisions of the CWA. The Regional Water Quality Control Board administers the certification program in California. Section 402 establishes a permitting system for the discharge of any pollutant (except dredged or fill material) into waters of the U.S. Section 404 establishes a permit program administered by the United States Army Corps of Engineers (USACE) that regulates the discharge of the dredged or fill material into waters of the U.S., including wetlands. The USACA implementing regulations are found in CFR, Title 33, Sections 320 and 330. Guidelines for implementation are referred to as the Section 404(b)(1) Guidelines, which were developed by the United States Environmental Protection Agency (EPA) in conjunction with USACE (40 CFR 230). The guidelines allow the discharge of dredged or fill material into the aquatic system only if there is no practicable alternative that would have less adverse impacts.

Applicable State Laws and Regulations

California Environmental Quality Act (California Public Resources Code, Sections 21000 - 21178, and Title 14 CCR, Section 753, and Chapter 3, Sections *15000 - 15387)*

The California Environmental Quality Act (CEQA) is California's broadest environmental law. CEQA helps guide the issuance of permits and approval of projects. Courts have interpreted CEQA to afford the fullest protection of the environment within the reasonable scope of the statutes. CEQA applies to all discretionary projects proposed to be conducted or approved by a State, County, or City agency, including private projects requiring discretionary government approval.

The purpose of CEQA is to disclose to the public the significant environmental effects of a proposed discretionary project; prevent or minimize damage to the environment through development of project alternatives, mitigation measures, and mitigation monitoring; disclose to the public the agency decision making process to approve discretionary projects; enhance public participation in the environmental review process; and improve interagency coordination.

State CEQA Guidelines Section 15380(b) provides that a species not listed on the federal or State list of protected species nonetheless may be considered rare or endangered for purposed of CEQA if the species can be shown to meet certain specified criteria. These criteria have been modeled after the definition in FESA and the section of the California Fish and Game Code dealing with rare or endangered plants or animals.

California Endangered Species Act (California Fish and Game Code Section 2050 et seq.)

The California Endangered Species Act (CESA) establishes the policy of the State to conserve, protect, restore, and enhance threatened or endangered species and their habitats. The CESA mandates that State agencies should not approve Projects that would jeopardize the continued existence of threatened or endangered species if reasonable and prudent alternatives are available that would avoid jeopardy. For Projects that would result in take of a species listed under the CESA, a project proponent would need to obtain a take permit under Section 2081(b). Alternatively, the CDFW has the option of issuing a Consistency Determination (Section 2080.1) for Projects that would affect a species listed under both the CESA and the FESA, as long as compliance with the FESA would satisfy the "fully mitigate" standard of CESA, and other applicable conditions.

Porter-Cologne Water Quality Control Act

Under Section 401 of the CWA, the RWQCB must certify that actions receiving authorization under Section 404 of the CWA also meet State water quality standards. The RWQCB regulates waters of the State under the authority of the Porter-Cologne Water Quality Control Act (Porter Cologne Act). The RWQCB requires Projects to avoid impacts to wetlands whenever feasible and requires that Projects do not result in a net loss of wetland acreage or a net loss

of wetland function and values. The RWQCB typically requires compensatory mitigation for impacts to wetlands and/or waters of the State. The RWQCB has jurisdiction over waters deemed 'isolated' or not subject to Section 404 jurisdiction under the Solid Waste Agency of Northern Cook County (SWANCC) decision. Dredging, filling, or excavation of isolated waters constitutes a discharge of waste into waters of the State, and such discharges are authorized through an Order of Waste Discharge (or waiver of discharge) from the RWQCB.

VARIOUS SECTIONS OF THE CALIFORNIA STATE AND FISH AND GAME CODE

Section 460 and Sections 4000-4003

Chapter 5 of the California Fish and Game Code (FGC) describes regulations concerning the take of furbearing mammals, including defining methods of take, seasons of take, bag and possession limits, and areas of the State where take is allowed. Section 4000-4003 defines furbearing mammals, and the issuance of permits by the Department. Sections 460 and 4000 identifies fisher, marten, river otter, desert kit fox and red fox as furbearing mammals, and Section 460 prohibits take of these species at any time. This section of the California Fish and Game Code (FGC) has historically been interpreted to apply to restriction on furbearer trapping permit but has recently been expanded by CDFW to apply to any forms of take and treated as if these species were listed under CESA.

Sections 1600 through 1616

Under these sections of the FGC, a Project operator is required to notify CDFW prior to any Project that would divert, obstruct, or change the natural flow, bed, channel, or bank of any river, stream, or lake. Pursuant to the California Code of Regulations, a "stream" is defined as a body of water that flows at least periodically, or intermittently, through a bed or channel having banks and supporting fish or other aquatic life. Based on this definition, a watercourse with surface or subsurface flows that supports of has supported riparian vegetation is a stream and is subject to CDFW jurisdiction. Altered or artificial watercourses valuable to fish and wildlife are subject to CDFW jurisdiction. CDFW also has jurisdiction over dry washes that carry water during storm events. Preliminary notification and Project review generally occur during the environmental process. When an existing fish or wildlife resource may be substantially adversely affected, CDFW is required to propose reasonable Project changes to protect the resource. These modifications are formalized in a Streambed Alteration Agreement.

Sections 3511, 4700, 5050, and 5515

The protection of fully protected species are described in Sections 3511, 4700, 5050, and 5515 of the FGC. These statues prohibit take or possession of fully protected species. CDFW is unable to authorize incidental take of fully protected species, except as allowed for in an approved Natural Communities Conservation Plan (NCCP), or through direct legislative action.

Sections 1900 through 1913 - Native Plant Protection Act

California's Native Plant Protection Act (NPPA) requires all State agencies to use their authority to carry out programs to conserve endangered and rare native plants. Provision of the NPPA prohibit that taking of listed plants from the wild and require notification of CDFW at least ten days in advance of any change in land use. This allows CDFW to salvage listed plant species that otherwise would be destroyed. A Project proponent is required to conduct botanical inventories and consult with CDFW during Project planning to comply with the provisions of this act and sections of CEQA that apply to rare or endangered plants.

Local and Regional Laws, Regulations, and Policies

KERN COUNTY GENERAL PLAN (KCGP)

The KCGP identifies the federal, State, and local statutes, ordinances, or policies that govern the conservation of biological resources that must be considered by Kern County (County) during the decision-making process for any project that could impact biological resources.

Land Use, Open Space, and Conservation Element. The Land Use, Open Space, and Conservation Element of the KCGP states that the element provides for a variety of land uses for future economic growth while also assuring the conservation of County's agricultural, natural, and resource attributes. Section 1.10, General Provisions, provides goals, policies, and implementation measures that apply to all types of discretionary projects.

Policies	
Policy 27.	Threatened or endangered plant and wildlife species should be protected in accordance with State and federal laws.
Policy 28.	County should work closely with State and federal agencies to assure that discretionary projects avoid or minimize impacts to fish, wildlife, and botanical resources.
Policy 29.	The County will seek cooperative efforts with local, State, and federal agencies to protect listed threatened and endangered plant and wildlife species through the use of conservation plans and other methods promoting management and conservation of habitat lands.
Policy 27.	The County will seek cooperative efforts with local, State, and federal agencies to protect listed threatened and endangered plant and wildlife species through the use of conservation plans and other methods promoting management and conservation of habitat lands.
Policy 30.	The County will promote public awareness of endangered species laws to help educate property owners and the development community of local, State, and federal programs concerning endangered species conservation issues.

Policy 31.	Under the provisions of the California Environmental Quality Act (CEQA), the County, as lead agency, will solicit comments from the California Department of Fish and Game and the U.S. Fish and Wildlife Service when an environmental document (Negative Declaration, Mitigated Negative Declaration, or Environmental Impact Report) is prepared.
Implementation Measures	
Implementation Measure Q.	Discretionary projects shall consider effects to biological resources as required by the California Environmental Quality Act.
Implementation Measure R.	Consult and consider the comments from responsible and trustee wildlife agencies when reviewing a discretionary project subject to the California Environmental Quality Act.
Implementation Measure S.	Pursue the development and implementation of conservation programs with State and federal wildlife agencies for property owners desiring streamlined endangered species mitigation programs.

Source: (Kern County, 2003)

RECOVERY PLAN FOR UPLAND SPECIES OF THE SAN JOAQUIN VALLEY

Recovery plans delineate reasonable actions that are believed to be required to recover and protect listed species. Plans are published by the U.S. Fish and Wildlife Service, sometimes prepared with the assistance of recovery teams, contractors, State agencies, and others. A recovery plan delineates, justifies, and schedules the research and management actions necessary to support recovery of a species. Recovery plans do not, of themselves, commit manpower or funds, but are used in setting regional and national funding priorities and providing direction to local, regional, and State planning efforts. The Recovery Plan for Upland Species of the San Joaquin Valley provides individual species accounts for 34 San Joaquin Valley species listed as federally protected or as candidates or species of concern.

APPENDIX C

REPRESENTATIVE PHOTOGRAPHS



Photograph 1: Representative view of existing wellpad and adjacent saltbush scrub habitat fragments.
GPS coordinates: 35.329751, -119.543047, facing southeast.
Photograph taken by Mitch Wayman on September 23, 2022.



Photograph 2: Representative view of existing pipeline route and adjacent habitat fragments.
GPS coordinates: 35.292959, -119.527528, facing east.
Photograph taken by Eric Madueno on December 15, 2022.



Photograph 3: Representative view of saltbush scrub habitat.
GPS coordinates: 35.274632, -119.464994, facing north.
Photograph taken by Mitch Wayman on October 17, 2022.



Photograph 4: Representative view of established pipeline route and adjacent habitat fragments.
GPS coordinates: 35.281262, -119.488705, facing east.
Photograph taken by Courtney Chaney on October 12, 2022.



Photograph 5: Representative photo of NHD/NWI drainage with no water and upland vegetation.
GPS coordinates: 35.315618, -119.54909, facing east.
Photograph taken by Karissa Denney on September 21, 2022.



Photograph 6: Representative photo of potentially suitable kangaroo rat burrow.
GPS coordinates: 35.31573, -119.545111.
Photograph taken by Eric Madueno on December 15, 2022.



Photograph 7: Representative photo of active San Joaquin antelope squirrel burrow.
GPS coordinates: 35.323186, -119.544908.
Photograph taken by Eric Madueno on December 14, 2022.



Photograph 8: Representative photo of potentially suitable kangaroo rat burrow.
GPS coordinates: 35.282469, -119.482045.
Photograph taken by Lauren Fah on October 03, 2022.



Photograph 9: Representative photo of potential San Joaquin kit fox den.
GPS coordinates: 35.281416, -119.494471.
Photograph taken by Lauren Fah on October 12, 2022.



Photograph 10: Representative photo of potential San Joaquin kit fox den.
GPS coordinates: 35.28669, -119.50617.
Photograph taken by Mitch Wayman on October 12, 2022.

APPENDIX D

PLANT AND ANIMAL SPECIES OBSERVED WITHIN THE BIOLOGICAL SURVEY AREA

Table D-1
Plant Species Observed within the Biological Study Area
Carbon TerraVault 1 Project, Kern County, California

Scientific Name	Common Name	Status	Native or Introduced
Shrubs			
Ambrosia salsola	cheesebush		Native
Atriplex polycarpa	allscale saltbush		Native
Atriplex spinifera	spinescale saltbush		Native
Ericameria linearifolia	interior goldenbush		Native
Eriogonum fasciculatum	California buckwheat		Native
Gutierrezia californica	matchweed		Native
Helianthus annuus	common sunflower		Native
Isocoma acradenia	alkali goldenbush		Native
Peritoma arborea	bladderpod		Native
Herbs			
Amaranthus palmeri	Palmer's amaranth		Native
Ambrosia acanthicarpa	annual burweed		Native
Amsinckia sp.	fiddleneck		Native
Astragalus sp.	milkvetch		Native
Brassica nigra	black mustard	CAL-IPC*: Moderate	Introduced
Centaurea melitensis	tocalote	CAL-IPC: Moderate	Introduced
Centaurea solstitialis	yellow starthistle	CAL-IPC: High	Introduced
Chenopodium album	lamb's quarters		Introduced
Croton setigerus	turkey mullein		Native
Cucurbita palmata	coyote melon		Native
Datura wrightii	jimsonweed		Native
Erigeron canadensis	horseweed		Native
Erodium cicutarium	redstem filaree	CAL-IPC: Limited	Introduced
Euphorbia albomarginata	rattlesnake sandmat		Native
Hirschfeldia incana	short podded mustard	CAL-IPC: Moderate	Introduced
Lactuca serriola	prickly lettuce		Introduced
Salsola tragus	Russian thistle	CAL-IPC: Limited	Introduced
Solanum elaeagnifolium	silverleaf nightshade		Introduced
Stephanomeria pauciflora	wire lettuce		Native
Tribulus terrestris	puncture vine	CAL-IPC: Limited	Introduced
Grasses			
Avena fatua	wild oat	Cal-IPC: Moderate	Introduced
Bromus diandrus	ripgut brome	CAL-IPC: Moderate	Introduced
Bromus rubens	red brome	CAL-IPC: High	Introduced
Bromus tectorum	downy brome	CAL-IPC: High	Introduced
Schismus arabicus	Arabian schismus	CAL-IPC: Limited	Introduced

*Cal-IPC = California Invasive Plant Council.
Rating system: **High** = several ecological impacts; **Moderate** = substantial but not severe ecological impacts; **Limited** = minor ecological impacts or not enough information to justify higher score; **Alert** = species ranked as High or Moderate with limited distribution, but potential to spread; **Watch** = could pose a high risk of becoming invasive in the future.

Table D-2
Animal Species Observed within the Biological Study Area
Carbon TerraVault 1 Project, Kern County, California

Scientific Name	Common Name	Native or Introduced
Birds		
Aphelocoma californica	California scrub-jay	Native
*Athene cunicularia**	burrowing owl	Native - SSC
Buteo jamaicensis	red-tailed hawk	Native
Callipepla californica	California quail	Native
Cathartes aura	turkey vulture	Native
Corvus brachyrhynchos	American crow	Native
Corvus corax	common raven	Native
Eremophila alpestris	horned lark	Native
Falco sparverius	American kestrel	Native
Mimus polyglottos	northern mockingbird	Native
Sayornis nigricans	black phoebe	Native
Sayornis saya	Say's phoebe	Native
Streptopelia decaocto	Eurasian collared dove	Introduced
Sturnella neglecta	western meadowlark	Native
Tyrannus verticalis	western kingbird	Native
Zenaida macroura	mourning dove	Native
Reptiles		
Aspidoscelis tigris	western whiptail	Native
Crotalus oreganus	Pacific rattlesnake (northern)	Native
Uta stansburiana	common side-blotched lizard	Native
Mammals		
Ammospermophilus nelsoni	San Joaquin antelope squirrel	Native - ST
Dipodomys sp.*	kangaroo rat	Native
Lepus californicus	black-tailed jackrabbit	Native
Otospermophilus beecheyi	California ground squirrel	Native
Sylvilagus audubonii	desert cottontail	Native
*Taxidea taxus**	American badger	Native - SSC
*Thomomys bottae**	Botta's pocket gopher	Native
*Vulpes macrotis mutica**	San Joaquin kit fox	Native - FE/ST

*Observed sign only i.e.: scat, tracks, prey remains, den, burrow, etc.

FE Federally Endangered
SE State Endangered
ST State Threatened
SSC State Species of Special Concern
SFP State Fully Protected

C.2 Conservation Easement Deed – Elk Hills Conservation Area

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Recording Requested by
CHICAGO TITLE COMPANY
Order No. 5411032b

James W. Fitch, Assessor-Recorder
Kern County Official Records

SR
1/07/2013
08:22 AM

Recorded Electronically by:
203 Chicago Title

DOC #: 000213002006

000213002006

Stat Types: 1	Pages: 18
FEES	66.00
TAXES	.00
OTHER	.00
PAID	66.00

RECORDING REQUESTED BY AND
WHEN RECORDED MAIL TO:

State of California
Wildlife Conservation Board
1807 13th Street, Suite 103
Sacramento, CA 95811-7117

Space Above Line for Recorder's Use Only

CONSERVATION EASEMENT DEED

THIS CONSERVATION EASEMENT DEED is made this 3rd day of October, 2012, by Occidental of Elk Hills, Inc., a Delaware Corporation ("OEHI" or "Grantor"), in favor of THE STATE OF CALIFORNIA ("Grantee"), acting by and through its Department of Fish and Game, a subdivision of the California Natural Resources Agency, with reference to the following facts:

RECITALS

A. Grantor is the sole owner in fee simple of certain real propertycontaining approximately 6,314 acres, located in the County of Kern, State of California, and described in Exhibit "A" attached hereto and incorporated herein by this reference (the "Property");

B. The Property possesses wildlife and habitat values (collectively, "conservation values") of great importance to Grantee and the people of the State of California;

C. The Property contains Valley Saltbush Scrub and other related habitats, and provides high quality habitat for endangered, threatened or other sensitive species such as San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, and San Joaquin antelope squirrel;

D. The Department of Fish and Game ("CDFG") has jurisdiction, pursuant to Fish and Game Code Section 1802, over the conservation, protection, and management of fish, wildlife, native plants and the habitat necessary for biologically sustainable populations of those species, and CDFG is authorized to hold easements for these purposes pursuant to Civil Code Section 815.3, Fish and Game Code Section 1348, and other provisions of California law.

E. This Conservation Easement provides mitigation for certain impacts of oil and gas production facilities and activities at the Elk Hills oil field, located in the County of Kern, State of California, pursuant to (1) the Biological Opinion issued by the U.S. Fish and Wildlife Service ("USFWS") to the U.S. Department of Energy on November 8, 1995 (No. 1-1-95-F-102), the rights and obligations of which were assigned to OEHI on February 5, 1998 in accordance with Section 3413 of Public Law 104-106 ("BiOp"); (2) a California Endangered Species Act Memorandum of Understanding and Take Authorization between OEHI and CDFG (December

1997), as amended (2010) ("MOU"); and (3) a Conservation Management Agreement/Declaration of Restrictions for the Elk Hills Unit between OEHI, CDFG and USFWS, dated November 6, 1998 ("CMA"). It is anticipated that the terms of the MOU and the CMA will be superseded by a Habitat Conservation Plan and associated State Incidental Take Permit pursuant to Fish and Game Code Section 2081 et. seq.

COVENANTS, TERMS, CONDITIONS AND RESTRICTIONS

For good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, and pursuant to California law, including Civil Code Section 815, *et seq.*, Grantor hereby voluntarily grants and conveys to Grantee a conservation easement in perpetuity over the Property.

1. Purposes. The purposes of this Conservation Easement are to ensure the Property will be retained forever in its natural condition and to prevent any use of the Property that will significantly impair or interfere with the conservation values of the Property, subject to Grantor's Reserved Rights as stated herein. Grantor intends that this Conservation Easement will confine the use of the Property to such activities that are consistent with those purposes, including, without limitation, those involving the preservation, restoration and enhancement of native species and their habitats, and minor oil and gas activities as provided in Grantor's Reserved Rights.

2. Grantee's Rights. To accomplish the purposes of this Conservation Easement, Grantor hereby grants and conveys the following rights to Grantee:

(a) To preserve and protect the conservation values of the Property consistent with this Conservation Easement;

(b) To enter upon the Property at reasonable times upon reasonable notice in order to monitor compliance with and otherwise enforce the terms of this Conservation Easement, and for scientific research and interpretive purposes by Grantee or its designees, provided that Grantee shall not unreasonably interfere with Grantor's authorized use and quiet enjoyment of the Property;

(c) To prevent any activity on or use of the Property that is inconsistent with the purposes of this Conservation Easement and to require the restoration of such areas or features of the Property that may be damaged by any act, failure to act, or any use that is inconsistent with the purposes of this Conservation Easement;

(d) All air and water rights necessary to protect and to sustain the biological resources of the Property, subject to Grantor's Reserved Rights; and

(e) All present and future development rights allocated, implied, reserved or inherent in the Property, except for Grantor's Reserved Rights; such development rights are hereby terminated and extinguished, and may not be used on or transferred to any portion of the Property, nor any other property adjacent or otherwise.

3. Prohibited Uses. Any activity on or use of the Property inconsistent with the purposes of this Conservation Easement is prohibited. Without limiting the generality of the foregoing, the following uses and activities by Grantor, Grantor's agents, and third parties, are expressly prohibited except insofar as they are allowed under Grantor's Reserved Rights:

(a) Unseasonal watering; use of fertilizers, pesticides, biocides, herbicides or other agricultural chemicals; weed abatement activities; incompatible fire protection activities; and any and all other activities and uses which may adversely affect the purposes of this Conservation Easement;

(b) Use of off-road vehicles and use of any other motorized vehicles except on existing roadways;

(c) Agricultural activity of any kind, except that grazing is permitted if done in accordance with a CDFG-approved grazing or management plan;

(d) Recreational activities including, but not limited to, horseback riding, biking, hunting or fishing, except as may be specifically permitted under this Conservation Easement;

(e) Commercial or industrial uses;

(f) Any legal or de facto division, subdivision or partitioning of the Property;

(g) Construction, reconstruction or placement of any building, billboard or sign, or any other structure or improvement of any kind;

(h) Depositing or accumulation of soil, trash, ashes, refuse, waste, bio-solids or any other materials;

(i) Planting, introduction or dispersal of non-native or exotic plant or animal species;

(j) Filling, dumping, excavating, draining, dredging, mining, drilling, removing or exploring for or extraction of minerals, loam, soil, sands, gravel, rocks or other material on or below the surface of the Property;

(k) Altering the surface or general topography of the Property, including building of roads;

(l) Removing, destroying, or cutting of trees, shrubs or other vegetation, except as required by law for (1) fire breaks, (2) maintenance of existing foot trails or roads, or (3) prevention or treatment of disease; and

(m) Manipulating, impounding or altering any natural water course, body of water or water circulation on the Property, and activities or uses detrimental to water quality, including but not limited to degradation or pollution of any surface or sub-surface waters.

4. Grantor's Duties. Grantor shall undertake all reasonable actions to prevent the unlawful entry and trespass by persons whose activities may degrade or harm the conservation values of the Property. In addition, Grantor shall undertake all necessary actions to perfect Grantee's rights under Section 2 of this Conservation Easement, including but not limited to, Grantee's water rights.

5. Reserved Rights.

(a) Grantor reserves to itself, and to its personal representatives, heirs, successors, and assigns, all rights accruing from their ownership of the Property, including the right to engage in or to permit or invite others to engage in all uses of the Property that are not expressly prohibited or limited by, and are consistent with the purposes of, this Conservation Easement.

(b) Consistent with the BiOp, MOU and CMA, the Minimum Conservation Area Acreage required to be preserved is 7,075 acres of undisturbed habitat. OEHI owns the majority of the land that is to be preserved and OEHI's portion of the 7,075 acres of undisturbed habitat is approximately 5,519 acres. The CDFG and USFWS recognized in the CMA, and CDFG again acknowledges in this Conservation Easement, that the Property's undisturbed habitat is more than ten percent (10%) larger than the 5,519 acres required to be preserved (i.e. larger by approximately 664 acres). Accordingly the CMA recognizes, and this Conservation Easement clarifies that Grantor may:

(i) Conduct oil and gas exploration, extraction, transport and related activities on the Property, so long as all surface disturbance associated with such activities does not disturb more than ten percent (10%) of any individual Quarter Section within any officially surveyed six hundred forty (640) acre land Section. In the event a particular portion of the Property is smaller than a Quarter Section, the aforementioned activities shall not disturb more than ten percent (10%) of that particular parcel. For example, T31S, R23E, Sec.4, SE/4 SW/4 is 40 acres so Grantor may disturb no more 4 acres of that parcel.

6. Grantee's Remedies. If Grantee determines that a violation of the terms of this Conservation Easement has occurred or is threatened, Grantee shall give written notice to Grantor of such violation and demand in writing the cure of such violation. If Grantor fails to cure the violation within thirty (30) days after receipt of written notice and demand from Grantee, or if the cure reasonably requires more than thirty (30) days to complete and Grantor fails to begin the cure within the thirty (30)-day period or fails to continue diligently to complete the cure, Grantee may bring an action at law or in equity in a court of competent jurisdiction to enforce the terms of this Conservation Easement, to recover any damages to which Grantee may be entitled for violation of the terms of this Conservation Easement or for any injury to the conservation values of the Property, to enjoin the violation, *ex parte* as necessary, by temporary or permanent injunction without the necessity of proving either actual damages or the inadequacy of otherwise available legal remedies, or for other equitable relief, including, but

not limited to, the restoration of the Property to the condition in which it existed prior to any such violation or injury. Without limiting Grantor's liability therefor, Grantee may apply any damages recovered to the cost of undertaking any corrective action on the Property.

If Grantee, in its sole discretion, determines that circumstances require immediate action to prevent or mitigate damage to the conservation values of the Property which is prohibited by this Conservation Easement, Grantee may pursue its remedies under this Section 6 without prior notice to Grantor or without waiting for the period provided for cure to expire. Grantee's rights under this section apply equally to actual or threatened violations of the terms of this Conservation Easement. Grantor agrees that Grantee's remedies at law for any violation of the terms of this Conservation Easement are inadequate and that Grantee shall be entitled to the injunctive relief described in this section, both prohibitive and mandatory, in addition to such other relief to which Grantee may be entitled, including specific performance of the terms of this Conservation Easement. Grantee's remedies described in this section shall be cumulative and shall be in addition to all remedies now or hereafter existing at law or in equity, including but not limited to, the remedies set forth in Civil Code Section 815, *et seq.*, inclusive. The failure of Grantee to discover a violation or to take immediate legal action shall not bar Grantee from taking such action at a later time.

If at any time in the future Grantor or any subsequent transferee uses or threatens to use the Property for purposes inconsistent with this Conservation Easement then, notwithstanding Civil Code Section 815.7, the California Attorney General or any entity or individual with a justiciable interest in the preservation of this Conservation Easement has standing as interested parties in any proceeding affecting this Conservation Easement.

6.1. Costs of Enforcement. Any costs incurred by Grantee, where Grantee is the prevailing party, in enforcing the terms of this Conservation Easement against Grantor, including, but not limited to, costs of suit and reasonable attorneys' and experts' fees, and any costs of restoration necessitated by Grantor's negligence or breach of this Conservation Easement shall be borne by Grantor.

6.2. Grantee's Discretion. Enforcement of the terms of this Conservation Easement by Grantee shall be at the discretion of Grantee, and any forbearance by Grantee to exercise its rights under this Conservation Easement in the event of any breach of any term of this Conservation Easement shall not be deemed or construed to be a waiver by Grantee of such term or of any subsequent breach of the same or any other term of this Conservation Easement or of any of Grantee's rights under this Conservation Easement. No delay or omission by Grantee in the exercise of any right or remedy shall impair such right or remedy or be construed as a waiver.

6.3. Acts Beyond Grantor's Control. Nothing contained in this Conservation Easement shall be construed to entitle Grantee to bring any action against Grantor for any injury to or change in the Property resulting from (i) any natural cause beyond Grantor's control, including, without limitation, fire not caused by Grantor, flood, storm, and earth movement, or any prudent action taken by Grantor under emergency conditions to prevent, abate, or mitigate significant injury to the Property resulting from such causes; or (ii) acts by Grantee or its employees.

6.4. Department of Fish and Game Right of Enforcement. All rights and remedies conveyed to Grantee under this Conservation Easement Deed shall extend to and are enforceable by CDFG. These rights are in addition to, and do not limit, the rights of enforcement under the MOU or CMA.

7. Fence Installation and Maintenance. Grantor shall install and maintain a fence reasonably satisfactory to Grantee around the Conservation Easement area to protect the conservation values of the Property, including but not limited to wildlife corridors.

8. Access. This Conservation Easement does not convey a general right of access to the public.

9. Costs and Liabilities. Grantor retains all responsibilities and shall bear all costs and liabilities of any kind related to the ownership, operation, upkeep, and maintenance of the Property. Grantor agrees that Grantee shall have no duty or responsibility for the operation, upkeep or maintenance of the Property, the monitoring of hazardous conditions thereon, or the protection of Grantor, the public or any third parties from risks relating to conditions on the Property. Grantor remains solely responsible for obtaining any applicable governmental permits and approvals for any activity or use permitted by this Conservation Easement Deed, and any activity or use shall be undertaken in accordance with all applicable federal, state, local and administrative agency statutes, ordinances, rules, regulations, orders and requirements.

9.1. Taxes; No Liens. Grantor shall pay before delinquency all taxes, assessments, fees, and charges of whatever description levied on or assessed against the Property by competent authority (collectively "taxes"), including any taxes imposed upon, or incurred as a result of, this Conservation Easement, and shall furnish Grantee with satisfactory evidence of payment upon request. Grantor shall keep the Property free from any liens, including those arising out of any obligations incurred by Grantor for any labor or materials furnished or alleged to have been furnished to or for Grantor at or for use on the Property.

9.2. Hold Harmless. Grantor shall hold harmless, protect and indemnify Grantee and its directors, officers, employees, agents, contractors, and representatives and the heirs, personal representatives, successors and assigns of each of them (each an "Indemnified Party" and, collectively, "Indemnified Parties") from and against any and all liabilities, penalties, costs, losses, damages, expenses (including, without limitation, reasonable attorneys' fees and experts' fees), causes of action, claims, demands, orders, liens or judgments (each a "Claim" and, collectively, "Claims"), arising from or in any way connected with: (1) injury to or the death of any person, or physical damage to any property, resulting from any act, omission, condition, or other matter related to or occurring on or about the Property, regardless of cause; notwithstanding the foregoing, in the event that Grantee's or any of its employees' negligence is a contributing cause of the injury or physical damage set forth above, this indemnity shall apply only to the injury or physical damage not caused by Grantee; (2) the obligations specified in Sections 4, 9, and 9.1; and (3) the existence or administration of this Conservation Easement.

9.3. Extinguishment. If circumstances arise in the future that render the purposes of this Conservation Easement impossible to accomplish, this Conservation Easement can only be terminated or extinguished, in whole or in part, by judicial proceedings in a court of competent jurisdiction.

9.4. Condemnation. This Conservation Easement is a "wildlife conservation easement" acquired by a State agency, the condemnation of which is prohibited except as provided in Fish and Game Code Section 1348.3.

10. Transfer of Easement. This Conservation Easement is transferable by Grantee, but Grantee may assign this Conservation Easement only to an entity or organization authorized to acquire and hold conservation easements pursuant to Civil Code Section 815.3 (or any successor provision then applicable) or the laws of the United States. Grantee shall give Grantor written notice of any transfer or assignment of this Conservation Easement. Grantee shall require the assignee to record the assignment in the county where the Property is located.

11. Transfer of Property. Grantor agrees to incorporate the terms of this Conservation Easement by reference in any deed or other legal instrument by which Grantor divests itself of any interest in all or any portion of the Property, including, without limitation, a leasehold interest. Grantor further agrees to give written notice to Grantee of the intent to transfer any interest at least thirty (30) days prior to the date of such transfer. Grantee shall have the right to prevent subsequent transfers in which prospective subsequent claimants or transferees are not given notice of the covenants, terms, conditions and restrictions of this Conservation Easement. The failure of Grantor or Grantee to perform any act provided in this section shall not impair the validity of this Conservation Easement or limit its enforceability in any way.

12. Notices. Any notice, demand, request, consent, approval, or communication that either party desires or is required to give to the other shall be in writing and be served personally or sent by recognized overnight courier that guarantees next-day delivery or by first class mail, postage fully prepaid, addressed as follows:

To Grantor:	President and General Manager Occidental of Elk Hills, Inc. 10800 Stockdale Highway Bakersfield, CA 93311
With a copy to:	Managing Counsel Occidental of Elk Hills, Inc. 10800 Stockdale Highway Bakersfield, CA 93311
To Grantee:	Department of Fish and Game Central Region 1234 E. Shaw Ave., Fresno CA 93710 Attn: Regional Manager
With a copy to:	Department of Fish and Game Office of the General Counsel 1416 Ninth Street, 12th Floor Sacramento, California 95814-2090 Attn: General Counsel

or to such other address as any party shall designate by written notice to the other. Notice shall be deemed effective upon delivery in the case of personal delivery or delivery by overnight courier or, in the case of delivery by first class mail, five (5) days after deposit into the United States mail.

13. Amendment. This Conservation Easement may be amended by Grantor and Grantee only by mutual written agreement. Any such amendment shall be consistent with the purposes of this Conservation Easement and California law governing conservation easements and shall not affect its perpetual duration. Any such amendment shall be recorded in the official records of Kern County, State of California.

14. General Provisions.

(a) Controlling Law. The interpretation and performance of this Conservation Easement shall be governed by the laws of the State of California, disregarding the conflicts of law principles of such state.

(b) Liberal Construction. Despite any general rule of construction to the contrary, this Conservation Easement shall be liberally construed to effect the purposes of this Conservation Easement and the policy and purpose of Civil Code Section 815, *et seq.* If any provision in this instrument is found to be ambiguous, an interpretation consistent with the purposes of this Conservation Easement that would render the provision valid shall be favored over any interpretation that would render it invalid.

(c) Severability. If a court of competent jurisdiction voids or invalidates on its face any provision of this Conservation Easement Deed, such action shall not affect the remainder of this Conservation Easement Deed. If a court of competent jurisdiction voids or invalidates the application of any provision of this Conservation Easement Deed to a person or circumstance, such action shall not affect the application of the provision to other persons or circumstances.

(d) Entire Agreement. This instrument sets forth the entire agreement of the parties with respect to the Conservation Easement and supersedes all prior discussions, negotiations, understandings, or agreements relating to the Conservation Easement. No alteration or variation of this instrument shall be valid or binding unless contained in an amendment in accordance with Section 13.

(e) No Forfeiture. Nothing contained herein will result in a forfeiture or reversion of Grantor's title in any respect.

(f) Successors. The covenants, terms, conditions, and restrictions of this Conservation Easement Deed shall be binding upon, and inure to the benefit of, the parties hereto and their respective personal representatives, heirs, successors, and assigns and shall constitute a servitude running in perpetuity with the Property.

(g) Termination of Rights and Obligations. A party's rights and obligations under this Conservation Easement terminate upon transfer of the party's interest in the Conservation Easement or Property, except that liability for acts or omissions occurring prior to transfer shall survive transfer.

(h) Captions. The captions in this instrument have been inserted solely for convenience of reference and are not a part of this instrument and shall have no effect upon its construction or interpretation.

(i) No Hazardous Materials Liability. Grantor represents and warrants that, to the best of its knowledge, it has no knowledge or notice of any Hazardous Materials (defined below) or underground storage tanks existing, generated, treated, stored, used, released, disposed of, deposited or abandoned in, on, under, or from the Property, or transported to or from or affecting the Property. Without limiting the obligations of Grantor under Section 9.2, Grantor hereby releases and agrees to indemnify, protect and

hold harmless the Indemnified Parties (defined in Section 9.2) from and against any and all Claims (defined in Section 9.2) arising from or connected with any Hazardous Materials or underground storage tanks present, alleged to be present, or otherwise associated with the Property at any time, except any Hazardous Materials placed, disposed or released by Grantee, its employees or agents. This release and indemnification includes, without limitation, Claims for (i) injury to or death of any person or physical damage to any property; and (ii) the violation or alleged violation of, or other failure to comply with, any Environmental Laws (defined below). If any action or proceeding is brought against any of the Indemnified Parties by reason of any such Claim, Grantor shall, at the election of and upon written notice from Grantee, defend such action or proceeding by counsel reasonably acceptable to the Indemnified Party or reimburse Grantee for all charges incurred for services of the Attorney General in defending the action or proceeding.

Despite any contrary provision of this Conservation Easement Deed, the parties do not intend this Conservation Easement to be, and this Conservation Easement shall not be, construed such that it creates in or gives to Grantee any of the following:

(1) The obligations or liability of an "owner" or "operator," as those terms are defined and used in Environmental Laws (defined below), including, without limitation, the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (42 U.S.C. Section 9601 *et seq.*; hereinafter, "CERCLA"); or

(2) The obligations or liabilities of a person described in 42 U.S.C. Section 9607(a)(3) or (4); or

(3) The obligations of a responsible person under any applicable Environmental Laws; or

(4) The right to investigate and remediate any Hazardous Materials associated with the Property; or

(5) Any control over Grantor's ability to investigate, remove, remediate or otherwise clean up any Hazardous Materials associated with the Property.

The term "Hazardous Materials" includes, without limitation, (a) material that is flammable, explosive or radioactive; (b) petroleum products, including by-products and fractions thereof; and (c) hazardous materials, hazardous wastes, hazardous or toxic substances, or related materials defined in CERCLA, the Resource Conservation and Recovery Act of 1976 (42 U.S.C. Section 6901 *et seq.*; hereinafter "RCRA"); the Hazardous Materials Transportation Act (49 U.S.C. Section 6901 *et seq.*; hereinafter "HTA"); the Hazardous Waste Control Law (California Health & Safety Code Section 25100 *et seq.*; hereinafter "HCL"); the Carpenter-Presley-Tanner Hazardous Substance Account Act

(California Health & Safety Code Section 25300 *et seq.*; hereinafter "HSA"), and in the regulations adopted and publications promulgated pursuant to them, or any other applicable Environmental Laws now in effect or enacted after the date of this Conservation Easement Deed.

The term "Environmental Laws" includes, without limitation, CERCLA, RCRA, HTA, HCL, HSA, and any other federal, state, local or administrative agency statute, ordinance, rule, regulation, order or requirement relating to pollution, protection of human health or safety, the environment or Hazardous Materials. Grantor represents, warrants and covenants to Grantee that activities upon and use of the Property by Grantor, its agents, employees, invitees and contractors will comply with all Environmental Laws.

(j) Warranty. Grantor represents and warrants that, to the best of its knowledge, there are no outstanding mortgages, liens, encumbrances or other interests in the Property (including, without limitation, mineral interests) which have not been expressly subordinated to this Conservation Easement Deed, and that the Property is not subject to any other conservation easement.

(k) Additional Easements. Grantor shall not grant any additional easements, rights of way or other interests in the Property (other than a security interest that is subordinate to this Conservation Easement Deed), or grant or otherwise abandon or relinquish any water agreement relating to the Property, without first obtaining the written consent of Grantee. Grantee may withhold such consent if it determines that the proposed interest or transfer is inconsistent with the purposes of this Conservation Easement or will impair or interfere with the conservation values of the Property. This Section 14(k) shall not prohibit transfer of a fee or leasehold interest in the Property that is subject to this Conservation Easement Deed and complies with Section 11.

(l) Recording. Grantee shall record this Conservation Easement Deed in the Official Records of Kern County, California, and may re-record it at any time as Grantee deems necessary to preserve its rights in this Conservation Easement.

IN WITNESS WHEREOF Grantor has executed this Conservation Easement Deed the day and year first above written.

GRANTOR:

OCCIDENTAL OF ELK HILLS, INC.

BY: _____

NAME: Shawn M. Kerns

TITLE: President & General Manager

DATE: 10/3/12

Approved as to form:

General Counsel
State of California
Department of Fish and Game

BY : _____
Thomas R. Gibson
General Counsel

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT

CIVIL CODE § 1189

State of California

County of Kern

On 10/3/2012 (Date) before me, Kathleen Wall, Notary Public, (Here Insert Name and Title of the Officer)

personally appeared Shannon M. Kerns (Name(s) of Signer(s))

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

KATHLEEN WALL
COMM. #1974153
NOTARY PUBLIC • CALIFORNIA
KERN COUNTY
My Comm. Exp. May 2, 2016

Signature: Kathleen Wall
Signature of Notary Public

Place Notary Seal Above

OPTIONAL

Though the information below is not required by law, it may prove valuable to persons relying on the document and could prevent fraudulent removal and reattachment of this form to another document.

Description of Attached Document

Title or Type of Document: _____

Document Date: _____ Number of Pages: _____

Signer(s) Other Than Named Above: _____

Capacity(ies) Claimed by Signer(s)

Signer's Name: _____	Signer's Name: _____
☐ Corporate Officer — Title(s): _____	☐ Corporate Officer — Title(s): _____
☐ Individual	☐ Individual
☐ Partner — ☐ Limited ☐ General	☐ Partner — ☐ Limited ☐ General
☐ Attorney in Fact	☐ Attorney in Fact
☐ Trustee	☐ Trustee
☐ Guardian or Conservator	☐ Guardian or Conservator
☐ Other: _____	☐ Other: _____
Signer Is Representing: _____	Signer Is Representing: _____
RIGHT THUMBPRINT OF SIGNER — Top of thumb here	RIGHT THUMBPRINT OF SIGNER — Top of thumb here

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Item #5907

EXHIBIT A

Elk Hills Conservation Area Conservation Easement Property Description

EXHIBIT A - LEGAL DESCRIPTION OF PROPERTY

Township/ Range	Section[1]	Exhibit A-2 Section ID	Undisturbed Acres	Disturbed Acres	Total Acres/Section	Comments
T30S, R22E	12	12Z	635.00	3.00	638.00	Full Section
T30S, R23E	10	10R	640.00	2.00	642.00	Full Section
	12	12R	611.00	22.00	633.00	Full Section, Less Elk Hills Road ROW
	13*	13R	318.00	1.00	319.00	Northeast Diagonal Section (Chevron)
T30S, R24E	17*	17S	578.00	8.00	586.00	Full Section, Less State Aqueduct Acreage and Parcel G/9 (Chevron)
	18	18S	635.00	5.00	640.00	Full Section
	20	20S	159.00	1.00	160.00	Northeast 1/4 Section
	21*	21S	319.00	1.00	320.00	North 1/2 Section (Chevron)
	21*	21S	158.00	2.00	160.00	North 1/2 of South 1/2 Section (Chevron)
	22	22S	152.00	8.00	160.00	North 1/2 of South 1/2 Section
T31S, R23E	2	2B	320.00	4.00	324.00	South 1/2 Section
	3	3B	322.00	-	322.00	South 1/2 Section
	4	4B	39.71	0.29	40.00	Southeast 1/4 of Southeast 1/4
	4	4B	39.51	0.49	40.00	Southwest 1/4 of Southeast 1/4
	4	4B	40.00	-	40.00	Southeast 1/4 of Southwest 1/4
	10	10B	625.00	12.00	637.00	Full Section
	11	11B	632.00	10.00	642.00	Full Section
	12	12B	61.00	-	61.00	Northwest 1/4 West of Elk Hills Road
	12	12B	164.00	-	164.00	Southwest 1/4 Section
	12	12B	49.00	-	49.00	Southeast 1/4 West of Elk Hills Road
	13	13B	309.00	13.00	322.00	North 1/2 Section
	13*	13B	322.00	7.00	329.00	South 1/2 Section (Chevron)
	14	14B	310.00	12.00	322.00	North 1/2 Section
	14	14B	121.00	-	121.00	North 1/2 of Southeast 1/4 and the Southeast 1/4 of Southeast 1/4
T31S, R24E	18	18G	22.00	1.00	23.00	Northwest 1/4 West of Elk Hills Road
	18	18G	297.00	37.00	334.00	South 1/2 Section
Total			**7,878.22**	**149.78**	**8,028.00**	

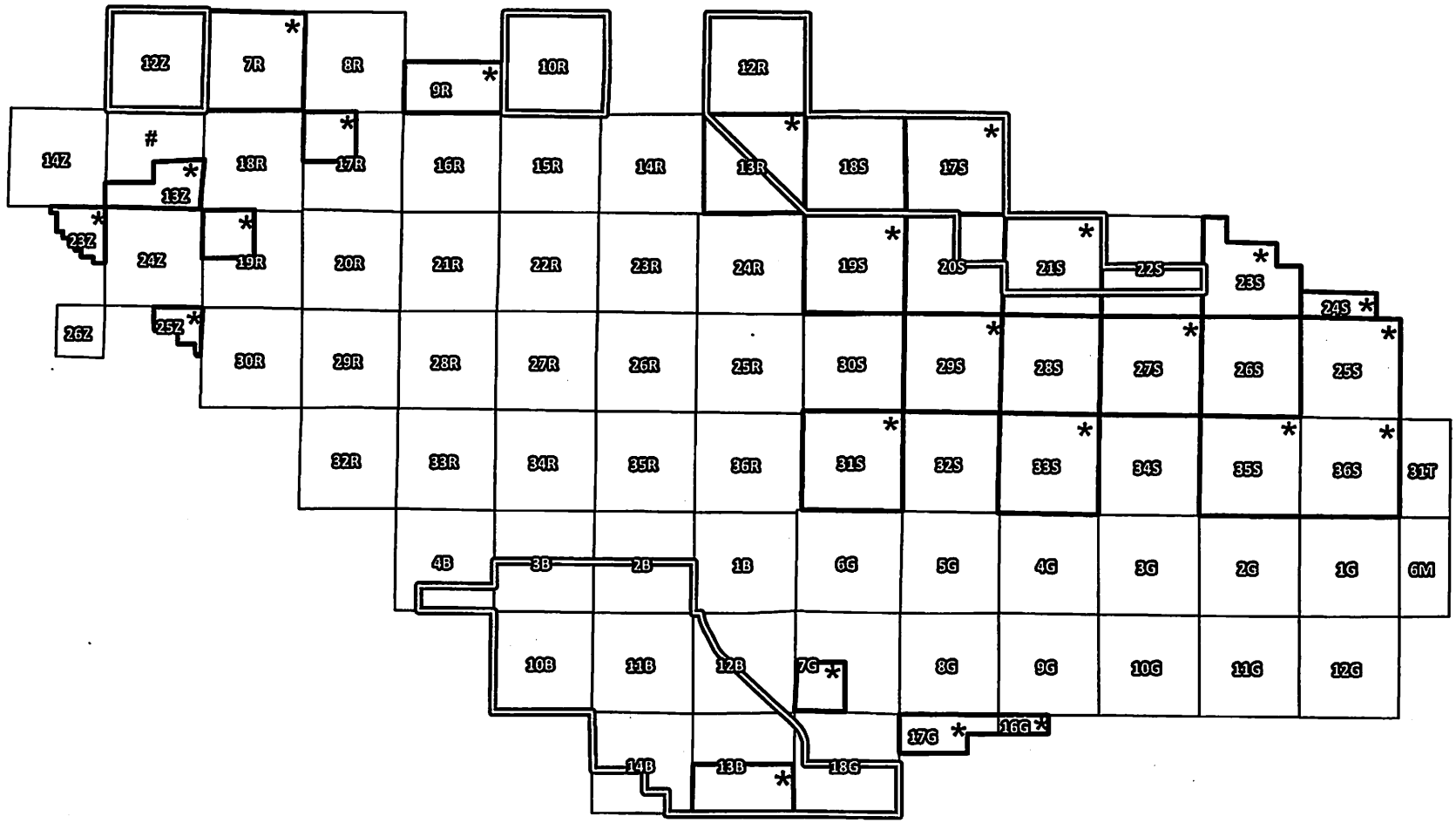
[1] Section numbers denoted with an asterisk indicate Chevron ownership which are not included in this Conservation Easement Deed for Occidental of Elk Hills Inc.'s property. Chevron's ownership is also indicated in the Comments column in bold. Chevron's ownership is listed for reference only.

	Undisturbed	Disturbed	Total	Delta
Occidental of Elk Hills Total Acres	6,183.22	130.78	6,314.00	98.44
Chevron Total Acres	1,695.00	19.00	1,714.00	(21.22)

	Percent Allocation	Total Area	Required Contribution	Percent Contribution
Occidental of Elk Hills Required Acreage	0.78	7,801.00	6,084.78	79.26
Chevron Required Acreage	0.22	7,801.00	1,716.22	21.73

OCCIDENTAL OF ELK HILLS, INC.

Exhibit A-2



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Miles

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ELK HILLS OIL FIELD CONSERVATION AREA (7,878 ACRES)

OCCIDENTAL OF ELK HILLS UNIT LAND

* INDICATES CHEVRON UNIT LAND

\# INDICATES CHEVRON NON-UNIT LAND

Quad Knopf

Source: Occidental of Elk Hills, Inc.

Exhibit A-3

SAVE AND EXCEPTED THEREFROM: Within the parcel described below, one hundred (100) feet in width running parallel with, and immediately adjacent to, the eastern Section boundary line of the North Half of the South Half, an easement to lay, construct, maintain, operate, repair, renew, from time to time change the size of, and remove a maximum of three (3) pipelines for the transportation of oil, gas, water, and such other substances as are suitable for transportation through a pipeline, together with such valves, meters, drips, taps, and similar appurtenances thereof (hereinafter referred to as "Said Facilities"), with the right of ingress and egress to and from the same in, under, along and across that certain real property (hereinafter referred to as "Said Premises") situated in the County of Kern, State of California, and described as follows:

Township 30 South, Range 24 East, M.D.B. & M.
Section 22; North Half of the South Half (N/2S/2)

Project: Occidental of Elk Hills, Inc. (CE)
Kern County

CERTIFICATE OF ACCEPTANCE

THIS IS TO CERTIFY that the interest in real property described in the Conservation Easement Deed dated October 3, 2012, from OCCIDENTAL OF ELK HILLS, INC., A DELAWARE CORPORATION, to the STATE OF CALIFORNIA, is hereby accepted by the undersigned officer on behalf of the State of California, Natural Resources Agency, Department of Fish and Game, pursuant to authority conferred by California Fish and Game Code and, in furtherance of said transfer, the grantee consents to the recordation of the aforementioned deed by its duly authorized officer.

STATE OF CALIFORNIA
Natural Resources Agency
Department of Fish and Game

By: _____
John P. Donnelly
Executive Director
Wildlife Conservation Board

Date: 12/24/2012

I hereby certify that all conditions for exemption have been complied with and this document is exempt from Department of General Services' approval.

WILDLIFE CONSERVATION BOARD

By: _____
(authorizing signatory)

C.3 Conservation Easement Deed – Elk Hills Conservation Area Map

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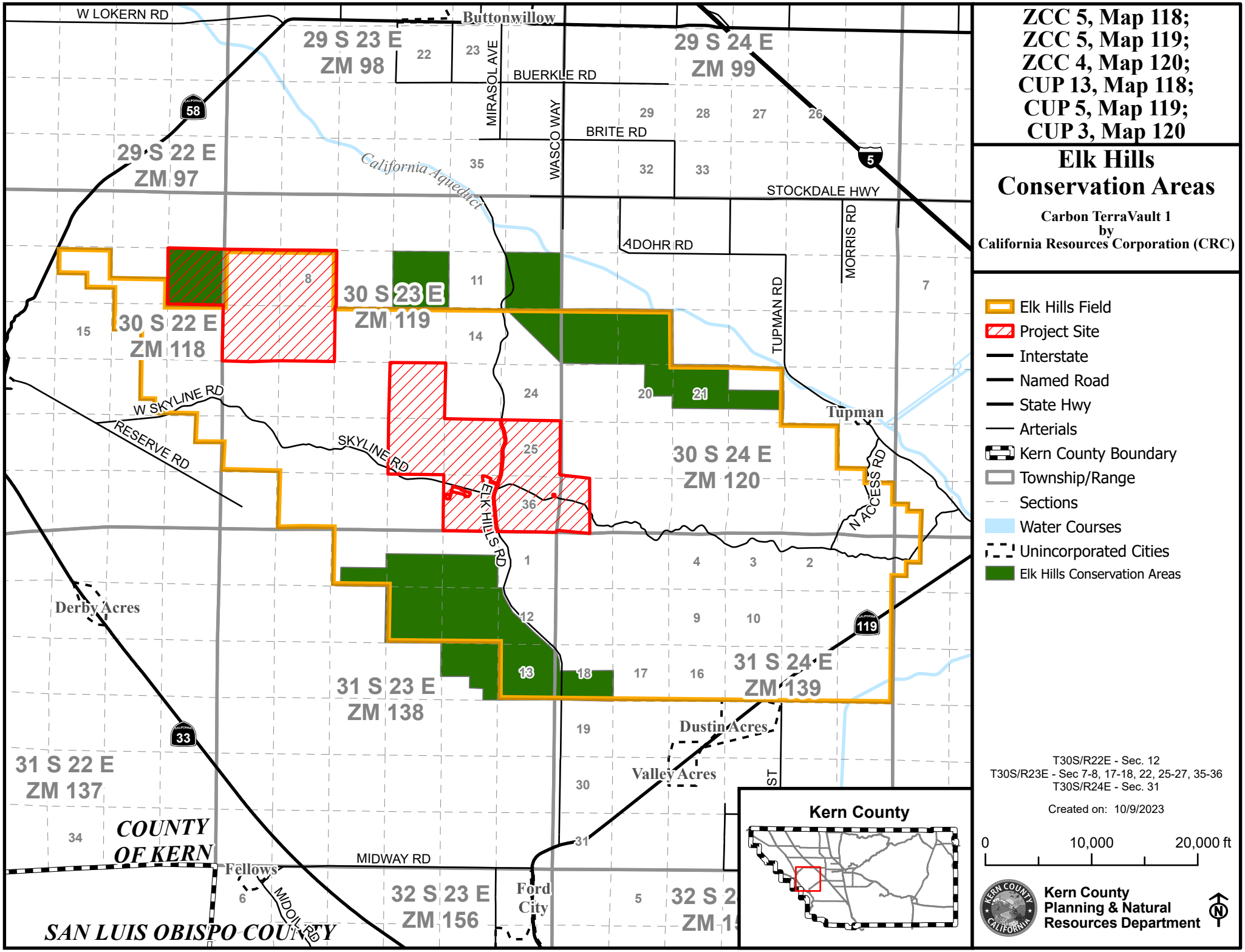
ZCC 5, Map 118;
ZCC 5, Map 119;
ZCC 4, Map 120;
CUP 13, Map 118;
CUP 5, Map 119;
CUP 3, Map 120
Elk Hills Conservation Areas
Carbon TerraVault 1
by
California Resources Corporation (CRC)
Elk Hills Field
Project Site
Interstate
Named Road
State Hwy
Arterials
Kern County Boundary
Township/Range
Sections
Water Courses
Unincorporated Cities
Elk Hills Conservation Areas
W LOKERN RD
Buttonwillow
29 S 23 E
ZM 98
29 S 24 E
ZM 99
MIRASOL AVE
BUERKLE RD
WASCO WAY
BRITE RD
29 S 22 E
ZM 97
California Aqueduct
STOCKDALE HWY
ADOHR RD
MORRIS RD
TUPMAN RD
30 S 23 E
ZM 119
30 S 22 E
ZM 118
W SKYLINE RD
RESERVE RD
SKYLINE RD
ELK HILLS RD
Tupman
30 S 24 E
ZM 120
N ACCESS RD
Derby Acres
31 S 23 E
ZM 138
31 S 24 E
ZM 139
Dustin Acres
Valley Acres
31 S 22 E
ZM 137
COUNTY OF KERN
Fellows
MIDWAY RD
MIDOIL RD
32 S 23 E
ZM 156
Ford City
SAN LUIS OBISPO COUNTY
Kern County
T30S/R22E - Sec. 12
T30S/R23E - Sec 7-8, 17-18, 22, 25-27, 35-36
T30S/R24E - Sec. 31
Created on: 10/9/2023
0
10,000
20,000 ft
Kern County
Planning & Natural
Resources Department

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Appendix D

Cultural Resources

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ASM affiliates
Archaeology • History • Ethnography • Architectural History

ASM Project Number: 28101.26

12 April 2023

Mr. Joe Ashley
Director, Governmental & External Affairs
California Resources Corporation
900 Old River Road
Bakersfield, California 93311

RE: Cultural Resource Review for the Carbon TerraVault I Project, Elk Hills Oil Field, Kern County, California

Dear Mr. Ashley:

This letter documents completion of a cultural resources review for the Carbon TerraVault I Project (Project). The Project is located in the Elk Hills Oil Field in Township 30 South, Range 24 East (T30S/R24E); Township 30 South, Range 22 East (T30S/R22E); and Township 30 South, Range 23 East (T30S/R23E), Mount Diablo Base and Meridian (MDBM), Kern County, California. This review was conducted to assist in compliance with the California Environmental Quality Act (CEQA). Peter A. Carey, M.A., RPA, served as Principal Investigator.

In summary, the study area had been entirely surveyed as a result of 16 previous surveys. No previously recorded resources exist within any areas that will undergo ground disturbing activities; however, a total of 5 previously recorded resources (2 historic-era, 2 prehistoric, and one multicomponent prehistoric/historic-era) within the plume areas for the Project. Condition assessments were conducted on the 5 previously recorded resources. Ground disturbing activities will avoid all 5 resources. A determination of no significant impacts to cultural resources is recommended for the Carbon TerraVault I Project.

Project Description

The proposed Project will involve the capture and storage of carbon from an existing gas fuel source to be input at the existing Elk Hills Power Plant. The Project will utilize existing pipelines and pad areas, with additional injection pipeline corridors built along existing pipeline Rights-of-Way (ROWs). There are two plume areas designated for the Project. The southeast plume area totals 1,388-acres and the northwest plume area totals 1,330-acres. With an applied 50-ft buffer, the proposed injection line corridor totals approximately 130-ac. The Project area totals 2,848-ac. There will be no ground disturbance occurring as a result of the plumes. Figure 1 shows the study area for the Project.

Method of Study:

Records Search

An archival records search conducted at the Southern San Joaquin Valley Information Center (IC), California State University, Bakersfield in 2020 for all of NPR1 was consulted for this study. This

records search was completed in order to determine whether the study area had been previously surveyed for cultural resources, and/or whether any such resources were known to exist on it. The records search was completed to determine: (i) if prehistoric or historical archaeological sites had previously been recorded within the study area; (ii) if the project area had been systematically surveyed by archaeologists prior to the initiation of this field study; and/or (iii) whether the region of the field project was known to contain archaeological sites and to thereby be archaeologically sensitive. Records examined included archaeological site files and maps, the National Register of Historic Places, Historic Property Data File, California Inventory of Historic Resources, and the California Points of Historic Interest.

According to the IC records, a total of sixteen previous surveys had been conducted within the Carbon TerraVault I study area (Table1). With five previously recorded cultural resources known to exist within (Table 2). Three studies had been conducted within 0.5-mi of the study area (Table 3) and twenty cultural resources are known to exist within that same radius (Table 4). The results of the records search which were consulted for this study area presented in Confidential Appendix A.

Table 1. Survey Reports within the Study Area

Report No.	Year	Author (s)/Affiliation	Title
KE-04916	2017	Macko, Michael/ Macko Archaeological	Archaeological Sensitivity Assessment Elk Hills Road & Skyline Road, Taft, California
KE-04376	2013	Romani, Gwen R./ Compass Rose Archaeological, Inc.	Archaeological Survey Report Improvements to Elk Hills Road from State Route 119 to Skyline Road (approximately 6.8 miles), Kern County, California
KE-02581	2001	Culleton, Brendan, Jackson, Thomas, Brewer, Sarah, DeJospeh, Denise, and O'Neill, Mary/ Pacific Legacy, Inc.	Cultural Resources Inventory, Evaluation, and Mitigation Plan for the Water Supply Line (Route 2), Elk Hills Power Project (99-AFC-1): Addendum to the Elk Hills Power Project Cultural Resources Monitoring and Mitigation Plan
KE-04512	2013	Romani, Gwen R./ Compass Rose Archaeological, Inc.	Archaeological Survey Report Improvements to Elk Hills Road, Skyline Road to State Route 58, Kern County, California
KE-00359	1997	Hamusek-McGann, Blossom, Baker, Cindy L., and Maniery, Mary L./ Par Environmental Services, Inc.	Historical Resources Evaluation and Assessment Report of Western Naval Petroleum Reserve No. 1, Elk Hills, Kern County, California
KE-00756	1990	Osborne, Richard H./Cultural Resource Facility, California State University, Bakersfield	An Archaeological Assessment of Approximately Seven Acres North of the Intersection of Elk Hills Road and Skyline Road Within the Elk Hills Naval Petroleum Reserve No. 1, Kern County, California
KE-00865	1996	Parr, Robert E./Center for Archaeological Research, California State University, Bakersfield	An Archaeological Assessment of Western Naval Petroleum Reserve No. 1, 3-D Seismic Survey Project, Elk Hills, Kern County, California. Volume I: TEXT
KE-00924	1991	Unknown/Peak and Associates, Inc.	Cultural Resource Assessment of Sample Areas of Naval Petroleum Reserve No. 1, Kern County, California
KE-02055	1998	Eidsness, Janet P./Pacific Legacy, Inc.	Archaeological Inventory and Assessment for Proposed Trash Clean-up at 17 Localities in Naval Petroleum Reserve No. 1, Elk Hills, Kern County, California

Report No.	Year	Author (s)/Affiliation	Title
KE-02268	1998	Jackson, Thomas L., Shapiro, Lisa A., and King, Jerome H./Pacific Legacy, Inc.	Prehistoric Archaeological Resources Inventory and Evaluation at Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California
KE-02269	1997	Jackson, Thomas L., Shapiro, Lisa A., and Alcock, Gwyn/Pacific Legacy, Inc.	Prehistoric Archaeological Extended Inventory Research at Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California
KE-02375	1999	Jackson, Thomas L., Shapiro, Lisa A., and King, Jerome H./Pacific Legacy, Inc.	Prehistoric Archaeological Resources Inventory and Evaluation at Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California
KE-03508	1997	Jackson, Thomas L., and Shapiro, Lisa A. /Pacific Legacy, Inc.	Cultural Resources Management Plan Naval Petroleum Reserve No. 1, Elk Hills, Kern County, California
KE-04413	2012	Andrews, Sherri and Whitley, David S./ASM Affiliates, Inc.	Class III Inventory of 4,510 Acres Comprising All or Portions of Section 6R, 26Z, 6B, 22B and 34B, 12C, and 7D, 9D, and 14D, Kern County, California
KE-04414	2012	Whitley, David S./ASM Affiliates, Inc.	Phase I/Class III Inventory of 1,280 Acres Comprising all of Sections 11 and 12, Kern County, California
KE-04661	2013	Jackson, Thomas and Reese, Elena/ Pacific Legacy	Addendum No. 1 to the 1998 Cultural Resources Management Plan, Former Naval Petroleum Reserve No. 1 Elk Hills, Kern County, California

Table 2. Resources within the Study Area

Resource	Type	Description
P-15-016812	Site	Foundations and refuse; Historic
P-15-010099	Site	Shell, lithic, and ground stone scatter; Prehistoric (Artifacts Collected)
P-15-006732	Site	Shell, Lithic scatter; Prehistoric
P-15-006447	Site	Foundations and refuse; Prehistoric
P-15-015296	Site	Foundations and a wooden well; Historic

Table 3. Survey Reports within 0.5-mi of the Study Area

Report No.	Year	Author (s)/Affiliation	Title
KE-00321	1979	Chavez, David/ URS Company	Final Report: Cultural Resources Evaluation of the Natural Gas Liquid (NGL) Pipeline Route, Natural Gas Liquid Railroad Facilities, and the Associated Spur Line, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California
KE-03509	1997	Hamusek-McGann, Blossom, Baker, Cindy L., and Maniery, Mary L./ PAR Environmental Srevices, Inc.	Historic Resources Evaluation and Assessment Report of Western Naval Petroleum Reserve No.1, Elk Hills, Kern County, California
KE-05122	2014	Bell, Arran and Whitley, David S./ ASM Affiliates Inc.	FINAL Class III Inventories of Portions of the Buena Vista Hills, Kern County, California

Table 4. Resources within 0.5-mi of the Study Area

Resource	Type	Description
P-15-003178	Site	Foundations, refuse and wells; Historic
P-15-003179	Site	Refuse scatter; Historic
P-15-006731	Site	Shell and lithic scatter; Prehistoric
P-15-006730	Site	Shell and lithic scatter; Prehistoric
P-15-006729	Site	Shell and lithic scatter; Prehistoric
P-15-003212	Site	Refuse; Historic
P-15-015293	Other	Brick scatter; Historic
P-15-015298	Site	Machinery, wooden wall; Historic
P-15-015413	Site	Foundation and structure; Historic
P-15-003182	Site	Well site; Historic
P-15-003183	Site	Concrete pads; Historic
P-15-003207	Site	Concrete pads; Historic
P-15-003208	Site	Concrete pads, lumber; Historic
P-15-003206	Site	Concrete pads; Historic
P-15-009821	Other	Flaked core; Prehistoric
P-15-006446	Site	Refuse; Historic
P-15-004943	Site	Well and refuse; Historic
P-15-009835	Other	Chert flake; Prehistoric
P-15-015255	Site	Refuse; Historic
P-15-015256	Site	Refuse; Historic

To date, few historical California oil industry sites and no California oil industry landscapes have been determined NRHP eligible/significant by the SHPO or the BLM despite dozens of evaluations, due to lack of integrity and/or research potential. According to a 1997 SHPO assessment of a landscape nomination for the National Petroleum Reserve #1 (NPR #1), oil field landscapes are unlikely to be determined eligible due to the long-history of continued use of the oil fields and these sites' resulting lack of integrity. Major discovery wells or industrial remains that represent significant technological innovations are the only potential sites that might be determined eligible, and these are very rare and already recorded (ASM Affiliates 2015).

Tribal Outreach

In addition to the records search, a contact-list obtained from the Native American Heritage Commission (NAHC) for a nearby project area was utilized to send tribal outreach letters for the Carbon TerraVault I Project. Outreach letters were sent to tribal organizations on the NAHC contact-list December 23rd, 2022, and follow-up emails were sent on the February 28th, 2023. The results of tribal outreach for this study are presented below in Table 5. The tribal communications are available in Confidential Appendix B.

Table 5. Tribal Communications

Tribe:	Attempts:	Response:
Big Pine Paiute Tribe of the Owens Valley	**Mailer:** 12/23/2022 E-mail: 02/28/2023	No Response
Chumash Council of Bakersfield	**Mailer:** 12/23/2022 E-mail: 02/28/2023	No Response
Coastal Band of the Chumash Nation	**Mailer:** 12/23/2022 E-mail: 02/28/2023	No Response

Tribe:	Attempts:	Response:
Kitanemuk & Yowlumne Tejon Indians	**Mailer:** 12/23/2022 E-mail: 02/28/2023	No Response
Salinan Tribe of Monterey, San Luis Obispo Counties	**Mailer:** 12/23/2022 E-mail: 02/28/2023	No Response
Santa Ynez Band of Chumash Indians	**Mailer:** 12/23/2022 E-mail: 02/28/2023	"Thank you for contacting the Tribal Elders' Council for the Santa Ynez Band of Chumash Indians. We acknowledge that the project may impact cultural resources and hope that you are consulting with local tribes. At this time, the Elders' Council requests no further consultation on this project; however, we understand that as part of NHPA Section 106, we must be notified of the project. Thank you for remembering that at one time our ancestors walked this sacred land."
Tejon Indian Tribe	**Mailer:** 12/23/2022 E-mail: 02/28/2023	No Response
Tule River Indian Tribe	**Mailer:** 12/23/2022 E-mail: 02/28/2023	"Thank you for your letter dated 12/23/22 regarding the Carbon Terra Vault I Project in Elk Hills, Kern County CA. At this time, we do not have any specific information regarding culturally important items or sites within the proposed project are. We would, however, like to continue consultation with you regarding this project at this time, and are interested in results from any cultural assessments that are conducted. We also may be interested in making a site visit, if warranted, since resources were found. This can be determined in the future."
Yak tityu tityu yak tilhini-Northern Chumash	**Mailer:** 12/23/2022 E-mail: 02/28/2023	Thank you for reaching out to our Tribe. We have no comments on this project at this time. We defer to the Tejon Tribe. "

Previously Recorded Sites – Condition Assessments

ASM revisited the 5 sites identified by the IC as being located within the plume areas for the Project and performed condition assessments. DPR Continuation Sheets were completed for each site condition assessment and are available in Confidential Appendix C.

P-15-006447/CA-KER-5270H

The site was originally recorded by Pacific Legacy, Inc. in 1998 and later updated in 2012. In 2012 all features recorded as portions of the Hay-Carmen Camp site were relocated as well as all features that were included in the 1998 sketch map. Changes to the site have occurred since the initial recordation.

During the current study, Feature 1 (partially deteriorated foundation) and Feature 2 (the corral) were successfully relocated. Both features were partially deteriorated and overgrown with vegetation. Refuse scatter "A" was noted on a slope and eroding down the hillside. Refuse scatter "B" could not be relocated. Refuse scatter "C" was relocated on a southwest facing slope within the site. The site appears to be in poor condition.

P-15-006732/CA-KER-5361

The site was originally recorded by Pacific Legacy in 1997 as a sparse scatter of freshwater mussel shell and chert debitage. The site is only partially located within the northwest plume area and only that portion of the site was revisited. The site was successfully relocated and remains as last described with no noticeable disturbances within the investigation portion of the site. Only a light scatter of freshwater shell was observed within the investigated portion of the site and no lithics were identified.

P-15-010099/CA-KER-5955

The site was originally recorded as an isolated modified quartzite boulder by Osborne in 1990. In 2001, Pacific Legacy, Inc. updated the resource to a site. The site was last described as a temporary camp comprised of freshwater shell, three Olivella shells, sparse lithics, fire-affected rock, and the modified quartzite boulder (presumed mortar) originally recorded by Osborne.

ASM attempted unsuccessfully to relocate the site. No evidence of the site could be identified, and it is presumed the site has been destroyed.

P-15-015296

The site was originally recorded by Pacific Legacy, Inc. in 2009 and was reported to consist of cement foundations and a wooden well. The site was successfully relocated. In addition to the cement foundations, a light scatter of wooden debris and bricks were noted scattered down an adjacent hillside. The site remains as last described with no noticeable disturbances.

P-15-016812/CA-KER-9240H

The site was originally recorded by Pacific Legacy, Inc. in 2012 as an oil industry site complex. A total of six features were identified in 2012. Feature 1 consisted of the main building with a basement, machinery mounts on the first floor, and a machinery mount complex to the north; Feature 2 appeared to be a tank storage area; Feature 3 consisted of a partly subsurface trough; Feature 4 was reported to be a foundation with six depressions for vertical tank storage; Feature 5 consisted of a pair of deteriorated concrete pads; and Feature 6 was a foundation with machinery mounts and a subsurface duct. In addition to the features, a sparse historic refuse scatter was also recorded.

During the current study, significant changes to the site were identified. ASM relocated Features 1 and 2 and found both to be heavily deteriorated and partially overgrown with vegetation. The remaining features (Feature 3 – Feature 6) and trash scatter were not relocated, and it is presumed they have been destroyed. The site is in poor condition.

Summary and Recommendations

A records search review and tribal outreach were conducted for the Carbon TerraVault I Project. The records search indicated the study area had been entirely surveyed as a result of 16 previous surveys. No previously recorded resources exist within any areas that will undergo ground

disturbing activities; however, a total of 5 previously recorded resources (2 historic-era, 2 prehistoric, and one multicomponent prehistoric/historic-era) within the plume areas for the Project.

Outreach letters were sent to tribal organizations on the NAHC contact-list on December 23rd, 2022, and follow-up emails were sent on the February 28th, 2023. A total of three responses were received as a result of the outreach: the Yak tityu tityu yak tilhini- Northern Chumash deferred to the Tejon Tribe; The Santa Ynez Band of Chumash Indians indicated they would not request consultation for the Project; and the Tule River Indian Tribe responded that they would like to continue consultation and requested the results of any cultural assessment and possibly a site visit. This report has been sent to the Tule River Indian Tribe and any continued correspondence will be forwarded to California Resources Corporation to be included with the study.

Condition assessments were conducted on the 5 previously recorded resources. With the exceptions of sites P-15-006732 and P-15-015296, significant disturbances were noted at all sites, including prehistoric site P-15-010099, which has been destroyed. Regardless of the condition of the sites, no ground disturbing activities take place in the recorded locations of the sites.

A determination of no significant impacts to cultural resources is recommended for the Carbon TerraVault I Project.

Please feel free to contact me if you have any questions.

Sincerely,



Peter A. Carey, M.A., RPA
Director

References Cited:

ASM Affiliates, Inc.
2015 Cultural Resources Technical Report: Kern County Oil and Gas Study. Report on file SSJVIC.

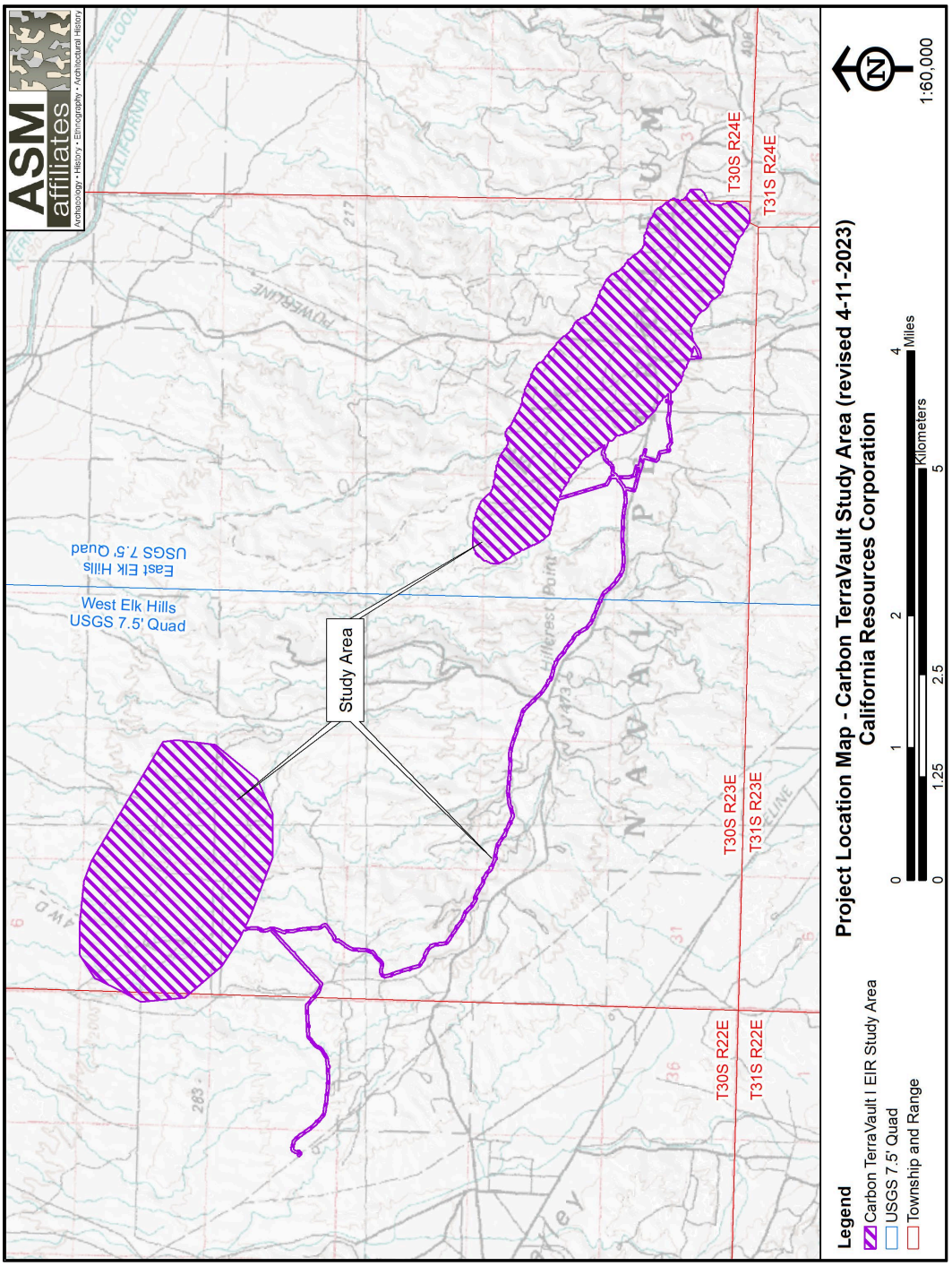

Figure 1. Location of Carbon TerraVault I Study Area (T30S/R24E, T31S/R24E; East Elk Hills) (T30S/R22E, T30S/R23E; West Elk Hills), Kern County, California.

Appendix E

Geologyy and Soils

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E.1 Preliminary Soil and Geological Evaluation

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PRELIMINARY SOIL AND GEOLOGIC EVALUATION
TERRA VAULT 1 CARBON CAPTURE PROJECT
ELK HILLS, KERN COUNTY, CALIFORNIA

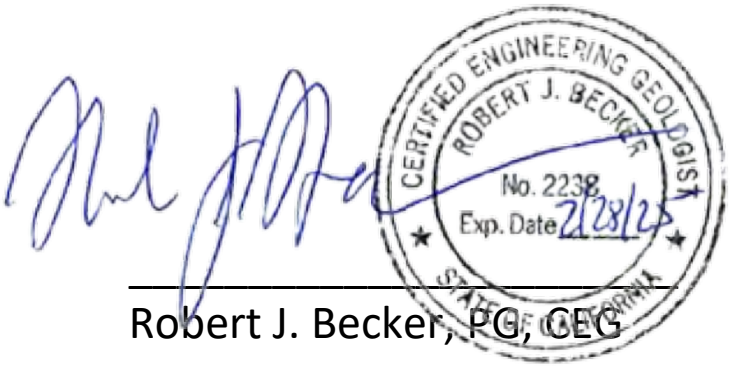
PREPARED FOR:

QUAD KNOPF, INC.
5080 California Avenue, Suite 220
Bakersfield, CA, 93309

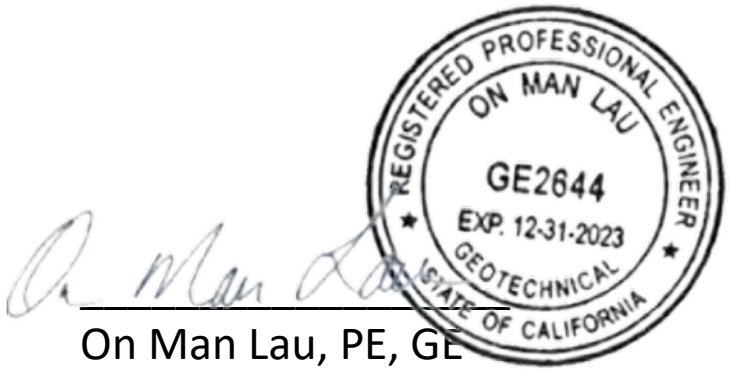
PREPARED BY:

SOILS ENGINEERING INC.
4400 Yeager Way
Bakersfield, CA 93313

SEI FILE NO. 22-18566



Robert J. Becker, PG, CEG



On Man Lau, PE, GE

October 2023

4400 YEAGER WAY
Bakersfield, CA 93313-2019
Phone: 661-831-5100
Fax: 661-831-2111
info@soilsengineering.com
www.soilsengineering.com

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APPENDICES

Appendix A:

Figure A-1 & A-2: Photograph Location Map
Site Photos Photo Plates 1 to 30

Appendix B: USDA Soil Properties

Engineering Properties Tables (2)
Chemical Soil Properties Table
Physical Soil Properties Tables (2)
Map Unit Descriptions (5)

Appendix C: Seismic Design Information - Preliminary

Deterministic Site Parameters - EQFAULTWIN data
EQSEARCHWIN data
USGS Seismic Design Report SEAOC/OSHPD
USGS Uniform Hazard Tool Results

PRELIMINARY SOIL AND GEOLOGIC EVALUATION
for the Proposed Terra Vault 1 Carbon Capture Project
in Elk Hills, Kern County, California
October 2023

1.0 INTRODUCTION

This report presents the results of a preliminary soil and geologic evaluation for the Proposed Terra Vault 1 Carbon Capture Project in Elk Hills, Kern County, California (project). The Project Area consists of the development of approximately 5,332.34 acres as shown on the Location Map, Figure 1 and the Site Plan Map, Figure 2.

SEI performed a site reconnaissance on December 13, 2022, to observe site features and soil conditions as related to geologic evaluation. This report provides a preliminary soil and geologic evaluation for use in the planning phase of the subject project. In the event that changes occur in the design of the project, the project engineer of record may make additional recommendations.

1.1 Planned Construction

The proposed project is a Conditional Use Permit for a 5,332.34 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells and related improvements for storage of Carbon Dioxide (CO_2). The project, Carbon TerraVault 1 (CTV 1), is a wholly owned subsidiary of California Resources Corporation, the applicant for the project. The proposed project would take local industrial sources of CO_2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project. Potential sources and locations of sources will be specifically identified and analyzed to the extent legally required by CEQA in the Draft EIR. The CO_2 would then be injected into identified geographically confined reservoirs for storage in perpetuity. This area has been identified as a location suitable for such storage and a potential to provide a contribution to the goals of California for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter (https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/). The project, as proposed, has the capacity for up to 48 million metric tons of estimated storage and capable of sequestrating over 1.5 million metric tons of CO_2 per year.

Implementation of the project would require permits from the Federal Environmental Protection Agency (EPA) for up to six (6) Class VI injection wells in compliance with the UIC program Class VI geologic sequestration regulations. Location of the proposed Class VI injection wells will be

within the proposed CUP boundary of 5,332.34 acres. All employee facilities needed to manage the project will be provided by the existing Elk Hills oil field facilities.

1.2 Purpose and Scope of Services

The objective of the preliminary soil and geologic evaluation was to provide a preliminary determination of geologic or geotechnical related issues and soil conditions at the Site. SEI's scope of services for this assessment included a Site reconnaissance, desktop review, and report preparation.

2.0 SITE CONDITIONS

The following sections address the Site description, surface conditions, and preliminary groundwater conditions at the Project Area. This information is based on SEI's field reconnaissance and review of published maps and reports.

2.1 Project Area Description and Surface Conditions

The Site will be located on roughly 5,332.34 acres of land that is currently part of the Elk Hills Oil Field, agricultural land or vacant land in the Central Valley portion of unincorporated Kern County. The project location encompasses the area west and slightly east of Elk Hills Road and north and slightly south of Skyline Road, within the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield (pop. 413,098), approximately 8.5 miles from the City of Taft (pop 8945) and approximately 4 miles from the unincorporated community of Buttonwillow (pop. 1443). The project location encompasses the areas within Section 12 of Township 30 South, Range 22 East, Sections 7, 8, 17, 18, 22, 25, 26, 27, 35 and 36 of Township 30 South, Range 23 East, and Section 31 Township 30 South, Range 24 East, Mount Diablo Base and Meridian (MDBM), County of Kern, State of California.

The proposed project site is located within the Elk Hills Oil Field which comprises approximately 75 square miles (47,800-acre) complex with surface and mineral rights privately held by CRC in the San Joaquin Valley of unincorporated Kern County. The surrounding area is comprised of agricultural fields, both active and fallow, and other existing oilfields. They include the Midway – Sunset Oil Field, McKittrick Oilfield and Cymric Oil Field. Skyline Road is closed to public entry and is the southern boundary of the project. Skyline Road connects to Elk Hills Road, which connects the town of Taft, to the south, with Buttonwillow to the north. California Resource Corporation's gated and guarded entrance to the field is located at the western intersection of Skyline Drive and Elk Hills Road.

The project site is not designated by the California Department of Conservation (DOC) as Prime Farmland, Farmland of Statewide Importance, or Unique Farmland. The project site is designated *Urban Built-Up Land* and *Vacant or Disturbed Land*. There is land designated as Non-Prime

Farmland, which is subject to a Williamson Act land Use Contract, immediately adjacent to the west of the project site.

The project site is not within a mineral recovery area, however seven parcels are within designated mineral and petroleum resource site designated by the Kern County General Plan. The project site is not located within the County's NR (Natural Resources) or PE (Petroleum Extraction) Zone Districts. *Table 1: Project Assessor Parcel Numbers, Existing Map Codes, Existing* Zoning, *and Acreage*, below identifies the individual parcels, their respective assessor parcel numbers (APN), acreages, and existing general plan and zoning designations.

Table 1: Project Assessor Parcel Numbers, Existing Map Codes, Existing Zoning, and Acreage

APN	Existing Map Code Designation	Existing Zoning	Proposed Zoning	Section/ Township/ Range	Acres	Agricultural Preserve Inclusion
157-060-02	8.4	A	A	12/30 S/R 22 E	159.50*	Ag Preserve No. 3
158-040-07	8.3/2.1	A	A	7/ 30 S/R 23 E	642.85	Ag Preserve No. 3
158-040-06	8.4	A-1	A	8/30 S/R 23 E	641.20	
158-070-02	8.3	A-1	A	17/30 S/R 23 E	156.44	
158-070-03	8.4	A-1	A	17/ 30 S/R 23 E	154.38*	
158-070-01	8.4	A-1	A	18/ 30 S/R 23 E	319.06*	
158-080-06	8.4	A-1	A	22/ 30 S/R 23 E	160.89*	
158-090-03	8.3	A-1	A	25/ 30 S/R 23 E	340.82*	
158-090-02	8.4	A-1	A	26/ 30 S/R 23 E	637.78	
158-090-01	8.4	A-1	A	27/ 30 S/R 23 E	637.54	
158-090-19	8.4; 8.3/2.1	A	A	35/ 30 S/R 23 E	637.89	Ag. Preserve 3
158-090-04	8.4	A	A	36/ 30 S/R 23 E	683.74	Ag Preserve 3
159-280-07	8.4	A-1	A	31/ 30 S/R 24 E	160.15*	
			Project Totals		5,332.34	

* = Represents a portion of total APN acreage.

General Plan Map Code:

8.3 = Extensive Agriculture (Min. 20 Acre Parcel Size)

8.4 = Mineral and Petroleum

2.1 = Seismic Hazard Overlay

2.4 = Steep Slope Overlay

Zone Designation:

A = Exclusive Agriculture

A-1 = Limited Agriculture

The Project Site Area is shown on Figure 2 along with the existing and planned pipelines. Figures 2a and 2b show the Western and Eastern Portions of the project area respectively, as aerial photos.

2.2 Project Area Observations

SEI performed a site reconnaissance on December 13, 2022 to observe site features and soil conditions within the main eastern and western project areas.

The December 13, 2022 site reconnaissance survey photographs are included in Appendix A. The locations of the photographs are presented on Figure A-1 and Figure A-2. Site observations indicate that most of the project properties are vacant land with low weed growth, oil wells, petroleum pipelines, dirt and paved roads with some oil production facilities.

Photos 1 to 12 show the western project area features including portions of Sections 7 and 8, T30S, R23E and adjacent Section 13 & 14, T30S, R22E where the existing pipelines are present. Photos 7 to 11 show where the proposed injection pipelines will be installed within Section 7.

Observations along the existing petroleum pipelines in the western portion included the following:

- The pipelines are aboveground except for where they pass under dirt roads or other permanent features.
- The pipelines are steel and have identification markings.
- The pipelines pass along undulating hills with no ground support in some of the low lying areas between ridges.
- Slopes of up to 50% were observed adjacent to some of the existing pipelines. The majority of the slopes where the existing pipelines are present range from <5% to up to approximately 30%.
- Erosional drainage features were observed along or adjacent to some of the existing pipelines. These included rills and gullies formed by flowing water erosion. See Photos 2, 3, and 4 for examples of erosion observed.

Observations in the proposed injection pipelines areas in the western portion included the following:

- Slopes of up to 50% were observed adjacent to the proposed pipelines. The majority of the slopes where the proposed pipelines will be installed range from <5% to up to approximately 30%.
- Erosional drainage features were observed along or adjacent to the proposed injection pipelines. These included rills and gullies formed by flowing water erosion. See Photo 8 for an example of erosion observed.
- The existing injection wells are located on flat drilling pads with some adjacent steep slopes up to 30%. See Photos 7, 9 and 11 for examples of the injection well areas.

Photos 13 to 30 show the eastern project area features including portions of Sections 26, 27 and 35, T30S, R23E where the existing pipelines are present. Photos 13 to 18, 20, and 22 to 30 show where the proposed injection pipelines will be installed within portions of Sections 27, 35 and 36.

Observations along the existing petroleum pipelines in the eastern portion included the following:

- The pipelines are aboveground except for where they pass under dirt roads or other permanent features.
- The pipelines are steel and have identification markings.
- The pipelines pass along undulating hills with little to no ground support in some of the low lying areas between ridges mainly just west of injection well 363-27R.
- Erosional drainage features were observed along or adjacent to some of the existing pipelines. These included rills and gullies formed by flowing water erosion. In a few areas cement slurry was present over or adjacent to pipelines to stabilize dirt banks that had eroded. See Photos 15, 21, 22 and 26 for examples of erosion observed.

Observations in the proposed injection pipelines areas in the eastern portion included the following:

- Slopes of up to 50% were observed adjacent to the proposed pipelines. The majority of the slopes where the proposed pipelines will be installed range from <5% to up to approximately 30%.
- Erosional drainage features were observed along or adjacent to the proposed injection pipelines. These included rills and gullies formed by flowing water erosion. See Photos 15, 22, and 26 for examples of erosion observed.
- The existing injection wells are located on flat drilling pads with some adjacent steep slopes up to 30%. See Photos 14, 24, 25, and 29 for examples of the injection well areas.

2.3 Project Area Topography

There are two main areas of interests within Elk Hills for this project. The eastern site area resides mainly on the northern limb and on the hinge of the eastern portion the Elk Hills Anticline within sections 31, 35, and 36. The western site area resides on the hinge (section 12) and on the northern limbs (section 7) of the Heller Anticline. The rest of the western site area resides on the northern limb of the Elk Hills Anticline.

The western site area includes Section 12, Township 30, Range 22 East and Sections 7, 8, 17, and 18 of Township 30 South, Range 23, East Mount Diablo Base and Meridian (MDBM), County of Kern, State of California. The general topography slopes to the north-northeast within sections 7, 8, 12 and 18. Section 17 slopes toward to the northwest. The elevation ranges from 575' to 1,150' within the western site area. Sections 7, 8, and 17 have multiple dirt access roads while section 18 has some dirt access roads showing that the accessibility will be feasible. Section 12 will have minimal access as most of the section is vacant native land with a dirt road along the eastern border.

The eastern site area includes Sections 22, 25, 26, 27, 35, and 36 of Township 30 South, Range 23 East and Section 31 Township 30 South, Range 24 East, Mount Diablo Base and Meridian (MDBM), County of Kern, State of California. General topography in sections 22, 25, 26, and 27 slope to the north with slight variations to the west and east. The southern portion of section 31, 35, and 36 generally slopes to the south-southwest and the northern portions slope to the north-northeast. The central portion of Section 36 is relatively flat when compared to the other sections and it holds multiple facilities in this section. The elevation ranges from 880' to 1,440' within the eastern site area. There are multiple access roads across the sections so accessibility will be feasible.

There are multiple drainages across all sections that flow down slope typically to the north on the western portion. The eastern portion typically drains to the north on the northern sections (22, 25, 26, 27) and to the south on the southern sections (31,35,36). See Figures 3, 3a, and 3b for the topography across the site areas.

2.4 Project Area Surface Soils

Figures 4 and 4A present soil maps showing the Western and Eastern Project Areas, respectively, with mapped soil types (USDA & USCS) based on the USDA Soil Survey Geographic (SSURGO) Database. According to the SSURGO database for Kern County, California, obtained from the USDA, Natural Resources Conservation Service, the Project Area soils consist of the following:

Western Portion:

- Elkhills-Torriorthents Stratified Complex, well drained, 9 to 15 percent slopes,
- Kimberlina sandy loam, well drained, 5 to 9 percent slopes,
- Elkhills sandy loam, eroded, well drained, 9 to 50 percent slopes,
- Elkhills-Torriorthents stratified, eroded complex, well drained, 15 to 50 percent slopes,

Eastern Portion:

- Torriorthents stratified, eroded-Elkhillls complex, well drained, 9 to 50 percent slopes,
- Elkhills-Torriorthents Stratified Complex, well drained, 9 to 15 percent slopes,
- Kimberlina sandy loam, well drained, 5 to 9 percent slopes,
- Elkhills sandy loam, eroded, well drained, 9 to 50 percent slopes,
- Elkhills-Torriorthents stratified, eroded complex, well drained, 15 to 50 percent slopes,

Figure 4b presents soils mapped by the wind erodibility index. The wind erodibility index is a numerical value indicating the susceptibility of soil to wind erosion, or the tons per acre per year that can be expected to be lost to wind erosion. The wind erodibility index ranges from 56 to 86 tons per acre per year throughout both areas of interest (Western Portion/Eastern Portion). The majority of the soils between both site areas have a wind erodibility index of 56 tons per acre per year. Soil unit descriptions with characteristic parameters are provided in Appendix A.

2.5 Groundwater Conditions

The Project Area is located within the San Joaquin Basin, Kern County Groundwater Subbasin. The Kern County Groundwater subbasin is bounded on the north by the Kern County line and the Tule Groundwater subbasin, on the east and southeast by granitic bedrock of the Sierra Nevada foothills and Tehachapi mountains, and on the southwest and west by the marine sediments of the San Emigdio Mountains and Coast Ranges.

According to information provided by the DWR and presented on the SGMA data viewer, depth to water in the Spring of 2022 ranges between 122’ to 148’ between the western and eastern portions of the project area and shows a gradient to the east-southeast (see Figure 5). However, depth to groundwater is estimated at over 500 feet below ground surface (bgs) in this area of Kem County. A groundwater assessment conducted by the Mark Group within section 27R near the subject site encountered no groundwater to a depth of 420' in 1987. In addition, a 1000-foot soil boring was drilled in 1991 at the nearby section 27R facility and did not encounter groundwater.

2.6 Geologic Setting

According to the 2010 Geologic Map of California the zone of influence for the proposed construction is located wholly within Quaternary Pliocene-Pleistocene non-marine sedimentary rocks (QPc) consisting of sandstone, shale, and gravel deposits; mostly loosely consolidated within the Elk Hills Oil and Gas Field (see Figure 6). The Elk Hills Oil and Gas Field is located about 25 miles southwest of the City of Bakersfield, within the San Joaquin Valley in Kern County, California. The San Joaquin Valley is a large alluvial plain bordered by the Sierra Nevada Mountains on the east, the Diablo and Temblor Ranges on the west, the Tehachapi Mountains on the south, and the San Joaquin River on the north. The San Joaquin Valley is filled with alluvial sediments generally thousands of feet thick eroded from the mountains on all sides. The Elk Hills Oil and Gas Field is an anticline, composed of stratified alluvial soils that have been uplifted (SCS, 1986). The Elk Hills are a spur of the Temblor Range that extend southeastward approximately 16 miles and are 6 miles wide, reaching a maximum elevation of 1,551 feet. This is 1,000 to 1,200 feet above the main floor of the San Joaquin Valley.

The Tertiary and Quaternary deposits underlying Elk Hills and nearby areas are up to 24,000 feet thick. The Tulare formation lies at the surface of the Elk Hills and consists of alternating beds of non-marine sand, gravel, silt and clay (most noticeably the Amnicola, Tulare and Corcoran clay units). The Tulare formation consists of both unsaturated and saturated zones. The upper units of the Tulare formation are mostly unsaturated, while the lower units can be saturated with both water and oil. A geologic cross section of the southern San Joaquin Valley and the Elk Hills Oil and Gas Field is provided as Figure 6A (Department of Conservation, 1986 in DOE, 1993).

The Tulare formation has been folded into a large compound anticline consisting of two subsidiary anticlines commonly referred to as the 29R and the 31S structures (DOE, 1997). The 29R structure is tightly folded, asymmetrical and faulted. The 31S structure is cut by numerous minor faults, four of which reach the surface in the northeast flank of the structure. Other faults in the shallow out-bearing beds do not reach the surface. Woodring et al. (1932) described smaller “earthquake cracks” along and parallel to the extreme north flank. Their trend is approximately perpendicular to the surface faults. Most noticeable among these cracks or small faults is the Tupman fault, which is a fracture cutting post-Tulare fan deposits with strike-slip and vertical displacement in the northeast flank of Elk Hills. A geologic cross section beneath the Elk Hills area, showing the 29R and 31S structures, is provided as Figure 6B (DOE, 1993). The site is not located in an Alquist-Priolo (earthquake fault) Special Study Zone, however there are numerous earthquake faults in the vicinity. The nearby faults, with distances from the site, are tabulated below.

Western Portion: Sections 7 and 7/18 of Township 30 South, Range 23 East

SAN ANDREAS (Multiple Segments)	14.3-14.5	miles/	23.0-23.3	kilometers
Kern Front	24.7-24.8	miles/	39.7-39.9	kilometers
San Juan	26.5-26.6	miles/	42.6-42.8	kilometers
Pleito Thrust	30.0-30.3	miles/	48.3-48.7	kilometers
White Wolf	30.2-30.4	miles/	48.6-48.9	kilometers
San Luis Range (S. Margin)	45.2-45.4	miles/	72.8-73.1	kilometers
Big Pine	45.3-45.6	miles/	72.9-73.4	kilometers
Great Valley 14	49.5-49.7	miles/	79.6-80.0	kilometers
Garlock (West)	49.5-49.7	miles/	79.6-80.0	kilometers

Eastern Portion: Sections 27, 35 and 36 of Township 30 South, Range 23 East

SAN ANDREAS (Multiple Segments)	14.9-15.3	miles/	23.9-24.6	kilometers
Kern Front	22.1-22.9	miles/	35.5-36.8	kilometers
White Wolf	24.4-26.4	miles/	39.2-42.5	kilometers
Pleito Thrust	24.9-26.7	miles/	40.0-42.9	kilometers
San Juan	28.4-29.6	miles/	45.7-47.6	kilometers
Big Pine	40.3-42.1	miles/	64.9-67.7	kilometers
Garlock (West)	43.7-45.7	miles/	70.3-73.6	kilometers
San Luis Range (S. Margin)	46.5-47.3	miles/	74.9-76.2	kilometers
North Channel Slope	48.7-49.8	miles/	78.4-80.1	kilometers

See Appendix B for the EQFault data from multiple locations within the project area.

3.0 GEOLOGIC/SEISMIC HAZARDS

The types of geologic and seismic hazards assessed include surface ground fault rupture, liquefaction, slope failure, flood hazards and inundation hazards.

3.1 Kern County General Plan Physical Constraints

The Project Area is located outside of the majority of the Kern County hazard zones shown within the Kern County General Plan. This includes shallow groundwater and flood zones, earthquake hazard zones, landslides, steep slopes, seiches and liquefaction. A portion of the project site is shown on the Land Subsidence Map (Figure 15 of the Safety Element) as an area of hydrocompaction. See Section 3.5 below for more details.

3.2 Fault Rupture Hazard Zones in California

The site is located within Section 12 of Township 30 South, Range 22 East, Sections 7, 8, 17, 18, 22, 25, 26, 27, 35 and 36 of Township 30 South, Range 23 East, and Section 31 Township 30 South, Range 24 East and is not located in an Alquist-Priolo special studies zone (California Fault Zone). The purpose of the Alquist-Priolo (AP) Geologic Hazards Zones Act, as summarized in California Division of Mines and Geology (CDMG) Special Publication 42 (SP 42), is to "prohibit the location of most structures for human occupancy across the traces of active faults and to mitigate thereby the hazard of fault- rupture." As indicated by SP 42, the State Geologist is required to delineate "earthquake fault zones" (EFZs) along known active faults in California. Cities and counties affected by the zones must regulate certain development 'projects' within the zones. They must withhold development permits for sites within the zones until geologic investigations demonstrate that the sites are not threatened by surface displacement from future faulting. See Figure 7 for the Earthquake Fault Map showing the closest AP Zones to the site area.

Local faults and general geology are also shown on the East Elk Hills Quadrangle and West Elk Hills Quadrangle, Seismic Hazard Atlas Maps prepared for the Kern County Council of Governments (Figure 7A).

Ground rupture may occur along a fault trace in a major earthquake. It is unlikely that ground rupture could occur at this site since it is not located within 500 feet of a suspected active fault. Some ground shaking is likely at this site in the event of a major earthquake on one of the nearby faults. Based on the predicted maximum horizontal accelerations at the site and the soil types identified in this investigation ground failure is highly unlikely at this site. According to the East Elk Hills Quadrangle and West Elk Hills Quadrangle Seismic Hazard Atlas Maps, no active faults are present within 2 miles of the site. The West Hills Quadrangle depicts the Elk Hills Fault that is a Quaternary fault (age undifferentiated) that intersects the northern portion of section 7 and within the northeastern border of section 8. On the northeast portion of section 18, there is an unnamed Quaternary fault (age undifferentiated).

The nearest major active faults in the western portion, as indicated by the computer-modeling program EQFault version 2.01, is the San Andreas Fault, which is approximately 23.0 to 23.3 kilometers to the southwest. The Kern Front Fault is approximately 39.7 to 39.9 kilometers to the northeast. The Pleito Fault is located approximately 48.3 to 48.7 kilometers southeast of the site. The White Fault is located approximately 48.6 to 48.9 kilometers east-southeast of the site. The closest minor active fault is the Buena Vista Fault approximately 15.42 kilometers away. Regional faults in relation to the site location are presented on Figure 8 from the Fault Activity Map of California (CDMG, 2010) and Figure 8A from EQFault.

The nearest major active faults in the eastern portion, as indicated by the computer-modeling program EQFault version 2.01, is the San Andreas Fault, which is approximately 23.9 to 24.6 kilometers to the southwest. The Kern Front Fault is approximately 35.5 to 36.8 kilometers to the northeast. The White Fault is located approximately 39.2 to 42.5 kilometers east-southeast of the site. The Pleito Fault is located approximately 40.0 to 42.9 kilometers southeast of the site. The closest minor active fault is the Buena Vista Fault approximately 9.41 kilometers to the southeast. Regional faults in relation to the site location are presented on Figure 8 from the Fault Activity Map of California (CDMG, 2010) and Figure 8A from EQFault.

3.3 State of California Seismic Hazard Zones (Liquefaction and Landslides)

Zones of Required Investigation referred to as "Seismic Hazard Zones" in CCR Article 10, Section 3722, are areas shown on Seismic Hazard Zone Maps where site investigations are required to determine the need for mitigation of potential liquefaction and/or earthquake-induced landslide ground displacements. There are no mapped areas that have Seismic Hazard Zones for liquefaction or landslides within the project area.

3.4 Slope Stability and Potential for Slope Failure

No evidence of historic landslides or creep was observed within the project areas. Some of the steeper slopes and cuts for roads and drilling pads, did show some erosional features such as rills and gullies from stormwater flow. There is a low to moderate potential for rockfalls or landslides to impact the site in the event of a major earthquake. Overall, the site appears to be very stable.

3.5 Land Subsidence

The Kern County General Plan includes a discussion on land subsidence potential in the Bakersfield area. The main causes of land subsidence are Tectonic Subsidence, Oil & Gas Fluid Extraction, Groundwater Withdrawal and Hydrocompaction of Moisture Deficient Alluvial Deposits. Figure 15 in the Safety Element shows the areas of significant subsidence within the Bakersfield area. The western site resides within the area where no historic land subsidence has occurred and is outside of the area of hydrocompaction. A portion of the eastern site (Section: 22, 27, Portion of 26 & 35) does reside within an area of hydrocompaction as shown on attached Figure 9. The estimated amount of land subsidence in the project area over the time period of 2015 to 2022 ranges from 0 to <1’ as shown on Figure 9A from the SGMA Data Viewer. The hydrocompaction and minor subsidence may be due to oil & gas fluid extraction from oil field activities. A closer investigation of the subsurface soils in the areas identified for hydrocompaction is required specifically where the pipelines are proposed to be placed.

3.6 Expansive Soils

Near-surface soils encountered in previous geotechnical investigations within or near the Site Areas and mapped by the USDA and presented on the Web Soil Survey, indicate that expansive soils may be located in the project areas. Expansive soils have the potential to cause displacement

and possible damage to surface improvements such as concrete slab-on-grade floors and exterior walkways. The potential effects of the shrinking and swelling of expansive soils and the associated impacts can be mitigated through prudent grading and design of the structures. Some of the soils in the Project Areas (Section 12, Section 27 and Section 35) have a clay fraction and may be expansive. A design level geotechnical investigation will be required to confirm the status of expansive soils in the project area. This would include the collection of near surface soil samples and testing them for expansion potential by ASTM D4829.

3.7 Flood and Inundation Hazards

An evaluation of flooding at the Project Area includes review of potential hazards from flooding during periods of heavy precipitation and flooding due to a catastrophic dam breach from up-gradient surface impoundments.

3.7.1 Flood Hazards

The site is located in an area with only a limited amount of surface water sources. It is very unlikely that earthquake-induced flooding would occur at this site. The site is located within flood Zone X with minimal potential flooding according to the Flood Insurance Rate Maps covering the site area (see Figure 10 for the Flood Hazard Map).

3.8 Corrosion Potential

The eastern and western portions of the site appear to have a range of no salt concentrations to very high concentration of salts that represent alkaline soils with a potential to be corrosive to metallic objects. A more detailed soil investigation (sampling and testing: chlorides, sulfates, and pH) is required along the proposed injection lines to determine localized corrosion potential. Corrosive soils require that all buried iron, steel, cast iron, ductile iron, galvanized steel, and dielectric coated steel or iron be properly protected against corrosion depending upon the critical nature of the structure.

4.0 SEISMIC HAZARD ASSESSMENT

The types of seismic hazards assessed include historical earthquake effects, earthquake induced ground motion, seismic induced landslides, liquefaction, and seismic induced settlement.

4.1 Seismic History & Seismic Sources

From 1852 through 2020, southern California has experienced at least 20 major earthquakes with estimated Richter scale magnitudes ranging from 5.9 to 8.0. The largest recorded earthquake in the region of Elk Hills occurred in 1952 with an estimated Richter scale magnitude of 7.7 on the White Wolf Fault (referred to as the Kern County Earthquake). Prior to Richter scale usage, the historical Fort Tejon earthquake of 1857 occurred along the San Andreas Fault (23.6 kilometers away) with an estimated magnitude of at least 7.9.

In addition to the two (2) major earthquakes mentioned above, many earthquakes have occurred in the Kern County area, but only a few have had a magnitude greater than five on the Richter scale. Some of these include; the Wheeler Ridge earthquake (5.2 magnitude) and the Bakersfield Quake (5.8 magnitude, an aftershock of the Kern County Earthquake).

The Wheeler Ridge earthquake occurred on May 27, 1993, 15 miles southwest of the city of Bakersfield; although noticed over a wide area of southern and central California, it caused little damage.

The Bakersfield Quake occurred on August 22, 1952 approximately 6 miles east southeast of Bakersfield. This Kern County Earthquake aftershock was the closest to Bakersfield and caused extensive damage to downtown Bakersfield and killed 2 people.

The Kern County Earthquake (magnitude 7.7), which occurred on July 21, 1952, claimed 12 lives and caused at least $50 million in damage.

The Fort Tejon earthquake (estimated magnitude 7.9), which occurred in January 1857 caused 2 deaths and severe damage to Fort Tejon and other small communities in the area. Since this was a sparsely populated area in 1857 the damage was not as much as it would be today. The severe shaking from this earthquake lasted for more than a minute and reportedly caused the Kern River to turn upstream, the waters of Tulare Lake to be thrown up onto it's shore stranding fish miles from the original Lake bed, and causing cracks in the ground as far away as San Bernardino, CA. The surface rupture along the San Andreas Fault was at least 220 miles, with an average slip of 15 feet and a maximum displacement of 30 feet (SCEDC, 2001).

Though the Elk Hills Oil and Gas Field is in a seismically active region, no historically active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) at Elk Hills (DOE 1993). Only minor or in-active faults have been mapped in the Elk Hills Oil and Gas Field including the Elk Hills Fault shown to be creeping within the northern portions of Sections 7 & 8. The closest major active fault near Elk Hills is the San Andreas fault, located approximately 14.3 to 15.3 miles west of Elk Hills on the west side of the Temblor Range. Other major faults near Elk Hills are the White Wolf fault (24.4 to 26.4 miles southeast from Elk Hills), the Kern Front fault (22.1 to 24.8 miles northeast from Elk Hills), and the Pleito Thrust fault (24.9 to 30.3 miles southeast from Elk Hills). The closest minor active fault is the Buena Vista Fault approximately 5 miles to the south.

The major quaternary faulting in the project vicinity is shown on Plate 5. Characteristics of major faults within 25 miles of the site are discussed in the following subsections and are shown on Table A below.

San Andreas Fault

The Carrizo segment of the San Andreas fault is located approximately 14.3 to 15.3 miles west of the site (Figure 7). Movement along the San Andreas in this area is almost pure strike-slip at

an average rate of 20 mm to 35 mm per year. The maximum moment magnitude (Mo) of this fault is reported as 7.8 to 8.0 by the California Division of Mines and Geology (CDMG). This segment of the San Andreas last ruptured in the 1857 Fort Tejon earthquake with displacements of 5-10 meters along a 220-mile surface rupture. An earthquake magnitude of 8.0 has been estimated by the U.S. Geological Survey for this segment and a conditional probability of occurrence of such an event of 0.1 over the 30 year period of 1988 to 2018 (USGS, 1988). Other segments of the San Andreas fault include the Cholame (north) and Mojave (south) segments; their respective distances from the site and characteristic magnitudes are 58 miles and magnitude 7.3 (Cholame) and 78 miles and magnitude 7.8 (Mojave). The associated conditional probabilities of occurrence, for the 30-year period of 1988 to 2018, estimated by the U. S. Geological Survey (1988), were 0.3 for both segments.

Boundary Zone Blind Thrusts

The Coast Ranges-Sierran Block boundary zone is a newly recognized 375-mile long zone of thrust and reverse faulting located along the western side of the Central Valley (Woodward-Clyde, 1991). The zone forms the tectonic boundary between the Coast Ranges and the Sierran crustal block. It is characterized by a series of anticlinal folds. The southernmost segment of the fault extends northward from the southwest corner of the San Joaquin Valley to north of Coalinga. Several recent earthquakes, including the Coalinga in 1983, North Kettleman Hills in 1985, Whittier Narrows in 1987, and Northridge in 1994 have occurred along the southern portion of this boundary zone. Several investigators have suggested that anticlinal folds along the west margin of the San Joaquin basin (including Elk Hills) can be related to blind thrusts. Three (3) potentially active thrust faults have been identified just south of Elk Hills approximately 1.0 mile northwest of Ford City (DOE, 1994). Two of the faults have been accurately located and trend northwest to southwest. The third fault is inferred to trend in the same direction and may be associated with the active Buena Vista Thrust fault (5 miles away). Displacement along each fault caused by creep has been identified (DOE, 1994). Fault creep was first reported in 1993 after causing several oil well casings to collapse (DOE, 1994). This fault creep may be associated with the withdrawal of oil in this area (SCECDC, 2001).

White Wolf Fault

The White Wolf and Pleito thrust faults are located near the junction of the Sierra Nevada -Great Valley and Mojave tectonic blocks with the San Andreas Fault to the west (Plate 7). Movement along the White Wolf has been reported at an average rate of 2 mm per year. The maximum moment magnitude of this fault is reported as 7.3 by the CDMG. The White Wolf fault is a northeast-trending reverse fault that ruptured during the magnitude 7.7 Kern County earthquake of July 21, 1952. The White Wolf fault is approximately 24.4 to 30.4 miles southeast of the site. Two (2) associated aftershocks occurring on July 29, and August 22, 1952 (referred to as the Bakersfield Quake) with magnitudes 6.1, and 5.8, respectively, occurred some distance (approximately 12 miles) northwest of the White Wolf fault and caused increased damage to downtown Bakersfield.

Pleito Thrust Fault

The Pleito thrust fault lies to the west of the White Wolf fault. It is an accurate, generally east-west trending, south dipping thrust fault along the southern margin of the San Joaquin Valley. The fault is approximately 24.9 to 30.3 miles from the site. Movement along the Pleito Thrust has been reported at an average rate of 2 mm per year. The maximum moment magnitude of this fault is reported as 7.3 by the CDMG. The latest movement is Holocene so the fault is classified as active, although there are no confirmed associations with historical seismicity. Wesnousky (1986) assessed a characteristic magnitude of 7.0 and return period of 1470 years for the fault.

SEI utilized the software program EQSEARCHWIN version 3.0 (Thomas F. Blake) to evaluate historical earthquakes in the area of the site over the last 200 years. The Earthquake Epicenter Map (Figure 11) shows earthquake magnitudes and the epicentral distance from the site. The majority of the seismic activity in the area of the site has been along the White Wolf Fault and the San Andreas Fault. The closest earthquake of at least 5.0 magnitude to the site was 35.2 to 44.7 kilometers away between the eastern and western portion, at a magnitude of 5.2 in June 1993. The largest magnitude earthquake within 100 miles was 7.9 on the San Andreas Fault in 1857. The largest estimated site accelerations are 0.221g (Section 36) to 0.295g (Section 7/18) from a 7.9 magnitude earthquake on January 9, 1857. The EQSEARCHWIN estimation of Peak Acceleration from California Earthquake Catalogs Table and a Earthquake Epicenter Map are presented in Appendix B.

Seismic Sources

A number of active faults are located within a 50-mile radius of the subject site. To evaluate the affect a major earthquake might have on the site, the computer modeling programs EQFaultwin vers. 3.0 (Thomas Blake) were utilized. Site-specific parameters were inputted, and the programs computed the maximum peak site ground accelerations resulting from an earthquake. Because ground accelerations are based largely on fault distance and magnitude, we have focused our analysis on those faults which are close to the site, or that have large maximum credible magnitudes, or a combination of the two. The result of this analysis is presented below in Table A.

TABLE A

FAULT	Approximate Distance (Km)	Maximum Earthquake Magnitude (Mw)	Maximum Peak Ground Acceleration	Estimated Site Intensity (MM)
San Andreas (Other Segments)	**23 to 24.6**	7.4 to **8.0**	0.128 to **0.258**	VIII to **IX**
Kern Front	35.5 to 39.9	6.3	0.085 to 0.093	VII
White Wolf	39.2 to 48.9	7.3	0.123 to 0.146	VIII
Pleito Thrust	40.0 to 48.7	7.0	0.105 to 0.122	VII
San Juan	42.6 to 47.6	7.1	0.093 to 0.101	VII
San Luis Range	72.8 to 76.2	7.2	0.083 to 0.086	VII
Big Pine	64.9 to 73.4	6.9	0.060 to 0.066	VI
Great Valley 14	79.6 to 85.7	6.4	0.050 to 0.052	VI
Garlock (west)	70.3 to 73.6	7.3	0.069 to 0.076	VI to VII

This analysis estimates that a maximum peak ground acceleration of up to 0.258g would be felt at the site as a result of a maximum earthquake of magnitude 8.0 on the San Andreas Fault approximately 23 to 24.6 kilometers away. A maximum probable earthquake of magnitude 7.3 on the White Wolf Fault approximately 39.2 to 39.9 kilometers away would create a peak site ground acceleration of up to 0.146g at the site. See attached Deterministic Site Parameters for a full listing of computed values for faults within a 100-mile radius of the site in Appendix C. Also attached is a California Fault Map showing nearby faults in relationship to the site (Figures 8A and 8B).

Utilizing the USGS Deaggregation program the Probabilistic Seismic Hazard Deaggregation for the Site was calculated to be 0.4334g to 0.4363g for a 5% chance every 50 years of exceedance with an earthquake magnitude of 7.35 to 7.4. See Appendix B for the calculation result pages.

4.2 Seismology & Calculation of Earthquake Ground Motion

The site is not located within or directly adjacent to a mapped Alquist-Priolo (AP) Earthquake Zone and is not a Seismic Design Category E or F. The site qualifies for the Site-Specific Ground Motion Hazard Analysis exemption under Section 11.4.8 of ASCE 7-16. The seismic design information in Section 4.2.2 will be utilized for this project.

4.2.1 Site Class

The Project Area surface soils are defined in Section 2.4 above and the Geologic Setting is defined in Section 2.6. The estimated preliminary site class C was used for seismic parameters based on geotechnical studies near the site area. Confirmation of site soil class can only be determined by a subsurface investigation including soil borings or through geophysical measurements of shear wave velocity. Determination of site soil class will require subsurface data and will be determined during the design level geotechnical investigation.

4.2.2 Seismic Design Criteria

The 2022 California Building Code (CBC) utilizes ground motion based on the Risk-Targeted Maximum Considered Earthquake (MCE_R) that is defined in the 2022 CBC as the most severe earthquake effects considered by this code, determined for the orientation that results in the largest maximum response to horizontal ground motions and with adjustment for targeted risk. Ground motion parameters in the 2022 CBC are based on American Society of Civil Engineers (ASCE) 7-16, Chapter 11.

The United States Geologic Survey (USGS) has prepared maps presenting the Risk-Targeted MCE spectral acceleration (5% damping) for periods of 0.2 seconds (S_S) and 1.0 seconds (S_1). The values of S_S and S_1 can be obtained from the Office of Statewide Health Planning and Development (OSHPD) Seismic Design Maps Application available at: https://seismicmaps.org/.

The Tables below present the spectral acceleration parameters produced for an assumed Site Class C by OSHPD Seismic Design Maps Application and Chapter 16 of the 2022 CBC based on ASCE 7-16.

Seismic Design

The seismic design values are presented in the tables below based on the 2022 California Building Code (CBC). The Site Class for the proposed improvements located within Section 12 of Township 30 South, Range 22 East, Sections 7, 8, 17, 18, 22, 25, 26, 27, 35 and 36 of Township 30 South, Range 23 East, and Section 31 Township 30 South, Range 24 East in Tupman, Kern County, California, were assumed to be a Site Class C based on previous seismic shear wave surveys and standard penetration test data within or near the project site areas. This will need to be confirmed by site-specific seismic shear wave surveys and/or evaluating the standard penetration test data obtained at the site areas during future site-specific design level Geotechnical Investigations. A total of 5 locations were evaluated within the project site.

Western Site Area

Location 1: Section 7, Township 30 South, Range 23 East with the following coordinates: North: 35.329491°, West: -119.544847°.

SEISMIC DESIGN CRITERIA		VALUE	SOURCE
Risk Category		**II**	2022 CBC Table 1604.5 or 1604*A*.5
Site Class		**C**	2022 CBC § 1613.2.2 or 1613*A*.2.2; ASCE 7-16 Table. 20.3-1; Site Specific Soils Report
Mapped MCE_R Spectral Response Acceleration, short period	**S_S**	**1.183g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(1)
Mapped MCE_R Spectral Response Acceleration, at 1-sec. Period	**S_1**	**0.47g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(2)
Site Coefficient	**F_a**	**1.2**	SEAOC- OSHPD software; 2022 CBC Table 1613.2.3(1) or 1613*A*.2.3(1)
Site Coefficient	**F_v**	**1.5**	2022 CBC Table 1613.2.3(2) or 1613*A*.2.3(2)
Adjusted MCE_R Spectral Response Acceleration, short period, $F_a * S_s$	**S_{MS}**	**1.419g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.3 or 1613*A*.2.3
Adjusted MCE_R Spectral Response Acceleration, 1-sec. period, $F_v * S_1$	**S_{M1}**	**0.705**	2022 CBC § 1613.2.3 or 1613*A*.2.3
Design Spectral Response Acceleration, short period, 2/3 * S_{MS}	**S_{DS}**	**0.946g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.4 or 1613*A*.2.4
Design Spectral Response Acceleration, 1-sec. period, 2/3 * S_{MI}	**S_{D1}**	**0.47**	2022 CBC § 1613.2.4 or 1613*A*.2.4
Peak Ground Acceleration for Max. Considered Earthquake (MCE_G)	**PGA**	**0.5g**	SEAOC- OSHPD software; ASCE 7-16 Fig 22-9
Site Coefficient, F_{PGA} = 1.2, F_{PGA}* PGA	**PGA_M**	**0.6g**	SEAOC- OSHPD software; ASCE 7-16 § 11.8.3.2
Mapped Risk Coefficient at 0.2 second Spectral Response Period	**C_{RS}**	**0.9**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-18A
Mapped Risk Coefficient at 1 second Spectral Response Period	**C_{R1}**	**0.889**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-19A
Seismic Design Category, short period		**D**	2022 CBC § 1613.2.5
Seismic Design Category, 1second period *****		**D**	2022 CBC § 1613.2.5

Location 2: Border of Sections 7 & 18, Township 30 South, Range 23 East with the following coordinates: North: 35.325027°, West: -119.544935°.

SEISMIC DESIGN CRITERIA		**VALUE**	**SOURCE**
Risk Category		**II**	2022 CBC Table 1604.5 or 1604*A*.5
Site Class		**C**	2022 CBC § 1613.2.2 or 1613*A*.2.2; ASCE 7-16 Table. 20.3-1; Site Specific Soils Report
Mapped MCE_R Spectral Response Acceleration, short period	**S_S**	**1.191g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(1)
Mapped MCE_R Spectral Response Acceleration, at 1-sec. Period	**S_1**	**0.474g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(2)
Site Coefficient	**F_a**	**1.2**	SEAOC- OSHPD software; 2022 CBC Table 1613.2.3(1) or 1613*A*.2.3(1)
Site Coefficient	**F_v**	**1.5**	2022 CBC Table 1613.2.3(2) or 1613*A*.2.3(2)
Adjusted MCE_R Spectral Response Acceleration, short period, $F_a * S_s$	**S_{MS}**	**1.43g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.3 or 1613*A*.2.3
Adjusted MCE_R Spectral Response Acceleration, 1-sec. period, $F_v * S_1$	**S_{M1}**	**0.711**	2022 CBC § 1613.2.3 or 1613*A*.2.3
Design Spectral Response Acceleration, short period, $2/3 * S_{MS}$	**S_{DS}**	**0.953g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.4 or 1613*A*.2.4
Design Spectral Response Acceleration, 1-sec. period, $2/3 * S_{MI}$	**S_{D1}***	**0.474**	2022 CBC § 1613.2.4 or 1613*A*.2.4
Peak Ground Acceleration for Max. Considered Earthquake (MCE_G)	**PGA**	**0.5g**	SEAOC- OSHPD software; ASCE 7-16 Fig 22-9
Site Coefficient, F_{PGA} = 1.2, F_{PGA}* PGA	**PGA_M**	**0.6g**	SEAOC- OSHPD software; ASCE 7-16 § 11.8.3.2
Mapped Risk Coefficient at 0.2 second Spectral Response Period	**C_{RS}**	**0.9**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-18A
Mapped Risk Coefficient at 1 second Spectral Response Period	**C_{R1}**	**0.888**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-19A
Seismic Design Category, short period		**D**	2022 CBC § 1613.2.5
Seismic Design Category, 1second period *		**D***	2022 CBC § 1613.2.5

Eastern Side Area

Location 3: Section 27, Township 30 South, Range 23 East with the following coordinates: North: 35.293161°, West: -119.489566°.

SEISMIC DESIGN CRITERIA		VALUE	SOURCE
Risk Category		**II**	2022 CBC Table 1604.5 or 1604*A*.5
Site Class		**C**	2022 CBC § 1613.2.2 or 1613*A*.2.2; ASCE 7-16 Table. 20.3-1; Site Specific Soils Report
Mapped MCE_R Spectral Response Acceleration, short period	**S_S**	**1.168g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(1)
Mapped MCE_R Spectral Response Acceleration, at 1-sec. Period	**S_1**	**0.463g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(2)
Site Coefficient	**F_a**	**1.2**	SEAOC- OSHPD software; 2022 CBC Table 1613.2.3(1) or 1613*A*.2.3(1)
Site Coefficient	**F_v**	**1.5**	2022 CBC Table 1613.2.3(2) or 1613*A*.2.3(2)
Adjusted MCE_R Spectral Response Acceleration, short period, $F_a * S_s$	**S_{MS}**	**1.402g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.3 or 1613*A*.2.3
Adjusted MCE_R Spectral Response Acceleration, 1-sec. period, $F_v * S_1$	**S_M**	**0.694**	2022 CBC § 1613.2.3 or 1613*A*.2.3
Design Spectral Response Acceleration, short period, 2/3 * S_{MS}	**S_{DS}**	**0.934g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.4 or 1613*A*.2.4
Design Spectral Response Acceleration, 1-sec. period, 2/3 * S_{MI}	**S_{D1}**	**0.463**	2022 CBC § 1613.2.4 or 1613*A*.2.4
Peak Ground Acceleration for Max. Considered Earthquake (MCE_G)	**PGA**	**0.5g**	SEAOC- OSHPD software; ASCE 7-16 Fig 22-9
Site Coefficient, F_{PGA} = 1.2, F_{PGA}* PGA	**PGA_M**	**0.6g**	SEAOC- OSHPD software; ASCE 7-16 § 11.8.3.2
Mapped Risk Coefficient at 0.2 second Spectral Response Period	**C_{RS}**	**0.902**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-18A
Mapped Risk Coefficient at 1 second Spectral Response Period	**C_{R1}**	**0.891**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-19A
Seismic Design Category, short period		**D**	2022 CBC § 1613.2.5
Seismic Design Category, 1second period *		**D**	2022 CBC § 1613.2.5

Location 4: Section 35, Township 30 South, Range 23 East with the following coordinates: North: 35.275656°, West: -119.471325°.

SEISMIC DESIGN CRITERIA		**VALUE**	**SOURCE**
Risk Category		**II**	2022 CBC Table 1604.5 or 1604*A*.5
Site Class		**C**	2022 CBC § 1613.2.2 or 1613*A*.2.2; ASCE 7-16 Table. 20.3-1; Site Specific Soils Report
Mapped MCE_R Spectral Response Acceleration, short period	**S_S**	**1.181g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(1)
Mapped MCE_R Spectral Response Acceleration, at 1-sec. Period	**S_1**	**0.468g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(2)
Site Coefficient	**F_a**	**1.2**	SEAOC- OSHPD software; 2022 CBC Table 1613.2.3(1) or 1613*A*.2.3(1)
Site Coefficient	**F_v**	**1.5**	2022 CBC Table 1613.2.3(2) or 1613*A*.2.3(2)
Adjusted MCE_R Spectral Response Acceleration, short period, $F_a * S_s$	**S_{MS}**	**1.417g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.3 or 1613*A*.2.3
Adjusted MCE_R Spectral Response Acceleration, 1-sec. period, $F_v * S_1$	**S_{M1}**	**0.702**	2022 CBC § 1613.2.3 or 1613*A*.2.3
Design Spectral Response Acceleration, short period, 2/3 * S_{MS}	**S_{DS}**	**0.945g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.4 or 1613*A*.2.4
Design Spectral Response Acceleration, 1-sec. period, 2/3 * S_{MI}	**S_{D1}**	**0.468**	2022 CBC § 1613.2.4 or 1613*A*.2.4
Peak Ground Acceleration for Max. Considered Earthquake (MCE_G)	**PGA**	**0.5g**	SEAOC- OSHPD software; ASCE 7-16 Fig 22-9
Site Coefficient, F_{PGA} = 1.2, F_{PGA}* PGA	**PGA_M**	**0.6g**	SEAOC- OSHPD software; ASCE 7-16 § 11.8.3.2
Mapped Risk Coefficient at 0.2 second Spectral Response Period	**C_{RS}**	**0.902**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-18A
Mapped Risk Coefficient at 1 second Spectral Response Period	**C_{R1}**	**0.891**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-19A
Seismic Design Category, short period		**D**	2022 CBC § 1613.2.5
Seismic Design Category, 1second period *****		**D**	2022 CBC § 1613.2.5

Location 5: Section 36, Township 30 South, Range 23 East with the following coordinates: North: 35.275718°, West: -119.459997°.

SEISMIC DESIGN CRITERIA		VALUE	SOURCE
Risk Category		**II**	2022 CBC Table 1604.5 or 1604*A*.5
Site Class		**C**	2022 CBC § 1613.2.2 or 1613*A*.2.2; ASCE 7-16 Table. 20.3-1; Site Specific Soils Report
Mapped MCE_R Spectral Response Acceleration, short period	**S_S**	**1.166g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(1)
Mapped MCE_R Spectral Response Acceleration, at 1-sec. Period	**S_1**	**0.46g**	SEAOC-OSHPD software; 2022 CBC Figure 1613.2.1(2)
Site Coefficient	**F_a**	**1.2**	SEAOC- OSHPD software; 2022 CBC Table 1613.2.3(1) or 1613*A*.2.3(1)
Site Coefficient	**F_v**	**1.5**	2022 CBC Table 1613.2.3(2) or 1613*A*.2.3(2)
Adjusted MCE_R Spectral Response Acceleration, short period, $F_a * S_s$	**S_{MS}**	**1.399g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.3 or 1613*A*.2.3
Adjusted MCE_R Spectral Response Acceleration, 1-sec. period, $F_v * S_1$	**S_{M1}**	**0.69**	2022 CBC § 1613.2.3 or 1613*A*.2.3
Design Spectral Response Acceleration, short period, 2/3 * S_{MS}	**S_{DS}**	**0.933g**	SEAOC- OSHPD software; 2022 CBC § 1613.2.4 or 1613*A*.2.4
Design Spectral Response Acceleration, 1-sec. period, 2/3 * S_{MI}	**S_{D1}**	**0.46**	2022 CBC § 1613.2.4 or 1613*A*.2.4
Peak Ground Acceleration for Max. Considered Earthquake (MCE_G)	**PGA**	**0.5g**	SEAOC- OSHPD software; ASCE 7-16 Fig 22-9
Site Coefficient, F_{PGA} = 1.2, F_{PGA}* PGA	**PGA_M**	**0.6g**	SEAOC- OSHPD software; ASCE 7-16 § 11.8.3.2
Mapped Risk Coefficient at 0.2 second Spectral Response Period	**C_{RS}**	**0.903**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-18A
Mapped Risk Coefficient at 1 second Spectral Response Period	**C_{R1}**	**0.892**	SEAOC- OSHPD software; ASCE 7-16 Figure 22-19A
Seismic Design Category, short period		**D**	2022 CBC § 1613.2.5
Seismic Design Category, 1second period *		**D**	2022 CBC § 1613.2.5

MCE_R = Maximum Considered Earthquake (risk targeted)
MCE_G = Maximum Considered Earthquake (geometric mean)

See attached SEAOC/OSHPD seismic design data in Appendix B.

4.2.3 Geometric Mean Peak Ground Acceleration

As per Section 1803.5.12 of the CBC, peak ground acceleration (PGA) utilized for dynamic lateral earth pressures and liquefaction, shall be based on a site-specific study (ASCE 7-16, Section 21.5) or ASCE 7-16, Section 11.8.3. The preliminary values are presented on the tables above in section 4.2.2.

For liquefaction analysis and seismic settlement calculations a PGA of 0.60g, depending on location, should be used. The levels of earthquake induced ground motion should be designed to comply with seismic response requirements at the Site. Structural dynamic characteristics contained in the Kern County Code of Buildings Regulations and the California Building Code and State of California design standards should be incorporated into the project design.

4.3 Liquefaction

Liquefaction describes a condition in which a saturated, cohesionless soil loses shear strength during earthquake shocks. Ground motion from an earthquake may induce cyclic reversals of shearing strains of large amplitude. Lateral and vertical movements of the soil mass, combined with loss of bearing strength, usually result from this phenomenon. Historically, liquefaction of soils has caused severe damage to structures, berms, levees, and roads. Seed and Idriss (1971) demonstrated that liquefaction potential depends on soil type, void ratio, depth to groundwater, duration of shaking, and confining pressures over the potentially liquefiable soil mass. Fine, well sorted, loose sand, shallow groundwater, severe seismic ground motion, and particularly long durations of ground shaking are conditions conducive for liquefaction.

The depth to groundwater, based on recent data, is greater than 100 feet bgs and historical data indicates that no shallow groundwater will be expected to be present within the Project Area. A design level geotechnical investigation will be required to confirm the liquefaction potential and seismic settlement in the Project Areas.

5.0 REGULATORY SETTING

5.1 Federal Regulations

5.1.1 Earthquake Hazards Reduction Act

The National Earthquake Hazards Reduction Program (NEHRP) leads the federal government's efforts to reduce the fatalities, injuries, and property losses caused by earthquakes. Congress established NEHRP in 1977, directing that four federal agencies coordinate their complementary activities to implement and maintain the program. These agencies are FEMA, the National Institute of Standards and Technology, the National Science Foundation, and the U.S. Geological Survey.

The NEHRP agencies pursue the goals of the program through collaboration with each other and numerous partners. In addition to other federal agencies, program partners include state and local governments, universities, research centers, professional societies, trade associations, and businesses, as well as associated councils, commissions, and consortia. NEHRP's work

encompasses research, development, and implementation activities. Program research helps to advance our understanding of why and how earthquakes occur and impact the natural and built environments. The program develops strategies, tools, techniques, and other measures that can reduce the adverse effects of earthquakes, and facilitates and promotes implementation of these measures, thereby strengthening earthquake resilience among at-risk communities.

5.2 State Regulations

5.2.1 California and Uniform Building Codes

The 2022 California Building Standards Code (Title 24) and the Uniform Building Code provide standards for building construction as well as seismic design parameters and grading requirements. These codes contain specific requirements for seismic safety, excavation, foundations, retaining walls, and all demolition and grading activities.

5.2.2 Alquist-Priolo-Earthquake Fault Zoning Act

The Alquist-Priolo Earthquake Fault Zoning Act was passed in 1972 to mitigate the hazard of surface faulting to structures for human occupancy. The purpose of the Alquist-Priolo Geologic Hazards Zones Act, as summarized in CDMG Special Publication 42 (SP 42), is to "prohibit the location of most structures for human occupancy across the traces of active faults and to mitigate thereby the hazard of fault- rupture." Requirements to perform a fault hazard investigation only applies to structure intended for human occupancy. As indicated by SP 42, "the State Geologist is required to delineate "earthquake fault zones" (EFZs) along known active faults in California. Cities and counties affected by the zones must regulate certain development 'projects' within the zones. They must withhold development permits for sites within the zones until geologic investigations demonstrate that the sites are not threatened by surface displacement from future faulting.

5.2.3 Seismic Hazards Mapping Act

The Seismic Hazards Mapping Act (1990) addresses non-surface fault rupture earthquake hazards such as liquefaction and seismically induced landslides. This Act requires the State Geologist to designate Seismic Hazard Zones. These Zones of Required Investigation referred to in CCR Article 10, Section 3722, are areas shown on Seismic Hazard Zone Maps where site investigations are required to determine the need for mitigation of potential liquefaction and/or earthquake-induced landslide ground displacements. The California Geological Survey has not issued a Seismic Hazards Maps for the project area.

5.2.4 NPDES General Permit for Construction Storm Water Discharges

The National Pollutant Discharge Elimination System (NPDES) General Permit for Storm Water Discharges Associated with Construction Activity (General Permit) Water Quality Order 99-08-DWQ applies to projects that disturb one or more acres of soil. General Permits are implemented and enforced by the California Regional Water Quality Control Board (RWQCB). The permit requires that the following general measures be implemented during construction activity:

- Elimination or reduction of non-stormwater discharges to storm water systems and other waters of the U.S.
- Development and implementation of a Storm Water Pollution Prevention Plan (SWPPP) prepared by a Qualified SWPPP Developer identifying Best Management Practices (BMPs) the discharger will use to protect storm water runoff and incorporating visual, chemical, and sediment monitoring programs.
- Inspections of storm water control structures and pollution prevention measures.

5.3 Local Regulations

5.3.1 Kern County Code of Building Regulations

The 2019 Kern County Code of Building Regulations was developed to promote the public safety and welfare by the adoption of minimum building standards to be required and enforced throughout the unincorporated territory of the County of Kern.

Construction in Kern County is required to conform to the Kern County Building Code (Chapter 17.08, Building Code, of the Kern County Code of Regulations). Kern County has adopted the California Building Code, with some modifications and amendments.

5.3.2 Chapter 17.28 Kern County Grading Code

The purpose of the Kern County Grading Code is to safeguard life, limb, property, and the public welfare by regulating grading on private property. All requirements of the Kern County Grading Code would be applied during implementation of the proposed project. All required grading permit(s) would be obtained prior to commencement of construction activities. Sections of the Grading Code that are particularly relevant to geology and soils are provided below.

17.28.140 Erosion control

A. Slopes

The faces of cut and fill slopes shall be prepared and maintained to control against erosion. This control may consist of effective planting. The protection for the slopes shall be installed as soon as practicable and prior to calling for final approval. Where cut slopes

are not subject to erosion due to the erosion-resistant character of the materials, such protection may be omitted.

B. Other Devices

Where necessary, check dams, cribbing, riprap or other devices or methods shall be employed to control erosion and provide safety.

C. Temporary Devices

Temporary drainage and erosion control shall be provided as needed at the end of each work day during grading operations, such that existing drainage channels would not be blocked. Dust control shall be applied to all graded areas and materials and shall consist of applying water or another approved dust palliative for the alleviation or prevention of dust nuisance. Deposition of rocks, earth materials or debris onto adjacent property, public roads or drainage channels shall not be allowed.

17.28.150 Drainage retention facilities

A. General

All drainage retention/detention facilities and their associated conveyance facilities shall be designed in accordance with the Kern County Development Standards or latest revision thereof.

17.28.160 Maintenance

The owner of any property on which grading has been performed pursuant to a permit issued under the provisions of this chapter, or any other person or agent in control of such property, shall maintain in good condition and repair all drainage structures, sumps and other protective devices shown on the grading plans filed with the application for grading permit and approved as a condition precedent to the issuance of such permit.

17.28.170 Grading inspection

A. General

All grading operations for which a permit is required shall be subject to inspection by the building official. Professional inspection of grading operations and testing shall be provided by the civil engineer, soils engineer, and the engineering geologist retained to provide such services in accordance with Subsection 17.28.170(E) for engineered grading and as required by the building official for regular grading.

B. Civil Engineer

The civil engineer shall provide professional inspection within such engineer's area of technical specialty, which shall consist of observation and review as to the establishment of line, grade and surface drainage of the development area. If revised plans are required during the course of the work, they shall be prepared by the civil engineer.

C. Soils Engineer

The soils engineer shall provide professional inspection within such engineer's area of technical specialty, which shall include observation during grading and testing for required compaction. The soils engineer shall provide sufficient observation during the preparation of the natural ground and placement and compaction of the fill to verify that such work is being performed in accordance with the conditions of the approved plan and the appropriate requirements of this chapter. Revised recommendations relating to conditions differing from the approved soils engineering and engineering geology reports shall be submitted to the permittee, the building official, and the civil engineer.

D. Engineering Geologist

The engineering geologist shall provide professional inspection within such engineer's area of technical specialty, which shall include professional inspection of the bedrock excavation to determine if conditions encountered are in conformance with the approved report. Revised recommendations relating to conditions differing from the approved engineering geology report shall be submitted to the soils engineer.

E. Permittee

The permittee shall be responsible for the work to be performed in accordance with the approved plans and specifications and in conformance with the provisions of this Ordinance Code, and the permittee shall engage consultants, if required, to provide professional inspections on a timely basis. The permittee shall act as a coordinator between the consultants, the contractor and the building official. In the event of changed conditions, the permittee shall be responsible for informing the building official of such change and shall provide revised plans for approval.

F. Building Official

The building official may inspect the project at the various stages of the work requiring approval to determine that adequate control is being exercised by the professional consultants.

G. Notification of Noncompliance

If, in the course of fulfilling their responsibility under this chapter, the civil engineer, the soils engineer, or the engineering geologist finds that the work is not being done in conformance with this chapter or the approved grading plans, the discrepancies shall be reported immediately in writing to the permittee and to the building official. Recommendations for corrective measures, if necessary, shall also be submitted.

H. Transfer of Responsibility

If the civil engineer, the soils engineer, or the engineering geologist of record is changed during the course of the work, the work shall be stopped until:

1. The civil engineer, soils engineer, or engineering geologist, has notified the building official in writing that they will no longer be responsible for the work and that a qualified replacement has been found who will assume responsibility.
2. The replacement civil engineer, soils engineer, or engineering geologist notifies the building official in writing that they have agreed to accept responsibility for the work.

5.4 Kern County Environmental Checklist

The Kern County CEQA Implementation Document and Kern County Environmental Checklist state that a project would have a significant effect if it:

- Exposes people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:
  - Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State geologist for the area or based on other substantial evidence of a known fault;
  - Strong seismic ground shaking;
  - Seismic-related ground failure, including liquefaction;
  - Landslides;
- Results in substantial soil erosion or the loss of topsoil;
- Is located on a geologic unit or soil that is unstable, or that would become unstable as a result of the proposed project, and potentially result in on-site or off-site landslide, lateral spreading, subsidence, liquefaction or collapse; is located on expansive soil, as defined in Section 1805.8 of the California Building Code, creating substantial risks to life or property.

An evaluation according to this checklist follows:

a) Exposes people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:

i) Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo (AP) Earthquake Fault Zoning Map issued by the state geologist for the area or based on other substantial evidence of a known fault.

The project area is not located in a Fault-Rupture Hazard Zone. No active faults have been mapped in the Project Area. Two (2) unnamed fault traces are shown within the southern portion of Section 12 based on USGS and State of California maps. The Elk Hills Fault is shown as a creeping fault within the northern portion of Sections 7 & 8 on the West Elk Hills Seismic Hazard Atlas Map. These fault traces appear to be inactive faults (>11,700 years since movement) and are not part of a mapped AP zone (see Figure 7). Any structure that is designated as occupied and located near an active fault trace would require a fault investigation.

Mitigation Measure GEO – 1: Project proponent will not place structures near any known active fault traces unless a fault investigation is completed. This would reduce the potential of exposure of structures to surface fault rupture and reduce the hazard to less than significant.

ii) Strong seismic ground shaking.

Estimated ground motion may be moderate to very intense and there are numerous faults in the area that are capable of producing strong ground motion. The threshold of significance would be exceeded if habitable structures are not designed to withstand seismic loading that could result in structure damage or collapse.

Mitigation Measure GEO – 2: Project proponent will design structures in accordance with state and county code requirements for seismic ground shaking and geotechnical and geohazard constraints. Designs shall comply with seismic, soil response at the site, and structural dynamic characteristics contained in the Kern County Code of Building Regulations and the California Building Code and State of California design standards Chapter 16 and 18.

These design standards are required by law for all new structures in Kern County and

were established to reduce the potential impact to structures from strong seismic shaking to a less than significant level.

iii) Seismic-related ground failure, including liquefaction.

Mitigation Measure GEO – 3: The potential for impacts relating to liquefaction and seismic settlements will be addressed by the applicant in the site-specific design-level geotechnical report prepared by a registered engineering geologist or soils engineer. The design-level geotechnical report will provide specific design requirements necessary for the design of the structures in relation to seismic-related ground failure, including liquefaction. The geotechnical investigation would include multiple soil borings to collect representative soil samples within each proposed structure area that will be tested for a variety of soil properties. The results of this geotechnical testing will be utilized in the evaluation of the subsurface soil conditions and how the potential seismic activity would impact the site area and to determine the liquefaction potential. These design requirements will comply with the current California Building Code and State of California design standards Chapter 16 which are required by law for all new structures in Kern County. These design standards and codes were established to reduce the potential impact to structures from seismic-related ground failure, including liquefaction to a less than significant level.

iv) Landslides.

The proposed project areas have undulating topography with some slopes up to 50% possible. This would include Sections 7, 8, 12, 17 & 18 in the western portion and sections 22, 25, 26 & 27 of the eastern portion. Sections 35 and 36 have relatively flat areas with some steeper cut slopes. The potential hazard due to landslides from adjacent features appears to be low to moderate.

Mitigation Measure GEO – 4: Development near steep slopes should maintain a sufficient setback distance to meet the requirements of 2022 CBC Section 1808.7. Maintaining sufficient setback distance would ensure that slope failures do not impact the Site and reduce the hazard of landslides to less than significant.

b) Result in substantial soil erosion or the loss of topsoil.

According to the Kern County General Plan Safety Element, the Site is not within a

zone that is prone to soil erosion (Kern County General Plan Safety Element, 2009). The proposed Site has undulating topography which will need to be graded properly to minimize the possibility for the formation of significant rills or gullies by water. With respect to soil erosion by wind, earthwork at the Site during construction might cause some disturbed soils to be affected by wind erosion (see Figure 4B for wind erodibility potential).

New construction and grading projects requiring a storm water pollution prevention plan (SWPPP) will also require an Erosion Control Plan (ECP) for the mitigation of potential soil erosion and sedimentation. Projects that involve more than an acre of disturbance that will result in the discharge of stormwater to a Water of the United States containing contaminants and/or sediments must comply with the State Water Resources Control Board's Construction General Permit. Additionally, the Kern County Engineering, Survey and Permit Services Department require that such projects complete an "Applicability of NPDES Storm Water Program" form. As required, the SWPPP will be submitted for approval by Kern County Engineering, Survey and Permit Services.

Mitigation Measure GEO – 5: Prior to construction, a SWPPP, Erosion Control Plan, and Applicability of NPDES Storm Water Program, will be submitted for approval by Kern County Engineering, Survey and Permit Services. Additionally, the applicant will apply for coverage under the State water Resources Control Board's Construction General Permit. Each of these plans and permits are designed to reduce erosion from wind, water, and construction activities. These plans would reduce the potential of substantial soil erosion or the loss of topsoil to a less than significant level. The erosion control plan should include measures to reduce wind erosion during construction. Measure could include reduced speed limits on construction traffic and continued wetting of construction roads.

c) Is located on a geologic unit or soil that is unstable, or that would become unstable as a result of the proposed project, and potentially result in on-site or off-site landslide, lateral spreading, subsidence, liquefaction or collapse.

Hydrocompaction is the consolidation of loose dry surface soils from the infiltration of water. Materials of unusually low density deposited in areas of low rainfall undergo significant compaction when they become thoroughly wetted. Site soils may have a potential for hydrocompaction in the eastern portion of the site which will require further evaluation (see Figure 9). A more detailed geotechnical investigation will be

performed once the layout of the structures is defined. Hydrocompaction materials consist of sediments loosely placed by wind or by mudflow, that when saturated, the material hydrocompacts (settlement). If hydrocompaction soil is encountered, project proponent shall: 1) over-excavate and re-compact the material, 2) design the foundation deeper than the hydrocompaction material zone, or 3) provide an alternative engineering solution to ensure that hydrocompaction will not result in instability of project features.

The depth to groundwater, based on recent and historical data, is and has been greater than 50 feet bgs, indicating that shallow groundwater should not present in the Project Area. A design level geotechnical investigation will be required to confirm the liquefaction potential and seismic settlement in the Project Area.

Mitigation Measure GEO – 6: The potential for impacts relating to unstable soils, on-site or off-site landslide, lateral spreading, subsidence, liquefaction, or collapse will be addressed by the applicant in the site-specific design-level geotechnical report prepared by a registered engineering geologist or soils engineer. Hydrocompaction assessment, seismic induced settlement evaluation and protection recommendations in the geotechnical investigation, and grading recommendations will mitigate these potential impacts. Prior to issuance of grading or building permits for the project, the applicant shall submit the geotechnical report to the Kern County Engineering, Surveying, and Permit Services Department for review and approval. The design-level geotechnical report will provide specific design requirements necessary for the design of the structures in relation to unstable soils, on-site or off-site landslides, lateral spreading, subsidence, liquefaction, or collapse. These design requirements will comply with California Building Code and State of California design standards Chapters 16 and 18 which are required by law for all new structures in Kern County. These design standards were established to reduce the potential impact related to unstable soils, on-site or off-site landslides, lateral spreading, subsidence, liquefaction, or collapse to a less than significant level.

d) Is located on expansive soil, as defined in Section 1805.8 of the California Building Code, creating substantial risks to life or property.

The Site area soils may be expansive. A geotechnical engineering evaluation would be needed to confirm the actual site conditions. Any recommendations based on the results of the evaluation would be performed according to standard geotechnical

engineering practices.

Mitigation Measure GEO – 7: The potential for impacts relating to expansive soils will be addressed by the applicant in the site-specific design-level geotechnical report prepared by a registered engineering geologist or soils engineer. The risk associated with expansive soils can be addressed during design of the project, in accordance with the requirements of Chapter 18 of the California Building Code. The standards set forth in the California Building Code are required to be implemented by law for new structures and are designed to reduce impacts from expansive soil to a less than significant level. Should expansive soils be identified, mitigation techniques can be readily implemented. Such techniques include overexcavation and replacement with non-expansive soil, moisture control, soil mixing, lime treatment, and/or development of specific structural designs for expansive soil conditions. In following the recommendations of the design-level geotechnical evaluation, project risks with respect to expansive soils can be adequately mitigated. We are not aware of any reason these expansive soil mitigation methods cannot be implemented effectively and reasonable for the Project. This impact is considered less than significant with mitigation incorporated.

e) Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water.

The Site does not require septic tanks or wastewater disposal systems as wastewater will not be produced from the Project Area and existing facilities will be utilized for wastewater disposal, if warranted. Therefore, there is no impact.

5.5 Cumulative Impacts

Development of the proposed project in addition to projected future development in the area will alter the landforms in the region and expose workers and structures to the geologic hazards of the region. Site- specific geologic and construction issues will be addressed and potential impacts mitigated by implementation of recommendations contained in site-specific geotechnical investigation(s) as the proposed project and improvements proceed through the permitting processes. The proposed project is not located close enough to other project sites in the area to cumulatively impact geology and soils. Furthermore, any geological and soil impacts are localized to the specific project areas and therefore, will not create a significant cumulative impact. The consideration of geologic and soil impacts and mitigation efforts of each proposed

project in the area will result in cumulative impacts that are less than significant.

6.0 LIMITATIONS

The findings expressed in this report are based on a limited preliminary study for the area that consisted of Site reconnaissance in accessible areas and a review of publicly available references. The findings and evaluations in this report do not represent an engineering analysis of actual site conditions such as those that would be determined through on-site geologic or geotechnical investigations. A detailed investigation consisting of field exploration (field exploration and soil sampling), laboratory testing of soil samples, and engineering analysis will be required for definitive evaluation of the potential environmental impacts from development.

The findings of this report are valid as of the present. However, changes in the conditions of the Site can occur with the passage of time, whether caused by natural processes or the work of man, on this property or adjacent property. In addition, changes in applicable or appropriate standards may occur, whether they result from legislation, governmental policy or the broadening of knowledge.

SEI has prepared this report for the exclusive use of the Client and members of the project design team. The report has been prepared in accordance with generally accepted geotechnical engineering practices which existed in Kern County at the time the report was written. No other warranties either expressed or implied are made as to the professional advice provided under the terms of SEI's agreement with Client and included in this report.

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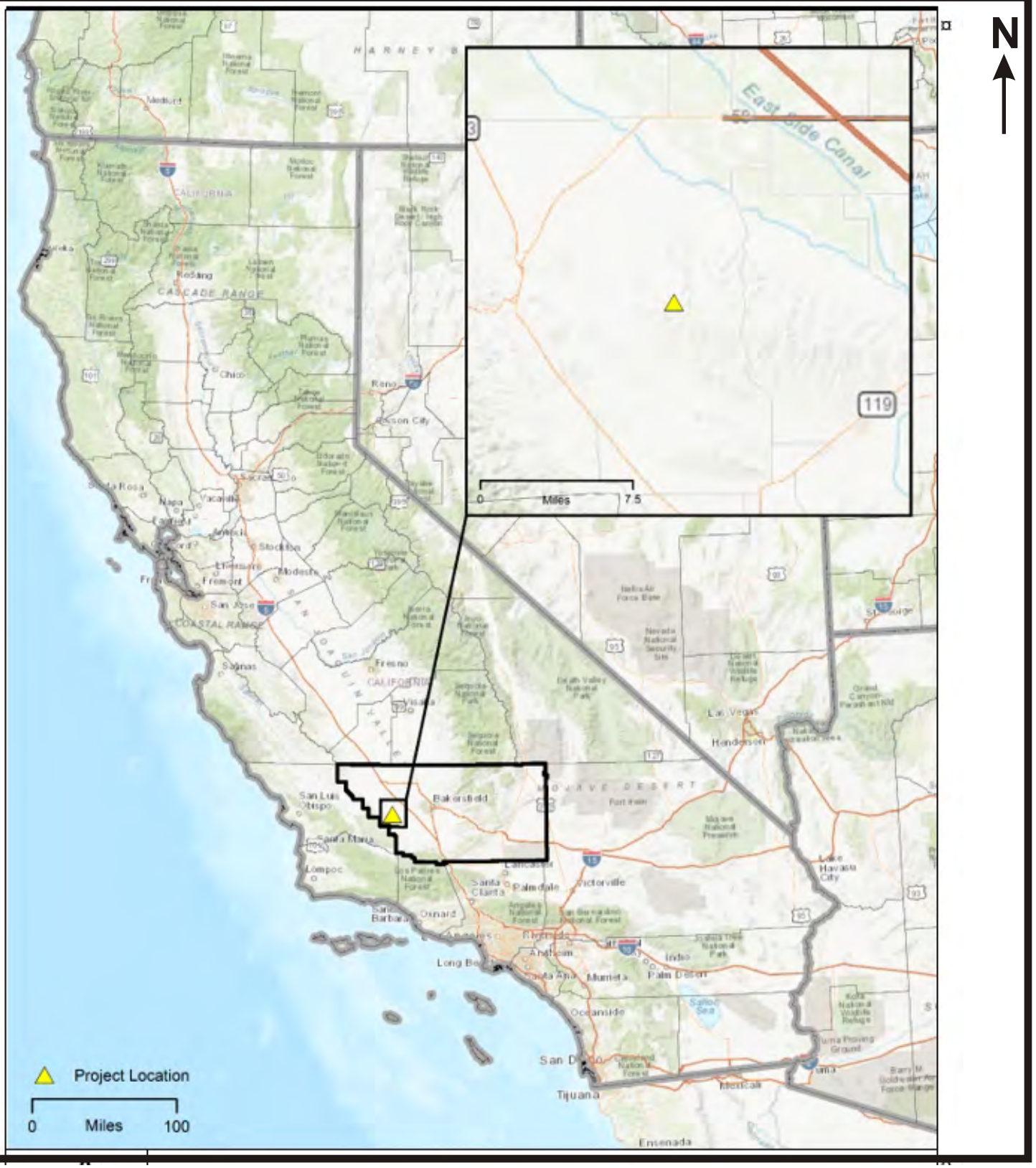


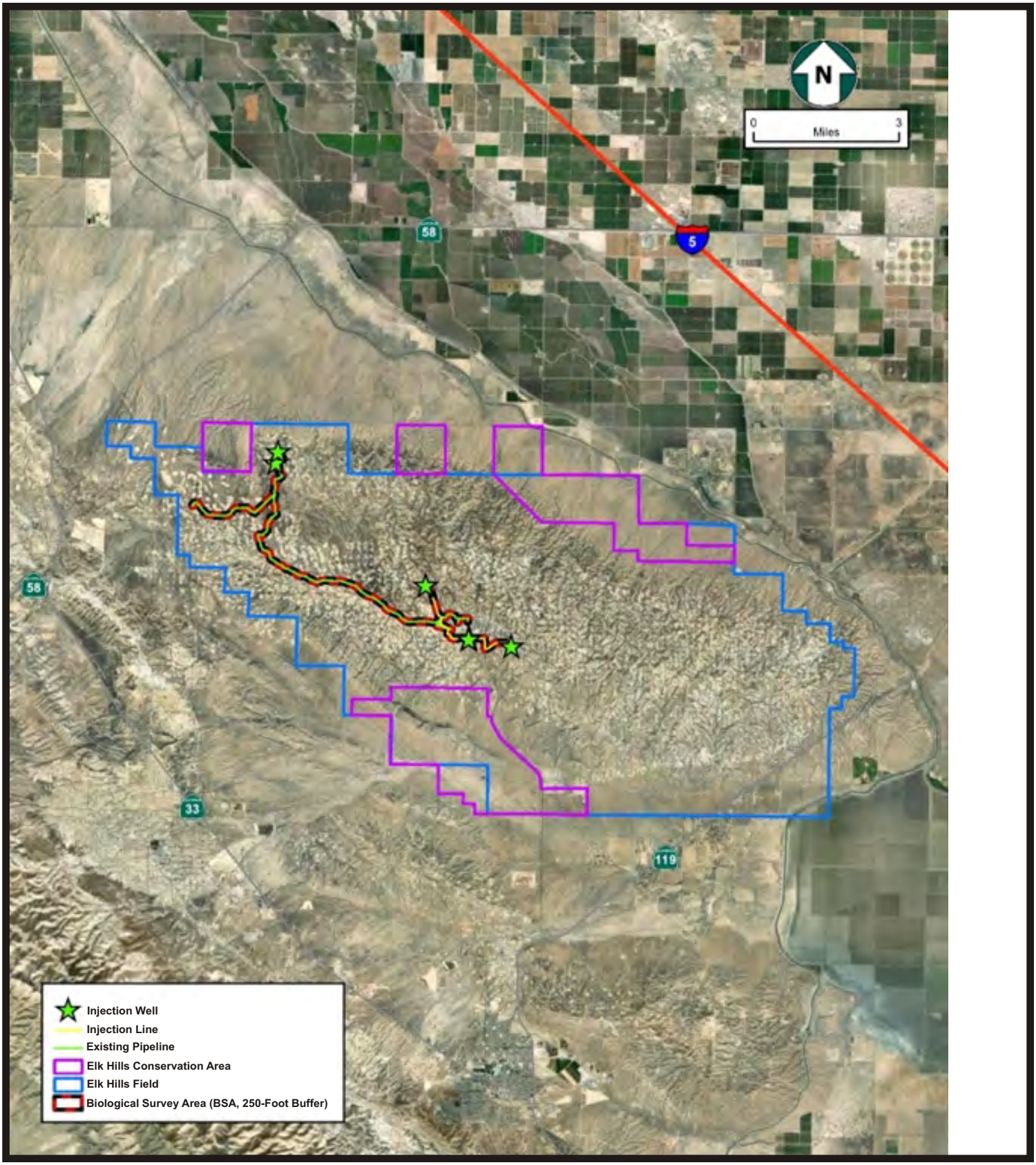
SOILS ENGINEERING, INC.
4400 Yeager Way
BAKERSFIELD, CA 93313

DATE: 10/23
PROJECT: #18566

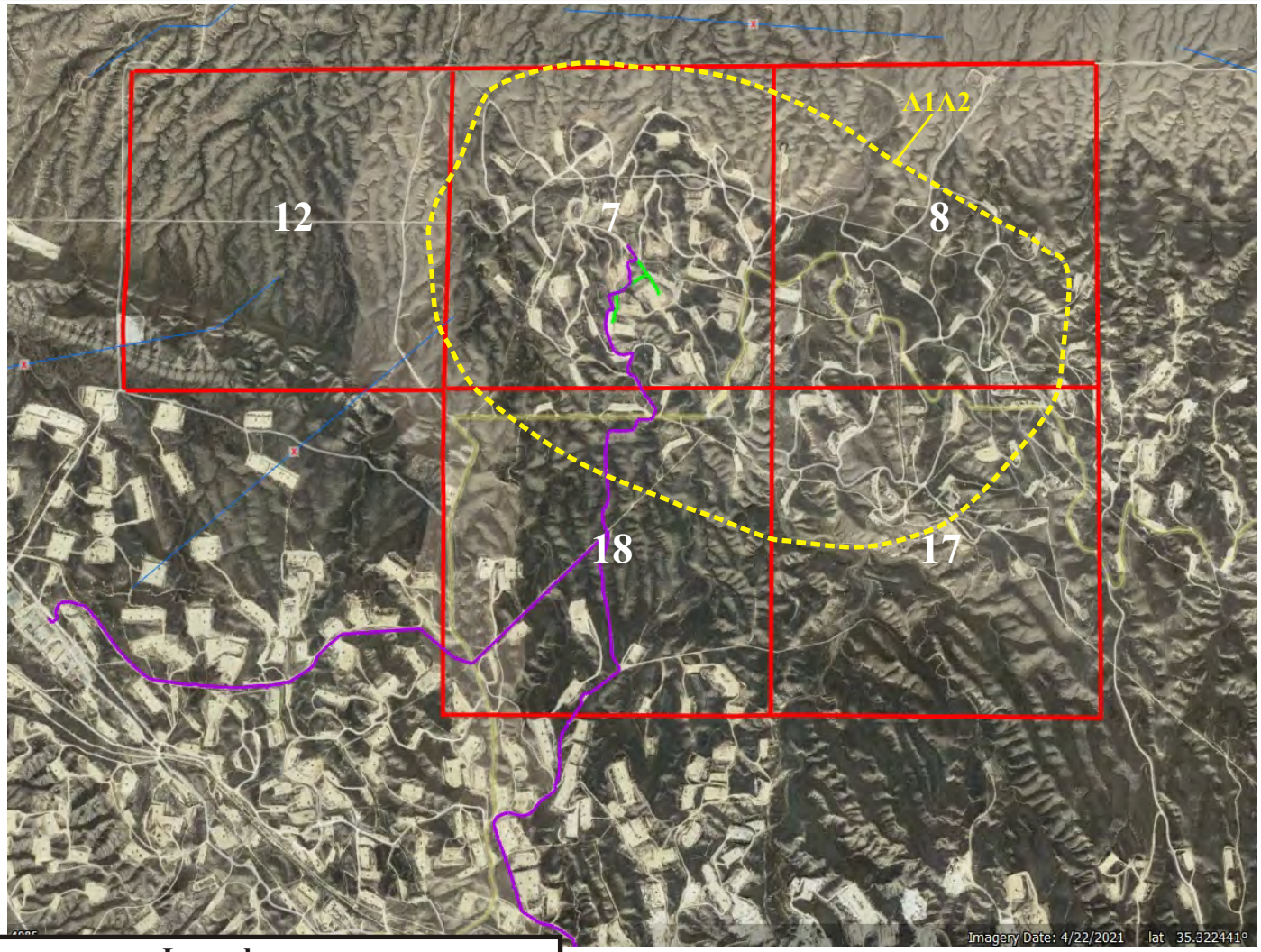
Carbon Capture TerraVault 1 Project
Elk Hills Oil Field
Kern County, CA

Location Map

Figure 1



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 10/23 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA** Project Area	Figure 2



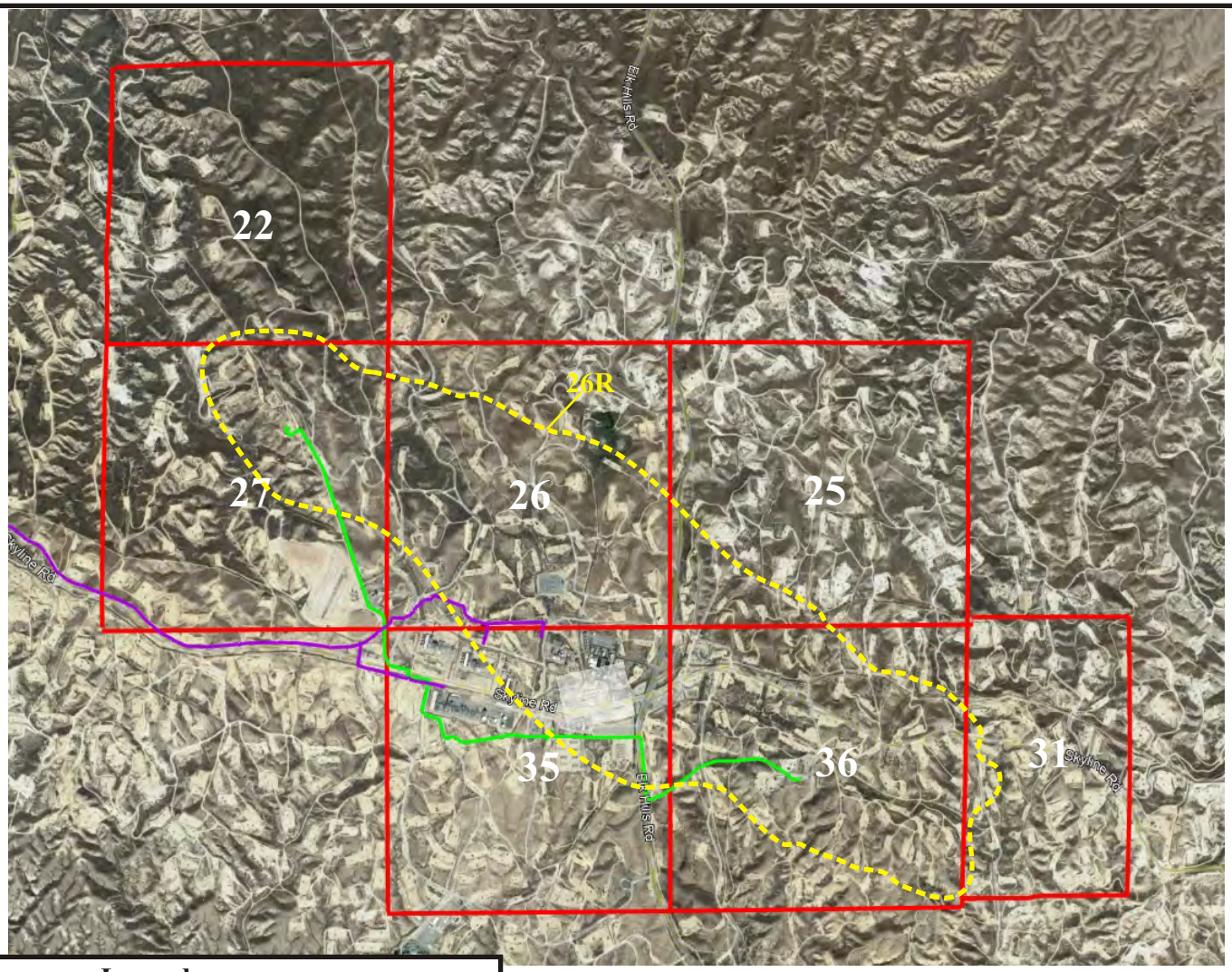
Legend

- Existing Pipeline
- Proposed Injection Pipeline
- # Project Sections
- AOR EPA - A1A2

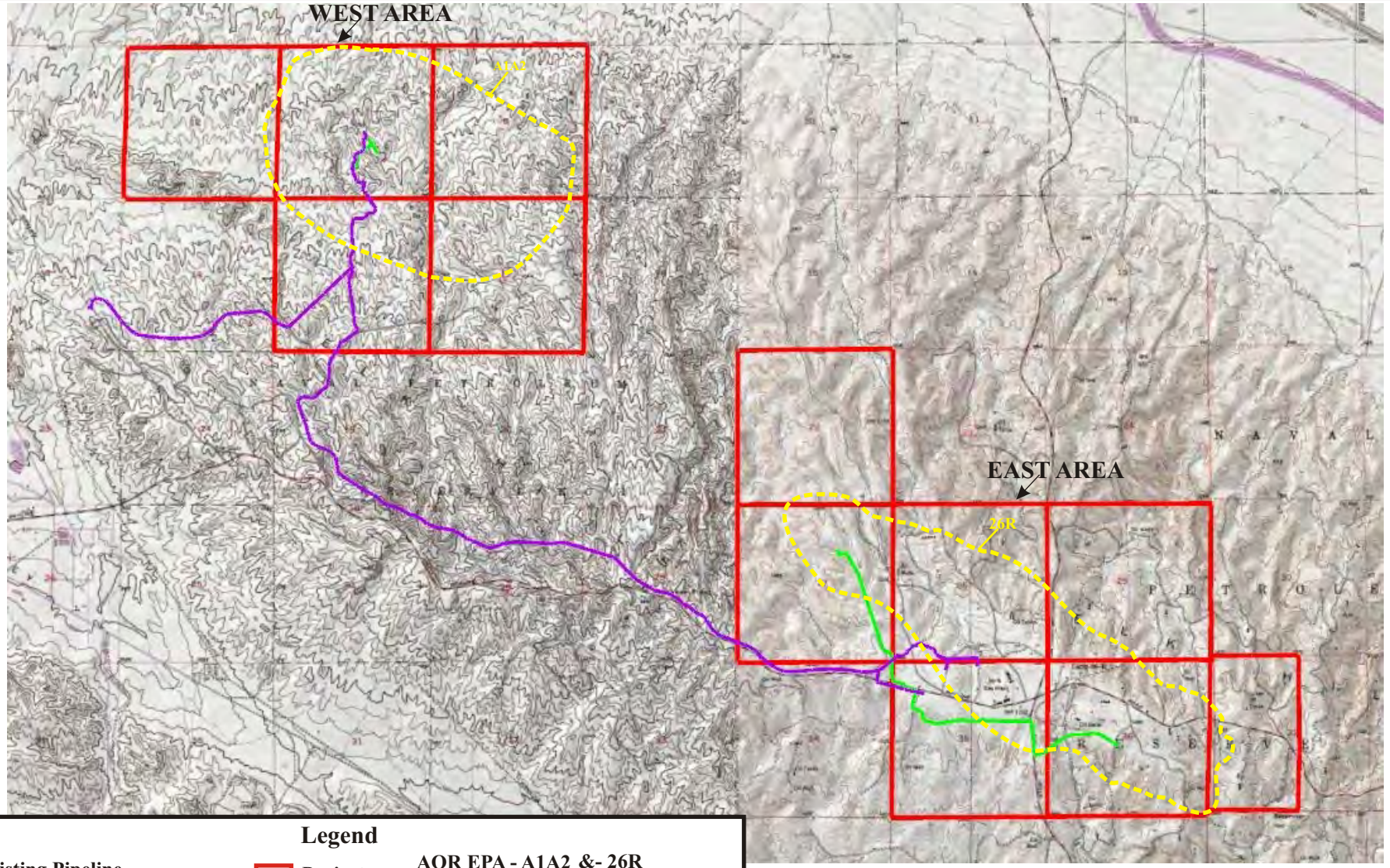
0 0.5 1 miles

Scale

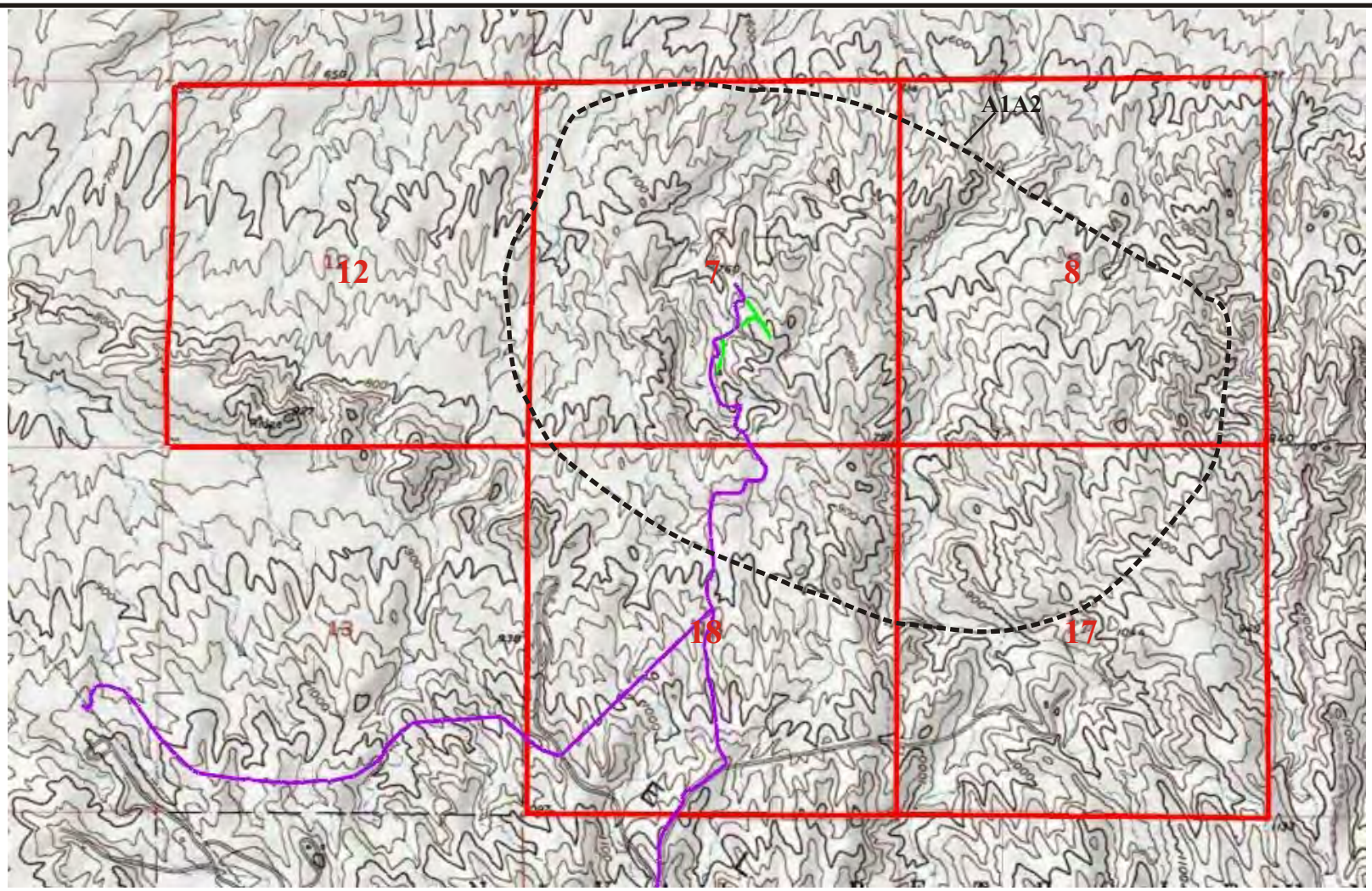
SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Western Portion Aerial**	**Figure 2A**



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Eastern Portion Aerial**	**Figure 2B**



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Topographic Map**	**Figure 3**



Legend

- Existing Pipeline
- Proposed Injection Pipeline
- # Project Sections
- AOR EPA - A1A2

0 0.5 1 miles

Scale

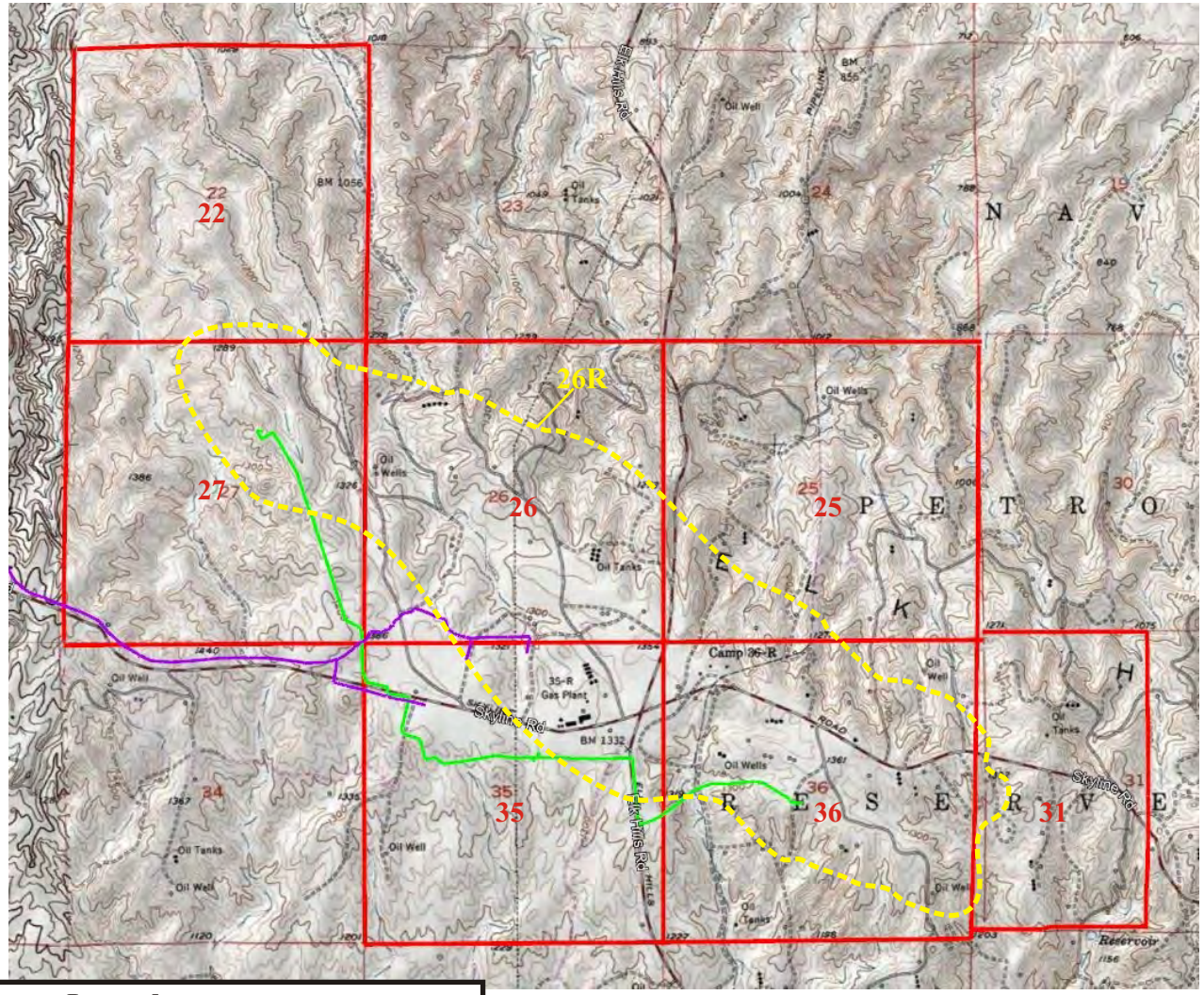
SOILS ENGINEERING, INC.
4400 Yeager Way
BAKERSFIELD, CA 93313

DATE: 12/22
PROJECT: #18566

Carbon Capture TerraVault 1 Project
Elk Hills Oil Field
Kern County, CA

Western Portion Topographic Map

Figure 3A



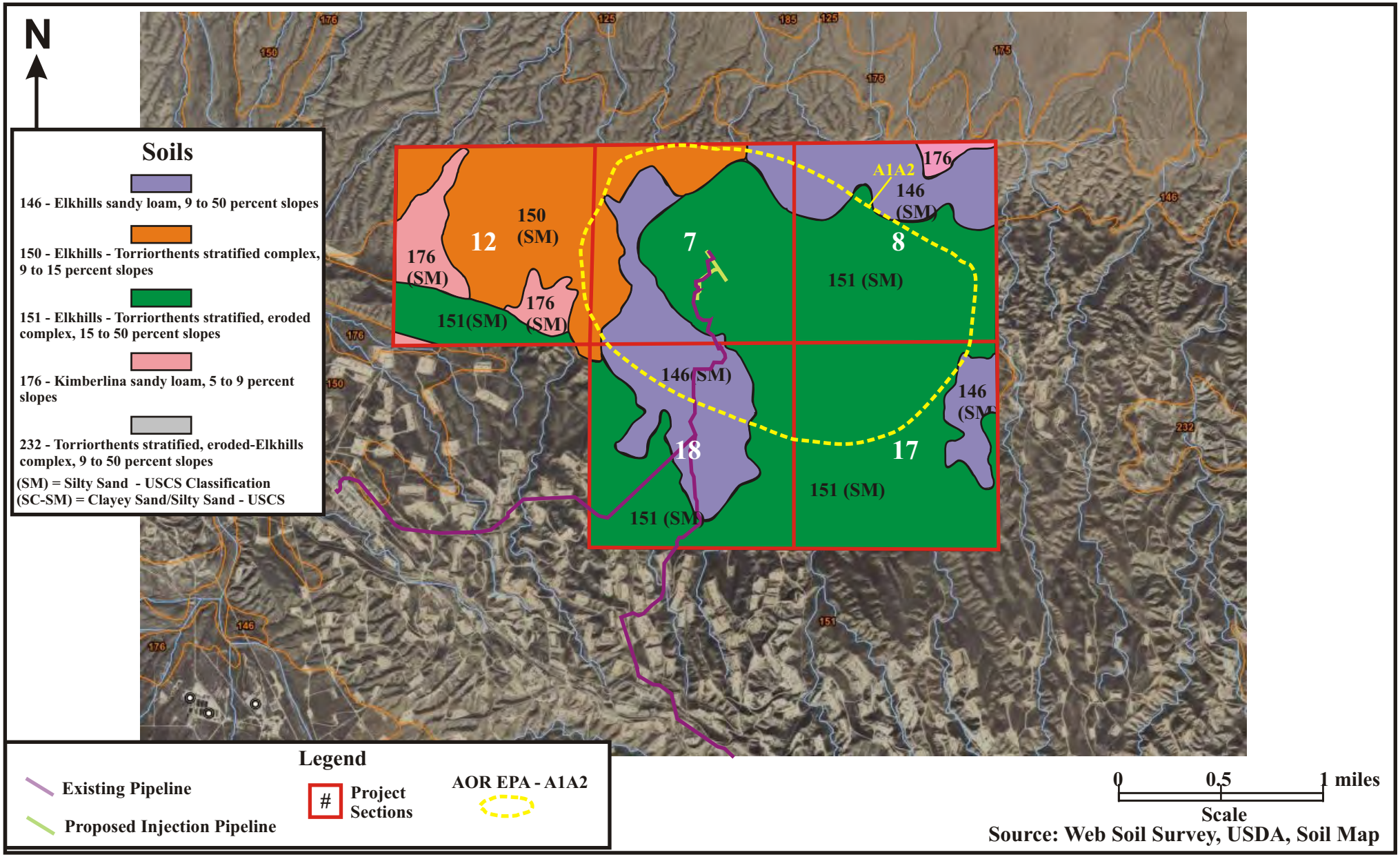
Legend

- Existing Pipeline
- Proposed Injection Pipeline
- # Project Sections
- AOR EPA - 26R

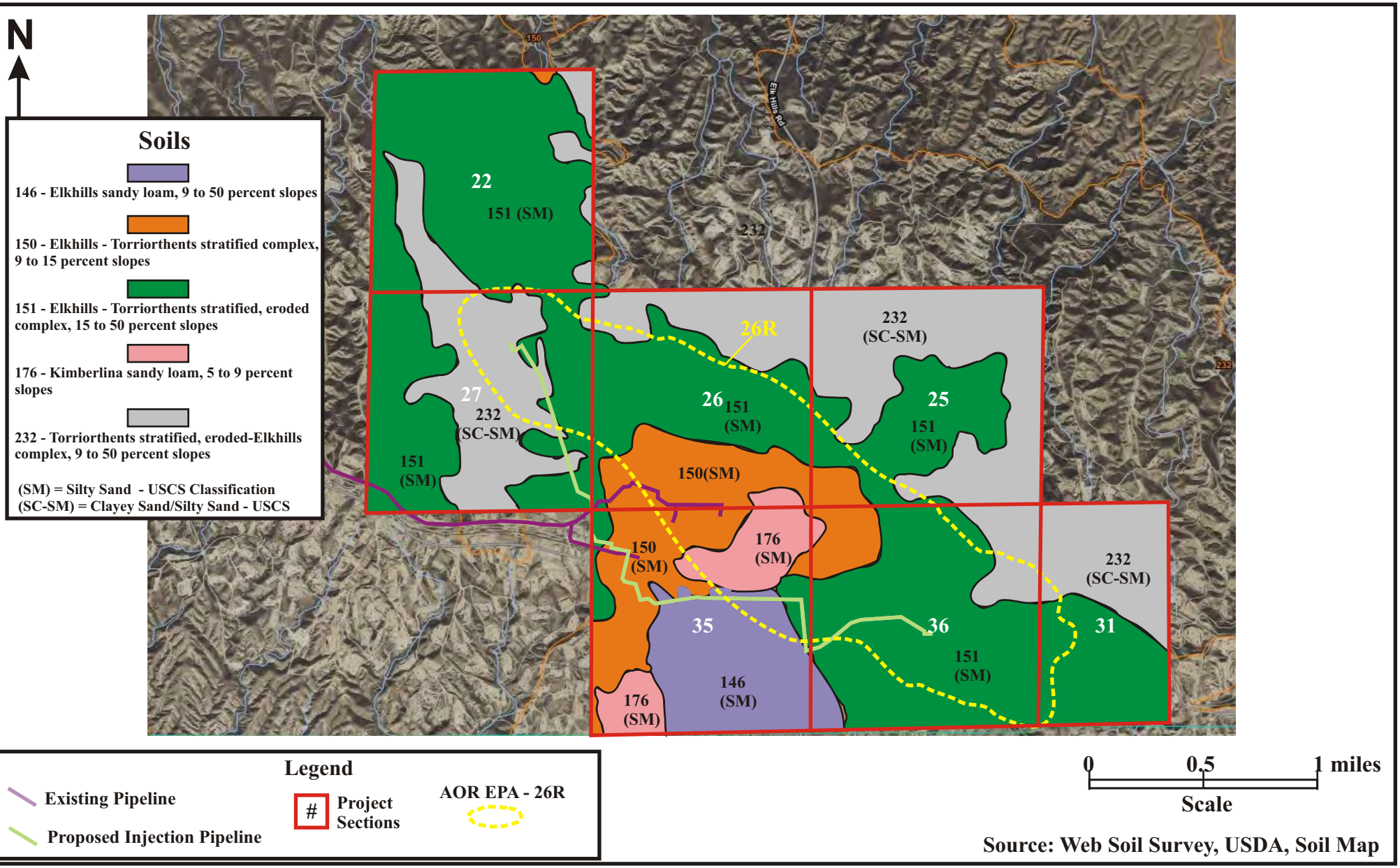
0 0.5 1 miles

Scale

SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Eastern Portion Topographic Map**	**Figure 3B**



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Soil Map** **Western Portion**	**Figure** **4**



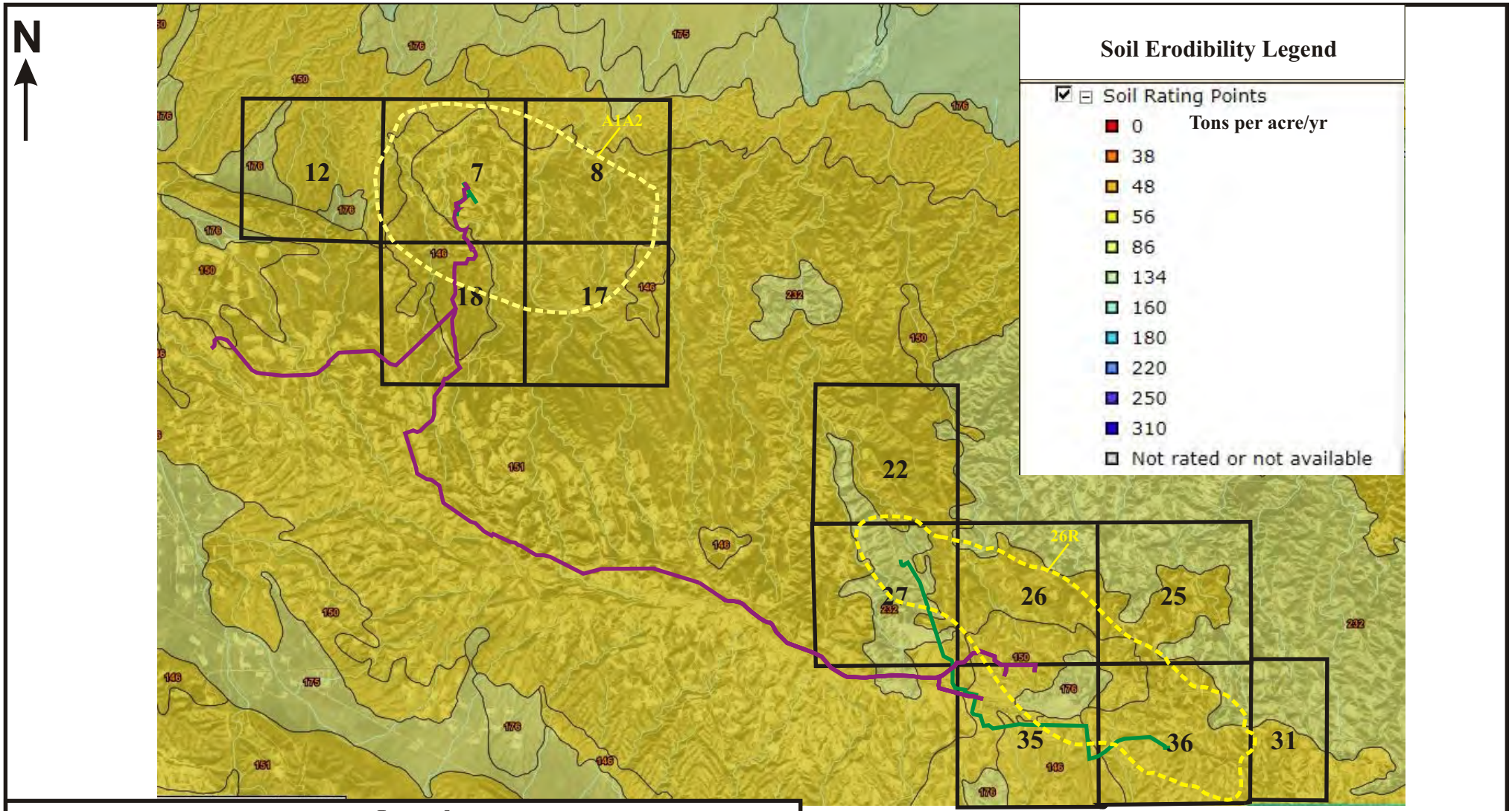
SOILS ENGINEERING, INC.
4400 Yeager Way
BAKERSFIELD, CA 93313

DATE: 12/22
PROJECT: #18566

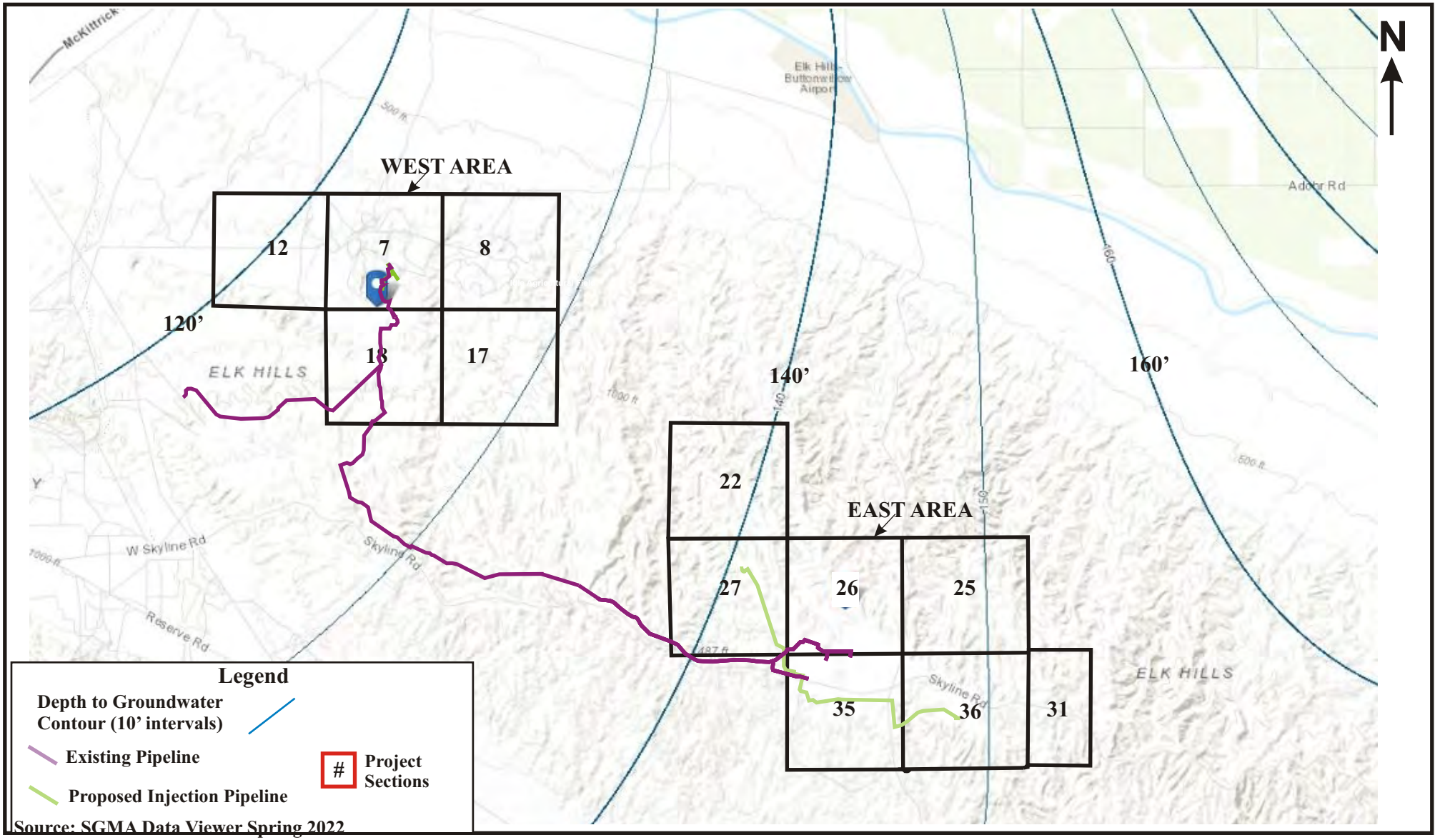
Carbon Capture TerraVault 1 Project
Elk Hills Oil Field
Kern County, CA

Soil Map
Eastern Portion

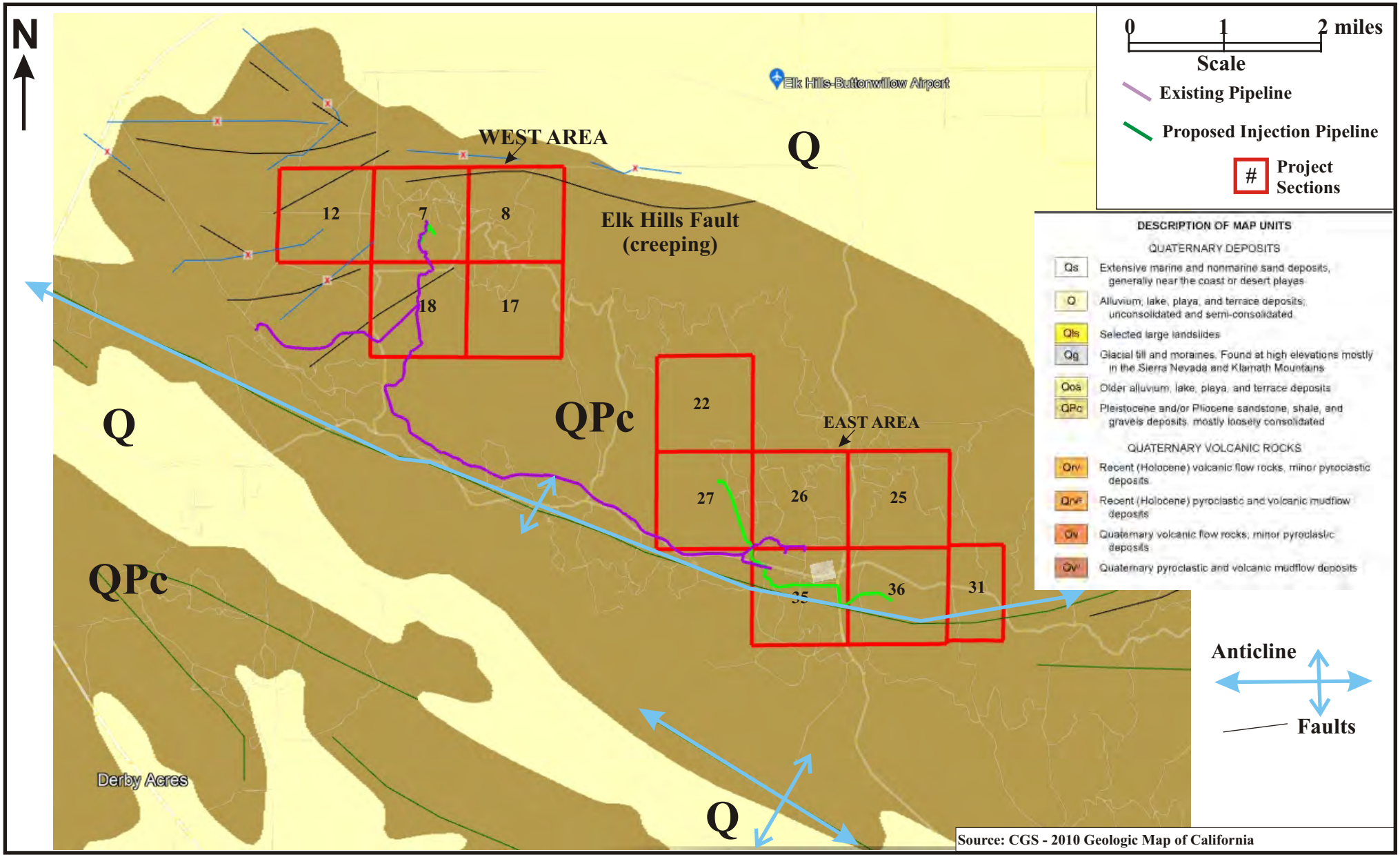
Figure 4A



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Wind Erodibility Map**	**Figure 4B**



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Depth To Groundwater Map**	**Figure 5**



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**2010 Geologic Map of CA**	**Figure 6**

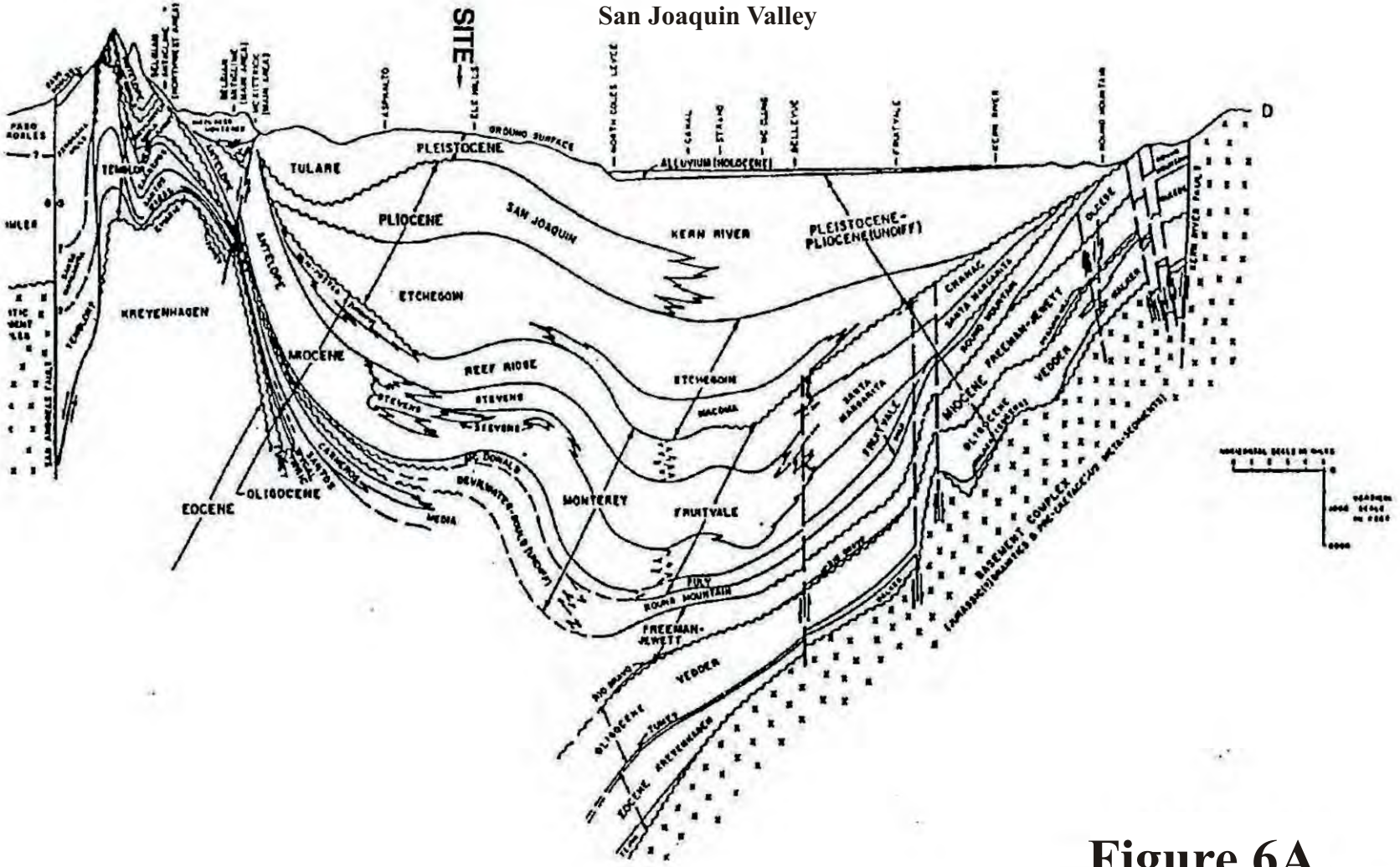
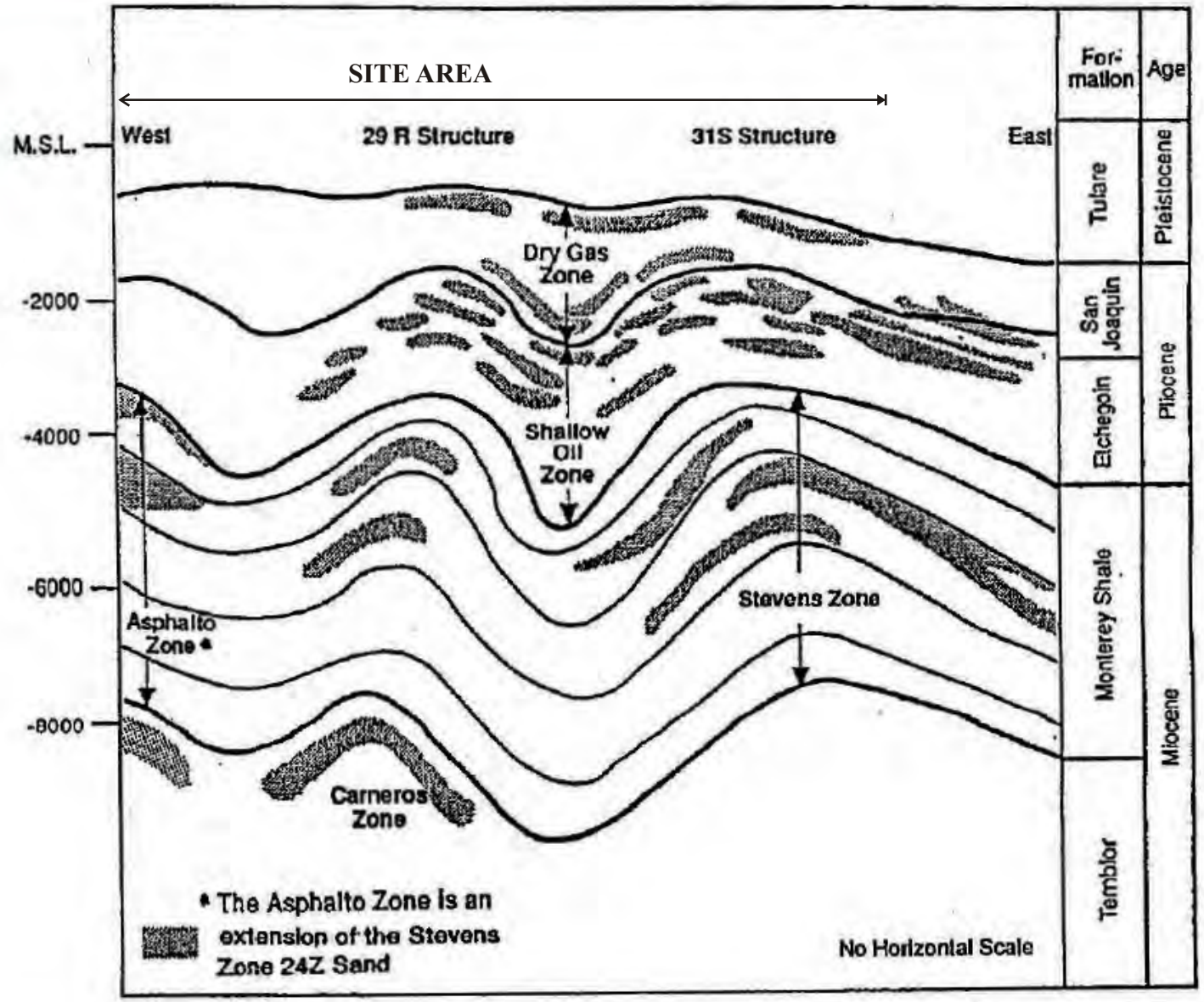


Figure 6A

Carbon Capture - TerraVault 1

Geologic Cross Section of the Elk Hills Area

Source: DOE, 1993

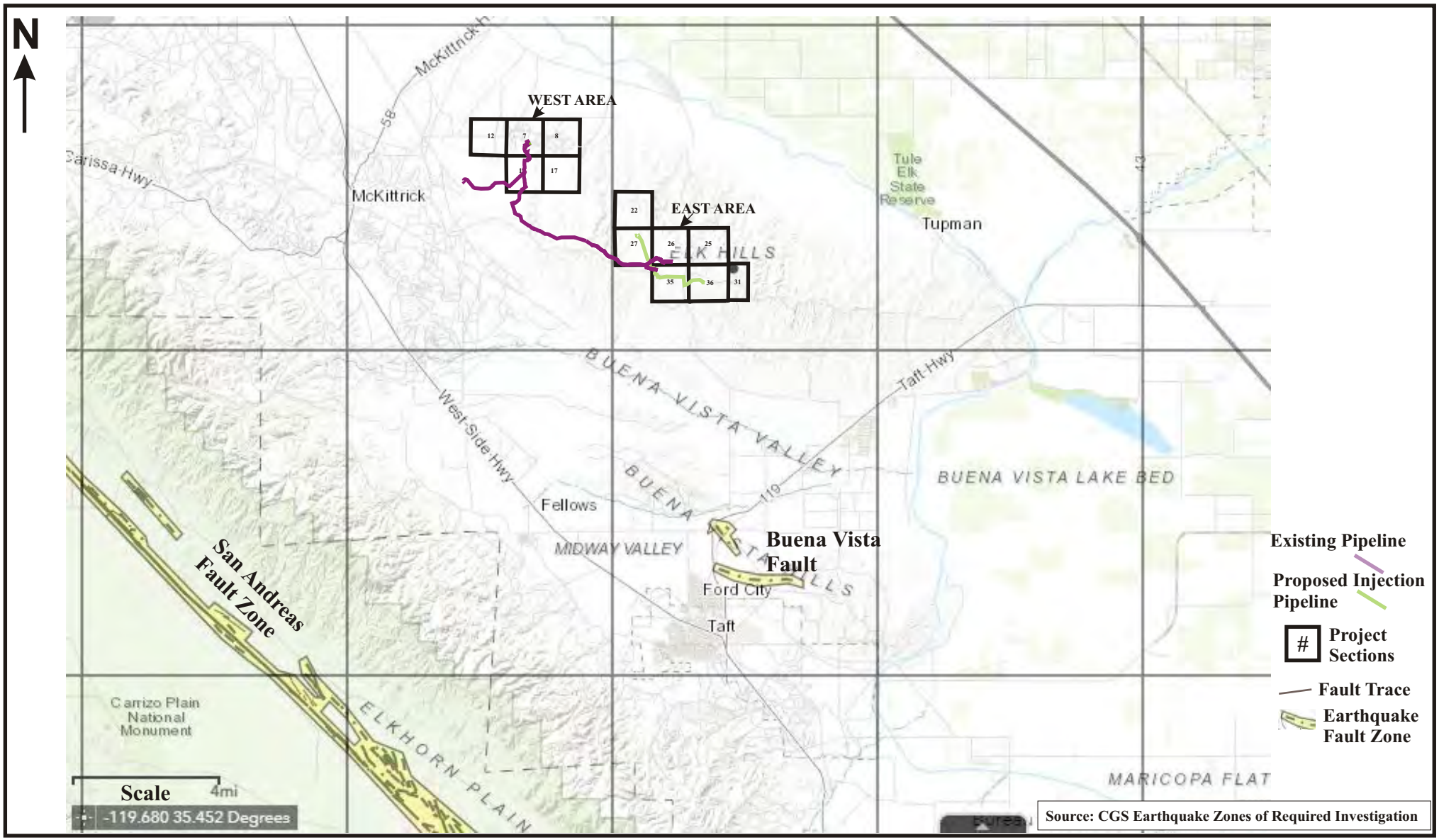


Source: DOE, 1993

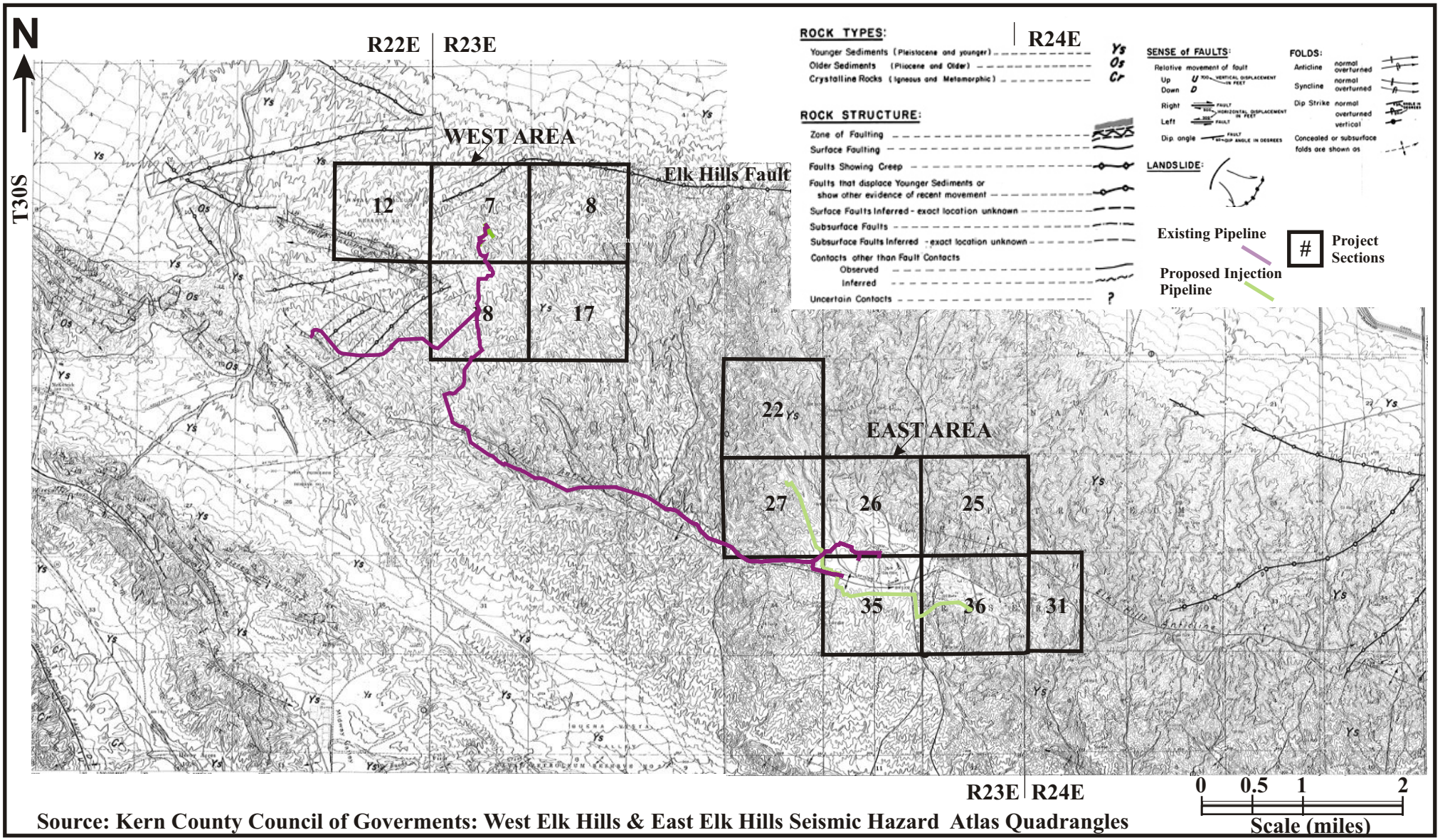
Figure 6B

Carbon Capture - TerraVault 1

Schematic Cross Section of the Elk Hills

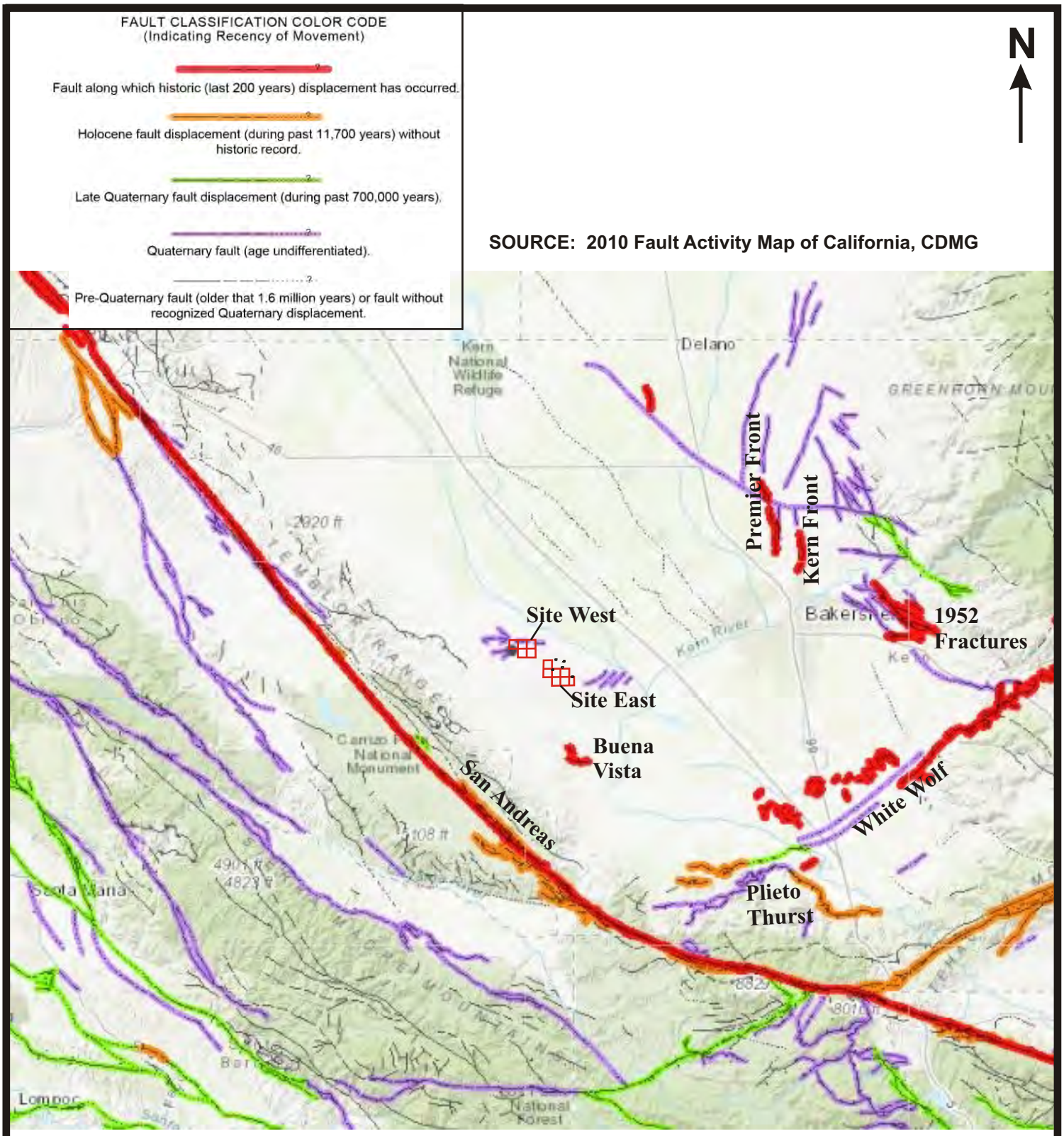


SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Earthquake Fault Zone Map**	**Figure 7**

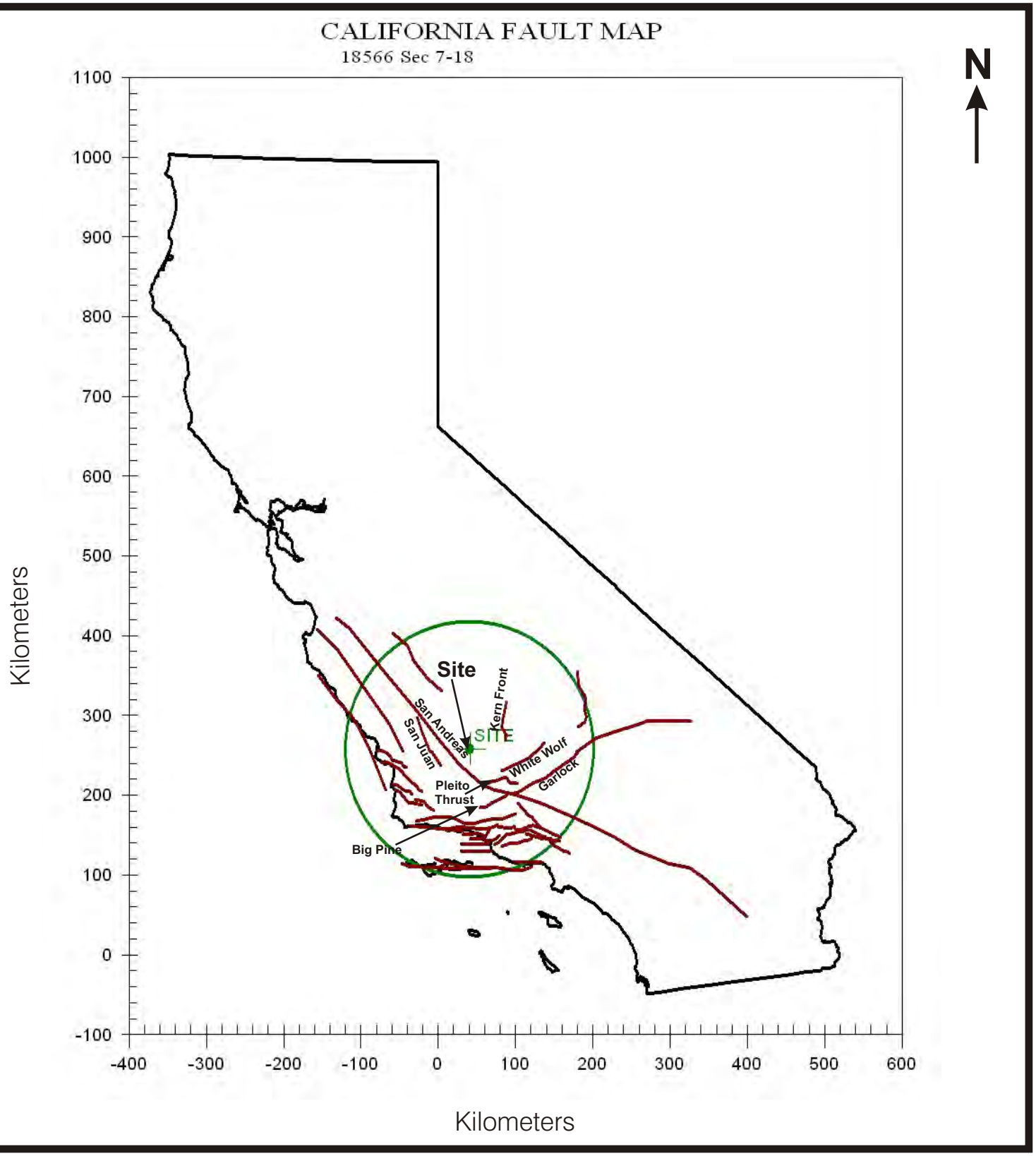


Source: Kern County Council of Goverments: West Elk Hills & East Elk Hills Seismic Hazard Atlas Quadrangles

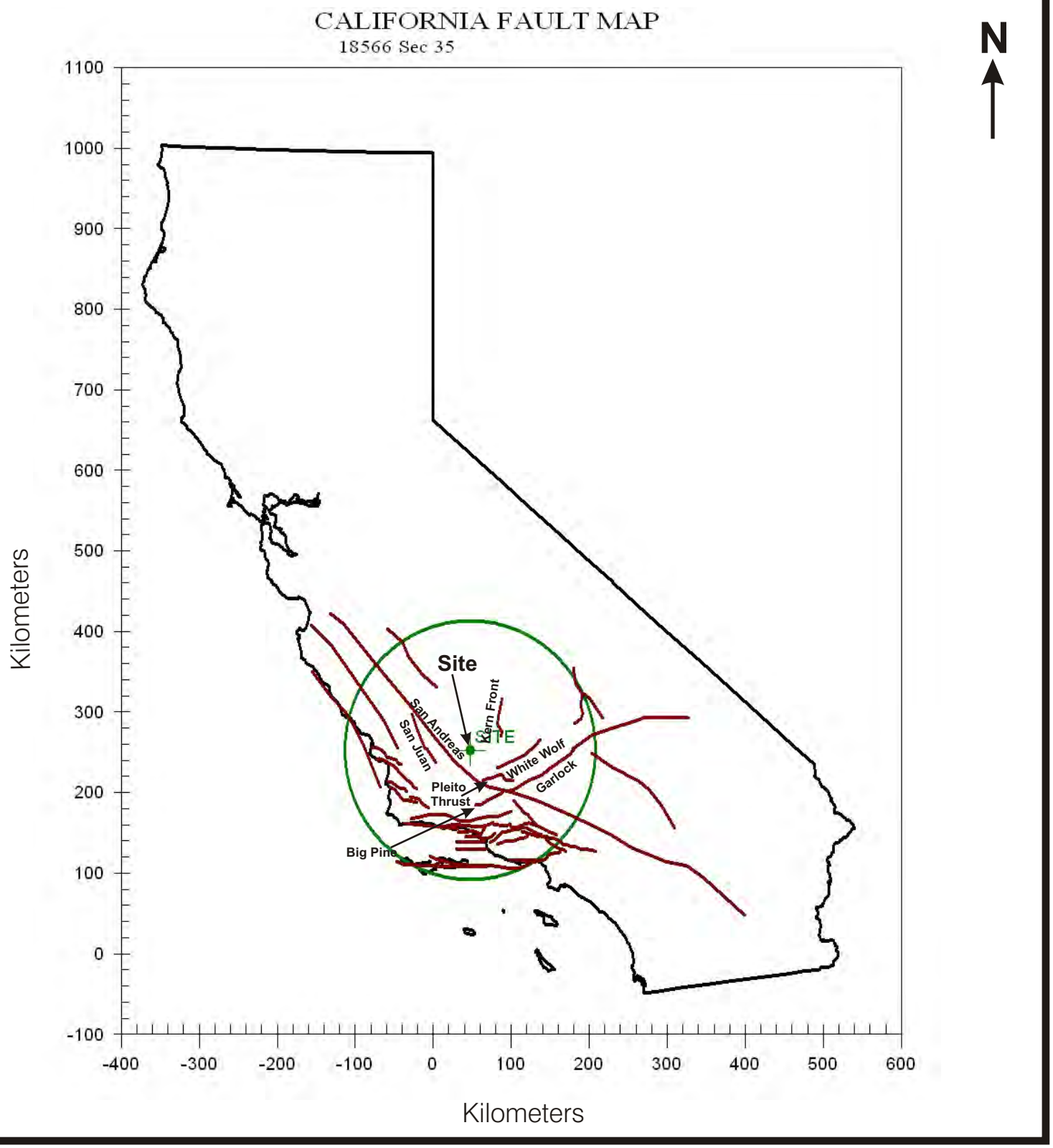
SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Seismic Hazard Atlas Map**	**Figure 7A**



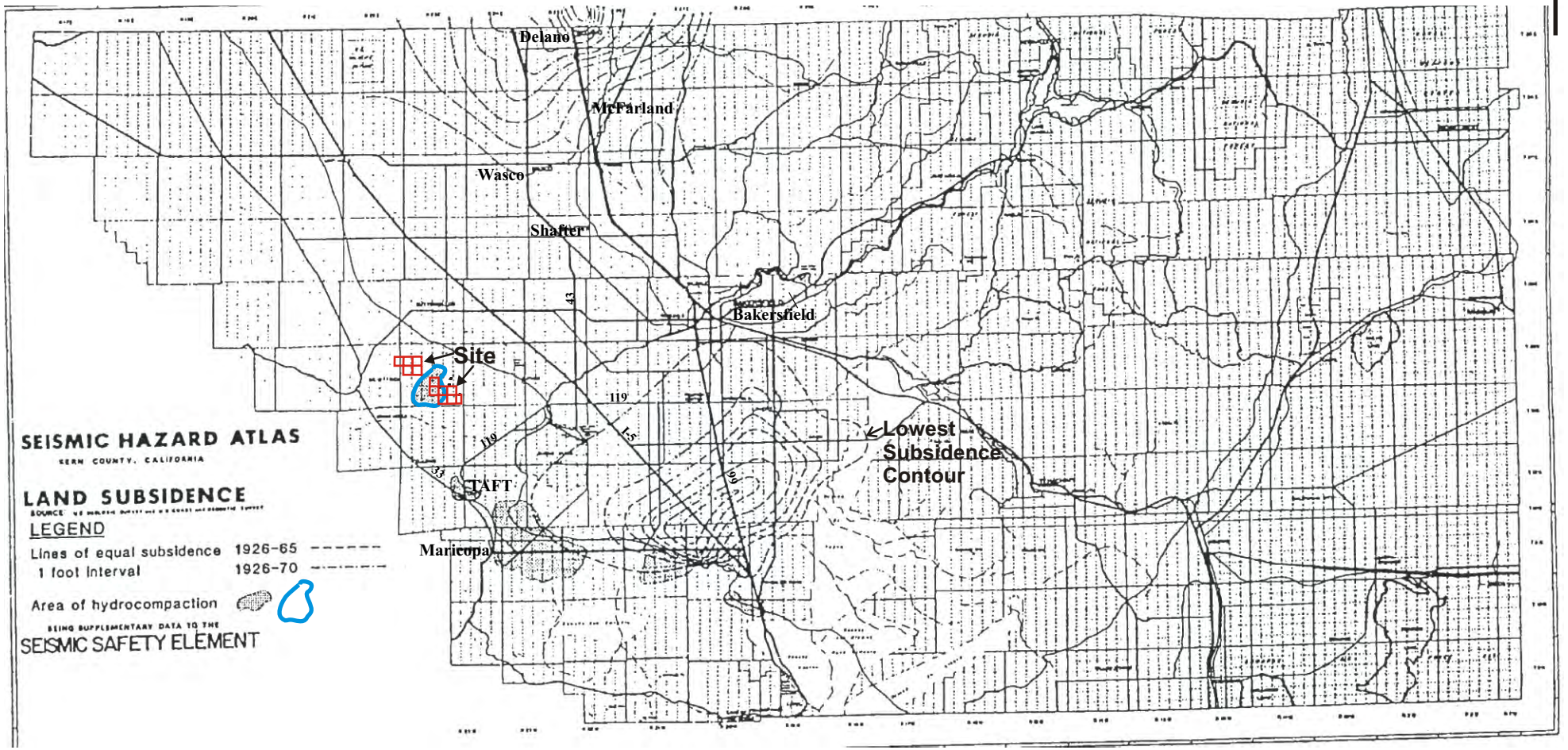
SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	Figure 8
DATE: 12/22 PROJECT: #18566	Regional Fault Map	



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA** Fault Location Map - Western Portion	Figure 8A



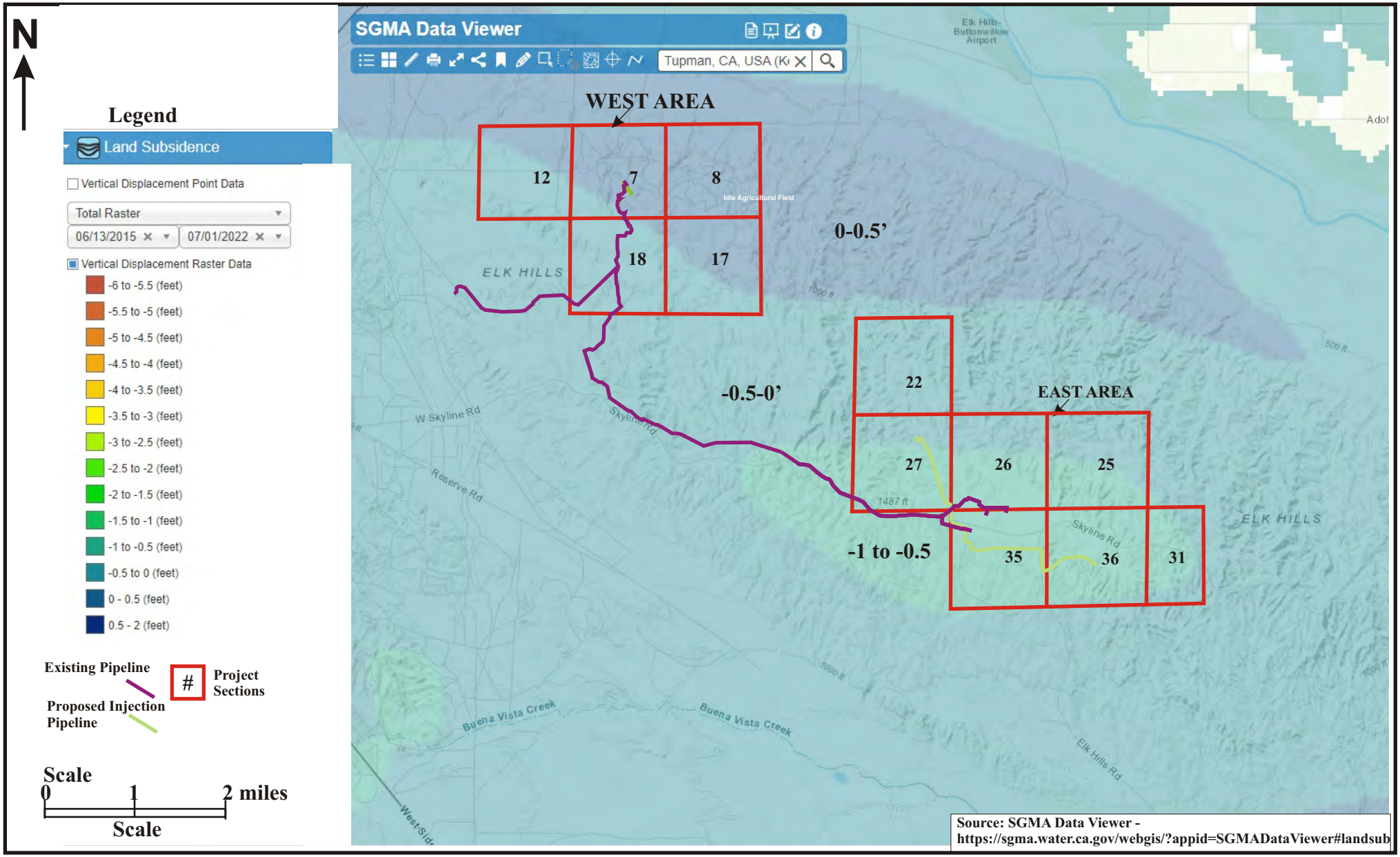
SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA** Fault Location Map - Eastern Portion	Figure 8B



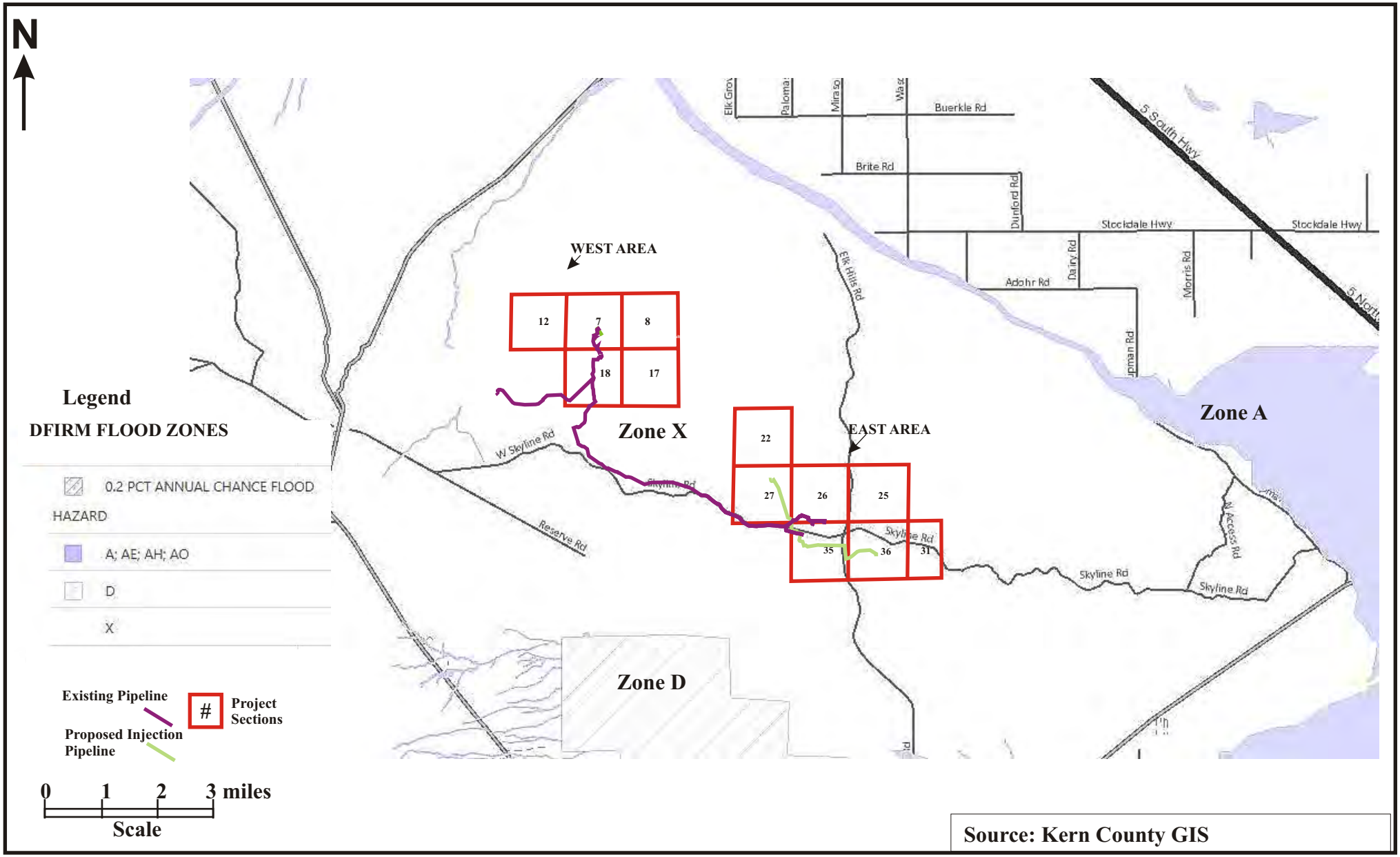
Regional Land Subsidence Map

From Kern County General Plan Safety Element (Figure 15)

Figure 9

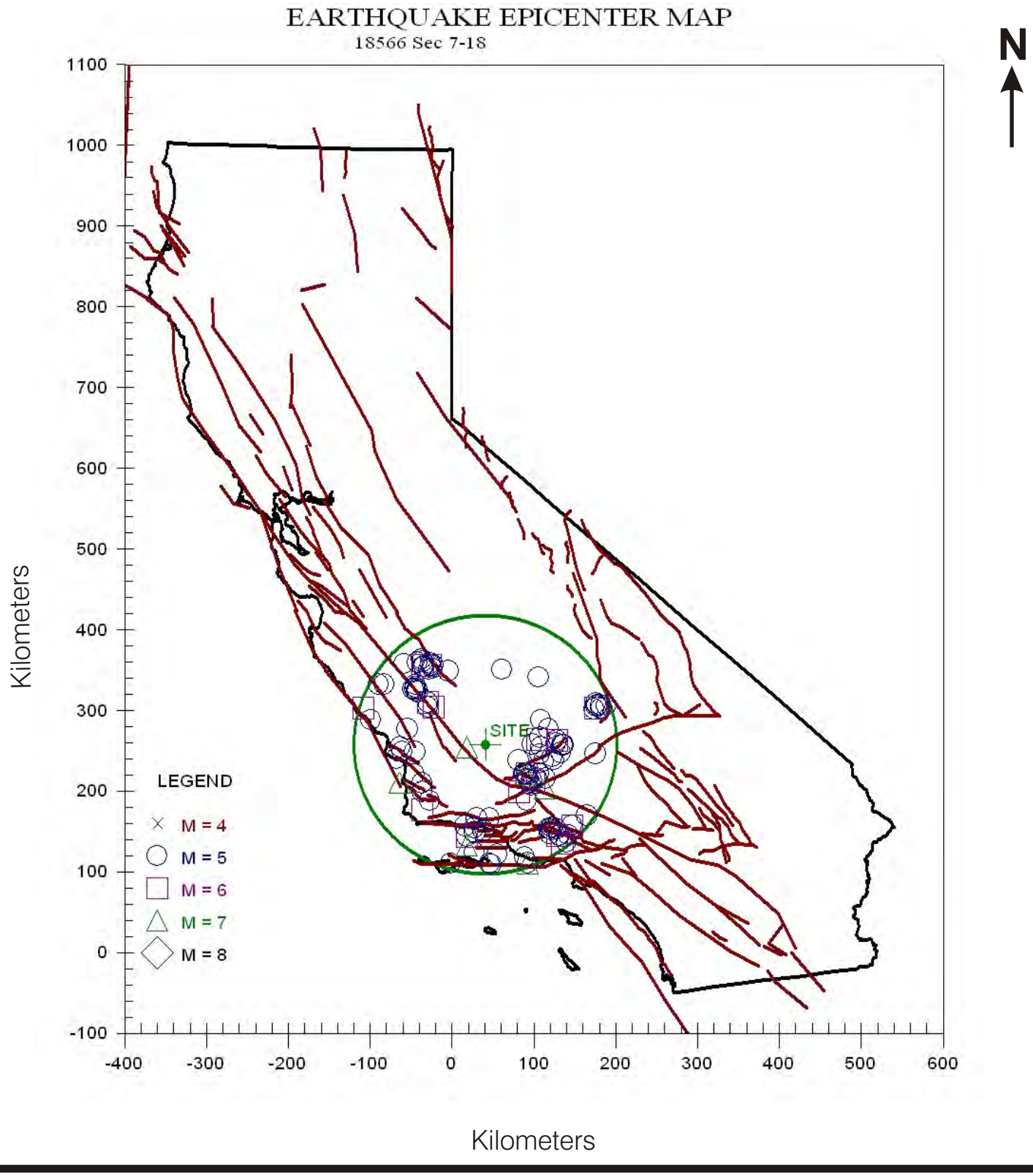


SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**Area** **Land Subsidence** **Map 2015-2022**	**Figure** **9A**

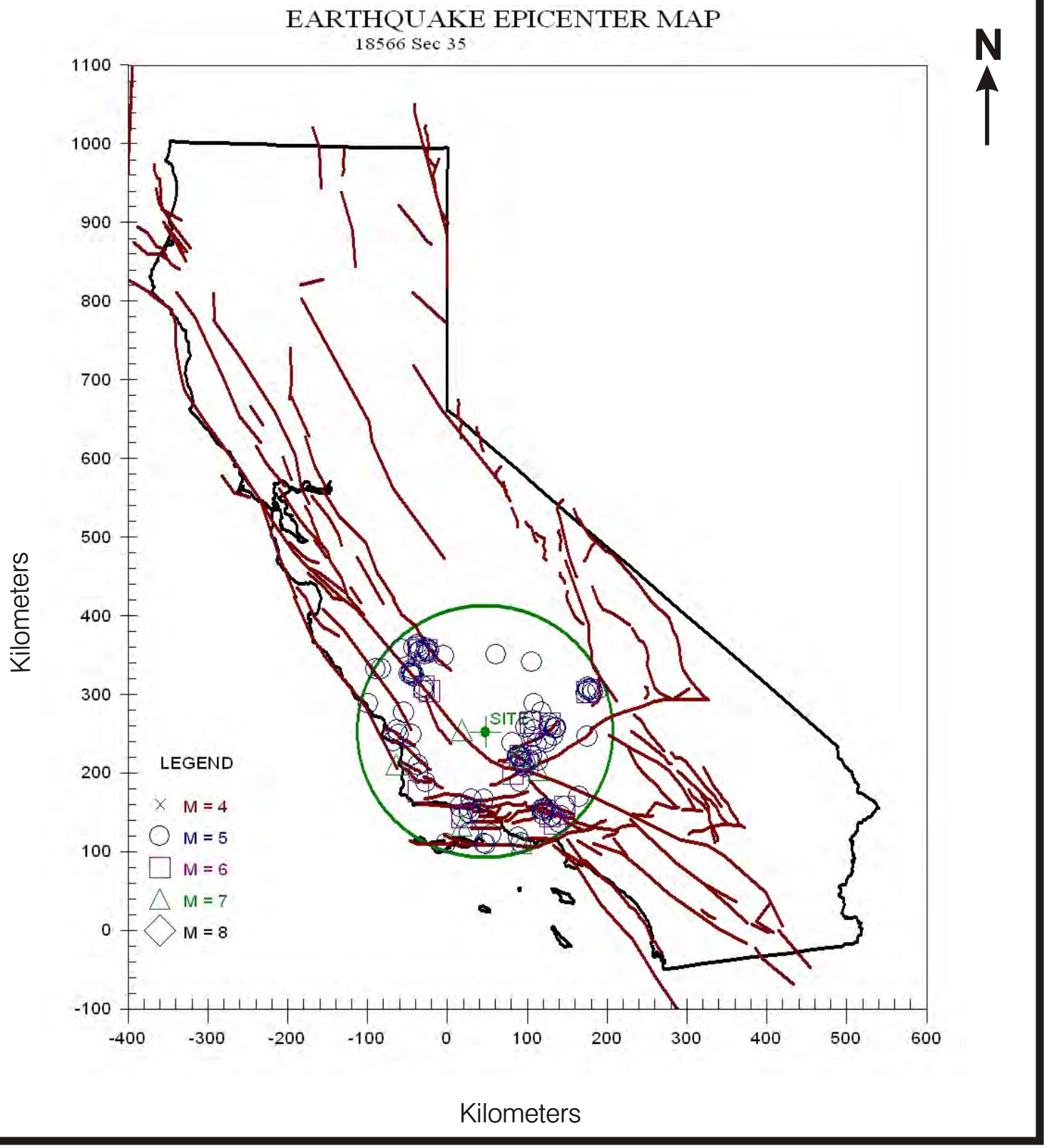


Source: Kern County GIS

SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA**	**FLOOD HAZARD MAP**	**Figure 10**



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA** Earthquake Epicenter Map - Western Portion	Figure 11



SOILS ENGINEERING, INC. 4400 Yeager Way BAKERSFIELD, CA 93313 DATE: 12/22 PROJECT: #18566	**Carbon Capture TerraVault 1 Project** **Elk Hills Oil Field** **Kern County, CA** Earthquake Epicenter Map - Eastern Portion	Figure 11A

APPENDIX A

SITE PHOTOS

4400 YEAGER WAY
Bakersfield, CA 93313-2019
Phone: 661-831-5100
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info@soilsengineering.com
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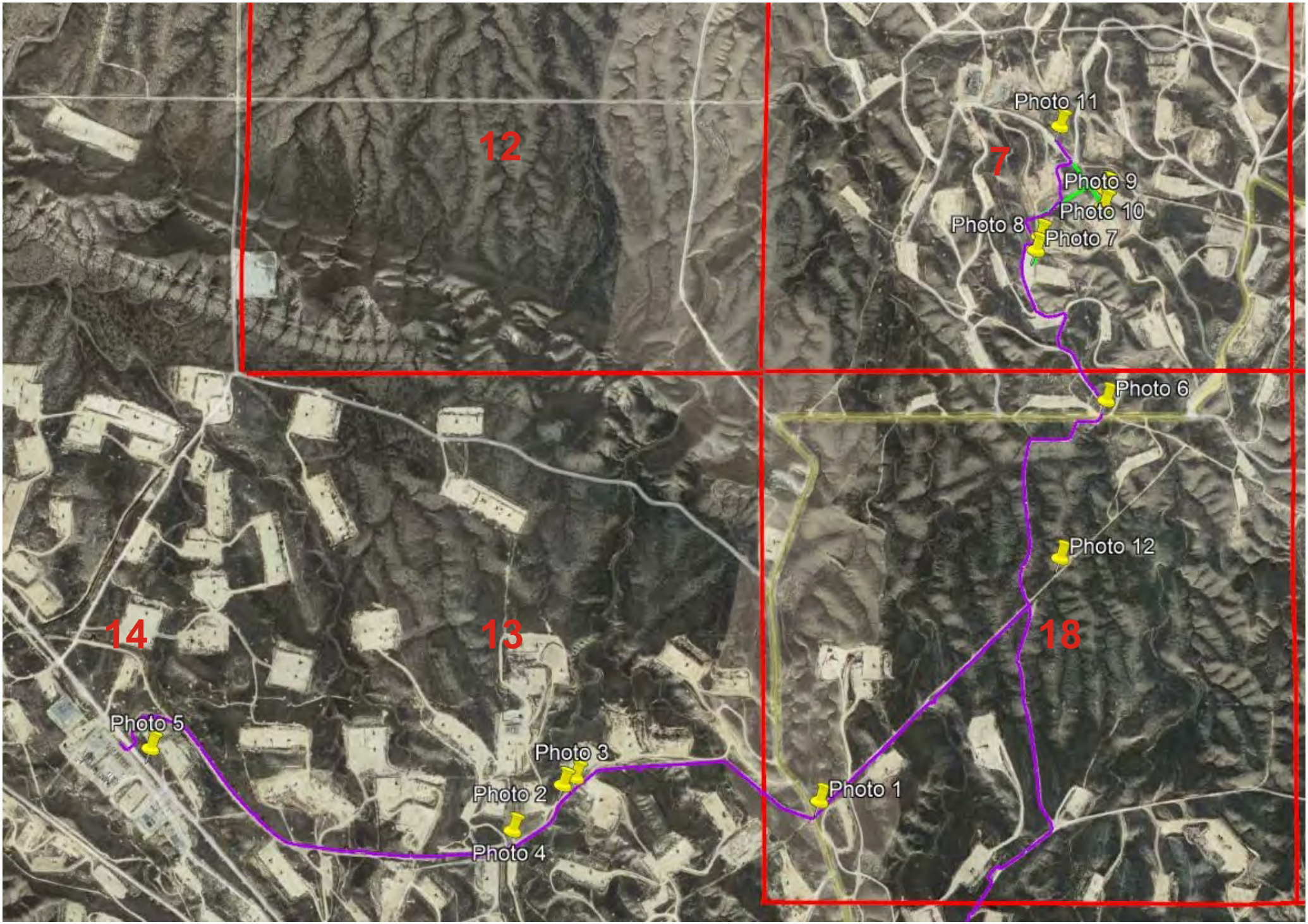
12
7
14
13
18
Photo 11
Photo 9
Photo 10
Photo 8
Photo 7
Photo 6
Photo 12
Photo 5
Photo 3
Photo 2
Photo 1
Photo 4

Figure A-1

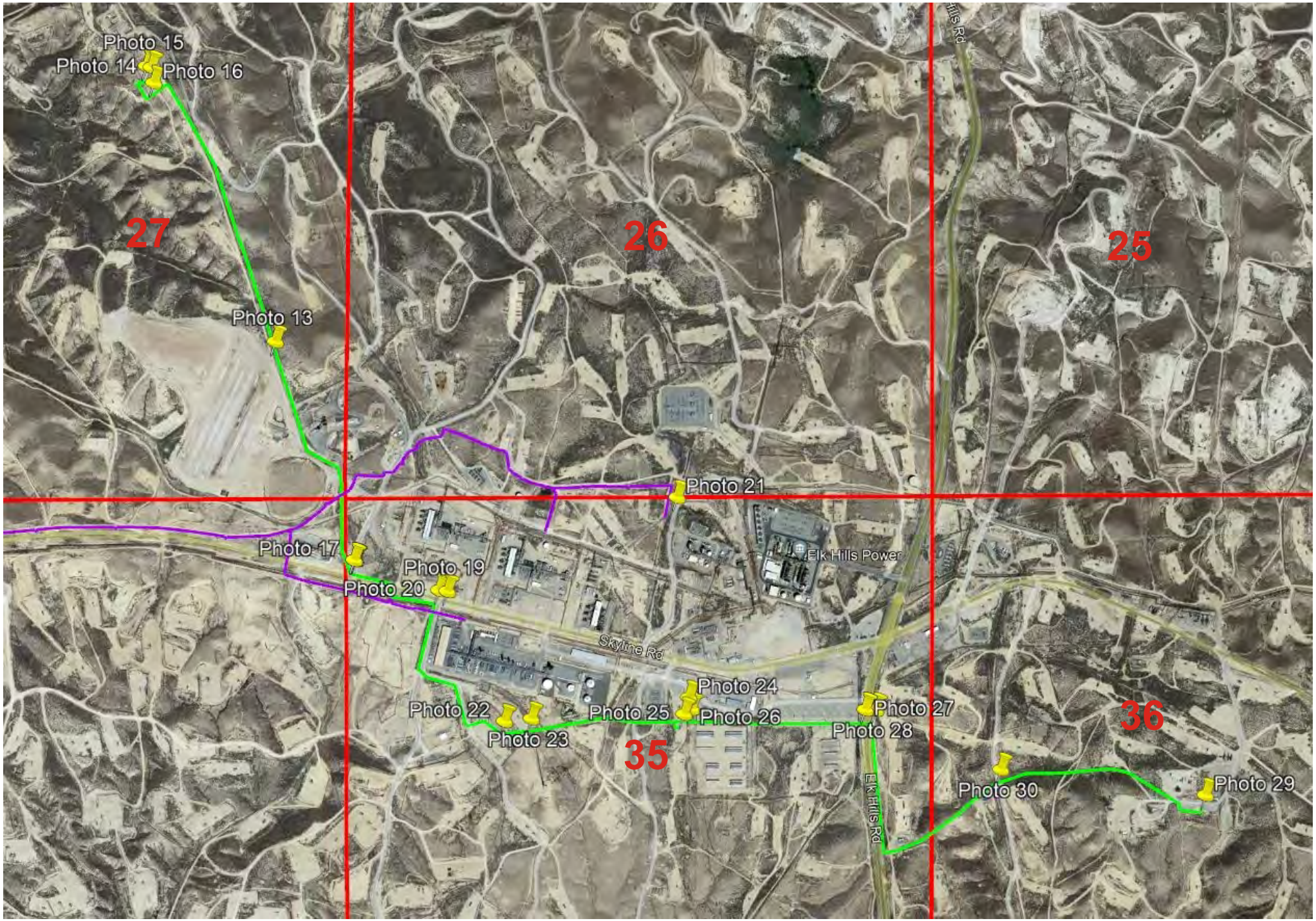
Photo 15
Photo 14
Photo 16
27
26
25
Photo 13
Photo 21
Photo 17
Photo 19
Photo 20
Elk Hills Power
Skyline Rd
Photo 24
Photo 22
Photo 25
Photo 26
Photo 27
Photo 23
Photo 28
35
36
Elk Hills Rd
Photo 30
Photo 29

Figure A-2



Picture 1. Looking northeast at existing injection line from adjacent to the SWC of Section 8.



Picture 2. Looking at erosional features in Section 13.



Picture 3. Looking at more erosional features on the existing line in section 13.



Picture 4. Looking at more erosional features on steep incline in section 13.



Picture 5. Looking at the most eastward section of the existing line in section 14.



Picture 6. Looking at the existing line that came out from under a road on the northern portion of Section 8.



Picture 7. Looking at the 357 - 7R injection well where the new injection line will connect.



Picture 8. Change in topography and erosion where the new injection line will be placed.



Picture 9. Looking at injection well 355X-7R in Section 7.



Picture 10. Change in topography where the new injection line will be placed.



Picture 11. Looking at injection well 355-7R and the direction the new injection line will be placed in Section 7.



Picture 12. Looking at the intersection of the existing injection lines adjacent to the center of Section 8.



Picture 13. Looking north from Section 27 where the new injection line will be placed.



Picture 14. Looking at injection well 363-27R.



Picture 15. Looking at the change in topography and erosional features where the new injection line will be placed.



Picture 16. Looking at the change in topography looking east towards where the new injection line will be placed.



Picture 17. From Skyline Rd in Section 35 looking NW where the new injection line is projected to go.



Picture 18. From Skyline Rd in Section 35 looking east where the new injection line is projected to go and eventually cross Skyline Rd.



Picture 19. Looking north at where the existing injection line connects to on the S side of Skyline Rd.



Picture 20. Looking south where the new injection line will go in Section 35.



Picture 21. Looking at the existing injection line and a bank that is slurried along the northern border of Section 35.



Picture 22. Looking at some erosional features where the new injection line will be placed adjacent to.



Picture 23. Looking ENE where the new injection line will be placed.



Picture 24. Looking at 373-35R.



Picture 25. Looking at 373-35R.



Picture 26. Looking at the change in topography and erosional features where the new injection line would go through.



Picture 27. Looking west where the new injection line will be placed.



Picture 28. Looking south where the new injection line is proposed to be placed on the east side of Elk Hills Rd by the dirt road.



Picture 29. Looking at 345-36R and towards where the new injection line will be placed.



Picture 30. Looking west at a steep hill where the new injection line will be placed in Section 36.

APPENDIX B

USDA SOIL PROPERTIES

Engineering Properties, Chemical Soil Properties, Physical Soil Properties & Map Unit Descriptions

4400 YEAGER WAY
Bakersfield, CA 93313-2019
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Fax: 661-831-2111
info@soilsengineering.com
www.soilsengineering.com

Report — Engineering Properties

Absence of an entry indicates that the data were not estimated. The asterisk '*' denotes the representative texture; other possible textures follow the dash. The criteria for determining the hydrologic soil group for individual soil components is found in the National Engineering Handbook, Chapter 7 issued May 2007(http://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=17757.wba). Three values are provided to identify the expected Low (L), Representative Value (R), and High (H).

Kern County, California, Northwestern Part

Map unit symbol and soil name	Pct. of map unit	Hydrologic group	Depth	USDA texture	Classification		Pct Fragments		Percentage passing sieve number—				Liquid limit	Plasticity index
					Unified	AASHTO	>10 inches	3-10 inches	4	10	40	200		
			In				*L-R-H*	*L-R-H*	*L-R-H*	*L-R-H*	*L-R-H*	*L-R-H*	*L-R-H*	*L-R-H*
146—Elkhills sandy loam, 9 to 50 percent slopes, eroded														
Elkhills	85	A	0-29	Gravelly sandy loam	SM	A-2, A-4	0- 0- 0	0- 3- 5	80-90-100	75-88-100	50-65-80	30-40-50	20-25-30	NP-3 -5
			29-49	Loam, coarse sandy loam, gravelly sandy loam	SM	A-4	0- 0- 0	0- 3- 5	80-90-100	75-88-100	50-65-80	35-43-50	20-25-30	NP-3 -5
			49-65	Stratified gravelly sand to silt loam	GM, SM	A-1, A-2, A-4	0- 0- 0	0- 5- 10	60-73-85	50-65-80	35-48-60	15-33-50	20-25-30	NP-3 -5
150—Elkhills-Torriorthents stratified complex, 9 to 15 perc ent slopes														
Elkhills	50	A	0-29	Gravelly sandy loam	SM	A-2, A-4	0- 0- 0	0- 3- 5	80-90-100	75-88-100	50-65-80	30-40-50	20-25-30	NP-3 -5
			29-49	Loam, coarse sandy loam, gravelly sandy loam	SM	A-4	0- 0- 0	0- 3- 5	80-90-100	75-88-100	50-65-80	35-43-50	20-25-30	NP-3 -5
			49-65	Stratified gravelly sand to silt loam	GM, SM	A-1, A-2, A-4	0- 0- 0	0- 5- 10	60-73-85	50-65-80	35-48-60	15-33-50	20-25-30	NP-3 -5

Report — Engineering Properties

Absence of an entry indicates that the data were not estimated. The asterisk '*' denotes the representative texture; other possible textures follow the dash. The criteria for determining the hydrologic soil group for individual soil components is found in the National Engineering Handbook, Chapter 7 issued May 2007(http://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=17757.wba). Three values are provided to identify the expected Low (L), Representative Value (R), and High (H).

Kern County, California, Northwestern Part

Map unit symbol and soil name	Pct. of map unit	Hydrologic group	Depth	USDA texture	Classification		Pct Fragments		Percentage passing sieve number—				Liquid limit	Plasticity index
					Unified	AASHTO	>10 inches	3-10 inches	4	10	40	200		
			In				L-R-H	L-R-H	L-R-H	L-R-H	L-R-H	L-R-H	L-R-H	L-R-H
Torriorthents	25	A	0-60	Variable	—	—	—	—	—	—	—	—	—	—
151—Elkhills-Torriorthents stratified, eroded complex, 15 t o 50 percent slopes														
Elkhills	50	A	0-29	Gravelly sandy loam	SM	A-2, A-4	0- 0- 0	0- 3- 5	80-90-100	75-88-100	50-65-80	30-40-50	20-25-30	NP-3 -5
			29-49	Gravelly sandy loam, coarse sandy loam, loam	SM	A-4	0- 0- 0	0- 3- 5	80-90-100	75-88-100	50-65-80	35-43-50	20-25-30	NP-3 -5
			49-65	Stratified gravelly sand to silt loam	GM, SM	A-1, A-2, A-4	0- 0- 0	0- 5- 10	60-73-85	50-65-80	35-48-60	15-33-50	20-25-30	NP-3 -5
Torriorthents	25	A	0-60	Variable	—	—	—	—	—	—	—	—	—	—
176—Kimberlina sandy loam, 5 to 9 percent slopes														
Kimberlina	85	A	0-9	Sandy loam	SM	A-2, A-4	0- 0- 0	0- 0- 0	80-90-100	75-88-100	40-55-70	25-38-50	20-23-25	NP-3 -5
			9-45	Fine sandy loam, sandy loam	SM	A-2, A-4	0- 0- 0	0- 0- 0	80-90-100	75-88-100	40-55-70	25-38-50	20-23-25	NP-3 -5
			45-71	Stratified silt loam to sandy clay loam	CL, SC-SM, SC, CL-ML	A-4, A-6	0- 0- 0	0- 0- 0	80-90-100	75-88-100	50-70-90	35-48-60	20-28-35	5-10-15
232—Torriorthents stratified, eroded-Elkhills complex, 9 to 50 percent slopes														
Torriorthents, stratified, eroded	50	C	0-4	Sandy loam, gravelly sandy loam	SC-SM, SC	A-2-4, A-6	0- 0- 0	0- 0- 0	92-92-100	84-84-100	60-65-83	28-33-45	20-26-33	4-9 -13
			4-54	Stratified sand to silty clay loam	CL, SM	A-4, A-6, A-7-6	0- 0- 0	0- 0- 0	92-92-100	84-84-100	59-76-100	40-57-78	18-36-46	2-17-25
			54-60	Stratified clay loam to clay	CL, CH	A-6, A-7-6	0- 0- 0	0- 3- 5	84-91-100	68-83-100	49-80-100	42-71-100	31-53-69	12-31-44
Elkhills	30	A	0-29	Gravelly sandy loam	SC-SM, SC, SM	A-1-b, A-2-4, A-6	0- 0- 0	0- 3- 5	84-90-100	63-79-100	45-62-85	22-32-47	17-24-31	2-7 -12
			29-49	Loam, gravelly sandy loam, coarse sandy loam	SC-SM, SC, SM	A-1-b, A-2-4, A-6	0- 0- 0	0- 3- 5	84-90-100	63-79-100	45-62-85	22-32-47	16-22-29	2-7 -12
			49-65	Stratified sand to gravelly silt loam	SC-SM, SC, SM	A-1-a, A-2-4, A-6	0- 0- 0	0- 4- 9	69-77-87	42-62-87	30-49-74	14-25-41	16-22-29	2-7 -12

Report — Chemical Soil Properties

Kern County, California, Northwestern Part

Map symbol and soil name	Depth	Cation-exchange capacity	Effective cation-exchange capacity	Soil reaction	Calcium carbonate	Gypsum	Salinity	Sodium adsorption ratio
	In	*meq/100g*	*meq/100g*	*pH*	*Pct*	*Pct*	*mmhos/cm*	
146—Elkhills sandy loam, 9 to 50 percent slopes, eroded								
Elkhills	0-29	5.0-10	—	7.4-8.4	1-3	0	0.0-2.0	0
	29-49	5.0-10	—	7.4-8.4	1-5	0	0.0-4.0	0
	49-65	5.0-10	—	7.4-8.4	1-5	0	0.0-8.0	0
150—Elkhills-Torriorthents stratified complex, 9 to 15 perc ent slopes								
Elkhills	0-29	5.0-10	—	7.4-8.4	1-3	0	0.0-2.0	0
	29-49	5.0-10	—	7.4-8.4	1-5	0	0.0-4.0	0
	49-65	5.0-10	—	7.4-8.4	1-5	0	0.0-8.0	0
Torriorthents	0-60	—	0.0-0.0	—	0	0	2.0-16.0	0
151—Elkhills-Torriorthents stratified, eroded complex, 15 t o 50 percent slopes								
Elkhills	0-29	5.0-10	—	7.4-8.4	1-3	0	0.0-2.0	0
	29-49	5.0-10	—	7.4-8.4	1-5	0	0.0-4.0	0
	49-65	5.0-10	—	7.4-8.4	1-5	0	0.0-8.0	0
Torriorthents	0-60	—	0.0-0.0	—	0	0	2.0-16.0	0
176—Kimberlina sandy loam, 5 to 9 percent slopes								
Kimberlina	0-9	5.0-10	—	6.6-8.4	0-5	0	0.0-2.0	0
	9-45	5.0-10	—	7.9-8.4	5-10	0	0.0-4.0	0
	45-71	5.0-10	—	7.9-8.4	5-10	0	0.0-4.0	0
232—Torriorthents stratified, eroded-Elkhills complex, 9 to 50 percent slopes								
Torriorthents, stratified, eroded	0-4	6.1-14	—	7.4-8.4	0-2	0-1	0.0-4.0	0-13
	4-54	3.1-22	—	7.9-9.0	1-4	0-2	8.0-16.0	15-50
	54-60	9.5-35	—	7.9-9.0	1-5	0-3	2.0-16.0	15-50
Elkhills	0-29	4.6-15	—	7.4-8.4	1-3	0	0.0-2.0	0
	29-49	4.1-13	—	7.4-8.4	1-5	0	0.0-4.0	0
	49-65	4.1-13	—	7.4-8.4	1-5	0	0.0-8.0	0

Report — Physical Soil Properties

Three values are provided to identify the expected Low (L), Representative Value (R), and High (H).

Kern County, California, Northwestern Part

Map symbol and soil name	Depth	Sand	Silt	Clay	Moist bulk density	Saturated hydraulic conductivity	Available water capacity	Linear extensibility	Organic matter	Erosion factors			Wind erodibility group	Wind erodibility index
										Kw	Kf	T		
	In	*Pct*	*Pct*	*Pct*	*g/cc*	*micro m/sec*	*In/In*	*Pct*	*Pct*					
146—Elkhills sandy loam, 9 to 50 percent slopes, eroded														
Elkhills	0-29	-66-	-23-	5-12- 18	1.50- 1.55-1.60	14.00-28.00- 42.00	0.09-0.11- 0.13	0.0- 1.5- 2.9	0.5- 0.8- 1.0	.17	.28	5	5	56
	29-49	-66-	-23-	5-12- 18	1.50- 1.55-1.60	14.00-28.00- 42.00	0.09-0.12- 0.15	0.0- 1.5- 2.9	0.0- 0.0- 0.0	.20	.28			
	49-65	-32-	-56-	5-12- 18	1.50- 1.60-1.70	14.00-28.00- 42.00	0.07-0.10- 0.12	0.0- 1.5- 2.9	0.0- 0.0- 0.0	.28	.55			
150—Elkhills-Torriorthents stratified complex, 9 to 15 perc ent slopes														
Elkhills	0-29	-66-	-23-	5-12- 18	1.50- 1.55-1.60	14.00-28.00- 42.00	0.09-0.11- 0.13	0.0- 1.5- 2.9	0.5- 0.8- 1.0	.17	.28	5	5	56
	29-49	-66-	-23-	5-12- 18	1.50- 1.55-1.60	14.00-28.00- 42.00	0.09-0.12- 0.15	0.0- 1.5- 2.9	0.0- 0.0- 0.0	.20	.28			
	49-65	-32-	-56-	5-12- 18	1.50- 1.60-1.70	14.00-28.00- 42.00	0.07-0.10- 0.12	0.0- 1.5- 2.9	0.0- 0.0- 0.0	.28	.55			
Torriorthents	0-60	—	—	—	—	10.00-28.00- 42.00	0.00-0.00- 0.00	—	0.5- 0.8- 1.0			5		
151—Elkhills-Torriorthents stratified, eroded complex, 15 t o 50 percent slopes														
Elkhills	0-29	-66-	-23-	5-12- 18	1.50- 1.55-1.60	14.00-28.00- 42.00	0.09-0.11- 0.13	0.0- 1.5- 2.9	0.5- 0.8- 1.0	.17	.28	5	5	56
	29-49	-66-	-23-	5-12- 18	1.50- 1.55-1.60	14.00-28.00- 42.00	0.09-0.12- 0.15	0.0- 1.5- 2.9	0.0- 0.0- 0.0	.20	.28			
	49-65	-32-	-56-	5-12- 18	1.50- 1.60-1.70	14.00-28.00- 42.00	0.07-0.10- 0.12	0.0- 1.5- 2.9	0.0- 0.0- 0.0	.28	.55			
Torriorthents	0-60	—	—	—	—	10.00-28.00- 42.00	0.00-0.00- 0.00	—	0.5- 0.8- 1.0			5		

Report — Physical Soil Properties

Three values are provided to identify the expected Low (L), Representative Value (R), and High (H).

Kern County, California, Northwestern Part

Map symbol and soil name	Depth	Sand	Silt	Clay	Moist bulk density	Saturated hydraulic conductivity	Available water capacity	Linear extensibility	Organic matter	Erosion factors			Wind erodibility group	Wind erodibility index
										Kw	Kf	T		
	In	*Pct*	*Pct*	*Pct*	*g/cc*	*micro m/sec*	*In/In*	*Pct*	*Pct*					
176—Kimberlina sandy loam, 5 to 9 percent slopes														
Kimberlina	0-9	-68-	-20-	6-12- 18	1.50-1.55-1.60	14.00-28.00-42.00	0.10-0.12-0.13	0.0- 1.5- 2.9	0.5- 0.8-1.0	.24	.24	5	3	86
	9-45	-70-	-16-	10-14- 18	1.50-1.55-1.60	14.00-28.00-42.00	0.10-0.12-0.13	0.0- 1.5- 2.9	0.0- 0.0-0.0	.28	.28			
	45-71	-63-	-19-	10-18- 25	1.45-1.50-1.55	4.00-9.00-14.00	0.13-0.15-0.17	3.0- 4.5- 5.9	0.0- 0.0-0.0	.28	.28			
232—Torriorthents stratified, eroded-Elkhills complex, 9 to 50 percent slopes														
Torriorthents, stratified, eroded	0-4	-67-	-19-	8-14- 20	1.50-1.55-1.60	14.11-28.23-42.34	0.08-0.10-0.11	0.0- 1.5- 2.9	0.5- 0.8-1.0	.17	.17	5	3	86
	4-54	-39-	-37-	5-25- 35	1.45-1.58-1.70	1.41-2.82-4.23	0.05-0.09-0.13	3.0- 4.5- 5.9	0.0- 0.3-0.5	.37	.37			
Elkhills	0-29	-66-	-23-	5-12- 18	1.50-1.55-1.60	14.11-28.23-42.34	0.09-0.11-0.13	0.0- 1.5- 2.9	0.5- 0.8-1.0	.17	.28	5	5	56
	29-49	-66-	-23-	5-12- 18	1.50-1.55-1.60	14.11-28.23-42.34	0.09-0.12-0.15	0.0- 1.5- 2.9	0.0- 0.0-0.0	.28	.28			
	49-65	-66-	-23-	5-12- 18	1.50-1.60-1.70	14.11-28.23-42.34	0.07-0.10-0.12	0.0- 1.5- 2.9	0.0- 0.0-0.0	.15	.28			

Map Unit Description

The map units delineated on the detailed soil maps in a soil survey represent the soils or miscellaneous areas in the survey area. The map unit descriptions in this report, along with the maps, can be used to determine the composition and properties of a unit.

A map unit delineation on a soil map represents an area dominated by one or more major kinds of soil or miscellaneous areas. A map unit is identified and named according to the taxonomic classification of the dominant soils. Within a taxonomic class there are precisely defined limits for the properties of the soils. On the landscape, however, the soils are natural phenomena, and they have the characteristic variability of all natural phenomena. Thus, the range of some observed properties may extend beyond the limits defined for a taxonomic class. Areas of soils of a single taxonomic class rarely, if ever, can be mapped without including areas of other taxonomic classes. Consequently, every map unit is made up of the soils or miscellaneous areas for which it is named, soils that are similar to the named components, and some minor components that differ in use and management from the major soils.

Most of the soils similar to the major components have properties similar to those of the dominant soil or soils in the map unit, and thus they do not affect use and management. These are called noncontrasting, or similar, components. They may or may not be mentioned in a particular map unit description. Some minor components, however, have properties and behavior characteristics divergent enough to affect use or to require different management. These are called contrasting, or dissimilar, components. They generally are in small areas and could not be mapped separately because of the scale used. Some small areas of strongly contrasting soils or miscellaneous areas are identified by a special symbol on the maps. If included in the database for a given area, the contrasting minor components are identified in the map unit descriptions along with some characteristics of each. A few areas of minor components may not have been observed, and consequently they are not mentioned in the descriptions, especially where the pattern was so complex that it was impractical to make enough observations to identify all the soils and miscellaneous areas on the landscape.

The presence of minor components in a map unit in no way diminishes the usefulness or accuracy of the data. The objective of mapping is not to delineate pure taxonomic classes but rather to separate the landscape into landforms or landform segments that have similar use and management requirements. The delineation of such segments on the map provides sufficient information for the development of resource plans. If intensive use of small areas is planned, however, onsite investigation is needed to define and locate the soils and miscellaneous areas.

An identifying symbol precedes the map unit name in the map unit descriptions. Each description includes general facts about the unit and gives important soil properties and qualities.

Soils that have profiles that are almost alike make up a *soil series*. All the soils of a series have major horizons that are similar in composition, thickness, and arrangement. Soils of a given series can differ in texture of the surface layer, slope, stoniness, salinity, degree of erosion, and other characteristics that affect their use. On the basis of such differences, a soil series is divided into *soil phases*. Most of the areas shown on the detailed soil maps are phases of soil series. The name of a soil phase commonly indicates a feature that affects use or management. For example, Alpha silt loam, 0 to 2 percent slopes, is a phase of the Alpha series.

Some map units are made up of two or more major soils or miscellaneous areas. These map units are complexes, associations, or undifferentiated groups.

A *complex* consists of two or more soils or miscellaneous areas in such an intricate pattern or in such small areas that they cannot be shown separately on the maps. The pattern and proportion of the soils or miscellaneous areas are somewhat similar in all areas. Alpha-Beta complex, 0 to 6 percent slopes, is an example.

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An *undifferentiated group* is made up of two or more soils or miscellaneous areas that could be mapped individually but are mapped as one unit because similar interpretations can be made for use and management. The pattern and proportion of the soils or miscellaneous areas in a mapped area are not uniform. An area can be made up of only one of the major soils or miscellaneous areas, or it can be made up of all of them. Alpha and Beta soils, 0 to 2 percent slopes, is an example.

Some surveys include *miscellaneous areas*. Such areas have little or no soil material and support little or no vegetation. Rock outcrop is an example.

Additional information about the map units described in this report is available in other soil reports, which give properties of the soils and the limitations, capabilities, and potentials for many uses. Also, the narratives that accompany the soil reports define some of the properties included in the map unit descriptions.

Kern County, California, Northwestern Part

146—Elkhills sandy loam, 9 to 50 percent slopes, eroded

Map Unit Setting

National map unit symbol: hkhs
Elevation: 400 to 1,600 feet
Mean annual precipitation: 6 to 8 inches
Mean annual air temperature: 61 to 64 degrees F
Frost-free period: 240 to 300 days

Farmland classification: Not prime farmland

Map Unit Composition

Elkhills and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Elkhills

Setting

Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

A - 0 to 29 inches: gravelly sandy loam
C1 - 29 to 49 inches: gravelly sandy loam
C2 - 49 to 65 inches: stratified gravelly sand to silt loam

Properties and qualities

Slope: 9 to 50 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.7 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

Minor Components

Very sandy soils

Percent of map unit: 5 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope

Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Torriorthents, stratified

Percent of map unit: 5 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Unnamed, finer textured underlying material

Percent of map unit: 5 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Data Source Information

Soil Survey Area: Kern County, California, Northwestern Part
Survey Area Data: Version 15, Sep 1, 2022

Map Unit Description

The map units delineated on the detailed soil maps in a soil survey represent the soils or miscellaneous areas in the survey area. The map unit descriptions in this report, along with the maps, can be used to determine the composition and properties of a unit.

A map unit delineation on a soil map represents an area dominated by one or more major kinds of soil or miscellaneous areas. A map unit is identified and named according to the taxonomic classification of the dominant soils. Within a taxonomic class there are precisely defined limits for the properties of the soils. On the landscape, however, the soils are natural phenomena, and they have the characteristic variability of all natural phenomena. Thus, the range of some observed properties may extend beyond the limits defined for a taxonomic class. Areas of soils of a single taxonomic class rarely, if ever, can be mapped without including areas of other taxonomic classes. Consequently, every map unit is made up of the soils or miscellaneous areas for which it is named, soils that are similar to the named components, and some minor components that differ in use and management from the major soils.

Most of the soils similar to the major components have properties similar to those of the dominant soil or soils in the map unit, and thus they do not affect use and management. These are called noncontrasting, or similar, components. They may or may not be mentioned in a particular map unit description. Some minor components, however, have properties and behavior characteristics divergent enough to affect use or to require different management. These are called contrasting, or dissimilar, components. They generally are in small areas and could not be mapped separately because of the scale used. Some small areas of strongly contrasting soils or miscellaneous areas are identified by a special symbol on the maps. If included in the database for a given area, the contrasting minor components are identified in the map unit descriptions along with some characteristics of each. A few areas of minor components may not have been observed, and consequently they are not mentioned in the descriptions, especially where the pattern was so complex that it was impractical to make enough observations to identify all the soils and miscellaneous areas on the landscape.

The presence of minor components in a map unit in no way diminishes the usefulness or accuracy of the data. The objective of mapping is not to delineate pure taxonomic classes but rather to separate the landscape into landforms or landform segments that have similar use and management requirements. The delineation of such segments on the map provides sufficient information for the development of resource plans. If intensive use of small areas is planned, however, onsite investigation is needed to define and locate the soils and miscellaneous areas.

An identifying symbol precedes the map unit name in the map unit descriptions. Each description includes general facts about the unit and gives important soil properties and qualities.

Soils that have profiles that are almost alike make up a *soil series*. All the soils of a series have major horizons that are similar in composition, thickness, and arrangement. Soils of a given series can differ in texture of the surface layer, slope, stoniness, salinity, degree of erosion, and other characteristics that affect their use. On the basis of such differences, a soil series is divided into *soil phases*. Most of the areas shown on the detailed soil maps are phases of soil series. The name of a soil phase commonly indicates a feature that affects use or management. For example, Alpha silt loam, 0 to 2 percent slopes, is a phase of the Alpha series.

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A *complex* consists of two or more soils or miscellaneous areas in such an intricate pattern or in such small areas that they cannot be shown separately on the maps. The pattern and proportion of the soils or miscellaneous areas are somewhat similar in all areas. Alpha-Beta complex, 0 to 6 percent slopes, is an example.

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An *undifferentiated group* is made up of two or more soils or miscellaneous areas that could be mapped individually but are mapped as one unit because similar interpretations can be made for use and management. The pattern and proportion of the soils or miscellaneous areas in a mapped area are not uniform. An area can be made up of only one of the major soils or miscellaneous areas, or it can be made up of all of them. Alpha and Beta soils, 0 to 2 percent slopes, is an example.

Some surveys include *miscellaneous areas*. Such areas have little or no soil material and support little or no vegetation. Rock outcrop is an example.

Additional information about the map units described in this report is available in other soil reports, which give properties of the soils and the limitations, capabilities, and potentials for many uses. Also, the narratives that accompany the soil reports define some of the properties included in the map unit descriptions.

Kern County, California, Northwestern Part

150—Elkhills-Torriorthents stratified complex, 9 to 15 perc ent slopes

Map Unit Setting

National map unit symbol: hkhx
Elevation: 400 to 3,500 feet
Mean annual precipitation: 6 to 8 inches
Mean annual air temperature: 61 to 64 degrees F

Frost-free period: 240 to 300 days
Farmland classification: Not prime farmland

Map Unit Composition

Elkhills and similar soils: 50 percent
Torriorthents and similar soils: 25 percent
Minor components: 25 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Elkhills

Setting

Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

A - 0 to 29 inches: gravelly sandy loam
C1 - 29 to 49 inches: gravelly sandy loam
C2 - 49 to 65 inches: stratified gravelly sand to silt loam

Properties and qualities

Slope: 9 to 15 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Low
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.7 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

Description of Torriorthents

Setting

Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope

Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

AC - 0 to 60 inches: variable

Properties and qualities

Slope: 9 to 15 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (1.42 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Maximum salinity: Very slightly saline to strongly saline (2.0 to 16.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 0.0 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XY906CA - Non-Alkali San Joaquin Valley Desert
Hydric soil rating: No

Minor Components

Very sandy soils

Percent of map unit: 7 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Linear
Hydric soil rating: No

Unnamed, gentler slopes

Percent of map unit: 7 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Linear
Hydric soil rating: No

Bitterwater

Percent of map unit: 7 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope

Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Unnamed, cemented layers in subsoil

Percent of map unit: 4 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Linear
Hydric soil rating: No

Data Source Information

Soil Survey Area: Kern County, California, Northwestern Part
Survey Area Data: Version 15, Sep 1, 2022

Map Unit Description

The map units delineated on the detailed soil maps in a soil survey represent the soils or miscellaneous areas in the survey area. The map unit descriptions in this report, along with the maps, can be used to determine the composition and properties of a unit.

A map unit delineation on a soil map represents an area dominated by one or more major kinds of soil or miscellaneous areas. A map unit is identified and named according to the taxonomic classification of the dominant soils. Within a taxonomic class there are precisely defined limits for the properties of the soils. On the landscape, however, the soils are natural phenomena, and they have the characteristic variability of all natural phenomena. Thus, the range of some observed properties may extend beyond the limits defined for a taxonomic class. Areas of soils of a single taxonomic class rarely, if ever, can be mapped without including areas of other taxonomic classes. Consequently, every map unit is made up of the soils or miscellaneous areas for which it is named, soils that are similar to the named components, and some minor components that differ in use and management from the major soils.

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The presence of minor components in a map unit in no way diminishes the usefulness or accuracy of the data. The objective of mapping is not to delineate pure taxonomic classes but rather to separate the landscape into landforms or landform segments that have similar use and management requirements. The delineation of such segments on the map provides sufficient information for the development of resource plans. If intensive use of small areas is planned, however, onsite investigation is needed to define and locate the soils and miscellaneous areas.

An identifying symbol precedes the map unit name in the map unit descriptions. Each description includes general facts about the unit and gives important soil properties and qualities.

Soils that have profiles that are almost alike make up a *soil series*. All the soils of a series have major horizons that are similar in composition, thickness, and arrangement. Soils of a given series can differ in texture of the surface layer, slope, stoniness, salinity, degree of erosion, and other characteristics that affect their use. On the basis of such differences, a soil series is divided into *soil phases*. Most of the areas shown on the detailed soil maps are phases of soil series. The name of a soil phase commonly indicates a feature that affects use or management. For example, Alpha silt loam, 0 to 2 percent slopes, is a phase of the Alpha series.

Some map units are made up of two or more major soils or miscellaneous areas. These map units are complexes, associations, or undifferentiated groups.

A *complex* consists of two or more soils or miscellaneous areas in such an intricate pattern or in such small areas that they cannot be shown separately on the maps. The pattern and proportion of the soils or miscellaneous areas are somewhat similar in all areas. Alpha-Beta complex, 0 to 6 percent slopes, is an example.

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An *undifferentiated group* is made up of two or more soils or miscellaneous areas that could be mapped individually but are mapped as one unit because similar interpretations can be made for use and management. The pattern and proportion of the soils or miscellaneous areas in a mapped area are not uniform. An area can be made up of only one of the major soils or miscellaneous areas, or it can be made up of all of them. Alpha and Beta soils, 0 to 2 percent slopes, is an example.

Some surveys include *miscellaneous areas*. Such areas have little or no soil material and support little or no vegetation. Rock outcrop is an example.

Additional information about the map units described in this report is available in other soil reports, which give properties of the soils and the limitations, capabilities, and potentials for many uses. Also, the narratives that accompany the soil reports define some of the properties included in the map unit descriptions.

Kern County, California, Northwestern Part

151—Elkhills-Torriorthents stratified, eroded complex, 15 t o 50 percent slopes

Map Unit Setting

National map unit symbol: hkhy
Elevation: 400 to 3,500 feet
Mean annual precipitation: 6 to 8 inches
Mean annual air temperature: 61 to 64 degrees F

Frost-free period: 240 to 300 days
Farmland classification: Not prime farmland

Map Unit Composition

Elkhills and similar soils: 50 percent
Torriorthents and similar soils: 25 percent
Minor components: 25 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Elkhills

Setting

Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Concave
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

A - 0 to 29 inches: gravelly sandy loam
C1 - 29 to 49 inches: gravelly sandy loam
C2 - 49 to 65 inches: stratified gravelly sand to silt loam

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.7 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

Description of Torriorthents

Setting

Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope

Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Concave
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

AC - 0 to 60 inches: variable

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (1.42 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Maximum salinity: Very slightly saline to strongly saline (2.0 to 16.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 0.0 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XY906CA - Non-Alkali San Joaquin Valley Desert
Hydric soil rating: No

Minor Components

Unnamed, gentler slopes

Percent of map unit: 7 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Concave
Hydric soil rating: No

Very sandy soils

Percent of map unit: 7 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Concave
Hydric soil rating: No

Unnamed, soils with hardpan

Percent of map unit: 7 percent
Landform: Erosion remnants on terraces
Landform position (two-dimensional): Backslope

Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Concave
Hydric soil rating: No

Bitterwater

Percent of map unit: 4 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Data Source Information

Soil Survey Area: Kern County, California, Northwestern Part
Survey Area Data: Version 15, Sep 1, 2022

Map Unit Description

The map units delineated on the detailed soil maps in a soil survey represent the soils or miscellaneous areas in the survey area. The map unit descriptions in this report, along with the maps, can be used to determine the composition and properties of a unit.

A map unit delineation on a soil map represents an area dominated by one or more major kinds of soil or miscellaneous areas. A map unit is identified and named according to the taxonomic classification of the dominant soils. Within a taxonomic class there are precisely defined limits for the properties of the soils. On the landscape, however, the soils are natural phenomena, and they have the characteristic variability of all natural phenomena. Thus, the range of some observed properties may extend beyond the limits defined for a taxonomic class. Areas of soils of a single taxonomic class rarely, if ever, can be mapped without including areas of other taxonomic classes. Consequently, every map unit is made up of the soils or miscellaneous areas for which it is named, soils that are similar to the named components, and some minor components that differ in use and management from the major soils.

Most of the soils similar to the major components have properties similar to those of the dominant soil or soils in the map unit, and thus they do not affect use and management. These are called noncontrasting, or similar, components. They may or may not be mentioned in a particular map unit description. Some minor components, however, have properties and behavior characteristics divergent enough to affect use or to require different management. These are called contrasting, or dissimilar, components. They generally are in small areas and could not be mapped separately because of the scale used. Some small areas of strongly contrasting soils or miscellaneous areas are identified by a special symbol on the maps. If included in the database for a given area, the contrasting minor components are identified in the map unit descriptions along with some characteristics of each. A few areas of minor components may not have been observed, and consequently they are not mentioned in the descriptions, especially where the pattern was so complex that it was impractical to make enough observations to identify all the soils and miscellaneous areas on the landscape.

The presence of minor components in a map unit in no way diminishes the usefulness or accuracy of the data. The objective of mapping is not to delineate pure taxonomic classes but rather to separate the landscape into landforms or landform segments that have similar use and management requirements. The delineation of such segments on the map provides sufficient information for the development of resource plans. If intensive use of small areas is planned, however, onsite investigation is needed to define and locate the soils and miscellaneous areas.

An identifying symbol precedes the map unit name in the map unit descriptions. Each description includes general facts about the unit and gives important soil properties and qualities.

Soils that have profiles that are almost alike make up a *soil series*. All the soils of a series have major horizons that are similar in composition, thickness, and arrangement. Soils of a given series can differ in texture of the surface layer, slope, stoniness, salinity, degree of erosion, and other characteristics that affect their use. On the basis of such differences, a soil series is divided into *soil phases*. Most of the areas shown on the detailed soil maps are phases of soil series. The name of a soil phase commonly indicates a feature that affects use or management. For example, Alpha silt loam, 0 to 2 percent slopes, is a phase of the Alpha series.

Some map units are made up of two or more major soils or miscellaneous areas. These map units are complexes, associations, or undifferentiated groups.

A *complex* consists of two or more soils or miscellaneous areas in such an intricate pattern or in such small areas that they cannot be shown separately on the maps. The pattern and proportion of the soils or miscellaneous areas are somewhat similar in all areas. Alpha-Beta complex, 0 to 6 percent slopes, is an example.

An *association* is made up of two or more geographically associated soils or miscellaneous areas that are shown as one unit on the maps. Because of present or anticipated uses of the map units in the survey area, it was not considered practical or necessary to map the soils or miscellaneous areas separately. The pattern and relative proportion of the soils or miscellaneous areas are somewhat similar. Alpha-Beta association, 0 to 2 percent slopes, is an example.

An *undifferentiated group* is made up of two or more soils or miscellaneous areas that could be mapped individually but are mapped as one unit because similar interpretations can be made for use and management. The pattern and proportion of the soils or miscellaneous areas in a mapped area are not uniform. An area can be made up of only one of the major soils or miscellaneous areas, or it can be made up of all of them. Alpha and Beta soils, 0 to 2 percent slopes, is an example.

Some surveys include *miscellaneous areas*. Such areas have little or no soil material and support little or no vegetation. Rock outcrop is an example.

Additional information about the map units described in this report is available in other soil reports, which give properties of the soils and the limitations, capabilities, and potentials for many uses. Also, the narratives that accompany the soil reports define some of the properties included in the map unit descriptions.

Kern County, California, Northwestern Part

176—Kimberlina sandy loam, 5 to 9 percent slopes

Map Unit Setting

National map unit symbol: hkjr
Elevation: 120 to 1,000 feet
Mean annual precipitation: 4 to 8 inches
Mean annual air temperature: 63 to 64 degrees F
Frost-free period: 190 to 300 days

Farmland classification: Farmland of statewide importance

Map Unit Composition

Kimberlina and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kimberlina

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

A - 0 to 9 inches: sandy loam
C - 9 to 45 inches: fine sandy loam
2C - 45 to 71 inches: stratified silt loam to sandy clay loam

Properties and qualities

Slope: 5 to 9 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Low
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.57 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to slightly saline (0.0 to 4.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 7.6 inches)

Interpretive groups

Land capability classification (irrigated): 3e
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XY906CA - Non-Alkali San Joaquin Valley Desert
Hydric soil rating: No

Minor Components

Kettleman

Percent of map unit: 4 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope

Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Panoche

Percent of map unit: 4 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Elkhills

Percent of map unit: 4 percent
Landform: Erosion remnants
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Milham

Percent of map unit: 3 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Data Source Information

Soil Survey Area: Kern County, California, Northwestern Part
Survey Area Data: Version 15, Sep 1, 2022

Map Unit Description

The map units delineated on the detailed soil maps in a soil survey represent the soils or miscellaneous areas in the survey area. The map unit descriptions in this report, along with the maps, can be used to determine the composition and properties of a unit.

A map unit delineation on a soil map represents an area dominated by one or more major kinds of soil or miscellaneous areas. A map unit is identified and named according to the taxonomic classification of the dominant soils. Within a taxonomic class there are precisely defined limits for the properties of the soils. On the landscape, however, the soils are natural phenomena, and they have the characteristic variability of all natural phenomena. Thus, the range of some observed properties may extend beyond the limits defined for a taxonomic class. Areas of soils of a single taxonomic class rarely, if ever, can be mapped without including areas of other taxonomic classes. Consequently, every map unit is made up of the soils or miscellaneous areas for which it is named, soils that are similar to the named components, and some minor components that differ in use and management from the major soils.

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The presence of minor components in a map unit in no way diminishes the usefulness or accuracy of the data. The objective of mapping is not to delineate pure taxonomic classes but rather to separate the landscape into landforms or landform segments that have similar use and management requirements. The delineation of such segments on the map provides sufficient information for the development of resource plans. If intensive use of small areas is planned, however, onsite investigation is needed to define and locate the soils and miscellaneous areas.

An identifying symbol precedes the map unit name in the map unit descriptions. Each description includes general facts about the unit and gives important soil properties and qualities.

Soils that have profiles that are almost alike make up a *soil series*. All the soils of a series have major horizons that are similar in composition, thickness, and arrangement. Soils of a given series can differ in texture of the surface layer, slope, stoniness, salinity, degree of erosion, and other characteristics that affect their use. On the basis of such differences, a soil series is divided into *soil phases*. Most of the areas shown on the detailed soil maps are phases of soil series. The name of a soil phase commonly indicates a feature that affects use or management. For example, Alpha silt loam, 0 to 2 percent slopes, is a phase of the Alpha series.

Some map units are made up of two or more major soils or miscellaneous areas. These map units are complexes, associations, or undifferentiated groups.

A *complex* consists of two or more soils or miscellaneous areas in such an intricate pattern or in such small areas that they cannot be shown separately on the maps. The pattern and proportion of the soils or miscellaneous areas are somewhat similar in all areas. Alpha-Beta complex, 0 to 6 percent slopes, is an example.

An *association* is made up of two or more geographically associated soils or miscellaneous areas that are shown as one unit on the maps. Because of present or anticipated uses of the map units in the survey area, it was not considered practical or necessary to map the soils or miscellaneous areas separately. The pattern and relative proportion of the soils or miscellaneous areas are somewhat similar. Alpha-Beta association, 0 to 2 percent slopes, is an example.

An *undifferentiated group* is made up of two or more soils or miscellaneous areas that could be mapped individually but are mapped as one unit because similar interpretations can be made for use and management. The pattern and proportion of the soils or miscellaneous areas in a mapped area are not uniform. An area can be made up of only one of the major soils or miscellaneous areas, or it can be made up of all of them. Alpha and Beta soils, 0 to 2 percent slopes, is an example.

Some surveys include *miscellaneous areas*. Such areas have little or no soil material and support little or no vegetation. Rock outcrop is an example.

Additional information about the map units described in this report is available in other soil reports, which give properties of the soils and the limitations, capabilities, and potentials for many uses. Also, the narratives that accompany the soil reports define some of the properties included in the map unit descriptions.

Kern County, California, Northwestern Part

232—Torriorthents stratified, eroded-Elkhills complex, 9 to 50 percent slopes

Map Unit Setting

National map unit symbol: hklk
Elevation: 400 to 3,500 feet
Mean annual precipitation: 6 to 8 inches
Mean annual air temperature: 61 to 64 degrees F

Frost-free period: 240 to 300 days
Farmland classification: Not prime farmland

Map Unit Composition

Torriorthents, stratified, eroded, and similar soils: 50 percent
Elkhills and similar soils: 30 percent
Minor components: 20 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Torriorthents, Stratified, Eroded

Setting

Landform: Fan remnants
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Linear
Across-slope shape: Concave
Parent material: Alluvium derived from mixed and/or lacustrine deposits

Typical profile

A - 0 to 4 inches: sandy loam
Cnz - 4 to 54 inches: stratified sand to silty clay loam
C - 54 to 60 inches: stratified clay loam to clay

Properties and qualities

Slope: 9 to 50 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: High
Capacity of the most limiting layer to transmit water (Ksat): Moderately low to moderately high (0.06 to 0.60 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Gypsum, maximum content: 3 percent
Maximum salinity: Moderately saline to strongly saline (8.0 to 16.0 mmhos/cm)
Sodium adsorption ratio, maximum: 50.0
Available water supply, 0 to 60 inches: Low (about 5.4 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: C
Ecological site: R017XY907CA - Aridic Alkali Desert
Hydric soil rating: No

Description of Elkhills

Setting

Landform: Erosion remnants

Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Linear
Across-slope shape: Concave
Parent material: Alluvium derived from mixed and/or lacustrine deposits

Typical profile

A - 0 to 29 inches: gravelly sandy loam
C1 - 29 to 49 inches: coarse sandy loam
C2 - 49 to 65 inches: stratified sand to gravelly silt loam

Properties and qualities

Slope: 9 to 50 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (2.00 to 6.00 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.7 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

Minor Components

Unnamed, severely eroded

Percent of map unit: 12 percent
Landform: Erosion remnants
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Linear
Across-slope shape: Concave
Ecological site: R017XY907CA - Aridic Alkali Desert
Hydric soil rating: No

Unnamed, hardpan

Percent of map unit: 4 percent
Landform: Erosion remnants
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Linear
Across-slope shape: Concave

Ecological site: R017XY907CA - Aridic Alkali Desert
Hydric soil rating: No

Unnamed, sandy

Percent of map unit: 4 percent
Landform: Erosion remnants, drainageways
Landform position (two-dimensional): Backslope, toeslope
Landform position (three-dimensional): Side slope, base slope
Down-slope shape: Linear, concave
Across-slope shape: Concave, linear
Ecological site: R017XY907CA - Aridic Alkali Desert
Hydric soil rating: No

Data Source Information

Soil Survey Area: Kern County, California, Northwestern Part
Survey Area Data: Version 15, Sep 1, 2022

APPENDIX C

Seismic Design Information - Preliminary
Deterministic Site Parameters - EQFAULTWIN data (5), EQSEARCHWIN data (5), USGS Seismic Design Reports SEAOC/OSHPD (5) and USGS Uniform Hazard Tool Results (2)

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Bakersfield, CA 93313-2019
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*    E Q F A U L T   *
*                    *
*    Version 3.00    *
*                    *
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DETERMINISTIC ESTIMATION OF
PEAK ACCELERATION FROM DIGITIZED FAULTS

JOB NUMBER: 18566

DATE: 11-28-2022

JOB NAME: 18566 Sec 7

CALCULATION NAME: Test Run Analysis

FAULT-DATA-FILE NAME: CGSFLTE.DAT

SITE COORDINATES:
SITE LATITUDE: 35.3295
SITE LONGITUDE: 119.5448

SEARCH RADIUS: 100 mi

ATTENUATION RELATION: 2) Boore et al. (1997) Horiz. - NEHRP C (520)
UNCERTAINTY (M=Median, S=Sigma): M Number of Sigmas: 0.0
DISTANCE MEASURE: cd_2drp
SCOND: 1
Basement Depth: 5.00 km Campbell SSR: Campbell SHR:
COMPUTE PEAK HORIZONTAL ACCELERATION

FAULT-DATA FILE USED: CGSFLTE.DAT

MINIMUM DEPTH VALUE (km): 0.0

EQFAULT SUMMARY

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT MAXIMUM EARTHQUAKE MAG.(Mw)	PEAK SITE ACCEL. g	EST. SITE INTENSITY MOD.MERC.
SAN ANDREAS - 1857 Rupture M-2a	14.5(23.3)	7.8	0.230	IX
SAN ANDREAS - Whole M-1a	14.5(23.3)	8.0	0.256	IX
SAN ANDREAS - Cho-Moj M-1b-1	14.5(23.3)	7.8	0.230	IX
SAN ANDREAS - Carrizo M-1c-2	14.5(23.3)	7.4	0.186	VIII
SAN ANDREAS - Cholame M-1c-1	18.1(29.2)	7.3	0.149	VIII
Kern Front	24.7(39.7)	6.3	0.085	VII
SAN JUAN	26.6(42.8)	7.1	0.101	VII
PLEITO THRUST	30.3(48.7)	7.0	0.105	VII
WHITE WOLF	30.4(48.9)	7.3	0.123	VII
SAN LUIS RANGE (S. Margin)	45.4(73.1)	7.2	0.085	VII
BIG PINE	45.6(73.4)	6.9	0.060	VI
GREAT VALLEY 14	49.5(79.6)	6.4	0.052	VI
GARLOCK (West)	49.7(80.0)	7.3	0.069	VI
SAN ANDREAS - Parkfield	51.6(83.1)	6.5	0.044	VI
NORTH CHANNEL SLOPE	51.8(83.4)	7.4	0.086	VII
LOS OSOS	53.4(85.9)	7.0	0.068	VI
SANTA YNEZ (West)	54.1(87.1)	7.1	0.058	VI
RINCONADA	54.4(87.6)	7.5	0.072	VI
LOS ALAMOS-W. BASELINE	55.9(90.0)	6.9	0.062	VI
M.RIDGE-ARROYO PARIDA-SANTA ANA	56.7(91.2)	7.2	0.072	VI
SAN GABRIEL	56.9(91.5)	7.2	0.059	VI
LIONS HEAD	57.0(91.8)	6.6	0.052	VI
SANTA YNEZ (East)	57.6(92.7)	7.1	0.055	VI
CASMALIA (Orcutt Frontal Fault)	58.3(93.8)	6.5	0.049	VI
SAN CAYETANO	61.1(98.3)	7.0	0.061	VI
RED MOUNTAIN	61.5(99.0)	7.0	0.061	VI
GREAT VALLEY 13	64.9(104.4)	6.5	0.045	VI
VENTURA - PITAS POINT	68.2(109.7)	6.9	0.053	VI
OAK RIDGE MID-CHANNEL STRUCTURE	68.8(110.8)	6.6	0.045	VI
SAN ANDREAS - Mojave M-1c-3	72.9(117.3)	7.4	0.054	VI
CHANNEL IS. THRUST (Eastern)	73.1(117.6)	7.5	0.069	VI
OAK RIDGE (Onshore)	73.3(117.9)	7.0	0.053	VI
SAN ANDREAS (Creeping)	73.8(118.7)	6.2	0.028	V
HOSGRI	74.9(120.6)	7.5	0.056	VI
SIMI-SANTA ROSA	75.7(121.8)	7.0	0.052	VI
HOLSER	76.0(122.3)	6.5	0.040	V
SANTA SUSANA	76.1(122.5)	6.7	0.044	VI
NORTHRIDGE (E. Oak Ridge)	79.5(128.0)	7.0	0.050	VI
OAK RIDGE(Blind Thrust Offshore)	80.1(128.9)	7.1	0.052	VI
ANACAPA-DUME	80.3(129.3)	7.5	0.064	VI

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT: MAXIMUM EARTHQUAKE MAG.(Mw)	ESTIMATED MAX. EARTHQUAKE EVENT: PEAK SITE ACCEL. g	ESTIMATED MAX. EARTHQUAKE EVENT: EST. SITE INTENSITY MOD.MERC.
GREAT VALLEY 12	83.3(134.0)	6.3	0.033	V
GARLOCK (East)	85.8(138.1)	7.5	0.050	VI
SIERRA MADRE (San Fernando)	86.9(139.8)	6.7	0.040	V
So. SIERRA NEVADA	89.0(143.2)	7.3	0.053	VI
SANTA CRUZ ISLAND	89.6(144.2)	7.0	0.045	VI
SANTA ROSA ISLAND	92.5(148.9)	7.1	0.047	VI
MALIBU COAST	92.8(149.4)	6.7	0.038	V
GREAT VALLEY 11	93.7(150.8)	6.4	0.032	V
VERDUGO	95.6(153.9)	6.9	0.041	V

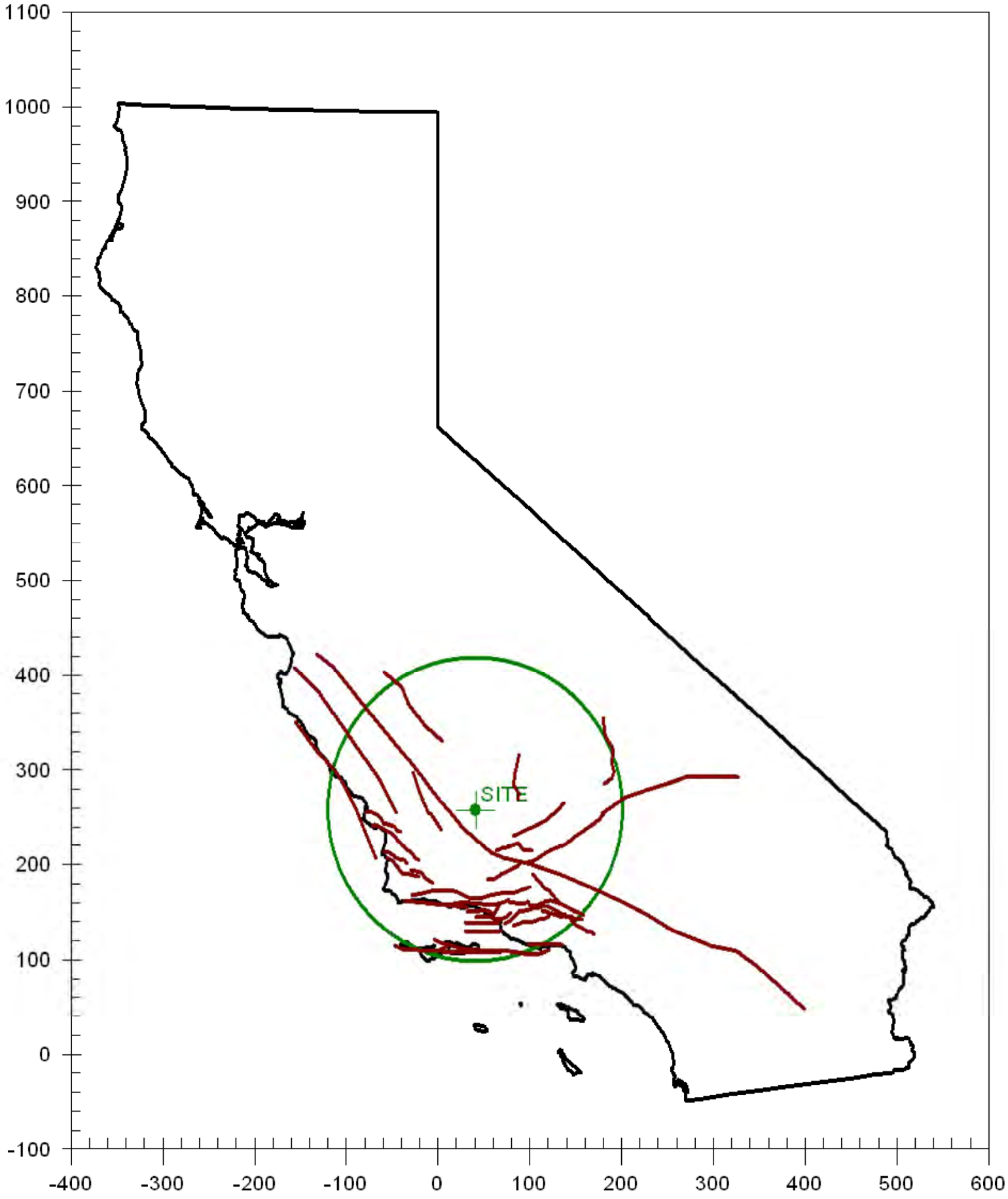
-END OF SEARCH- 49 FAULTS FOUND WITHIN THE SPECIFIED SEARCH RADIUS.

THE SAN ANDREAS - Whole M-1a FAULT IS CLOSEST TO THE SITE.
IT IS ABOUT 14.5 MILES (23.3 km) AWAY.

LARGEST MAXIMUM-EARTHQUAKE SITE ACCELERATION: 0.2557 g

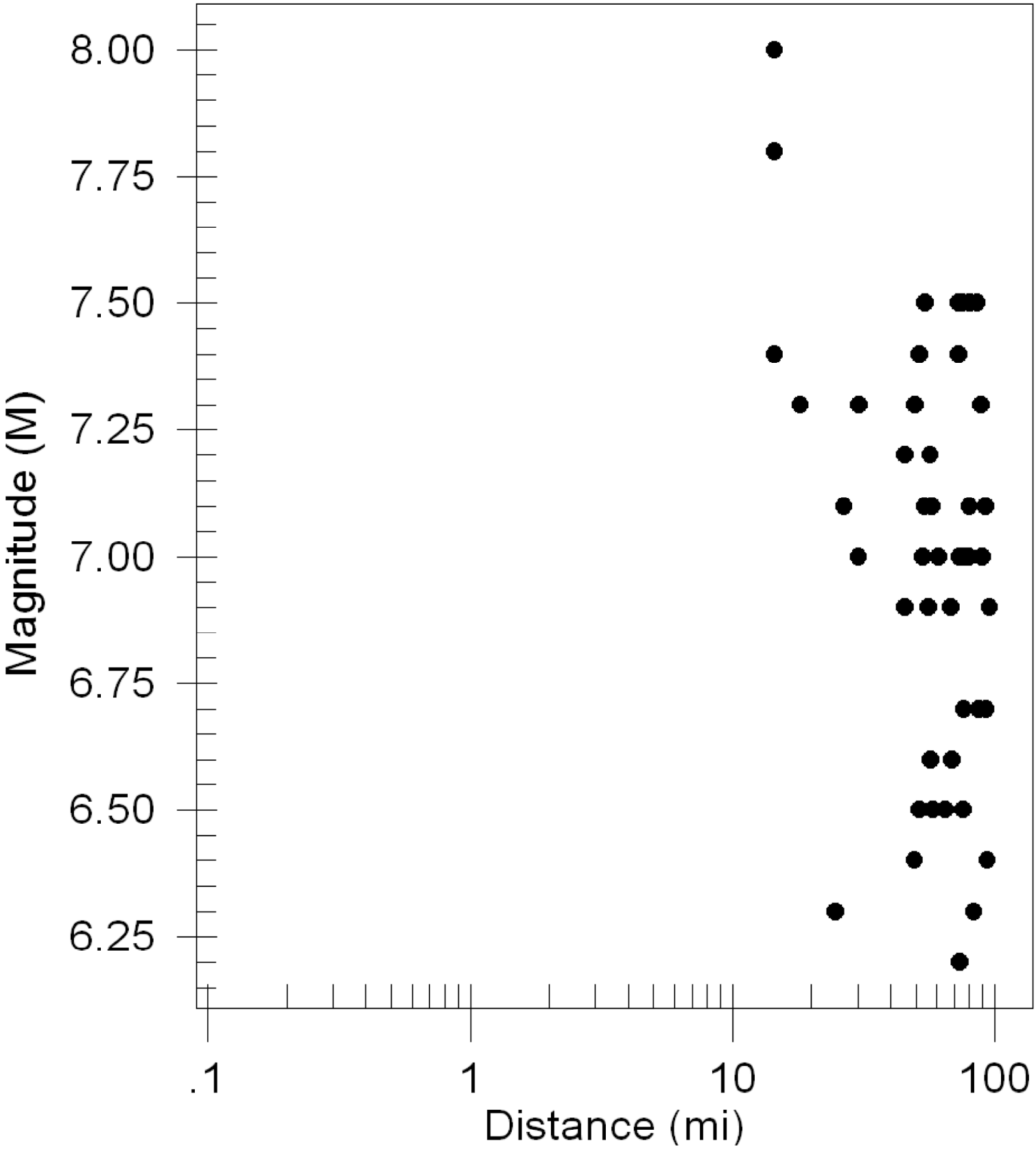
CALIFORNIA FAULT MAP

1855 - 7



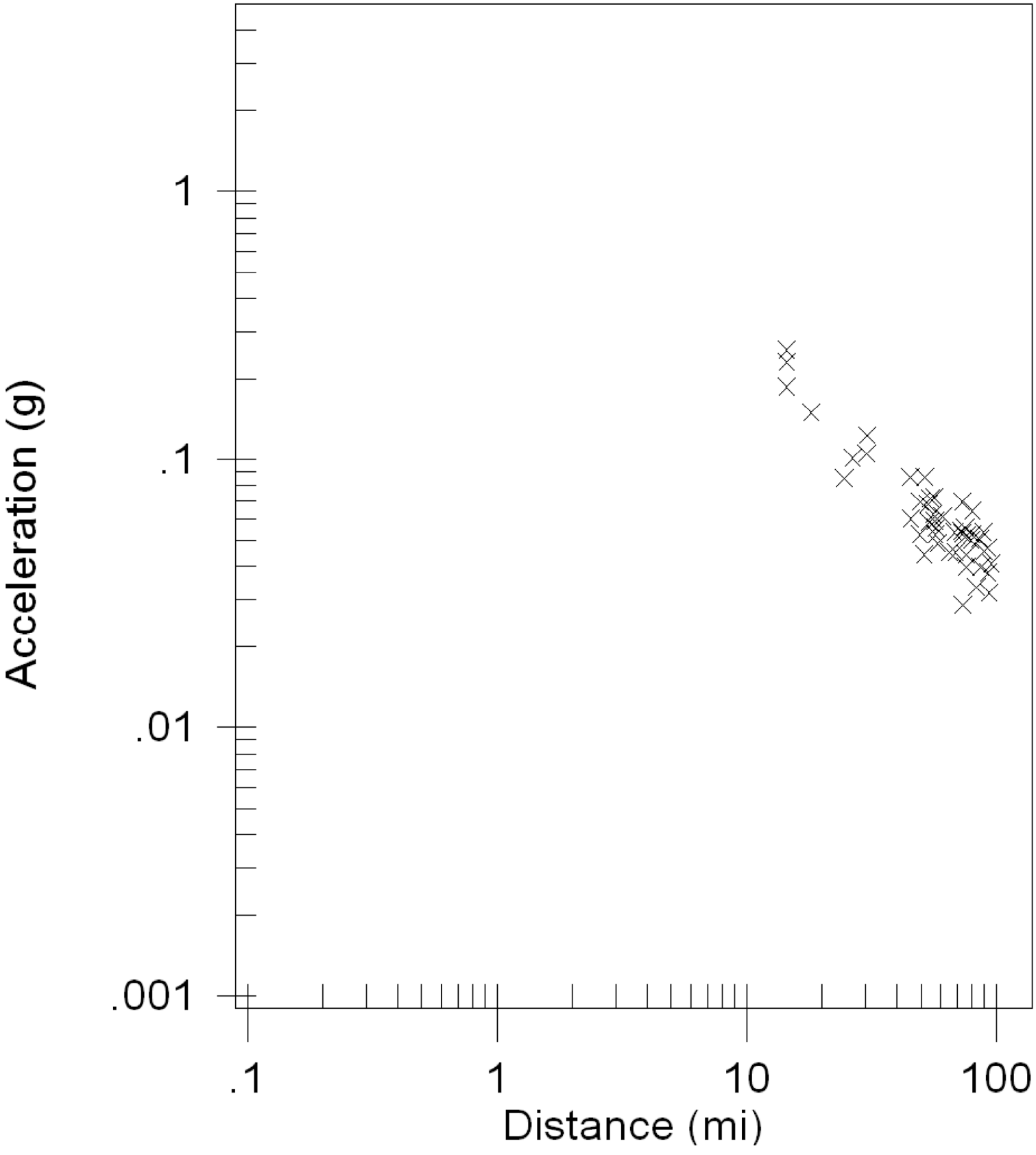
EARTHQUAKE MAGNITUDES & DISTANCES

18566 Sec 7



MAXIMUM EARTHQUAKES

18566 Sec 7



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*    E Q S E A R C H    *
*                       *
*     Version 3.00      *
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      ESTIMATION OF
  PEAK ACCELERATION FROM
CALIFORNIA EARTHQUAKE CATALOGS


JOB NUMBER: 18566
                                                DATE: 11-28-2022

JOB NAME: 18566 Sec 7

EARTHQUAKE-CATALOG-FILE NAME: C:\Program Files\EQSEARCH\ALLQUAKE.DAT

SITE COORDINATES:
   SITE LATITUDE:  35.3295
   SITE LONGITUDE:  119.5448

SEARCH DATES:
           START DATE:   1800
           END DATE:   2010

SEARCH RADIUS:
           100.0 mi
           160.9 km

ATTENUATION RELATION:   2) Boore et al. (1997) Horiz. - NEHRP C (520)
   UNCERTAINTY (M=Median, S=Sigma): M       Number of Sigmas:  0.0
   ASSUMED SOURCE TYPE:  DS [SS=Strike-slip, DS=Reverse-slip, BT=Blind-
thrust]
   SCOND:   1  Depth Source:  A
   Basement Depth:  5.00 km     Campbell SSR:        Campbell SHR:
   COMPUTE PEAK HORIZONTAL ACCELERATION

MINIMUM DEPTH VALUE (km):  0.0
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EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	35.3000	119.8000	01/09/1857	16 0 0.0	0.0	7.90	0.295	IX	14.5(23.4)
GSP	35.1490	119.1040	05/28/1993	044740.6	21.0	5.20	0.043	VI	27.8(44.7)
DMG	35.3330	118.9170	08/22/1952	224124.0	0.0	5.80	0.050	VI	35.4(56.9)
DMG	35.0000	119.0330	07/21/1952	12 2 0.0	0.0	5.60	0.043	VI	36.8(59.2)
DMG	35.0000	119.0170	01/12/1954	233349.0	0.0	5.90	0.050	VI	37.5(60.3)
DMG	35.0000	119.0170	07/21/1952	115214.0	0.0	7.70	0.129	VIII	37.5(60.3)
DMG	35.0000	119.0000	07/21/1952	12 531.0	0.0	6.40	0.064	VI	38.2(61.6)
DMG	35.0000	119.0000	02/16/1919	1557 0.0	0.0	5.00	0.031	V	38.2(61.6)
DMG	35.3830	118.8500	07/29/1952	7 347.0	0.0	6.10	0.054	VI	39.3(63.2)
DMG	34.9830	118.9830	05/23/1954	235243.0	0.0	5.10	0.031	V	39.7(63.9)
DMG	35.4000	118.8170	07/29/1952	8 146.0	0.0	5.10	0.030	V	41.3(66.4)
DMG	34.9410	118.9870	11/15/1961	53855.5	10.7	5.00	0.029	V	41.4(66.6)
DMG	35.2170	118.8170	07/23/1952	1317 5.0	0.0	5.70	0.041	V	41.7(67.2)
DMG	35.3000	118.8000	12/23/1905	2223 0.0	0.0	5.00	0.028	V	42.0(67.6)
DMG	34.9320	118.9760	03/01/1963	02557.9	13.9	5.00	0.028	V	42.2(68.0)
DMG	34.8000	119.1000	09/05/1883	1230 0.0	0.0	6.00	0.046	VI	44.4(71.4)
DMG	34.9000	118.9500	08/01/1952	13 430.0	0.0	5.10	0.029	V	44.8(72.1)
T-A	34.9200	118.9200	01/20/1857	0 0 0.0	0.0	5.00	0.027	V	45.2(72.8)
T-A	34.9200	118.9200	05/23/1857	0 0 0.0	0.0	5.00	0.027	V	45.2(72.8)
DMG	35.6000	118.8000	06/30/1926	1331 0.0	0.0	5.00	0.027	V	45.9(73.8)
DMG	35.1330	118.7670	07/21/1952	194122.0	0.0	5.50	0.035	V	45.9(73.9)
DMG	35.0000	118.8330	07/23/1952	181351.0	0.0	5.20	0.029	V	46.2(74.3)
DMG	35.0000	118.8330	07/23/1952	75319.0	0.0	5.40	0.033	V	46.2(74.3)
DMG	34.9500	118.8670	07/21/1952	121936.0	0.0	5.30	0.031	V	46.4(74.6)
DMG	34.9000	118.9000	10/23/1916	244 0.0	0.0	6.00	0.044	VI	47.0(75.6)
DMG	34.8670	118.9330	09/21/1941	1953 7.2	0.0	5.20	0.029	V	47.1(75.7)
DMG	35.5000	118.7000	01/06/1905	1430 0.0	0.0	5.00	0.025	V	49.0(78.8)
DMG	35.7500	120.2500	03/10/1922	112120.0	0.0	6.50	0.056	VI	49.1(79.0)
DMG	35.1830	118.6500	07/21/1952	151358.0	0.0	5.10	0.026	V	51.4(82.8)
PAS	34.9430	118.7430	06/10/1988	23 643.0	6.8	5.40	0.030	V	52.5(84.6)
DMG	35.7500	120.3300	08/18/1922	512 0.0	0.0	5.00	0.024	IV	52.8(85.0)
DMG	35.1500	118.6330	01/27/1954	141948.0	0.0	5.00	0.024	IV	52.9(85.1)
DMG	35.3330	118.6000	07/31/1952	12 9 9.0	0.0	5.80	0.036	V	53.2(85.6)
DMG	34.7000	119.0000	10/23/1916	254 0.0	0.0	5.50	0.031	V	53.3(85.7)
MGI	35.2500	120.5000	07/10/1917	043 0.0	0.0	5.30	0.027	V	54.1(87.1)
MGI	35.2500	120.5000	07/10/1917	045 0.0	0.0	5.30	0.027	V	54.1(87.1)
MGI	35.2500	120.5000	07/09/1917	2222 0.0	0.0	5.00	0.023	IV	54.1(87.1)
MGI	35.2500	120.5000	07/09/1917	2238 0.0	0.0	5.30	0.027	V	54.1(87.1)
DMG	35.3670	118.5830	07/23/1952	31923.0	0.0	5.00	0.023	IV	54.2(87.3)
DMG	35.3670	118.5830	07/23/1952	03832.0	0.0	6.10	0.042	VI	54.2(87.3)
DMG	35.8000	120.3300	06/08/1934	447 0.0	0.0	6.00	0.039	V	54.8(88.1)
DMG	35.8000	120.3300	12/28/1939	121538.0	0.0	5.00	0.023	IV	54.8(88.1)
DMG	35.8000	120.3300	06/08/1934	430 0.0	0.0	5.00	0.023	IV	54.8(88.1)
DMG	35.8000	120.3300	06/05/1934	2148 0.0	0.0	5.00	0.023	IV	54.8(88.1)
T-A	34.8300	118.7500	11/27/1852	0 0 0.0	0.0	7.00	0.065	VI	56.6(91.1)
MGI	34.9000	120.4000	03/29/1928	625 0.0	0.0	5.30	0.026	V	56.7(91.2)
DMG	34.5000	119.5000	08/05/1930	1125 0.0	0.0	5.00	0.022	IV	57.3(92.3)
DMG	34.5000	119.5000	06/29/1926	2321 0.0	0.0	5.50	0.029	V	57.3(92.3)
DMG	35.2330	118.5330	07/21/1952	174244.0	0.0	5.10	0.024	IV	57.4(92.4)
T-A	34.5000	119.6700	06/01/1893	12 0 0.0	0.0	5.00	0.022	IV	57.7(92.9)
DMG	35.3150	118.5160	07/25/1952	194323.7	11.2	5.70	0.032	V	58.0(93.3)
MGI	35.0000	120.5000	11/19/1927	332 0.0	0.0	5.00	0.022	IV	58.5(94.2)
DMG	35.3110	118.4990	07/25/1952	1313 8.2	2.8	5.00	0.022	IV	58.9(94.8)

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	35.3170	118.4940	07/25/1952	19 944.6	5.5	5.70	0.032	V	59.2(95.3)
T-A	36.1700	119.3200	07/25/1868	230 0.0	0.0	5.00	0.022	IV	59.4(95.6)
MGI	35.5000	120.6000	01/01/1830	0 0 0.0	0.0	5.00	0.021	IV	60.5(97.4)
MGI	34.8000	120.4000	12/12/1902	0 0 0.0	0.0	5.70	0.031	V	60.6(97.5)
DMG	34.7000	120.3000	01/12/1915	431 0.0	0.0	5.50	0.028	V	60.9(98.1)
DMG	34.7000	120.3000	07/31/1902	920 0.0	0.0	5.50	0.028	V	60.9(98.1)
PAS	36.1510	120.0490	08/04/1985	12 156.0	6.0	5.80	0.032	V	63.4(102.0)
T-A	35.2500	120.6700	00/00/1830	0 0 0.0	0.0	5.70	0.030	V	63.6(102.4)
T-A	35.2500	120.6700	12/17/1852	0 0 0.0	0.0	5.70	0.030	V	63.6(102.4)
T-A	34.4200	119.8200	00/00/1862	0 0 0.0	0.0	5.70	0.029	V	64.7(104.1)
MGI	34.4000	119.7000	03/25/1806	8 0 0.0	0.0	5.00	0.020	IV	64.8(104.2)
MGI	35.3000	120.7000	12/07/1906	640 0.0	0.0	5.90	0.033	V	65.1(104.8)
GSB	35.9170	120.4650	12/20/1994	102747.2	8.0	5.00	0.020	IV	65.7(105.7)
DMG	36.0800	118.8200	05/29/1915	646 0.0	0.0	5.00	0.020	IV	65.8(106.0)
DMG	34.3670	119.5830	07/01/1941	75054.8	0.0	5.90	0.032	V	66.5(107.0)
DMG	35.9300	120.4800	12/24/1934	1626 0.0	0.0	5.00	0.020	IV	66.9(107.6)
DMG	35.9500	120.4700	11/16/1956	323 9.0	0.0	5.00	0.020	IV	67.3(108.3)
PAS	34.3470	119.6960	08/13/1978	225453.4	12.8	5.10	0.021	IV	68.4(110.0)
DMG	35.9500	120.5000	06/28/1966	42613.4	0.0	5.50	0.025	V	68.6(110.4)
MGI	35.1700	120.7500	12/01/1916	2253 0.0	0.0	5.70	0.028	V	68.8(110.8)
DMG	35.9700	120.5000	06/28/1966	4 856.2	0.0	5.10	0.020	IV	69.5(111.8)
MGI	34.6000	120.4000	08/01/1902	330 0.0	0.0	6.30	0.038	V	69.8(112.4)
MGI	34.6000	120.4000	07/28/1902	657 0.0	0.0	6.30	0.038	V	69.8(112.4)
DMG	35.9500	120.5300	06/29/1966	195325.9	0.0	5.00	0.019	IV	69.9(112.5)
DMG	36.0000	120.5000	03/03/1901	745 0.0	0.0	5.50	0.025	V	70.8(113.9)
DMG	36.0000	120.5000	02/02/1881	011 0.0	0.0	5.60	0.026	V	70.8(113.9)
PAS	36.1820	120.2680	02/14/1987	72650.8	6.0	5.10	0.020	IV	71.5(115.0)
DMG	34.9000	120.7000	11/04/1927	135053.0	0.0	7.50	0.070	VI	71.7(115.3)
DMG	36.1700	120.3200	12/27/1926	919 0.0	0.0	5.00	0.019	IV	72.5(116.6)
DMG	34.3000	119.8000	06/29/1925	144216.0	0.0	6.25	0.036	V	72.5(116.7)
MGI	34.3000	119.8000	07/03/1925	1638 0.0	0.0	5.30	0.022	IV	72.5(116.7)
MGI	34.3000	119.8000	07/03/1925	1821 0.0	0.0	5.30	0.022	IV	72.5(116.7)
BRK	36.2200	120.2600	09/09/1983	91614.0	0.0	5.40	0.023	IV	73.4(118.1)
BRK	36.2200	120.2900	05/02/1983	234239.0	0.0	6.70	0.045	VI	74.3(119.6)
BRK	36.2200	120.2900	05/02/1983	2346 6.0	0.0	5.60	0.025	V	74.3(119.6)
BRK	36.2400	120.2900	05/09/1983	24912.0	0.0	5.20	0.020	IV	75.5(121.4)
BRK	36.2100	120.3800	07/25/1983	223140.0	0.0	5.10	0.019	IV	76.7(123.4)
BRK	36.2000	120.4000	07/22/1983	343 2.0	0.0	5.00	0.018	IV	76.9(123.7)
BRK	36.2200	120.4000	07/22/1983	23955.0	0.0	6.00	0.030	V	77.9(125.4)
DMG	34.2000	119.8000	12/21/1812	19 0 0.0	0.0	7.00	0.050	VI	79.3(127.6)
BRK	36.2600	120.4000	07/09/1983	74052.0	0.0	5.30	0.020	IV	80.1(129.0)
GSB	34.3790	118.7110	01/19/1994	210928.6	14.0	5.50	0.022	IV	80.9(130.1)
GSP	34.3770	118.6980	01/18/1994	004308.9	11.0	5.20	0.019	IV	81.4(131.0)
GSP	34.3940	118.6690	06/26/1995	084028.9	13.0	5.00	0.017	IV	81.4(131.1)
BRK	36.2500	120.4700	06/11/1983	3 954.0	0.0	5.10	0.018	IV	82.0(132.0)
PAS	36.2860	120.4130	10/25/1982	2226 4.0	6.0	5.60	0.023	IV	82.0(132.0)
GSP	34.3690	118.6720	04/26/1997	103730.7	16.0	5.10	0.018	IV	82.7(133.1)
GSP	35.2100	118.0660	07/11/1992	181416.2	10.0	5.70	0.024	V	83.8(134.8)
GSP	34.3780	118.6180	01/19/1994	211144.9	11.0	5.10	0.018	IV	84.1(135.3)
DMG	34.1180	119.7020	07/05/1968	04517.2	5.9	5.20	0.018	IV	84.1(135.4)
GSP	34.3260	118.6980	01/17/1994	233330.7	9.0	5.60	0.023	IV	84.3(135.6)
DMG	34.1000	119.4000	05/19/1893	035 0.0	0.0	5.50	0.021	IV	85.3(137.2)
DMG	35.7150	118.0740	03/15/1946	14 035.4	0.0	5.30	0.019	IV	86.8(139.7)

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	36.2300	120.6500	02/05/1947	614 0.0	0.0	5.00	0.016	IV	87.7(141.2)
DMG	35.7250	118.0550	03/15/1946	134935.9	22.0	6.30	0.032	V	88.1(141.7)
DMG	34.3000	118.6000	04/04/1893	1940 0.0	0.0	6.00	0.027	V	89.0(143.2)
DMG	35.7450	118.0390	03/16/1946	94617.9	0.0	5.10	0.017	IV	89.3(143.8)
MGI	35.6000	121.1000	02/01/1853	21 0 0.0	0.0	5.00	0.016	IV	89.4(143.9)
GSP	34.3050	118.5790	01/29/1994	112036.0	1.0	5.10	0.017	IV	89.4(143.9)
DMG	35.7780	118.0490	01/28/1961	81246.2	5.5	5.30	0.019	IV	89.5(144.1)
DMG	36.0000	120.9200	11/02/1955	1940 6.0	0.0	5.20	0.018	IV	90.0(144.8)
DMG	35.7510	118.0290	03/15/1946	215433.4	0.0	5.20	0.018	IV	90.0(144.8)
GSB	34.3010	118.5650	01/17/1994	204602.4	9.0	5.20	0.018	IV	90.1(145.1)
DMG	34.4110	118.4010	02/09/1971	14 1 8.0	8.0	5.80	0.024	V	90.7(145.9)
DMG	34.4110	118.4010	02/09/1971	14 244.0	8.0	5.80	0.024	V	90.7(145.9)
DMG	34.4110	118.4010	02/09/1971	141028.0	8.0	5.30	0.018	IV	90.7(145.9)
DMG	34.4110	118.4010	02/09/1971	14 041.8	8.4	6.40	0.033	V	90.7(145.9)
DMG	34.0000	119.5000	02/18/1926	1818 0.0	0.0	5.00	0.016	IV	91.8(147.8)
DMG	34.0650	119.0350	02/21/1973	144557.3	8.0	5.90	0.025	V	92.0(148.0)
DMG	35.7140	117.9770	03/15/1946	191853.6	0.0	5.40	0.019	IV	92.0(148.1)
DMG	35.7530	117.9860	03/15/1946	1321 0.9	0.0	5.20	0.017	IV	92.3(148.6)
DMG	33.9860	119.4750	08/06/1973	232917.0	16.9	5.00	0.015	IV	92.8(149.4)
DMG	34.3080	118.4540	02/09/1971	144346.7	6.2	5.20	0.017	IV	93.8(150.9)
DMG	36.0000	121.0000	02/26/1932	1658 0.0	0.0	5.00	0.015	IV	93.8(151.0)
DMG	34.5190	118.1980	08/23/1952	10 9 7.1	13.1	5.00	0.015	IV	94.6(152.2)
DMG	34.0000	120.0170	04/01/1945	234342.0	0.0	5.40	0.019	IV	95.6(153.9)
GSP	34.2130	118.5370	01/17/1994	123055.4	18.0	6.70	0.037	V	96.0(154.4)
DMG	35.7470	117.9080	03/18/1946	155042.6	4.4	5.30	0.018	IV	96.4(155.1)
MGI	34.0000	119.0000	12/14/1912	0 0 0.0	0.0	5.70	0.022	IV	96.9(155.9)
DMG	34.0000	119.0000	09/24/1827	4 0 0.0	0.0	7.00	0.043	VI	96.9(155.9)
DMG	35.7300	121.2000	11/22/1952	74637.0	0.0	6.00	0.025	V	97.0(156.1)
GSP	34.2310	118.4750	03/20/1994	212012.3	13.0	5.30	0.017	IV	97.1(156.3)

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-END OF SEARCH- 135 EARTHQUAKES FOUND WITHIN THE SPECIFIED SEARCH AREA.

TIME PERIOD OF SEARCH: 1800 TO 2010

LENGTH OF SEARCH TIME: 211 years

THE EARTHQUAKE CLOSEST TO THE SITE IS ABOUT 14.5 MILES (23.4 km) AWAY.

LARGEST EARTHQUAKE MAGNITUDE FOUND IN THE SEARCH RADIUS: 7.9

LARGEST EARTHQUAKE SITE ACCELERATION FROM THIS SEARCH: 0.295 g

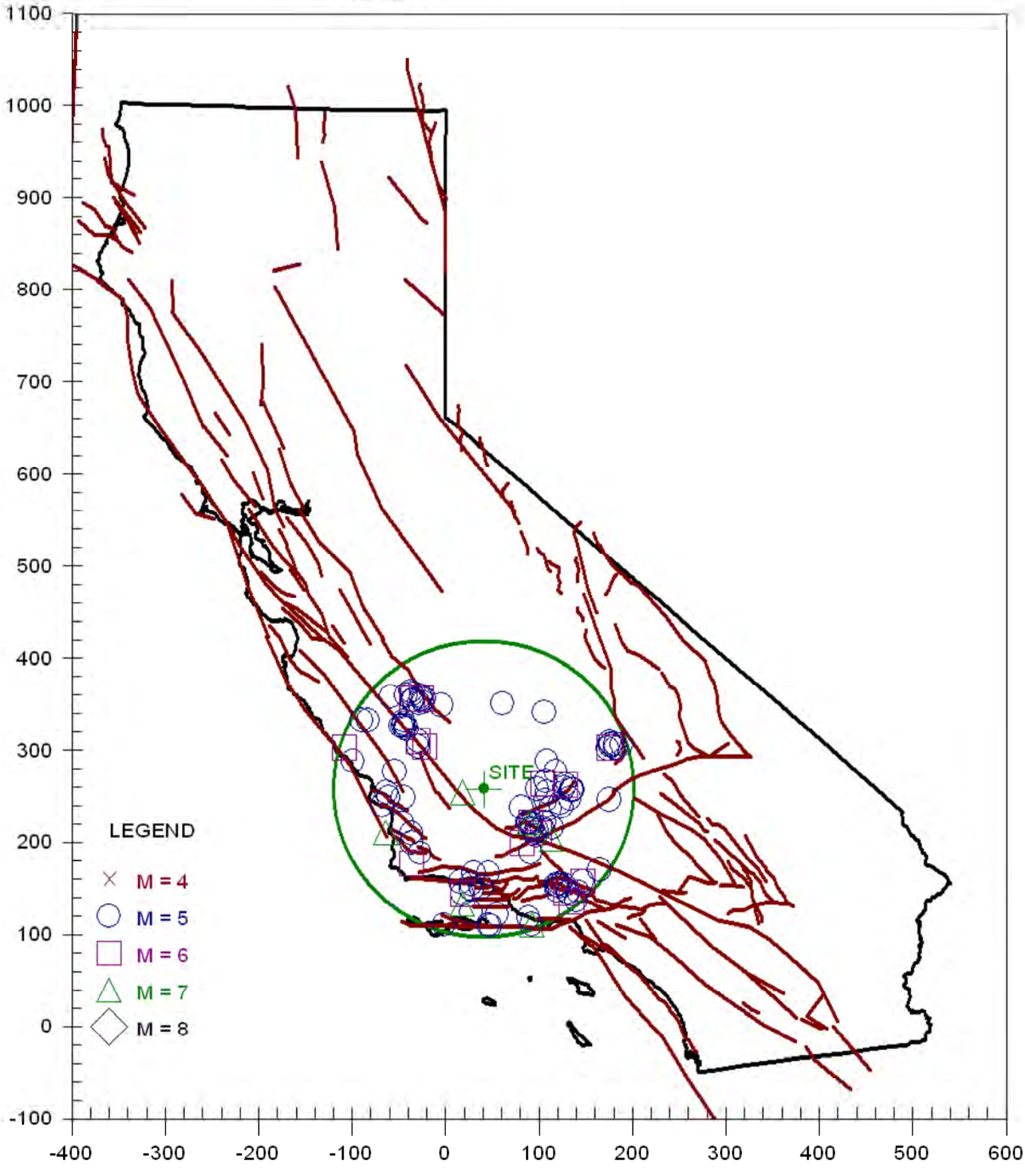
COEFFICIENTS FOR GUTENBERG & RICHTER RECURRENCE RELATION:
a-value= 1.495
b-value= 0.384
beta-value= 0.884

TABLE OF MAGNITUDES AND EXCEEDANCES:

Earthquake Magnitude	Number of Times Exceeded	Cumulative No. / Year
4.0	135	0.64286
4.5	135	0.64286
5.0	135	0.64286
5.5	56	0.26667
6.0	23	0.10952
6.5	9	0.04286
7.0	6	0.02857
7.5	3	0.01429

EARTHQUAKE EPICENTER MAP

18566 - 7



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*                    *
*    E Q F A U L T   *
*                    *
*    Version 3.00    *
*                    *
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DETERMINISTIC ESTIMATION OF
PEAK ACCELERATION FROM DIGITIZED FAULTS

JOB NUMBER: 18566

DATE: 11-28-2022

JOB NAME: 18566 Sec 7-18

CALCULATION NAME: Test Run Analysis

FAULT-DATA-FILE NAME: CGSFLTE.DAT

SITE COORDINATES:
SITE LATITUDE: 35.3250
SITE LONGITUDE: 119.5449

SEARCH RADIUS: 100 mi

ATTENUATION RELATION: 2) Boore et al. (1997) Horiz. - NEHRP C (520)
UNCERTAINTY (M=Median, S=Sigma): M Number of Sigmas: 0.0
DISTANCE MEASURE: cd_2drp
SCOND: 1
Basement Depth: 5.00 km Campbell SSR: Campbell SHR:
COMPUTE PEAK HORIZONTAL ACCELERATION

FAULT-DATA FILE USED: CGSFLTE.DAT

MINIMUM DEPTH VALUE (km): 0.0

EQFAULT SUMMARY

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT MAXIMUM EARTHQUAKE MAG.(Mw)	PEAK SITE ACCEL. g	EST. SITE INTENSITY MOD.MERC.
SAN ANDREAS - 1857 Rupture M-2a	14.3(23.0)	7.8	0.232	IX
SAN ANDREAS - Whole M-1a	14.3(23.0)	8.0	0.258	IX
SAN ANDREAS - Cho-Moj M-1b-1	14.3(23.0)	7.8	0.232	IX
SAN ANDREAS - Carrizo M-1c-2	14.3(23.0)	7.4	0.188	VIII
SAN ANDREAS - Cholame M-1c-1	18.1(29.2)	7.3	0.149	VIII
Kern Front	24.8(39.9)	6.3	0.085	VII
SAN JUAN	26.5(42.6)	7.1	0.101	VII
PLEITO THRUST	30.0(48.3)	7.0	0.106	VII
WHITE WOLF	30.2(48.6)	7.3	0.123	VII
SAN LUIS RANGE (S. Margin)	45.2(72.8)	7.2	0.086	VII
BIG PINE	45.3(72.9)	6.9	0.060	VI
GARLOCK (West)	49.5(79.6)	7.3	0.069	VI
GREAT VALLEY 14	49.7(80.0)	6.4	0.052	VI
NORTH CHANNEL SLOPE	51.5(82.9)	7.4	0.086	VII
SAN ANDREAS - Parkfield	51.8(83.4)	6.5	0.044	VI
LOS OSOS	53.3(85.8)	7.0	0.068	VI
SANTA YNEZ (West)	53.9(86.7)	7.1	0.058	VI
RINCONADA	54.4(87.5)	7.5	0.072	VI
LOS ALAMOS-W. BASELINE	55.7(89.6)	6.9	0.062	VI
M.RIDGE-ARROYO PARIDA-SANTA ANA	56.4(90.7)	7.2	0.072	VII
SAN GABRIEL	56.6(91.1)	7.2	0.059	VI
LIONS HEAD	56.9(91.5)	6.6	0.052	VI
SANTA YNEZ (East)	57.3(92.2)	7.1	0.056	VI
CASMALIA (Orcutt Frontal Fault)	58.1(93.5)	6.5	0.049	VI
SAN CAYETANO	60.8(97.8)	7.0	0.061	VI
RED MOUNTAIN	61.2(98.5)	7.0	0.061	VI
GREAT VALLEY 13	65.1(104.8)	6.5	0.045	VI
VENTURA - PITAS POINT	67.9(109.2)	6.9	0.053	VI
OAK RIDGE MID-CHANNEL STRUCTURE	68.5(110.3)	6.6	0.045	VI
SAN ANDREAS - Mojave M-1c-3	72.7(117.0)	7.4	0.054	VI
CHANNEL IS. THRUST (Eastern)	72.8(117.1)	7.5	0.069	VI
OAK RIDGE (Onshore)	73.0(117.5)	7.0	0.053	VI
SAN ANDREAS (Creeping)	73.9(119.0)	6.2	0.028	V
HOSGRI	74.8(120.4)	7.5	0.056	VI
SIMI-SANTA ROSA	75.4(121.4)	7.0	0.052	VI
HOLSER	75.8(122.0)	6.5	0.040	V
SANTA SUSANA	75.9(122.1)	6.7	0.044	VI
NORTHRIDGE (E. Oak Ridge)	79.3(127.6)	7.0	0.050	VI
OAK RIDGE(Blind Thrust Offshore)	79.8(128.4)	7.1	0.052	VI
ANACAPA-DUME	80.0(128.8)	7.5	0.065	VI

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT: MAXIMUM EARTHQUAKE MAG.(Mw)	PEAK SITE ACCEL. g	EST. SITE INTENSITY MOD.MERC.
GREAT VALLEY 12	83.5(134.4)	6.3	0.033	V
GARLOCK (East)	85.8(138.1)	7.5	0.050	VI
SIERRA MADRE (San Fernando)	86.6(139.4)	6.7	0.040	V
So. SIERRA NEVADA	89.0(143.3)	7.3	0.053	VI
SANTA CRUZ ISLAND	89.3(143.7)	7.0	0.046	VI
SANTA ROSA ISLAND	92.2(148.4)	7.1	0.047	VI
MALIBU COAST	92.6(149.0)	6.7	0.038	V
GREAT VALLEY 11	94.0(151.2)	6.4	0.032	V
VERDUGO	95.4(153.6)	6.9	0.041	V

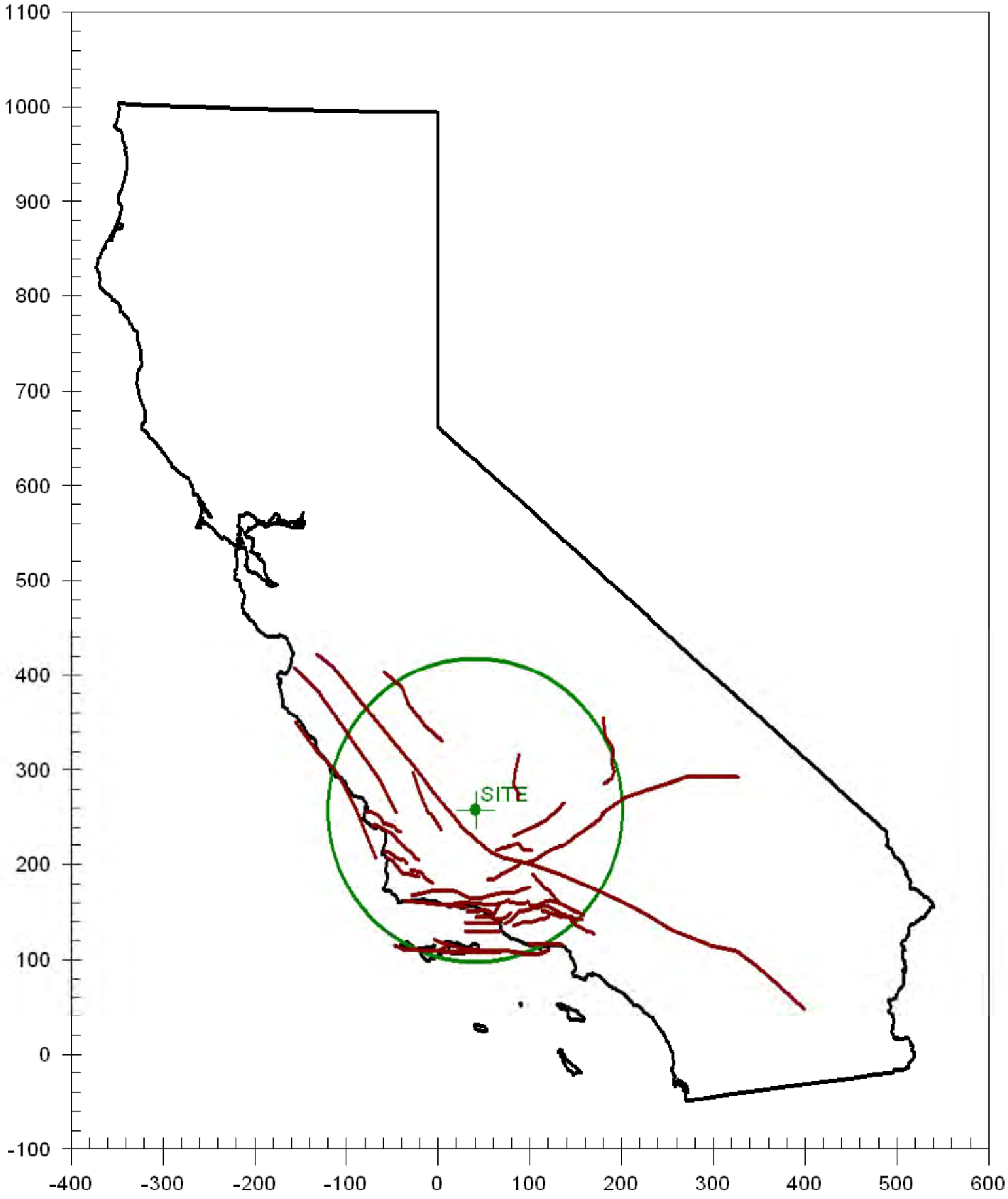
-END OF SEARCH- 49 FAULTS FOUND WITHIN THE SPECIFIED SEARCH RADIUS.

THE SAN ANDREAS - Whole M-1a FAULT IS CLOSEST TO THE SITE.
IT IS ABOUT 14.3 MILES (23.0 km) AWAY.

LARGEST MAXIMUM-EARTHQUAKE SITE ACCELERATION: 0.2582 g

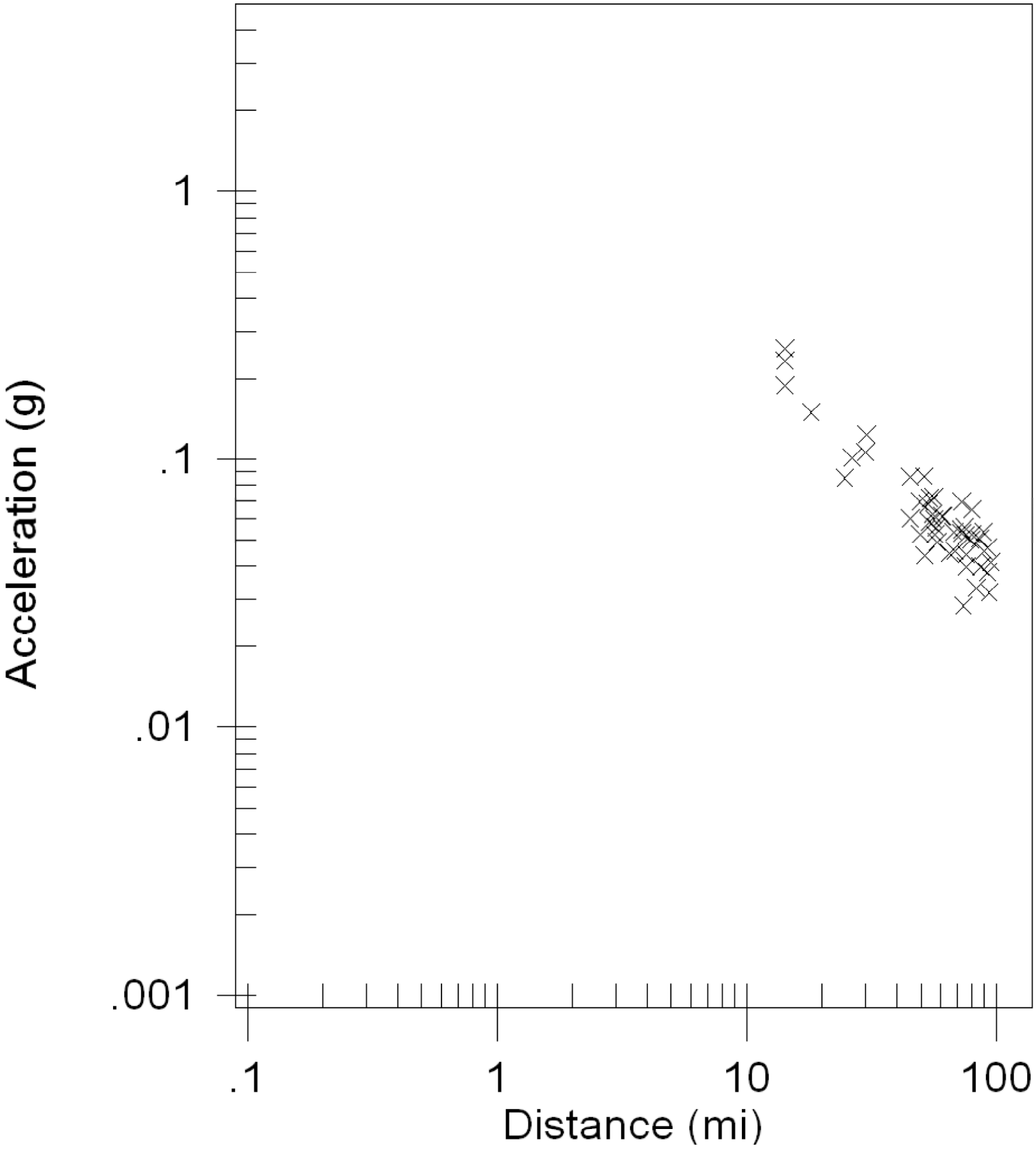
CALIFORNIA FAULT MAP

18566 Sec 7-18



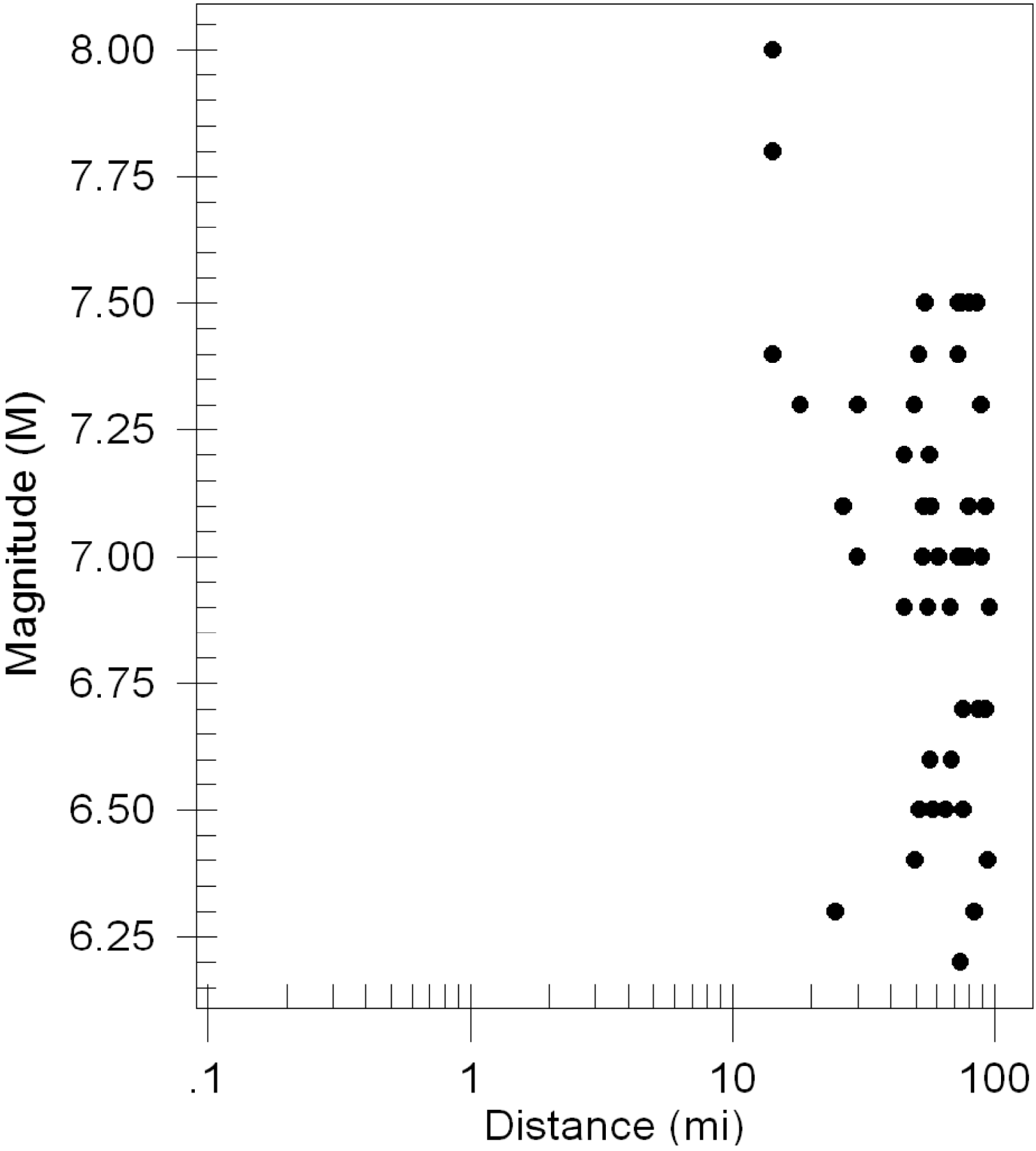
MAXIMUM EARTHQUAKES

18566 Sec 7-18



EARTHQUAKE MAGNITUDES & DISTANCES

18566 Sec 7-18



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*                       *
*    E Q S E A R C H    *
*                       *
*     Version 3.00      *
*                       *
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      ESTIMATION OF
   PEAK ACCELERATION FROM
CALIFORNIA EARTHQUAKE CATALOGS


JOB NUMBER: 18566
                                                DATE: 11-28-2022

JOB NAME: 18566 Sec 7-18

EARTHQUAKE-CATALOG-FILE NAME: C:\Program Files\EQSEARCH\ALLQUAKE.DAT

SITE COORDINATES:
   SITE LATITUDE:  35.3250
   SITE LONGITUDE:  119.5449

SEARCH DATES:
           START DATE:   1800
           END DATE:   2010

SEARCH RADIUS:
           100.0 mi
           160.9 km

ATTENUATION RELATION:   2) Boore et al. (1997) Horiz. - NEHRP C (520)
   UNCERTAINTY (M=Median, S=Sigma): M       Number of Sigmas:  0.0
   ASSUMED SOURCE TYPE:  DS [SS=Strike-slip, DS=Reverse-slip, BT=Blind-
thrust]
   SCOND:   1  Depth Source:  A
   Basement Depth:  5.00 km     Campbell SSR:        Campbell SHR:
   COMPUTE PEAK HORIZONTAL ACCELERATION

MINIMUM DEPTH VALUE (km):  0.0
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EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	35.3000	119.8000	01/09/1857	16 0 0.0	0.0	7.90	0.295	IX	14.5(23.3)
GSP	35.1490	119.1040	05/28/1993	044740.6	21.0	5.20	0.044	VI	27.7(44.5)
DMG	35.3330	118.9170	08/22/1952	224124.0	0.0	5.80	0.050	VI	35.4(56.9)
DMG	35.0000	119.0330	07/21/1952	12 2 0.0	0.0	5.60	0.043	VI	36.6(58.9)
DMG	35.0000	119.0170	01/12/1954	233349.0	0.0	5.90	0.050	VI	37.3(60.0)
DMG	35.0000	119.0170	07/21/1952	115214.0	0.0	7.70	0.130	VIII	37.3(60.0)
DMG	35.0000	119.0000	07/21/1952	12 531.0	0.0	6.40	0.064	VI	38.1(61.3)
DMG	35.0000	119.0000	02/16/1919	1557 0.0	0.0	5.00	0.031	V	38.1(61.3)
DMG	35.3830	118.8500	07/29/1952	7 347.0	0.0	6.10	0.054	VI	39.3(63.3)
DMG	34.9830	118.9830	05/23/1954	235243.0	0.0	5.10	0.031	V	39.5(63.6)
DMG	34.9410	118.9870	11/15/1961	53855.5	10.7	5.00	0.029	V	41.2(66.3)
DMG	35.4000	118.8170	07/29/1952	8 146.0	0.0	5.10	0.030	V	41.3(66.5)
DMG	35.2170	118.8170	07/23/1952	1317 5.0	0.0	5.70	0.041	V	41.7(67.1)
DMG	35.3000	118.8000	12/23/1905	2223 0.0	0.0	5.00	0.028	V	42.0(67.6)
DMG	34.9320	118.9760	03/01/1963	02557.9	13.9	5.00	0.028	V	42.0(67.7)
DMG	34.8000	119.1000	09/05/1883	1230 0.0	0.0	6.00	0.046	VI	44.1(71.0)
DMG	34.9000	118.9500	08/01/1952	13 430.0	0.0	5.10	0.029	V	44.6(71.8)
T-A	34.9200	118.9200	01/20/1857	0 0 0.0	0.0	5.00	0.027	V	45.0(72.5)
T-A	34.9200	118.9200	05/23/1857	0 0 0.0	0.0	5.00	0.027	V	45.0(72.5)
DMG	35.1330	118.7670	07/21/1952	194122.0	0.0	5.50	0.035	V	45.8(73.7)
DMG	35.6000	118.8000	06/30/1926	1331 0.0	0.0	5.00	0.027	V	46.0(74.0)
DMG	35.0000	118.8330	07/23/1952	181351.0	0.0	5.20	0.029	V	46.0(74.1)
DMG	35.0000	118.8330	07/23/1952	75319.0	0.0	5.40	0.033	V	46.0(74.1)
DMG	34.9500	118.8670	07/21/1952	121936.0	0.0	5.30	0.031	V	46.2(74.4)
DMG	34.9000	118.9000	10/23/1916	244 0.0	0.0	6.00	0.044	VI	46.8(75.3)
DMG	34.8670	118.9330	09/21/1941	1953 7.2	0.0	5.20	0.029	V	46.8(75.4)
DMG	35.5000	118.7000	01/06/1905	1430 0.0	0.0	5.00	0.025	V	49.1(78.9)
DMG	35.7500	120.2500	03/10/1922	112120.0	0.0	6.50	0.055	VI	49.3(79.3)
DMG	35.1830	118.6500	07/21/1952	151358.0	0.0	5.10	0.026	V	51.4(82.7)
PAS	34.9430	118.7430	06/10/1988	23 643.0	6.8	5.40	0.030	V	52.4(84.3)
DMG	35.1500	118.6330	01/27/1954	141948.0	0.0	5.00	0.024	IV	52.8(85.0)
DMG	35.7500	120.3300	08/18/1922	512 0.0	0.0	5.00	0.024	IV	53.0(85.3)
DMG	34.7000	119.0000	10/23/1916	254 0.0	0.0	5.50	0.031	V	53.0(85.3)
DMG	35.3330	118.6000	07/31/1952	12 9 9.0	0.0	5.80	0.036	V	53.2(85.7)
MGI	35.2500	120.5000	07/10/1917	043 0.0	0.0	5.30	0.027	V	54.1(87.0)
MGI	35.2500	120.5000	07/10/1917	045 0.0	0.0	5.30	0.027	V	54.1(87.0)
MGI	35.2500	120.5000	07/09/1917	2222 0.0	0.0	5.00	0.023	IV	54.1(87.0)
MGI	35.2500	120.5000	07/09/1917	2238 0.0	0.0	5.30	0.027	V	54.1(87.0)
DMG	35.3670	118.5830	07/23/1952	31923.0	0.0	5.00	0.023	IV	54.2(87.3)
DMG	35.3670	118.5830	07/23/1952	03832.0	0.0	6.10	0.042	VI	54.2(87.3)
DMG	35.8000	120.3300	06/08/1934	447 0.0	0.0	6.00	0.039	V	55.0(88.4)
DMG	35.8000	120.3300	12/28/1939	121538.0	0.0	5.00	0.023	IV	55.0(88.4)
DMG	35.8000	120.3300	06/08/1934	430 0.0	0.0	5.00	0.023	IV	55.0(88.4)
DMG	35.8000	120.3300	06/05/1934	2148 0.0	0.0	5.00	0.023	IV	55.0(88.4)
T-A	34.8300	118.7500	11/27/1852	0 0 0.0	0.0	7.00	0.065	VI	56.4(90.8)
MGI	34.9000	120.4000	03/29/1928	625 0.0	0.0	5.30	0.027	V	56.5(90.9)
DMG	34.5000	119.5000	08/05/1930	1125 0.0	0.0	5.00	0.022	IV	57.0(91.8)
DMG	34.5000	119.5000	06/29/1926	2321 0.0	0.0	5.50	0.029	V	57.0(91.8)
DMG	35.2330	118.5330	07/21/1952	174244.0	0.0	5.10	0.024	IV	57.4(92.3)
T-A	34.5000	119.6700	06/01/1893	12 0 0.0	0.0	5.00	0.022	IV	57.4(92.4)
DMG	35.3150	118.5160	07/25/1952	194323.7	11.2	5.70	0.032	V	58.0(93.3)
MGI	35.0000	120.5000	11/19/1927	332 0.0	0.0	5.00	0.022	IV	58.4(94.0)
DMG	35.3110	118.4990	07/25/1952	1313 8.2	2.8	5.00	0.022	IV	58.9(94.8)

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	35.3170	118.4940	07/25/1952	19 944.6	5.5	5.70	0.032	V	59.2(95.3)
T-A	36.1700	119.3200	07/25/1868	230 0.0	0.0	5.00	0.022	IV	59.7(96.0)
MGI	34.8000	120.4000	12/12/1902	0 0 0.0	0.0	5.70	0.031	V	60.4(97.2)
MGI	35.5000	120.6000	01/01/1830	0 0 0.0	0.0	5.00	0.021	IV	60.6(97.5)
DMG	34.7000	120.3000	01/12/1915	431 0.0	0.0	5.50	0.028	V	60.7(97.7)
DMG	34.7000	120.3000	07/31/1902	920 0.0	0.0	5.50	0.028	V	60.7(97.7)
T-A	35.2500	120.6700	00/00/1830	0 0 0.0	0.0	5.70	0.030	V	63.6(102.4)
T-A	35.2500	120.6700	12/17/1852	0 0 0.0	0.0	5.70	0.030	V	63.6(102.4)
PAS	36.1510	120.0490	08/04/1985	12 156.0	6.0	5.80	0.031	V	63.6(102.4)
T-A	34.4200	119.8200	00/00/1862	0 0 0.0	0.0	5.70	0.030	V	64.4(103.6)
MGI	34.4000	119.7000	03/25/1806	8 0 0.0	0.0	5.00	0.020	IV	64.5(103.7)
MGI	35.3000	120.7000	12/07/1906	640 0.0	0.0	5.90	0.033	V	65.1(104.8)
GSB	35.9170	120.4650	12/20/1994	102747.2	8.0	5.00	0.020	IV	65.9(106.0)
DMG	36.0800	118.8200	05/29/1915	646 0.0	0.0	5.00	0.020	IV	66.1(106.4)
DMG	34.3670	119.5830	07/01/1941	75054.8	0.0	5.90	0.032	V	66.2(106.5)
DMG	35.9300	120.4800	12/24/1934	1626 0.0	0.0	5.00	0.020	IV	67.1(107.9)
DMG	35.9500	120.4700	11/16/1956	323 9.0	0.0	5.00	0.020	IV	67.5(108.6)
PAS	34.3470	119.6960	08/13/1978	225453.4	12.8	5.10	0.021	IV	68.1(109.5)
MGI	35.1700	120.7500	12/01/1916	2253 0.0	0.0	5.70	0.028	V	68.8(110.7)
DMG	35.9500	120.5000	06/28/1966	42613.4	0.0	5.50	0.025	V	68.8(110.7)
MGI	34.6000	120.4000	08/01/1902	330 0.0	0.0	6.30	0.038	V	69.6(112.0)
MGI	34.6000	120.4000	07/28/1902	657 0.0	0.0	6.30	0.038	V	69.6(112.0)
DMG	35.9700	120.5000	06/28/1966	4 856.2	0.0	5.10	0.020	IV	69.7(112.1)
DMG	35.9500	120.5300	06/29/1966	195325.9	0.0	5.00	0.019	IV	70.1(112.8)
DMG	36.0000	120.5000	03/03/1901	745 0.0	0.0	5.50	0.025	V	71.0(114.3)
DMG	36.0000	120.5000	02/02/1881	011 0.0	0.0	5.60	0.026	V	71.0(114.3)
DMG	34.9000	120.7000	11/04/1927	135053.0	0.0	7.50	0.070	VI	71.5(115.1)
PAS	36.1820	120.2680	02/14/1987	72650.8	6.0	5.10	0.020	IV	71.7(115.4)
DMG	34.3000	119.8000	06/29/1925	144216.0	0.0	6.25	0.036	V	72.2(116.2)
MGI	34.3000	119.8000	07/03/1925	1638 0.0	0.0	5.30	0.022	IV	72.2(116.2)
MGI	34.3000	119.8000	07/03/1925	1821 0.0	0.0	5.30	0.022	IV	72.2(116.2)
DMG	36.1700	120.3200	12/27/1926	919 0.0	0.0	5.00	0.019	IV	72.7(117.0)
BRK	36.2200	120.2600	09/09/1983	91614.0	0.0	5.40	0.023	IV	73.6(118.5)
BRK	36.2200	120.2900	05/02/1983	234239.0	0.0	6.70	0.045	VI	74.6(120.0)
BRK	36.2200	120.2900	05/02/1983	2346 6.0	0.0	5.60	0.025	V	74.6(120.0)
BRK	36.2400	120.2900	05/09/1983	24912.0	0.0	5.20	0.020	IV	75.7(121.8)
BRK	36.2100	120.3800	07/25/1983	223140.0	0.0	5.10	0.019	IV	77.0(123.8)
BRK	36.2000	120.4000	07/22/1983	343 2.0	0.0	5.00	0.018	IV	77.1(124.1)
BRK	36.2200	120.4000	07/22/1983	23955.0	0.0	6.00	0.030	V	78.2(125.8)
DMG	34.2000	119.8000	12/21/1812	19 0 0.0	0.0	7.00	0.050	VI	79.0(127.1)
BRK	36.2600	120.4000	07/09/1983	74052.0	0.0	5.30	0.020	IV	80.4(129.3)
GSB	34.3790	118.7110	01/19/1994	210928.6	14.0	5.50	0.022	IV	80.6(129.7)
GSP	34.3770	118.6980	01/18/1994	004308.9	11.0	5.20	0.019	IV	81.2(130.6)
GSP	34.3940	118.6690	06/26/1995	084028.9	13.0	5.00	0.017	IV	81.2(130.7)
BRK	36.2500	120.4700	06/11/1983	3 954.0	0.0	5.10	0.018	IV	82.2(132.3)
PAS	36.2860	120.4130	10/25/1982	2226 4.0	6.0	5.60	0.023	IV	82.2(132.4)
GSP	34.3690	118.6720	04/26/1997	103730.7	16.0	5.10	0.018	IV	82.5(132.7)
GSP	35.2100	118.0660	07/11/1992	181416.2	10.0	5.70	0.024	V	83.7(134.8)
DMG	34.1180	119.7020	07/05/1968	04517.2	5.9	5.20	0.019	IV	83.8(134.9)
GSP	34.3780	118.6180	01/19/1994	211144.9	11.0	5.10	0.018	IV	83.9(135.0)
GSP	34.3260	118.6980	01/17/1994	233330.7	9.0	5.60	0.023	IV	84.0(135.2)
DMG	34.1000	119.4000	05/19/1893	035 0.0	0.0	5.50	0.021	IV	85.0(136.7)
DMG	35.7150	118.0740	03/15/1946	14 035.4	0.0	5.30	0.019	IV	86.9(139.9)

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	36.2300	120.6500	02/05/1947	614 0.0	0.0	5.00	0.016	IV	88.0(141.5)
DMG	35.7250	118.0550	03/15/1946	134935.9	22.0	6.30	0.032	V	88.2(141.9)
DMG	34.3000	118.6000	04/04/1893	1940 0.0	0.0	6.00	0.027	V	88.8(142.8)
GSP	34.3050	118.5790	01/29/1994	112036.0	1.0	5.10	0.017	IV	89.2(143.5)
DMG	35.7450	118.0390	03/16/1946	94617.9	0.0	5.10	0.017	IV	89.4(143.9)
MGI	35.6000	121.1000	02/01/1853	21 0 0.0	0.0	5.00	0.016	IV	89.5(144.0)
DMG	35.7780	118.0490	01/28/1961	81246.2	5.5	5.30	0.019	IV	89.7(144.3)
GSB	34.3010	118.5650	01/17/1994	204602.4	9.0	5.20	0.018	IV	89.9(144.7)
DMG	35.7510	118.0290	03/15/1946	215433.4	0.0	5.20	0.018	IV	90.1(145.0)
DMG	36.0000	120.9200	11/02/1955	1940 6.0	0.0	5.20	0.018	IV	90.1(145.0)
DMG	34.4110	118.4010	02/09/1971	14 1 8.0	8.0	5.80	0.024	V	90.4(145.6)
DMG	34.4110	118.4010	02/09/1971	14 244.0	8.0	5.80	0.024	V	90.4(145.6)
DMG	34.4110	118.4010	02/09/1971	141028.0	8.0	5.30	0.018	IV	90.4(145.6)
DMG	34.4110	118.4010	02/09/1971	14 041.8	8.4	6.40	0.033	V	90.4(145.6)
DMG	34.0000	119.5000	02/18/1926	1818 0.0	0.0	5.00	0.016	IV	91.5(147.3)
DMG	34.0650	119.0350	02/21/1973	144557.3	8.0	5.90	0.025	V	91.7(147.5)
DMG	35.7140	117.9770	03/15/1946	191853.6	0.0	5.40	0.019	IV	92.1(148.2)
DMG	35.7530	117.9860	03/15/1946	1321 0.9	0.0	5.20	0.017	IV	92.4(148.7)
DMG	33.9860	119.4750	08/06/1973	232917.0	16.9	5.00	0.015	IV	92.5(148.9)
DMG	34.3080	118.4540	02/09/1971	144346.7	6.2	5.20	0.017	IV	93.6(150.6)
DMG	36.0000	121.0000	02/26/1932	1658 0.0	0.0	5.00	0.015	IV	94.0(151.3)
DMG	34.5190	118.1980	08/23/1952	10 9 7.1	13.1	5.00	0.015	IV	94.4(151.9)
DMG	34.0000	120.0170	04/01/1945	234342.0	0.0	5.40	0.019	IV	95.3(153.4)
GSP	34.2130	118.5370	01/17/1994	123055.4	18.0	6.70	0.037	V	95.7(154.0)
DMG	35.7470	117.9080	03/18/1946	155042.6	4.4	5.30	0.018	IV	96.5(155.2)
MGI	34.0000	119.0000	12/14/1912	0 0 0.0	0.0	5.70	0.022	IV	96.6(155.4)
DMG	34.0000	119.0000	09/24/1827	4 0 0.0	0.0	7.00	0.043	VI	96.6(155.4)
GSP	34.2310	118.4750	03/20/1994	212012.3	13.0	5.30	0.017	IV	96.9(155.9)
DMG	35.7300	121.2000	11/22/1952	74637.0	0.0	6.00	0.025	V	97.1(156.3)

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-END OF SEARCH- 135 EARTHQUAKES FOUND WITHIN THE SPECIFIED SEARCH AREA.

TIME PERIOD OF SEARCH: 1800 TO 2010

LENGTH OF SEARCH TIME: 211 years

THE EARTHQUAKE CLOSEST TO THE SITE IS ABOUT 14.5 MILES (23.3 km) AWAY.

LARGEST EARTHQUAKE MAGNITUDE FOUND IN THE SEARCH RADIUS: 7.9

LARGEST EARTHQUAKE SITE ACCELERATION FROM THIS SEARCH: 0.295 g

COEFFICIENTS FOR GUTENBERG & RICHTER RECURRENCE RELATION:
a-value= 1.495
b-value= 0.384
beta-value= 0.884

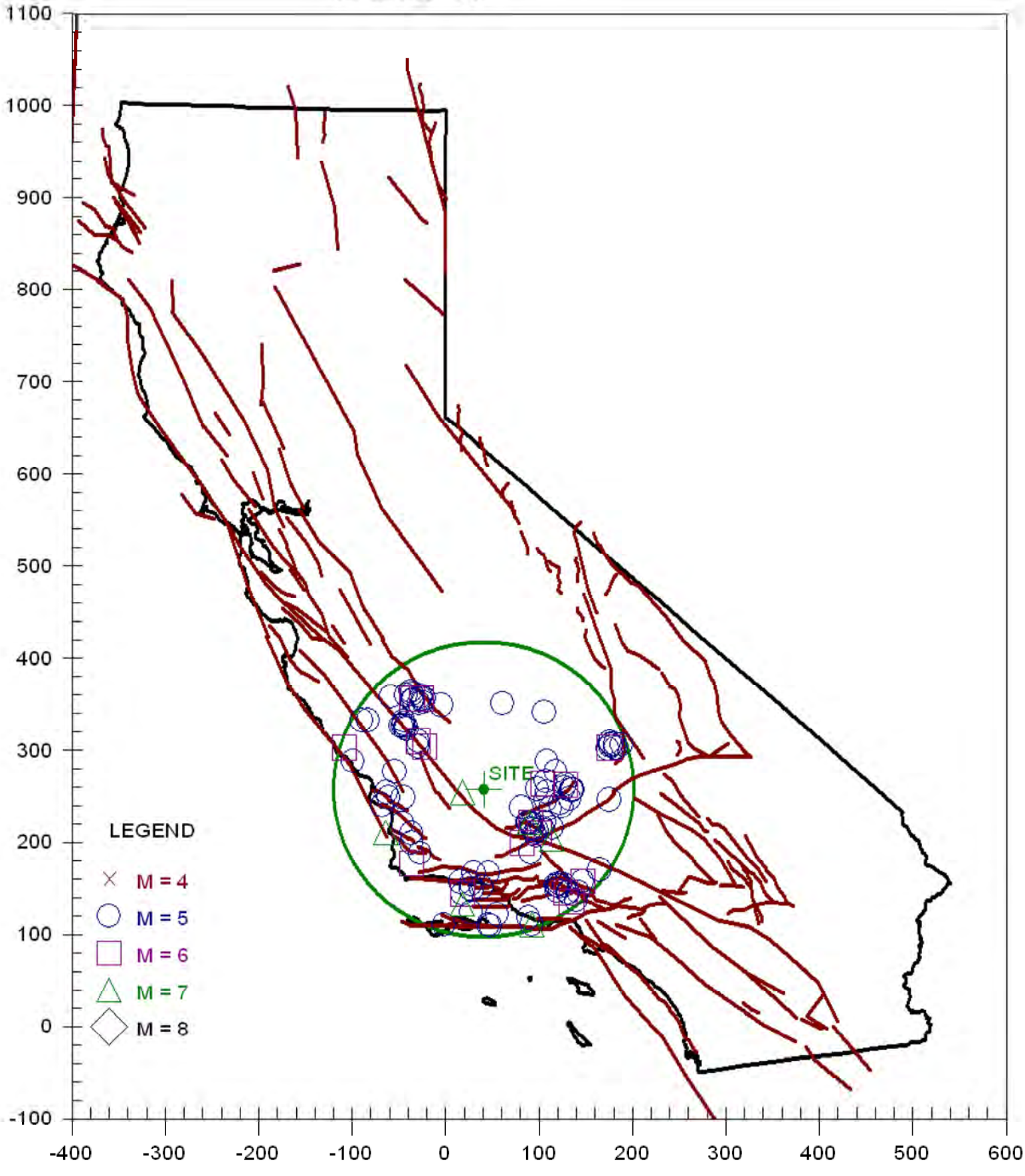
TABLE OF MAGNITUDES AND EXCEEDANCES:

Earthquake	Number of Times	Cumulative

Magnitude	Exceeded	No. / Year
4.0	135	0.64286
4.5	135	0.64286
5.0	135	0.64286
5.5	56	0.26667
6.0	23	0.10952
6.5	9	0.04286
7.0	6	0.02857
7.5	3	0.01429

EARTHQUAKE EPICENTER MAP

18566 Sec 7-18



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DETERMINISTIC ESTIMATION OF
PEAK ACCELERATION FROM DIGITIZED FAULTS

JOB NUMBER: 18566

DATE: 11-28-2022

JOB NAME: 18566 Sec 27

CALCULATION NAME: Test Run Analysis

FAULT-DATA-FILE NAME: CGSFLTE.DAT

SITE COORDINATES:
SITE LATITUDE: 35.2932
SITE LONGITUDE: 119.4896

SEARCH RADIUS: 100 mi

ATTENUATION RELATION: 2) Boore et al. (1997) Horiz. - NEHRP C (520)
UNCERTAINTY (M=Median, S=Sigma): M Number of Sigmas: 0.0
DISTANCE MEASURE: cd_2drp
SCOND: 1
Basement Depth: 5.00 km Campbell SSR: Campbell SHR:
COMPUTE PEAK HORIZONTAL ACCELERATION

FAULT-DATA FILE USED: CGSFLTE.DAT

MINIMUM DEPTH VALUE (km): 0.0

EQFAULT SUMMARY

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT MAXIMUM EARTHQUAKE MAG.(Mw)	PEAK SITE ACCEL. g	EST. SITE INTENSITY MOD.MERC.
SAN ANDREAS - 1857 Rupture M-2a	15.0(24.2)	7.8	0.224	IX
SAN ANDREAS - Whole M-1a	15.0(24.2)	8.0	0.249	IX
SAN ANDREAS - Cho-Moj M-1b-1	15.0(24.2)	7.8	0.224	IX
SAN ANDREAS - Carrizo M-1c-2	15.0(24.2)	7.4	0.181	VIII
SAN ANDREAS - Cholame M-1c-1	21.3(34.2)	7.3	0.133	VIII
Kern Front	22.9(36.8)	6.3	0.090	VII
WHITE WOLF	26.4(42.5)	7.3	0.137	VIII
PLEITO THRUST	26.7(42.9)	7.0	0.116	VII
SAN JUAN	28.4(45.7)	7.1	0.096	VII
BIG PINE	42.1(67.7)	6.9	0.064	VI
GARLOCK (West)	45.7(73.6)	7.3	0.074	VII
SAN LUIS RANGE (S. Margin)	46.5(74.9)	7.2	0.084	VII
NORTH CHANNEL SLOPE	49.8(80.1)	7.4	0.088	VII
SANTA YNEZ (West)	52.7(84.8)	7.1	0.059	VI
SAN GABRIEL	52.9(85.2)	7.2	0.062	VI
GREAT VALLEY 14	53.3(85.7)	6.4	0.050	VI
SANTA YNEZ (East)	54.5(87.7)	7.1	0.058	VI
M.RIDGE-ARROYO PARIDA-SANTA ANA	54.6(87.9)	7.2	0.074	VII
SAN ANDREAS - Parkfield	55.6(89.5)	6.5	0.042	VI
LOS OSOS	55.8(89.8)	7.0	0.066	VI
LOS ALAMOS-W. BASELINE	56.0(90.2)	6.9	0.062	VI
LIONS HEAD	57.5(92.5)	6.6	0.052	VI
RINCONADA	57.5(92.6)	7.5	0.069	VI
SAN CAYETANO	57.6(92.7)	7.0	0.064	VI
RED MOUNTAIN	58.9(94.8)	7.0	0.063	VI
CASMALIA (Orcutt Frontal Fault)	59.4(95.6)	6.5	0.048	VI
VENTURA - PITAS POINT	65.5(105.4)	6.9	0.055	VI
OAK RIDGE MID-CHANNEL STRUCTURE	66.4(106.9)	6.6	0.046	VI
GREAT VALLEY 13	68.7(110.6)	6.5	0.043	VI
SAN ANDREAS - Mojave M-1c-3	68.9(110.9)	7.4	0.057	VI
OAK RIDGE (Onshore)	69.8(112.3)	7.0	0.055	VI
CHANNEL IS. THRUST (Eastern)	70.6(113.6)	7.5	0.071	VI
HOLSER	72.2(116.2)	6.5	0.041	V
SANTA SUSANA	72.3(116.3)	6.7	0.046	VI
SIMI-SANTA ROSA	72.4(116.5)	7.0	0.054	VI
NORTHRIDGE (E. Oak Ridge)	75.7(121.8)	7.0	0.052	VI
HOSGRI	76.9(123.8)	7.5	0.055	VI
OAK RIDGE(Blind Thrust Offshore)	77.7(125.0)	7.1	0.053	VI
SAN ANDREAS (Creeping)	77.7(125.1)	6.2	0.027	V
ANACAPA-DUME	77.8(125.2)	7.5	0.066	VI

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT: MAXIMUM EARTHQUAKE MAG.(Mw)	ESTIMATED MAX. EARTHQUAKE EVENT: PEAK SITE ACCEL. g	ESTIMATED MAX. EARTHQUAKE EVENT: EST. SITE INTENSITY MOD.MERC.
GARLOCK (East)	82.6(133.0)	7.5	0.052	VI
SIERRA MADRE (San Fernando)	82.9(133.4)	6.7	0.041	V
So. SIERRA NEVADA	86.5(139.2)	7.3	0.055	VI
GREAT VALLEY 12	87.1(140.1)	6.3	0.032	V
SANTA CRUZ ISLAND	88.3(142.1)	7.0	0.046	VI
MALIBU COAST	89.4(143.8)	6.7	0.039	V
SANTA ROSA ISLAND	90.8(146.2)	7.1	0.047	VI
VERDUGO	91.7(147.6)	6.9	0.042	VI
SIERRA MADRE	96.7(155.6)	7.2	0.048	VI
SANTA MONICA	97.0(156.1)	6.6	0.035	V
LENWOOD-LOCKHART-OLD WOMAN SPRGS	97.6(157.0)	7.5	0.045	VI
GREAT VALLEY 11	97.6(157.1)	6.4	0.031	V

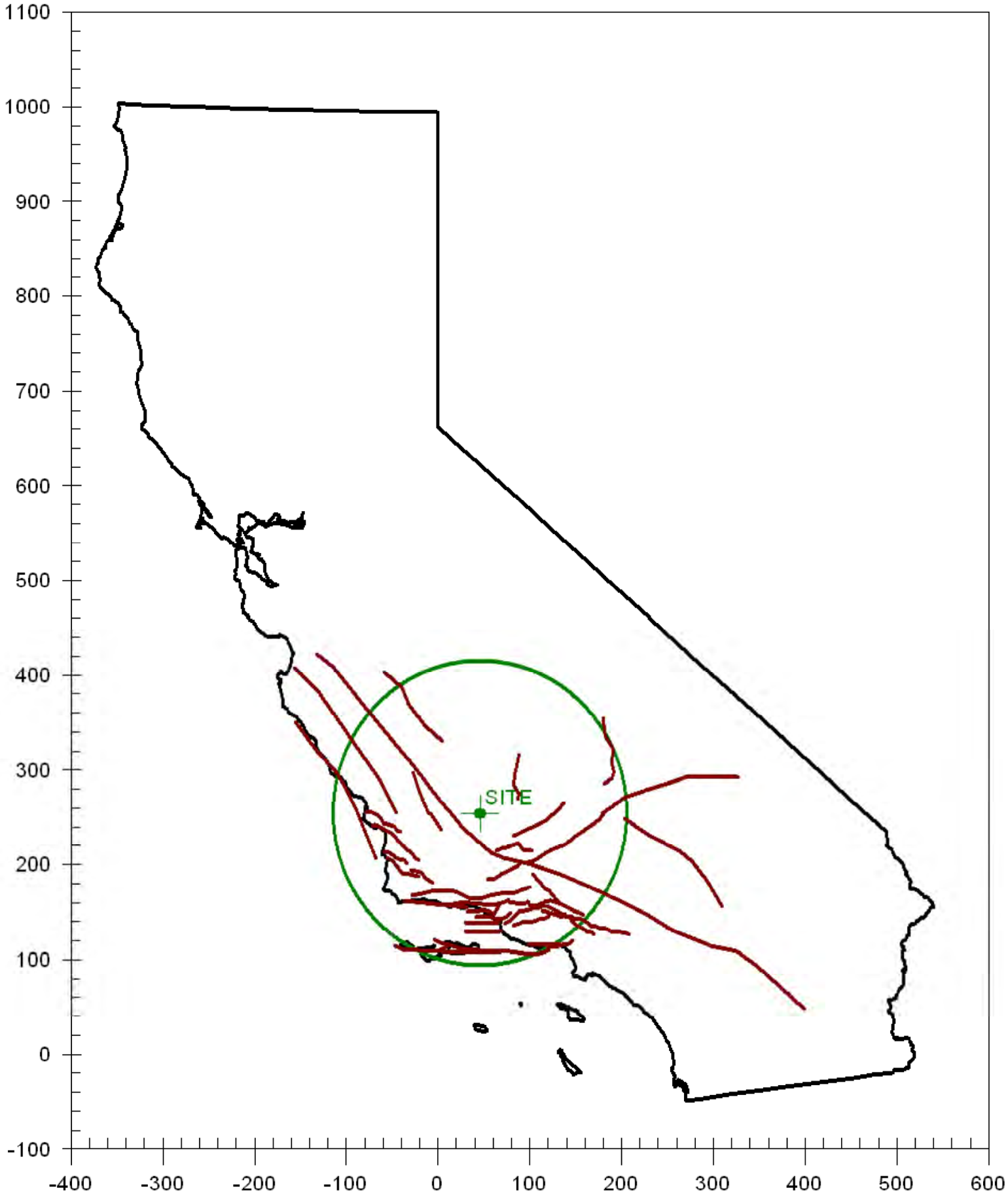
-END OF SEARCH- 52 FAULTS FOUND WITHIN THE SPECIFIED SEARCH RADIUS.

THE SAN ANDREAS - Whole M-1a FAULT IS CLOSEST TO THE SITE.
IT IS ABOUT 15.0 MILES (24.2 km) AWAY.

LARGEST MAXIMUM-EARTHQUAKE SITE ACCELERATION: 0.2487 g

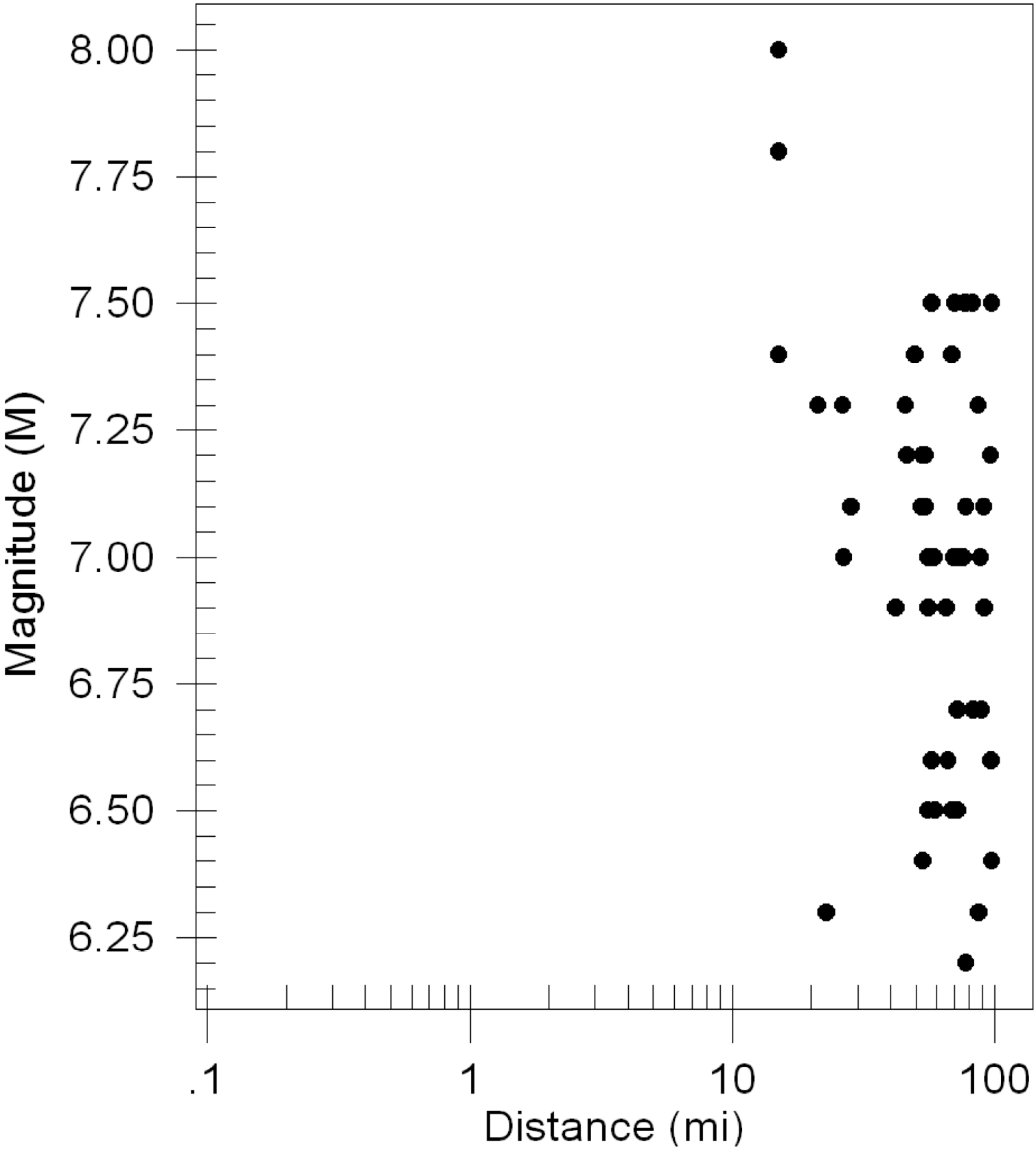
CALIFORNIA FAULT MAP

18566 Sec 27



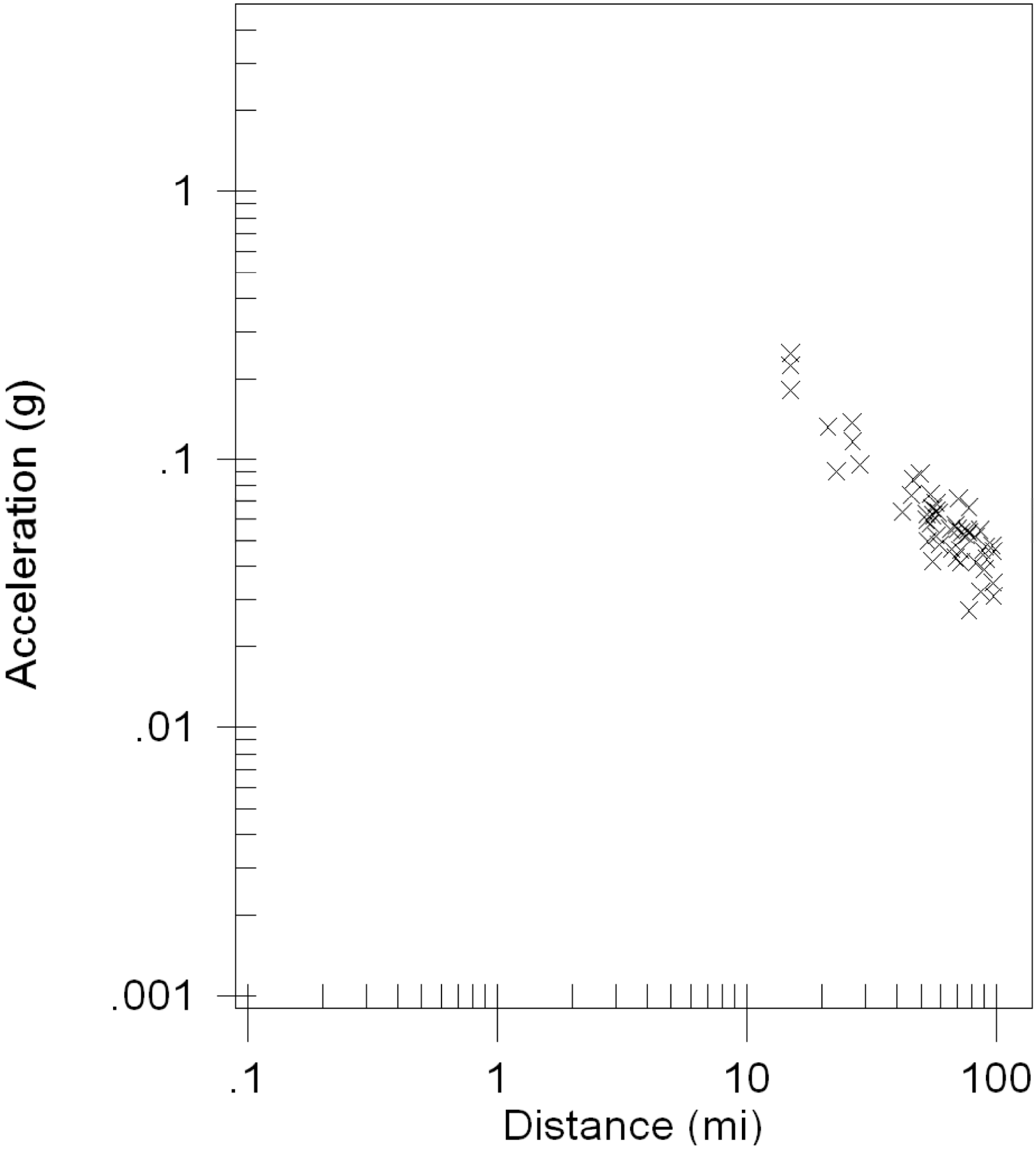
EARTHQUAKE MAGNITUDES & DISTANCES

18566 Sec 27



MAXIMUM EARTHQUAKES

18566 Sec 27



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      ESTIMATION OF
   PEAK ACCELERATION FROM
CALIFORNIA EARTHQUAKE CATALOGS


JOB NUMBER: 18566
                                                DATE: 11-28-2022

JOB NAME: 18566 Sec 27

EARTHQUAKE-CATALOG-FILE NAME: ALLQUAKE.DAT

SITE COORDINATES:
   SITE LATITUDE:  35.2932
   SITE LONGITUDE:  119.4896

SEARCH DATES:
           START DATE:   1800
           END DATE:   2010

SEARCH RADIUS:
           100.0 mi
           160.9 km

ATTENUATION RELATION:   2) Boore et al. (1997) Horiz. - NEHRP C (520)
   UNCERTAINTY (M=Median, S=Sigma): M       Number of Sigmas:  0.0
   ASSUMED SOURCE TYPE:  DS [SS=Strike-slip, DS=Reverse-slip, BT=Blind-
thrust]
   SCOND:   1  Depth Source:  A
   Basement Depth:  5.00 km     Campbell SSR:        Campbell SHR:
   COMPUTE PEAK HORIZONTAL ACCELERATION

MINIMUM DEPTH VALUE (km):  0.0
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EARTHQUAKE SEARCH RESULTS

Page 1

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	35.3000	119.8000	01/09/1857	16 0 0.0	0.0	7.90	0.256	IX	17.5(28.2)
GSP	35.1490	119.1040	05/28/1993	044740.6	21.0	5.20	0.049	VI	23.9(38.5)
DMG	35.3330	118.9170	08/22/1952	224124.0	0.0	5.80	0.053	VI	32.4(52.1)
DMG	35.0000	119.0330	07/21/1952	12 2 0.0	0.0	5.60	0.047	VI	32.8(52.7)
DMG	35.0000	119.0170	07/21/1952	115214.0	0.0	7.70	0.141	VIII	33.5(53.9)
DMG	35.0000	119.0170	01/12/1954	233349.0	0.0	5.90	0.055	VI	33.5(53.9)
DMG	35.0000	119.0000	07/21/1952	12 531.0	0.0	6.40	0.070	VI	34.3(55.1)
DMG	35.0000	119.0000	02/16/1919	1557 0.0	0.0	5.00	0.033	V	34.3(55.1)
DMG	34.9830	118.9830	05/23/1954	235243.0	0.0	5.10	0.034	V	35.7(57.5)
DMG	35.3830	118.8500	07/29/1952	7 347.0	0.0	6.10	0.057	VI	36.5(58.8)
DMG	34.9410	118.9870	11/15/1961	53855.5	10.7	5.00	0.031	V	37.4(60.1)
DMG	34.9320	118.9760	03/01/1963	02557.9	13.9	5.00	0.031	V	38.3(61.6)
DMG	35.2170	118.8170	07/23/1952	1317 5.0	0.0	5.70	0.044	VI	38.3(61.6)
DMG	35.4000	118.8170	07/29/1952	8 146.0	0.0	5.10	0.032	V	38.6(62.1)
DMG	35.3000	118.8000	12/23/1905	2223 0.0	0.0	5.00	0.030	V	38.9(62.5)
DMG	34.8000	119.1000	09/05/1883	1230 0.0	0.0	6.00	0.050	VI	40.5(65.3)
DMG	34.9000	118.9500	08/01/1952	13 430.0	0.0	5.10	0.031	V	40.8(65.7)
T-A	34.9200	118.9200	01/20/1857	0 0 0.0	0.0	5.00	0.029	V	41.2(66.3)
T-A	34.9200	118.9200	05/23/1857	0 0 0.0	0.0	5.00	0.029	V	41.2(66.3)
DMG	35.1330	118.7670	07/21/1952	194122.0	0.0	5.50	0.037	V	42.2(68.0)
DMG	35.0000	118.8330	07/23/1952	75319.0	0.0	5.40	0.035	V	42.2(68.0)
DMG	35.0000	118.8330	07/23/1952	181351.0	0.0	5.20	0.032	V	42.2(68.0)
DMG	34.9500	118.8670	07/21/1952	121936.0	0.0	5.30	0.033	V	42.4(68.2)
DMG	34.9000	118.9000	10/23/1916	244 0.0	0.0	6.00	0.047	VI	43.0(69.1)
DMG	34.8670	118.9330	09/21/1941	1953 7.2	0.0	5.20	0.031	V	43.1(69.3)
DMG	35.6000	118.8000	06/30/1926	1331 0.0	0.0	5.00	0.027	V	44.2(71.1)
DMG	35.5000	118.7000	01/06/1905	1430 0.0	0.0	5.00	0.026	V	46.7(75.1)
DMG	35.1830	118.6500	07/21/1952	151358.0	0.0	5.10	0.027	V	48.0(77.2)
PAS	34.9430	118.7430	06/10/1988	23 643.0	6.8	5.40	0.031	V	48.6(78.2)
DMG	35.1500	118.6330	01/27/1954	141948.0	0.0	5.00	0.025	V	49.3(79.4)
DMG	34.7000	119.0000	10/23/1916	254 0.0	0.0	5.50	0.033	V	49.4(79.6)
DMG	35.3330	118.6000	07/31/1952	12 9 9.0	0.0	5.80	0.038	V	50.2(80.8)
DMG	35.3670	118.5830	07/23/1952	03832.0	0.0	6.10	0.044	VI	51.3(82.6)
DMG	35.3670	118.5830	07/23/1952	31923.0	0.0	5.00	0.024	V	51.3(82.6)
T-A	34.8300	118.7500	11/27/1852	0 0 0.0	0.0	7.00	0.069	VI	52.6(84.7)
DMG	35.7500	120.2500	03/10/1922	112120.0	0.0	6.50	0.052	VI	53.1(85.5)
DMG	35.2330	118.5330	07/21/1952	174244.0	0.0	5.10	0.025	V	54.1(87.0)
DMG	34.5000	119.5000	06/29/1926	2321 0.0	0.0	5.50	0.030	V	54.8(88.1)
DMG	34.5000	119.5000	08/05/1930	1125 0.0	0.0	5.00	0.023	IV	54.8(88.1)
DMG	35.3150	118.5160	07/25/1952	194323.7	11.2	5.70	0.033	V	54.9(88.3)
T-A	34.5000	119.6700	06/01/1893	12 0 0.0	0.0	5.00	0.023	IV	55.7(89.6)
DMG	35.3110	118.4990	07/25/1952	1313 8.2	2.8	5.00	0.023	IV	55.8(89.8)
DMG	35.3170	118.4940	07/25/1952	19 944.6	5.5	5.70	0.033	V	56.1(90.3)
DMG	35.7500	120.3300	08/18/1922	512 0.0	0.0	5.00	0.023	IV	56.8(91.4)
MGI	35.2500	120.5000	07/10/1917	043 0.0	0.0	5.30	0.026	V	57.0(91.8)
MGI	35.2500	120.5000	07/09/1917	2238 0.0	0.0	5.30	0.026	V	57.0(91.8)
MGI	35.2500	120.5000	07/09/1917	2222 0.0	0.0	5.00	0.022	IV	57.0(91.8)
MGI	35.2500	120.5000	07/10/1917	045 0.0	0.0	5.30	0.026	V	57.0(91.8)
MGI	34.9000	120.4000	03/29/1928	625 0.0	0.0	5.30	0.026	V	58.2(93.6)
DMG	35.8000	120.3300	06/08/1934	447 0.0	0.0	6.00	0.037	V	58.8(94.6)
DMG	35.8000	120.3300	12/28/1939	121538.0	0.0	5.00	0.022	IV	58.8(94.6)
DMG	35.8000	120.3300	06/08/1934	430 0.0	0.0	5.00	0.022	IV	58.8(94.6)
DMG	35.8000	120.3300	06/05/1934	2148 0.0	0.0	5.00	0.022	IV	58.8(94.6)

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
MGI	35.0000	120.5000	11/19/1927	332 0.0	0.0	5.00	0.021	IV	60.5(97.4)
T-A	36.1700	119.3200	07/25/1868	230 0.0	0.0	5.00	0.021	IV	61.3(98.6)
DMG	34.7000	120.3000	07/31/1902	920 0.0	0.0	5.50	0.028	V	61.5(98.9)
DMG	34.7000	120.3000	01/12/1915	431 0.0	0.0	5.50	0.028	V	61.5(98.9)
MGI	34.8000	120.4000	12/12/1902	0 0 0.0	0.0	5.70	0.031	V	61.7(99.3)
MGI	34.4000	119.7000	03/25/1806	8 0 0.0	0.0	5.00	0.021	IV	62.8(101.1)
T-A	34.4200	119.8200	00/00/1862	0 0 0.0	0.0	5.70	0.030	V	63.1(101.6)
MGI	35.5000	120.6000	01/01/1830	0 0 0.0	0.0	5.00	0.021	IV	64.1(103.2)
DMG	34.3670	119.5830	07/01/1941	75054.8	0.0	5.90	0.033	V	64.2(103.3)
DMG	36.0800	118.8200	05/29/1915	646 0.0	0.0	5.00	0.020	IV	66.0(106.3)
PAS	34.3470	119.6960	08/13/1978	225453.4	12.8	5.10	0.021	IV	66.4(106.8)
T-A	35.2500	120.6700	00/00/1830	0 0 0.0	0.0	5.70	0.029	V	66.6(107.2)
T-A	35.2500	120.6700	12/17/1852	0 0 0.0	0.0	5.70	0.029	V	66.6(107.2)
PAS	36.1510	120.0490	08/04/1985	12 156.0	6.0	5.80	0.030	V	67.0(107.8)
MGI	35.3000	120.7000	12/07/1906	640 0.0	0.0	5.90	0.031	V	68.2(109.8)
GSB	35.9170	120.4650	12/20/1994	102747.2	8.0	5.00	0.019	IV	69.7(112.1)
MGI	34.6000	120.4000	07/28/1902	657 0.0	0.0	6.30	0.038	V	70.3(113.2)
MGI	34.6000	120.4000	08/01/1902	330 0.0	0.0	6.30	0.038	V	70.3(113.2)
MGI	34.3000	119.8000	07/03/1925	1638 0.0	0.0	5.30	0.022	IV	70.8(113.9)
DMG	34.3000	119.8000	06/29/1925	144216.0	0.0	6.25	0.037	V	70.8(113.9)
MGI	34.3000	119.8000	07/03/1925	1821 0.0	0.0	5.30	0.022	IV	70.8(113.9)
DMG	35.9300	120.4800	12/24/1934	1626 0.0	0.0	5.00	0.019	IV	70.9(114.1)
DMG	35.9500	120.4700	11/16/1956	323 9.0	0.0	5.00	0.019	IV	71.3(114.7)
MGI	35.1700	120.7500	12/01/1916	2253 0.0	0.0	5.70	0.027	V	71.6(115.2)
DMG	35.9500	120.5000	06/28/1966	42613.4	0.0	5.50	0.024	V	72.6(116.8)
DMG	35.9700	120.5000	06/28/1966	4 856.2	0.0	5.10	0.019	IV	73.5(118.2)
DMG	34.9000	120.7000	11/04/1927	135053.0	0.0	7.50	0.069	VI	73.6(118.4)
DMG	35.9500	120.5300	06/29/1966	195325.9	0.0	5.00	0.018	IV	73.9(119.0)
DMG	36.0000	120.5000	03/03/1901	745 0.0	0.0	5.50	0.024	IV	74.8(120.4)
DMG	36.0000	120.5000	02/02/1881	011 0.0	0.0	5.60	0.025	V	74.8(120.4)
PAS	36.1820	120.2680	02/14/1987	72650.8	6.0	5.10	0.019	IV	75.3(121.2)
DMG	36.1700	120.3200	12/27/1926	919 0.0	0.0	5.00	0.018	IV	76.4(122.9)
GSB	34.3790	118.7110	01/19/1994	210928.6	14.0	5.50	0.023	IV	77.0(123.9)
BRK	36.2200	120.2600	09/09/1983	91614.0	0.0	5.40	0.022	IV	77.2(124.2)
DMG	34.2000	119.8000	12/21/1812	19 0 0.0	0.0	7.00	0.051	VI	77.5(124.7)
GSP	34.3770	118.6980	01/18/1994	004308.9	11.0	5.20	0.020	IV	77.5(124.8)
GSP	34.3940	118.6690	06/26/1995	084028.9	13.0	5.00	0.018	IV	77.6(124.8)
BRK	36.2200	120.2900	05/02/1983	234239.0	0.0	6.70	0.043	VI	78.1(125.7)
BRK	36.2200	120.2900	05/02/1983	2346 6.0	0.0	5.60	0.024	V	78.1(125.7)
GSP	34.3690	118.6720	04/26/1997	103730.7	16.0	5.10	0.018	IV	78.9(126.9)
BRK	36.2400	120.2900	05/09/1983	24912.0	0.0	5.20	0.019	IV	79.3(127.6)
GSP	34.3780	118.6180	01/19/1994	211144.9	11.0	5.10	0.018	IV	80.2(129.1)
GSP	34.3260	118.6980	01/17/1994	233330.7	9.0	5.60	0.024	IV	80.5(129.5)
GSP	35.2100	118.0660	07/11/1992	181416.2	10.0	5.70	0.025	V	80.5(129.5)
BRK	36.2100	120.3800	07/25/1983	223140.0	0.0	5.10	0.018	IV	80.6(129.7)
BRK	36.2000	120.4000	07/22/1983	343 2.0	0.0	5.00	0.017	IV	80.8(130.0)
BRK	36.2200	120.4000	07/22/1983	23955.0	0.0	6.00	0.029	V	81.8(131.7)
DMG	34.1180	119.7020	07/05/1968	04517.2	5.9	5.20	0.019	IV	82.0(132.0)
DMG	34.1000	119.4000	05/19/1893	035 0.0	0.0	5.50	0.022	IV	82.5(132.8)
BRK	36.2600	120.4000	07/09/1983	74052.0	0.0	5.30	0.019	IV	84.0(135.2)
DMG	35.7150	118.0740	03/15/1946	14 035.4	0.0	5.30	0.019	IV	84.7(136.3)
DMG	34.3000	118.6000	04/04/1893	1940 0.0	0.0	6.00	0.028	V	85.1(137.0)
GSP	34.3050	118.5790	01/29/1994	112036.0	1.0	5.10	0.017	IV	85.6(137.7

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
PAS	36.2860	120.4130	10/25/1982	2226 4.0	6.0	5.60	0.022	IV	85.9(138.2)
BRK	36.2500	120.4700	06/11/1983	3 954.0	0.0	5.10	0.017	IV	85.9(138.2)
DMG	35.7250	118.0550	03/15/1946	134935.9	22.0	6.30	0.032	V	86.0(138.3)
GSB	34.3010	118.5650	01/17/1994	204602.4	9.0	5.20	0.018	IV	86.3(138.8)
DMG	34.4110	118.4010	02/09/1971	14 244.0	8.0	5.80	0.025	V	86.7(139.5)
DMG	34.4110	118.4010	02/09/1971	14 1 8.0	8.0	5.80	0.025	V	86.7(139.5)
DMG	34.4110	118.4010	02/09/1971	14 041.8	8.4	6.40	0.034	V	86.7(139.5)
DMG	34.4110	118.4010	02/09/1971	141028.0	8.0	5.30	0.019	IV	86.7(139.5)
DMG	35.7450	118.0390	03/16/1946	94617.9	0.0	5.10	0.017	IV	87.3(140.5)
DMG	35.7780	118.0490	01/28/1961	81246.2	5.5	5.30	0.019	IV	87.6(140.9)
DMG	35.7510	118.0290	03/15/1946	215433.4	0.0	5.20	0.018	IV	88.0(141.5)
DMG	34.0650	119.0350	02/21/1973	144557.3	8.0	5.90	0.026	V	88.6(142.6)
DMG	34.0000	119.5000	02/18/1926	1818 0.0	0.0	5.00	0.016	IV	89.3(143.7)
DMG	35.7140	117.9770	03/15/1946	191853.6	0.0	5.40	0.020	IV	89.8(144.6)
DMG	34.3080	118.4540	02/09/1971	144346.7	6.2	5.20	0.018	IV	89.9(144.6)
DMG	33.9860	119.4750	08/06/1973	232917.0	16.9	5.00	0.016	IV	90.3(145.2)
DMG	35.7530	117.9860	03/15/1946	1321 0.9	0.0	5.20	0.017	IV	90.3(145.2)
DMG	34.5190	118.1980	08/23/1952	10 9 7.1	13.1	5.00	0.016	IV	90.6(145.8)
DMG	36.2300	120.6500	02/05/1947	614 0.0	0.0	5.00	0.016	IV	91.7(147.6)
GSP	34.2130	118.5370	01/17/1994	123055.4	18.0	6.70	0.038	V	92.1(148.2)
MGI	35.6000	121.1000	02/01/1853	21 0 0.0	0.0	5.00	0.015	IV	93.0(149.7)
GSP	34.2310	118.4750	03/20/1994	212012.3	13.0	5.30	0.018	IV	93.2(150.0)
DMG	34.0000	119.0000	09/24/1827	4 0 0.0	0.0	7.00	0.044	VI	93.5(150.5)
MGI	34.0000	119.0000	12/14/1912	0 0 0.0	0.0	5.70	0.022	IV	93.5(150.5)
DMG	36.0000	120.9200	11/02/1955	1940 6.0	0.0	5.20	0.017	IV	93.9(151.1)
DMG	34.0000	120.0170	04/01/1945	234342.0	0.0	5.40	0.019	IV	94.2(151.6)
DMG	35.7470	117.9080	03/18/1946	155042.6	4.4	5.30	0.018	IV	94.2(151.7)
DMG	36.0000	121.0000	02/26/1932	1658 0.0	0.0	5.00	0.015	IV	97.8(157.4)

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-END OF SEARCH- 134 EARTHQUAKES FOUND WITHIN THE SPECIFIED SEARCH AREA.

TIME PERIOD OF SEARCH: 1800 TO 2010

LENGTH OF SEARCH TIME: 211 years

THE EARTHQUAKE CLOSEST TO THE SITE IS ABOUT 17.5 MILES (28.2 km) AWAY.

LARGEST EARTHQUAKE MAGNITUDE FOUND IN THE SEARCH RADIUS: 7.9

LARGEST EARTHQUAKE SITE ACCELERATION FROM THIS SEARCH: 0.256 g

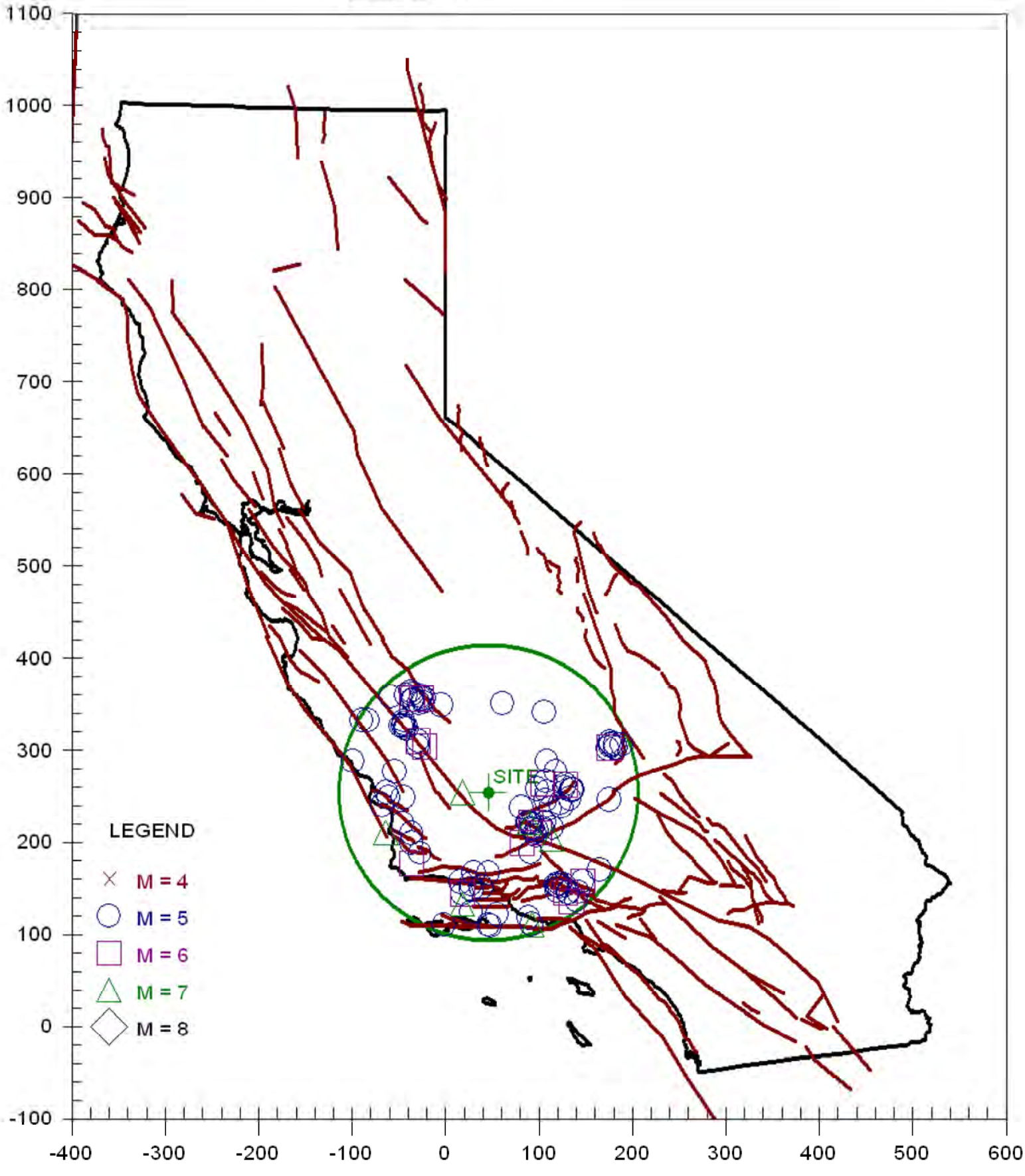
COEFFICIENTS FOR GUTENBERG & RICHTER RECURRENCE RELATION:
a-value= 1.525
b-value= 0.391
beta-value= 0.901

TABLE OF MAGNITUDES AND EXCEEDANCES:

Earthquake Magnitude	Number of Times Exceeded	Cumulative No. / Year
4.0	134	0.63810
4.5	134	0.63810
5.0	134	0.63810
5.5	55	0.26190
6.0	22	0.10476
6.5	9	0.04286
7.0	6	0.02857
7.5	3	0.01429

EARTHQUAKE EPICENTER MAP

18566 Sec 27



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DETERMINISTIC ESTIMATION OF
PEAK ACCELERATION FROM DIGITIZED FAULTS

JOB NUMBER: 18566

DATE: 11-28-2022

JOB NAME: 18566 Sec 35

CALCULATION NAME: Test Run Analysis

FAULT-DATA-FILE NAME: CGSFLTE.DAT

SITE COORDINATES:
SITE LATITUDE: 35.2757
SITE LONGITUDE: 119.4713

SEARCH RADIUS: 100 mi

ATTENUATION RELATION: 2) Boore et al. (1997) Horiz. - NEHRP C (520)
UNCERTAINTY (M=Median, S=Sigma): M Number of Sigmas: 0.0
DISTANCE MEASURE: cd_2drp
SCOND: 1
Basement Depth: 5.00 km Campbell SSR: Campbell SHR:
COMPUTE PEAK HORIZONTAL ACCELERATION

FAULT-DATA FILE USED: CGSFLTE.DAT

MINIMUM DEPTH VALUE (km): 0.0

EQFAULT SUMMARY

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT: MAXIMUM EARTHQUAKE MAG.(Mw)	ESTIMATED MAX. EARTHQUAKE EVENT: PEAK SITE ACCEL. g	ESTIMATED MAX. EARTHQUAKE EVENT: EST. SITE INTENSITY MOD.MERC.
SAN ANDREAS - 1857 Rupture M-2a	14.9(23.9)	7.8	0.226	IX
SAN ANDREAS - Whole M-1a	14.9(23.9)	8.0	0.251	IX
SAN ANDREAS - Cho-Moj M-1b-1	14.9(23.9)	7.8	0.226	IX
SAN ANDREAS - Carrizo M-1c-2	14.9(23.9)	7.4	0.183	VIII
SAN ANDREAS - Cholame M-1c-1	22.4(36.1)	7.3	0.127	VIII
Kern Front	22.6(36.4)	6.3	0.091	VII
WHITE WOLF	24.9(40.0)	7.3	0.143	VIII
PLEITO THRUST	25.1(40.4)	7.0	0.121	VII
SAN JUAN	29.0(46.7)	7.1	0.094	VII
BIG PINE	40.6(65.3)	6.9	0.065	VI
GARLOCK (West)	44.1(71.0)	7.3	0.076	VII
SAN LUIS RANGE (S. Margin)	46.8(75.3)	7.2	0.084	VII
NORTH CHANNEL SLOPE	48.7(78.4)	7.4	0.090	VII
SAN GABRIEL	51.3(82.6)	7.2	0.064	VI
SANTA YNEZ (West)	51.9(83.5)	7.1	0.060	VI
SANTA YNEZ (East)	53.1(85.5)	7.1	0.059	VI
M.RIDGE-ARROYO PARIDA-SANTA ANA	53.5(86.1)	7.2	0.075	VII
GREAT VALLEY 14	54.9(88.3)	6.4	0.048	VI
LOS ALAMOS-W. BASELINE	55.7(89.6)	6.9	0.062	VI
SAN CAYETANO	56.1(90.3)	7.0	0.065	VI
LOS OSOS	56.6(91.1)	7.0	0.065	VI
SAN ANDREAS - Parkfield	57.2(92.0)	6.5	0.041	V
LIONS HEAD	57.4(92.4)	6.6	0.052	VI
RED MOUNTAIN	57.7(92.9)	7.0	0.064	VI
RINCONADA	58.6(94.3)	7.5	0.068	VI
CASMALIA (Orcutt Frontal Fault)	59.6(95.9)	6.5	0.048	VI
VENTURA - PITAS POINT	64.2(103.3)	6.9	0.056	VI
OAK RIDGE MID-CHANNEL STRUCTURE	65.2(105.0)	6.6	0.047	VI
SAN ANDREAS - Mojave M-1c-3	67.4(108.4)	7.4	0.058	VI
OAK RIDGE (Onshore)	68.3(109.9)	7.0	0.056	VI
CHANNEL IS. THRUST (Eastern)	69.4(111.7)	7.5	0.072	VI
GREAT VALLEY 13	70.3(113.2)	6.5	0.042	VI
HOLSER	70.6(113.6)	6.5	0.042	VI
SANTA SUSANA	70.6(113.7)	6.7	0.047	VI
SIMI-SANTA ROSA	71.0(114.2)	7.0	0.054	VI
NORTHRIDGE (E. Oak Ridge)	74.1(119.3)	7.0	0.053	VI
ANACAPA-DUME	76.6(123.2)	7.5	0.067	VI
OAK RIDGE(Blind Thrust Offshore)	76.6(123.2)	7.1	0.054	VI
HOSGRI	77.5(124.7)	7.5	0.054	VI
SAN ANDREAS (Creeping)	79.3(127.7)	6.2	0.027	V

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT: MAXIMUM EARTHQUAKE MAG.(Mw)	ESTIMATED MAX. EARTHQUAKE EVENT: PEAK SITE ACCEL. g	ESTIMATED MAX. EARTHQUAKE EVENT: EST. SITE INTENSITY MOD.MERC.
SIERRA MADRE (San Fernando)	81.3(130.9)	6.7	0.042	VI
GARLOCK (East)	81.6(131.4)	7.5	0.052	VI
So. SIERRA NEVADA	85.7(138.0)	7.3	0.055	VI
SANTA CRUZ ISLAND	87.6(140.9)	7.0	0.046	VI
MALIBU COAST	87.9(141.4)	6.7	0.039	V
GREAT VALLEY 12	88.7(142.7)	6.3	0.032	V
SANTA ROSA ISLAND	89.9(144.7)	7.1	0.048	VI
VERDUGO	90.1(145.0)	6.9	0.043	VI
SIERRA MADRE	95.1(153.1)	7.2	0.048	VI
SANTA MONICA	95.4(153.6)	6.6	0.035	V
LENWOOD-LOCKHART-OLD WOMAN SPRGS	96.5(155.3)	7.5	0.046	VI
HOLLYWOOD	99.0(159.3)	6.4	0.031	V
GREAT VALLEY 11	99.2(159.6)	6.4	0.031	V
LITTLE LAKE	99.9 (160.7)	6.9	0.033	V

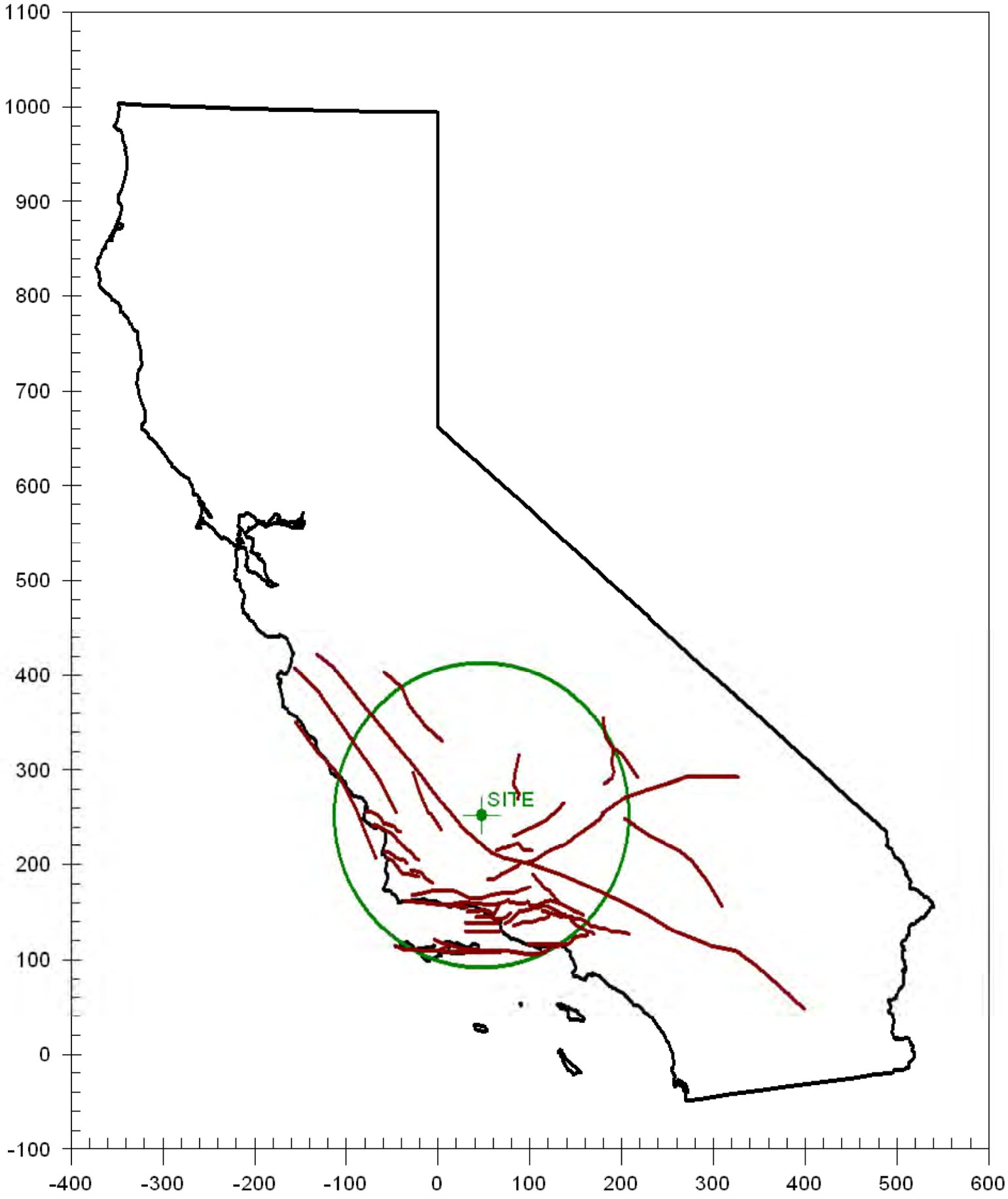
-END OF SEARCH- 54 FAULTS FOUND WITHIN THE SPECIFIED SEARCH RADIUS.

THE SAN ANDREAS - Whole M-1a FAULT IS CLOSEST TO THE SITE.
IT IS ABOUT 14.9 MILES (23.9 km) AWAY.

LARGEST MAXIMUM-EARTHQUAKE SITE ACCELERATION: 0.2510 g

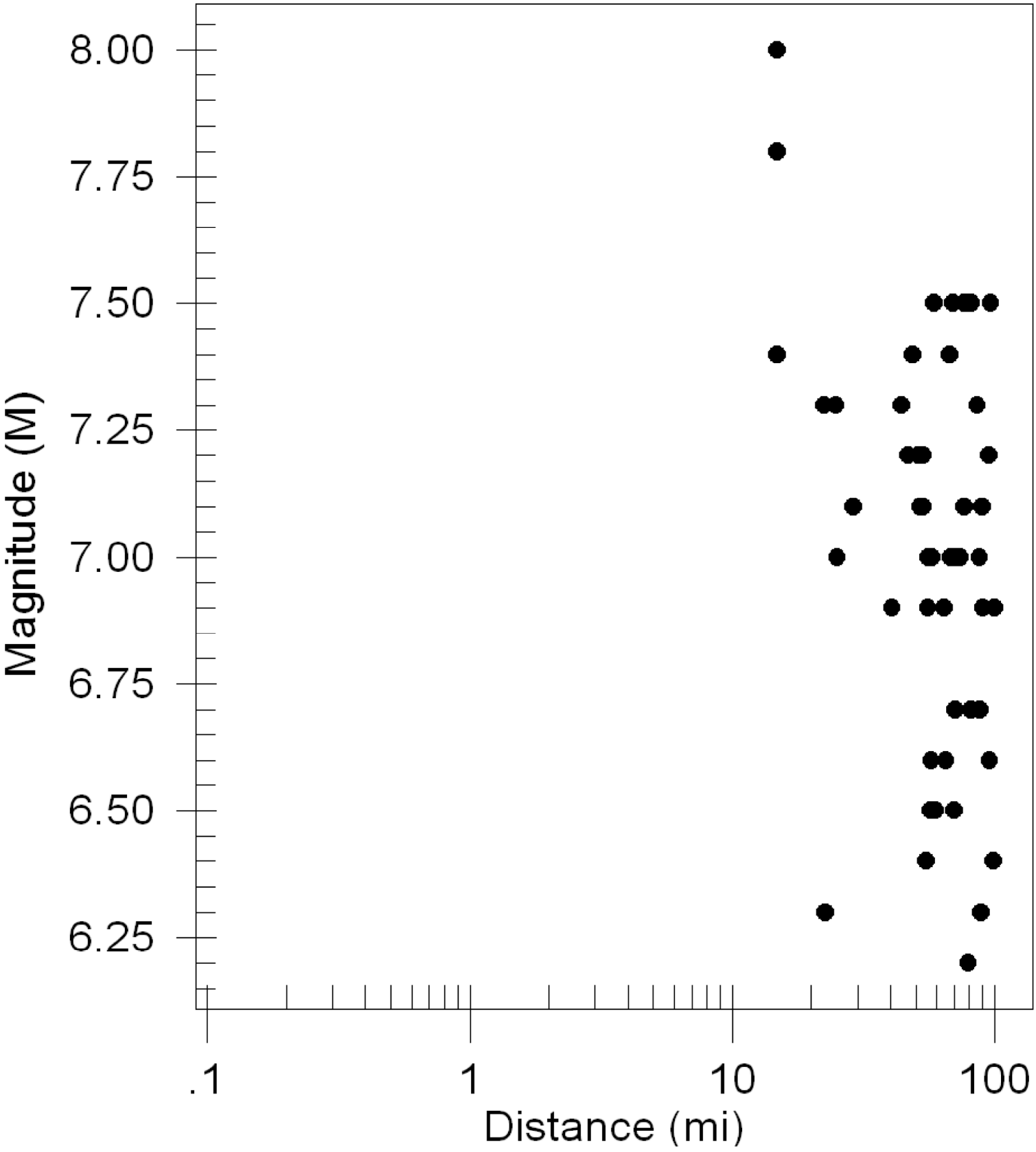
CALIFORNIA FAULT MAP

18566 Sec 35



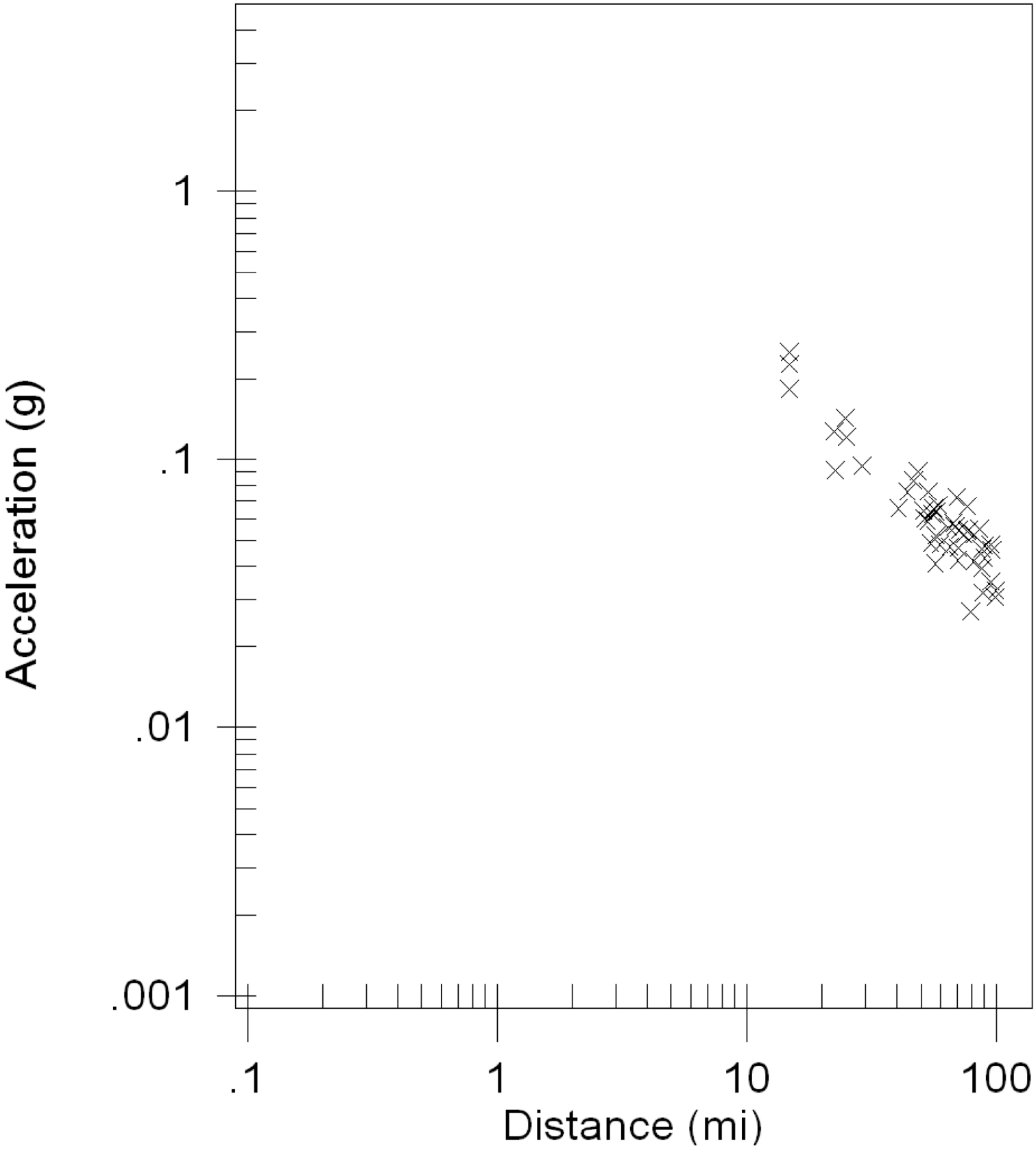
EARTHQUAKE MAGNITUDES & DISTANCES

18566 Sec 35



MAXIMUM EARTHQUAKES

18566 Sec 35



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      ESTIMATION OF
   PEAK ACCELERATION FROM
CALIFORNIA EARTHQUAKE CATALOGS


JOB NUMBER: 18566
                                                DATE: 11-28-2022

JOB NAME: 18566 - 35

EARTHQUAKE-CATALOG-FILE NAME: ALLQUAKE.DAT

SITE COORDINATES:
   SITE LATITUDE:  35.2757
   SITE LONGITUDE:  119.4713

SEARCH DATES:
           START DATE:   1800
           END DATE:   2010

SEARCH RADIUS:
           100.0 mi
           160.9 km

ATTENUATION RELATION:   2) Boore et al. (1997) Horiz. - NEHRP C (520)
   UNCERTAINTY (M=Median, S=Sigma): M       Number of Sigmas:  0.0
   ASSUMED SOURCE TYPE:  DS [SS=Strike-slip, DS=Reverse-slip, BT=Blind-
thrust]
   SCOND:   1  Depth Source:  A
   Basement Depth:  5.00 km     Campbell SSR:        Campbell SHR:
   COMPUTE PEAK HORIZONTAL ACCELERATION

MINIMUM DEPTH VALUE (km):  0.0
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EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	35.3000	119.8000	01/09/1857	16 0 0.0	0.0	7.90	0.245	IX	18.6(29.9)
GSP	35.1490	119.1040	05/28/1993	044740.6	21.0	5.20	0.051	VI	22.5(36.2)
DMG	35.0000	119.0330	07/21/1952	12 2 0.0	0.0	5.60	0.049	VI	31.2(50.2)
DMG	35.3330	118.9170	08/22/1952	224124.0	0.0	5.80	0.054	VI	31.5(50.7)
DMG	35.0000	119.0170	07/21/1952	115214.0	0.0	7.70	0.146	VIII	31.9(51.4)
DMG	35.0000	119.0170	01/12/1954	233349.0	0.0	5.90	0.057	VI	31.9(51.4)
DMG	35.0000	119.0000	07/21/1952	12 531.0	0.0	6.40	0.072	VII	32.7(52.6)
DMG	35.0000	119.0000	02/16/1919	1557 0.0	0.0	5.00	0.035	V	32.7(52.6)
DMG	34.9830	118.9830	05/23/1954	235243.0	0.0	5.10	0.035	V	34.2(55.0)
DMG	35.3830	118.8500	07/29/1952	7 347.0	0.0	6.10	0.058	VI	35.8(57.6)
DMG	34.9410	118.9870	11/15/1961	53855.5	10.7	5.00	0.032	V	35.8(57.6)
DMG	34.9320	118.9760	03/01/1963	02557.9	13.9	5.00	0.032	V	36.7(59.0)
DMG	35.2170	118.8170	07/23/1952	1317 5.0	0.0	5.70	0.045	VI	37.1(59.7)
DMG	35.4000	118.8170	07/29/1952	8 146.0	0.0	5.10	0.033	V	37.8(60.9)
DMG	35.3000	118.8000	12/23/1905	2223 0.0	0.0	5.00	0.031	V	37.9(60.9)
DMG	34.8000	119.1000	09/05/1883	1230 0.0	0.0	6.00	0.051	VI	39.0(62.7)
DMG	34.9000	118.9500	08/01/1952	13 430.0	0.0	5.10	0.032	V	39.2(63.2)
T-A	34.9200	118.9200	01/20/1857	0 0 0.0	0.0	5.00	0.030	V	39.7(63.8)
T-A	34.9200	118.9200	05/23/1857	0 0 0.0	0.0	5.00	0.030	V	39.7(63.8)
DMG	35.0000	118.8330	07/23/1952	75319.0	0.0	5.40	0.036	V	40.8(65.6)
DMG	35.0000	118.8330	07/23/1952	181351.0	0.0	5.20	0.032	V	40.8(65.6)
DMG	34.9500	118.8670	07/21/1952	121936.0	0.0	5.30	0.034	V	40.9(65.8)
DMG	35.1330	118.7670	07/21/1952	194122.0	0.0	5.50	0.038	V	40.9(65.9)
DMG	34.9000	118.9000	10/23/1916	244 0.0	0.0	6.00	0.049	VI	41.4(66.6)
DMG	34.8670	118.9330	09/21/1941	1953 7.2	0.0	5.20	0.032	V	41.5(66.8)
DMG	35.6000	118.8000	06/30/1926	1331 0.0	0.0	5.00	0.028	V	43.9(70.6)
DMG	35.5000	118.7000	01/06/1905	1430 0.0	0.0	5.00	0.027	V	46.1(74.2)
DMG	35.1830	118.6500	07/21/1952	151358.0	0.0	5.10	0.028	V	46.8(75.2)
PAS	34.9430	118.7430	06/10/1988	23 643.0	6.8	5.40	0.032	V	47.1(75.8)
DMG	34.7000	119.0000	10/23/1916	254 0.0	0.0	5.50	0.034	V	47.9(77.0)
DMG	35.1500	118.6330	01/27/1954	141948.0	0.0	5.00	0.026	V	48.1(77.4)
DMG	35.3330	118.6000	07/31/1952	12 9 9.0	0.0	5.80	0.038	V	49.3(79.3)
DMG	35.3670	118.5830	07/23/1952	03832.0	0.0	6.10	0.044	VI	50.4(81.2)
DMG	35.3670	118.5830	07/23/1952	31923.0	0.0	5.00	0.025	V	50.4(81.2)
T-A	34.8300	118.7500	11/27/1852	0 0 0.0	0.0	7.00	0.070	VI	51.1(82.2)
DMG	35.2330	118.5330	07/21/1952	174244.0	0.0	5.10	0.025	V	53.0(85.3)
DMG	34.5000	119.5000	06/29/1926	2321 0.0	0.0	5.50	0.031	V	53.6(86.2)
DMG	34.5000	119.5000	08/05/1930	1125 0.0	0.0	5.00	0.024	IV	53.6(86.2)
DMG	35.3150	118.5160	07/25/1952	194323.7	11.2	5.70	0.034	V	53.9(86.7)
DMG	35.7500	120.2500	03/10/1922	112120.0	0.0	6.50	0.051	VI	54.7(88.0)
T-A	34.5000	119.6700	06/01/1893	12 0 0.0	0.0	5.00	0.023	IV	54.7(88.1)
DMG	35.3110	118.4990	07/25/1952	1313 8.2	2.8	5.00	0.023	IV	54.8(88.3)
DMG	35.3170	118.4940	07/25/1952	19 944.6	5.5	5.70	0.033	V	55.1(88.7)
MGI	35.2500	120.5000	07/10/1917	043 0.0	0.0	5.30	0.026	V	58.0(93.4)
MGI	35.2500	120.5000	07/09/1917	2222 0.0	0.0	5.00	0.022	IV	58.0(93.4)
MGI	35.2500	120.5000	07/09/1917	2238 0.0	0.0	5.30	0.026	V	58.0(93.4)
MGI	35.2500	120.5000	07/10/1917	045 0.0	0.0	5.30	0.026	V	58.0(93.4)
DMG	35.7500	120.3300	08/18/1922	512 0.0	0.0	5.00	0.022	IV	58.3(93.8)
MGI	34.9000	120.4000	03/29/1928	625 0.0	0.0	5.30	0.026	V	58.5(94.2)
DMG	35.8000	120.3300	06/08/1934	447 0.0	0.0	6.00	0.036	V	60.3(97.1)
DMG	35.8000	120.3300	12/28/1939	121538.0	0.0	5.00	0.022	IV	60.3(97.1)
DMG	35.8000	120.3300	06/08/1934	430 0.0	0.0	5.00	0.022	IV	60.3(97.1)
DMG	35.8000	120.3300	06/05/1934	2148 0.0	0.0	5.00	0.022	IV	60.3(97.1)

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
MGI	35.0000	120.5000	11/19/1927	332 0.0	0.0	5.00	0.021	IV	61.1(98.4)
DMG	34.7000	120.3000	07/31/1902	920 0.0	0.0	5.50	0.028	V	61.5(98.9)
DMG	34.7000	120.3000	01/12/1915	431 0.0	0.0	5.50	0.028	V	61.5(98.9)
MGI	34.4000	119.7000	03/25/1806	8 0 0.0	0.0	5.00	0.021	IV	61.8(99.5)
MGI	34.8000	120.4000	12/12/1902	0 0 0.0	0.0	5.70	0.030	V	61.9(99.7)
T-A	34.4200	119.8200	00/00/1862	0 0 0.0	0.0	5.70	0.030	V	62.3(100.2)
T-A	36.1700	119.3200	07/25/1868	230 0.0	0.0	5.00	0.021	IV	62.3(100.3)
DMG	34.3670	119.5830	07/01/1941	75054.8	0.0	5.90	0.033	V	63.1(101.5)
PAS	34.3470	119.6960	08/13/1978	225453.4	12.8	5.10	0.021	IV	65.4(105.2)
MGI	35.5000	120.6000	01/01/1830	0 0 0.0	0.0	5.00	0.020	IV	65.4(105.2)
DMG	36.0800	118.8200	05/29/1915	646 0.0	0.0	5.00	0.020	IV	66.5(107.0)
T-A	35.2500	120.6700	00/00/1830	0 0 0.0	0.0	5.70	0.028	V	67.6(108.8)
T-A	35.2500	120.6700	12/17/1852	0 0 0.0	0.0	5.70	0.028	V	67.6(108.8)
PAS	36.1510	120.0490	08/04/1985	12 156.0	6.0	5.80	0.030	V	68.6(110.3)
MGI	35.3000	120.7000	12/07/1906	640 0.0	0.0	5.90	0.031	V	69.3(111.5)
MGI	34.3000	119.8000	07/03/1925	1638 0.0	0.0	5.30	0.022	IV	69.9(112.5)
DMG	34.3000	119.8000	06/29/1925	144216.0	0.0	6.25	0.037	V	69.9(112.5)
MGI	34.3000	119.8000	07/03/1925	1821 0.0	0.0	5.30	0.022	IV	69.9(112.5)
MGI	34.6000	120.4000	07/28/1902	657 0.0	0.0	6.30	0.038	V	70.3(113.1)
MGI	34.6000	120.4000	08/01/1902	330 0.0	0.0	6.30	0.038	V	70.3(113.1)
GSB	35.9170	120.4650	12/20/1994	102747.2	8.0	5.00	0.019	IV	71.2(114.6)
DMG	35.9300	120.4800	12/24/1934	1626 0.0	0.0	5.00	0.019	IV	72.4(116.6)
MGI	35.1700	120.7500	12/01/1916	2253 0.0	0.0	5.70	0.027	V	72.5(116.7)
DMG	35.9500	120.4700	11/16/1956	323 9.0	0.0	5.00	0.019	IV	72.9(117.3)
DMG	34.9000	120.7000	11/04/1927	135053.0	0.0	7.50	0.069	VI	74.1(119.3)
DMG	35.9500	120.5000	06/28/1966	42613.4	0.0	5.50	0.024	IV	74.2(119.4)
DMG	35.9700	120.5000	06/28/1966	4 856.2	0.0	5.10	0.019	IV	75.0(120.8)
GSB	34.3790	118.7110	01/19/1994	210928.6	14.0	5.50	0.024	IV	75.4(121.4)
DMG	35.9500	120.5300	06/29/1966	195325.9	0.0	5.00	0.018	IV	75.5(121.5)
GSP	34.3770	118.6980	01/18/1994	004308.9	11.0	5.20	0.020	IV	76.0(122.2)
GSP	34.3940	118.6690	06/26/1995	084028.9	13.0	5.00	0.018	IV	76.0(122.3)
DMG	36.0000	120.5000	03/03/1901	745 0.0	0.0	5.50	0.023	IV	76.4(122.9)
DMG	36.0000	120.5000	02/02/1881	011 0.0	0.0	5.60	0.025	V	76.4(122.9)
DMG	34.2000	119.8000	12/21/1812	19 0 0.0	0.0	7.00	0.051	VI	76.6(123.2)
PAS	36.1820	120.2680	02/14/1987	72650.8	6.0	5.10	0.019	IV	76.9(123.7)
GSP	34.3690	118.6720	04/26/1997	103730.7	16.0	5.10	0.019	IV	77.3(124.4)
DMG	36.1700	120.3200	12/27/1926	919 0.0	0.0	5.00	0.018	IV	77.9(125.4)
GSP	34.3780	118.6180	01/19/1994	211144.9	11.0	5.10	0.018	IV	78.6(126.5)
BRK	36.2200	120.2600	09/09/1983	91614.0	0.0	5.40	0.022	IV	78.8(126.8)
GSP	34.3260	118.6980	01/17/1994	233330.7	9.0	5.60	0.024	V	78.9(126.9)
GSP	35.2100	118.0660	07/11/1992	181416.2	10.0	5.70	0.025	V	79.4(127.7)
BRK	36.2200	120.2900	05/02/1983	234239.0	0.0	6.70	0.042	VI	79.7(128.3)
BRK	36.2200	120.2900	05/02/1983	2346 6.0	0.0	5.60	0.024	IV	79.7(128.3)
BRK	36.2400	120.2900	05/09/1983	24912.0	0.0	5.20	0.019	IV	80.8(130.1)
DMG	34.1180	119.7020	07/05/1968	04517.2	5.9	5.20	0.019	IV	81.0(130.3)
DMG	34.1000	119.4000	05/19/1893	035 0.0	0.0	5.50	0.022	IV	81.3(130.8)
BRK	36.2100	120.3800	07/25/1983	223140.0	0.0	5.10	0.018	IV	82.2(132.3)
BRK	36.2000	120.4000	07/22/1983	343 2.0	0.0	5.00	0.017	IV	82.3(132.5)
BRK	36.2200	120.4000	07/22/1983	23955.0	0.0	6.00	0.028	V	83.4(134.2)
DMG	34.3000	118.6000	04/04/1893	1940 0.0	0.0	6.00	0.028	V	83.5(134.4)
GSP	34.3050	118.5790	01/29/1994	112036.0	1.0	5.10	0.018	IV	84.0(135.1)
DMG	35.7150	118.0740	03/15/1946	14 035.4	0.0	5.30	0.019	IV	84.2(135.5)
GSB	34.3010	118.5650	01/17/1994	204602.4	9.0	5.20	0.018	IV	84.7(136.3

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	34.4110	118.4010	02/09/1971	14 244.0	8.0	5.80	0.025	V	85.1(136.9)
DMG	34.4110	118.4010	02/09/1971	14 1 8.0	8.0	5.80	0.025	V	85.1(136.9)
DMG	34.4110	118.4010	02/09/1971	14 041.8	8.4	6.40	0.034	V	85.1(136.9)
DMG	34.4110	118.4010	02/09/1971	141028.0	8.0	5.30	0.019	IV	85.1(136.9)
DMG	35.7250	118.0550	03/15/1946	134935.9	22.0	6.30	0.033	V	85.4(137.5)
BRK	36.2600	120.4000	07/09/1983	74052.0	0.0	5.30	0.019	IV	85.6(137.7)
DMG	35.7450	118.0390	03/16/1946	94617.9	0.0	5.10	0.017	IV	86.8(139.6)
DMG	35.7780	118.0490	01/28/1961	81246.2	5.5	5.30	0.019	IV	87.1(140.2)
DMG	34.0650	119.0350	02/21/1973	144557.3	8.0	5.90	0.026	V	87.2(140.3)
DMG	35.7510	118.0290	03/15/1946	215433.4	0.0	5.20	0.018	IV	87.4(140.7)
PAS	36.2860	120.4130	10/25/1982	2226 4.0	6.0	5.60	0.022	IV	87.5(140.7)
BRK	36.2500	120.4700	06/11/1983	3 954.0	0.0	5.10	0.017	IV	87.5(140.8)
DMG	34.0000	119.5000	02/18/1926	1818 0.0	0.0	5.00	0.016	IV	88.1(141.8)
DMG	34.3080	118.4540	02/09/1971	144346.7	6.2	5.20	0.018	IV	88.3(142.0)
DMG	34.5190	118.1980	08/23/1952	10 9 7.1	13.1	5.00	0.016	IV	89.0(143.3)
DMG	33.9860	119.4750	08/06/1973	232917.0	16.9	5.00	0.016	IV	89.0(143.3)
DMG	35.7140	117.9770	03/15/1946	191853.6	0.0	5.40	0.020	IV	89.3(143.7)
DMG	35.7530	117.9860	03/15/1946	1321 0.9	0.0	5.20	0.018	IV	89.7(144.4)
GSP	34.2130	118.5370	01/17/1994	123055.4	18.0	6.70	0.038	V	90.5(145.7)
GSP	34.2310	118.4750	03/20/1994	212012.3	13.0	5.30	0.018	IV	91.6(147.5)
DMG	34.0000	119.0000	09/24/1827	4 0 0.0	0.0	7.00	0.044	VI	92.1(148.1)
MGI	34.0000	119.0000	12/14/1912	0 0 0.0	0.0	5.70	0.022	IV	92.1(148.1)
DMG	36.2300	120.6500	02/05/1947	614 0.0	0.0	5.00	0.015	IV	93.3(150.1)
DMG	34.0000	120.0170	04/01/1945	234342.0	0.0	5.40	0.019	IV	93.4(150.3)
DMG	35.7470	117.9080	03/18/1946	155042.6	4.4	5.30	0.018	IV	93.7(150.8)
MGI	35.6000	121.1000	02/01/1853	21 0 0.0	0.0	5.00	0.015	IV	94.3(151.8)
DMG	36.0000	120.9200	11/02/1955	1940 6.0	0.0	5.20	0.017	IV	95.4(153.6)
DMG	36.0000	121.0000	02/26/1932	1658 0.0	0.0	5.00	0.015	IV	99.3(159.8)

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-END OF SEARCH- 134 EARTHQUAKES FOUND WITHIN THE SPECIFIED SEARCH AREA.

TIME PERIOD OF SEARCH: 1800 TO 2010

LENGTH OF SEARCH TIME: 211 years

THE EARTHQUAKE CLOSEST TO THE SITE IS ABOUT 18.6 MILES (29.9 km) AWAY.

LARGEST EARTHQUAKE MAGNITUDE FOUND IN THE SEARCH RADIUS: 7.9

LARGEST EARTHQUAKE SITE ACCELERATION FROM THIS SEARCH: 0.245 g

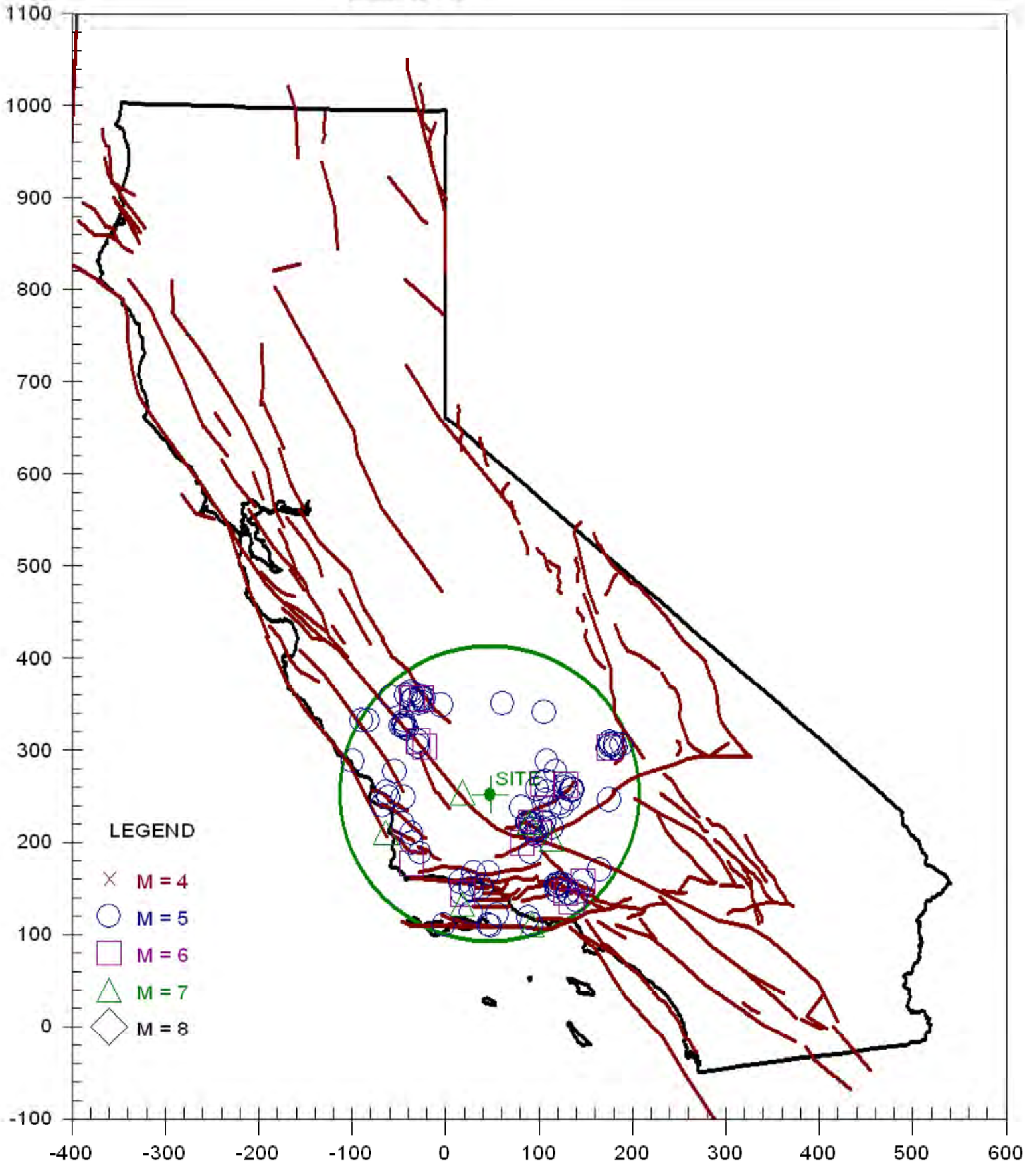
COEFFICIENTS FOR GUTENBERG & RICHTER RECURRENCE RELATION:
a-value= 1.525
b-value= 0.391
beta-value= 0.901

TABLE OF MAGNITUDES AND EXCEEDANCES:

Earthquake Magnitude	Number of Times Exceeded	Cumulative No. / Year
4.0	134	0.63810
4.5	134	0.63810
5.0	134	0.63810
5.5	55	0.26190
6.0	22	0.10476
6.5	9	0.04286
7.0	6	0.02857
7.5	3	0.01429

EARTHQUAKE EPICENTER MAP

18566 Sec 35



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*    Version 3.00    *
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DETERMINISTIC ESTIMATION OF
PEAK ACCELERATION FROM DIGITIZED FAULTS

JOB NUMBER: 18566

DATE: 11-28-2022

JOB NAME: 18566 Sec 36

CALCULATION NAME: Test Run Analysis

FAULT-DATA-FILE NAME: CGSFLTE.DAT

SITE COORDINATES:
SITE LATITUDE: 35.2757
SITE LONGITUDE: 119.4600

SEARCH RADIUS: 100 mi

ATTENUATION RELATION: 2) Boore et al. (1997) Horiz. - NEHRP C (520)
UNCERTAINTY (M=Median, S=Sigma): M Number of Sigmas: 0.0
DISTANCE MEASURE: cd_2drp
SCOND: 1
Basement Depth: 5.00 km Campbell SSR: Campbell SHR:
COMPUTE PEAK HORIZONTAL ACCELERATION

FAULT-DATA FILE USED: CGSFLTE.DAT

MINIMUM DEPTH VALUE (km): 0.0

EQFAULT SUMMARY

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT: MAXIMUM EARTHQUAKE MAG.(Mw)	PEAK SITE ACCEL. g	EST. SITE INTENSITY MOD.MERC.
SAN ANDREAS - 1857 Rupture M-2a	15.3(24.6)	7.8	0.221	IX
SAN ANDREAS - Whole M-1a	15.3(24.6)	8.0	0.246	IX
SAN ANDREAS - Cho-Moj M-1b-1	15.3(24.6)	7.8	0.221	IX
SAN ANDREAS - Carrizo M-1c-2	15.3(24.6)	7.4	0.179	VIII
Kern Front	22.1(35.5)	6.3	0.093	VII
SAN ANDREAS - Cholame M-1c-1	23.1(37.1)	7.3	0.125	VII
WHITE WOLF	24.4(39.2)	7.3	0.146	VIII
PLEITO THRUST	24.9(40.0)	7.0	0.122	VII
SAN JUAN	29.6(47.6)	7.1	0.093	VII
BIG PINE	40.3(64.9)	6.9	0.066	VI
GARLOCK (West)	43.7(70.3)	7.3	0.076	VII
SAN LUIS RANGE (S. Margin)	47.3(76.2)	7.2	0.083	VII
NORTH CHANNEL SLOPE	48.8(78.6)	7.4	0.090	VII
SAN GABRIEL	50.9(81.9)	7.2	0.064	VI
SANTA YNEZ (West)	52.1(83.8)	7.1	0.060	VI
SANTA YNEZ (East)	53.0(85.3)	7.1	0.059	VI
M.RIDGE-ARROYO PARIDA-SANTA ANA	53.6(86.3)	7.2	0.075	VII
GREAT VALLEY 14	55.2(88.9)	6.4	0.048	VI
SAN CAYETANO	55.9(89.9)	7.0	0.066	VI
LOS ALAMOS-W. BASELINE	56.0(90.2)	6.9	0.062	VI
LOS OSOS	57.2(92.1)	7.0	0.064	VI
SAN ANDREAS - Parkfield	57.7(92.8)	6.5	0.040	V
RED MOUNTAIN	57.7(92.9)	7.0	0.064	VI
LIONS HEAD	57.9(93.2)	6.6	0.052	VI
RINCONADA	59.2(95.3)	7.5	0.067	VI
CASMALIA (Orcutt Frontal Fault)	60.1(96.8)	6.5	0.048	VI
VENTURA - PITAS POINT	64.2(103.3)	6.9	0.056	VI
OAK RIDGE MID-CHANNEL STRUCTURE	65.3(105.1)	6.6	0.047	VI
SAN ANDREAS - Mojave M-1c-3	66.9(107.6)	7.4	0.058	VI
OAK RIDGE (Onshore)	68.0(109.5)	7.0	0.056	VI
CHANNEL IS. THRUST (Eastern)	69.4(111.7)	7.5	0.072	VI
HOLSER	70.2(113.0)	6.5	0.042	VI
SANTA SUSANA	70.3(113.1)	6.7	0.047	VI
GREAT VALLEY 13	70.7(113.8)	6.5	0.042	VI
SIMI-SANTA ROSA	70.8(113.9)	7.0	0.055	VI
NORTHRIDGE (E. Oak Ridge)	73.8(118.7)	7.0	0.053	VI
ANACAPA-DUME	76.6(123.2)	7.5	0.067	VI
OAK RIDGE(Blind Thrust Offshore)	76.6(123.2)	7.1	0.054	VI
HOSGRI	78.0(125.6)	7.5	0.054	VI
SAN ANDREAS (Creeping)	79.8(128.5)	6.2	0.027	V

DETERMINISTIC SITE PARAMETERS

ABBREVIATED FAULT NAME	APPROXIMATE DISTANCE mi (km)	ESTIMATED MAX. EARTHQUAKE EVENT: MAXIMUM EARTHQUAKE MAG.(Mw)	ESTIMATED MAX. EARTHQUAKE EVENT: PEAK SITE ACCEL. g	ESTIMATED MAX. EARTHQUAKE EVENT: EST. SITE INTENSITY MOD.MERC.
SIERRA MADRE (San Fernando)	80.9(130.2)	6.7	0.042	VI
GARLOCK (East)	81.0(130.4)	7.5	0.053	VI
So. SIERRA NEVADA	85.1(137.0)	7.3	0.055	VI
MALIBU COAST	87.7(141.1)	6.7	0.039	V
SANTA CRUZ ISLAND	87.7(141.2)	7.0	0.046	VI
GREAT VALLEY 12	89.0(143.2)	6.3	0.032	V
VERDUGO	89.7(144.3)	6.9	0.043	VI
SANTA ROSA ISLAND	90.1(145.0)	7.1	0.048	VI
SIERRA MADRE	94.7(152.4)	7.2	0.048	VI
SANTA MONICA	95.2(153.2)	6.6	0.035	V
LENWOOD-LOCKHART-OLD WOMAN SPRGS	95.9(154.3)	7.5	0.046	VI
HOLLYWOOD	98.6(158.7)	6.4	0.031	V
LITTLE LAKE	99.3(159.8)	6.9	0.033	V
GREAT VALLEY 11	99.5 (160.2)	6.4	0.031	V

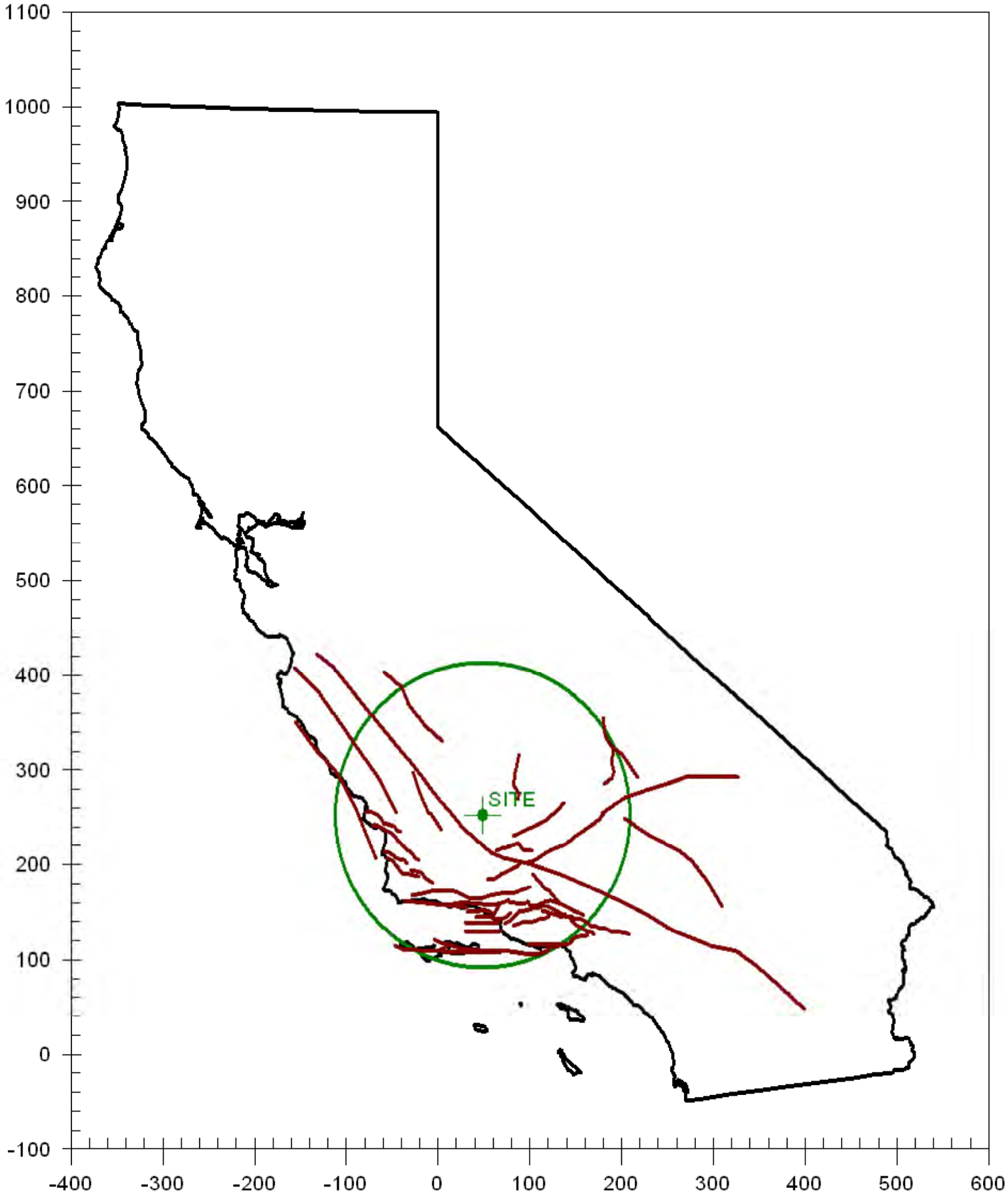
-END OF SEARCH- 54 FAULTS FOUND WITHIN THE SPECIFIED SEARCH RADIUS.

THE SAN ANDREAS - Whole M-1a FAULT IS CLOSEST TO THE SITE.
IT IS ABOUT 15.3 MILES (24.6 km) AWAY.

LARGEST MAXIMUM-EARTHQUAKE SITE ACCELERATION: 0.2457 g

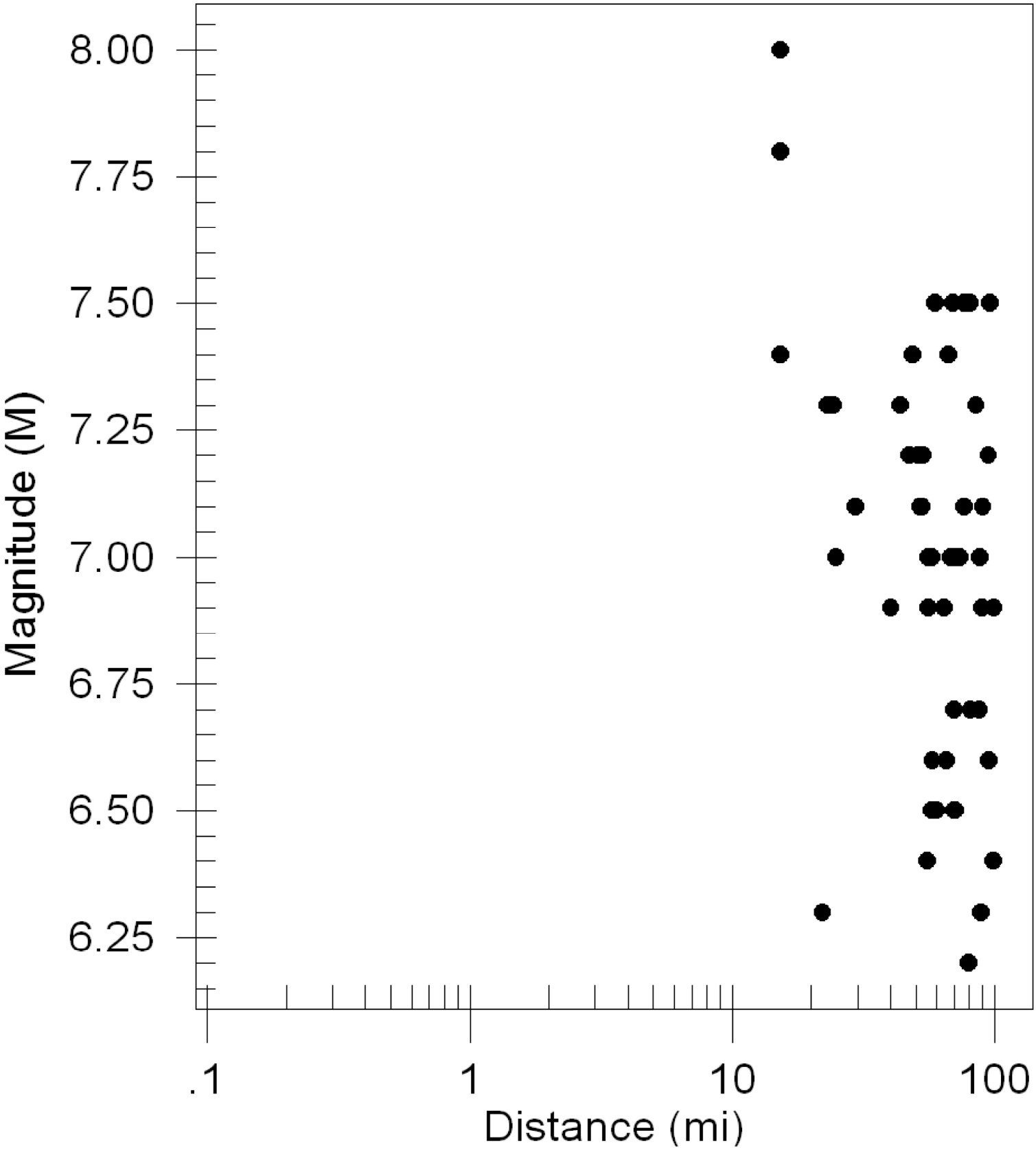
CALIFORNIA FAULT MAP

18566 Sec 36



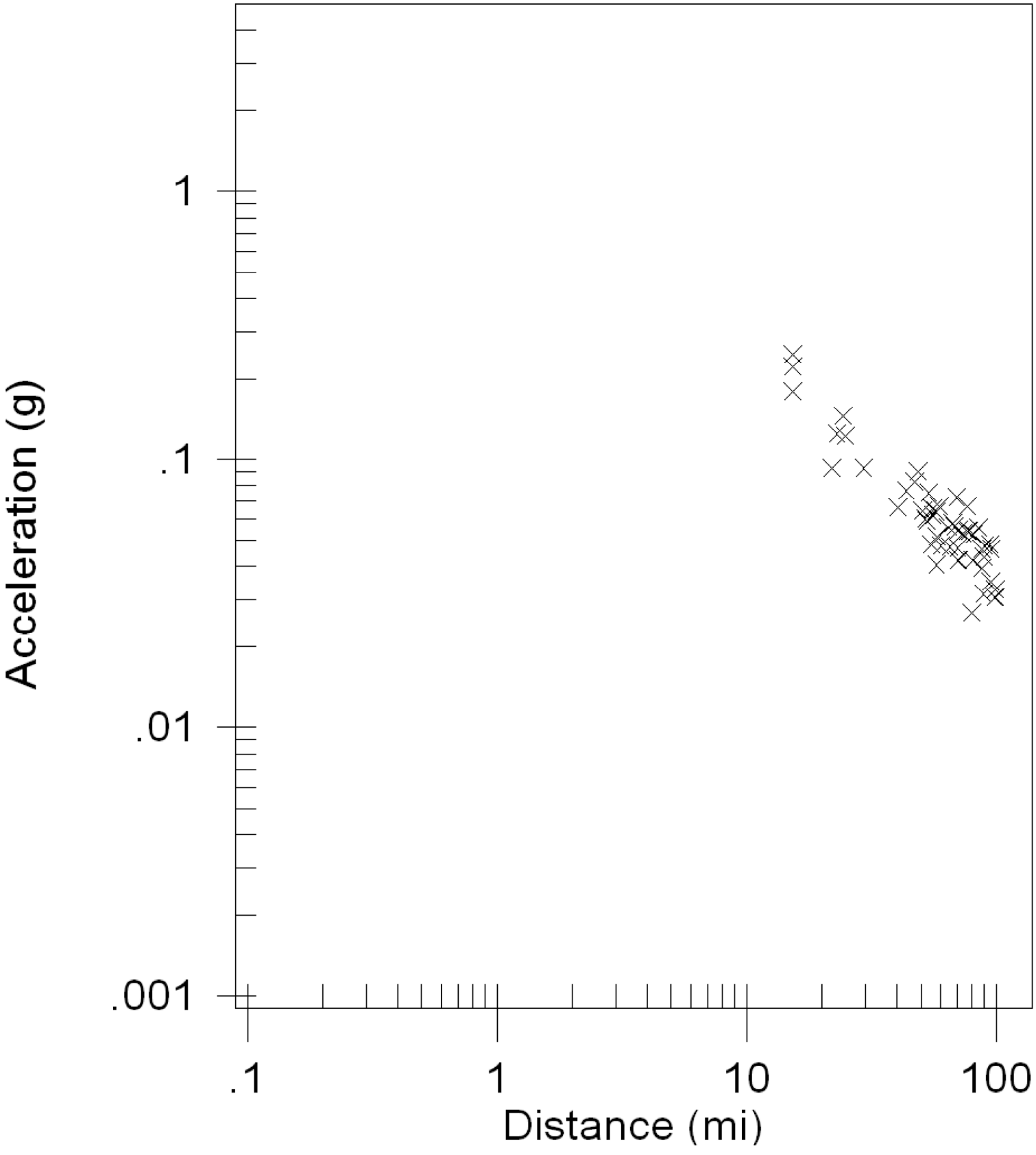
EARTHQUAKE MAGNITUDES & DISTANCES

18566 Sec 36



MAXIMUM EARTHQUAKES

18566 Sec 36



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*     Version 3.00      *
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      ESTIMATION OF
   PEAK ACCELERATION FROM
CALIFORNIA EARTHQUAKE CATALOGS


JOB NUMBER: 18566
                                                DATE: 11-28-2022

JOB NAME: 18566 Sec 36

EARTHQUAKE-CATALOG-FILE NAME: C:\Program Files\EQSEARCH\ALLQUAKE.DAT

SITE COORDINATES:
   SITE LATITUDE:  35.2757
   SITE LONGITUDE:  119.4600

SEARCH DATES:
           START DATE:   1800
           END DATE:   2010

SEARCH RADIUS:
           100.0 mi
           160.9 km

ATTENUATION RELATION:   2) Boore et al. (1997) Horiz. - NEHRP C (520)
   UNCERTAINTY (M=Median, S=Sigma): M       Number of Sigmas:  0.0
   ASSUMED SOURCE TYPE:  DS [SS=Strike-slip, DS=Reverse-slip, BT=Blind-
thrust]
   SCOND:   1  Depth Source:  A
   Basement Depth:  5.00 km     Campbell SSR:        Campbell SHR:
   COMPUTE PEAK HORIZONTAL ACCELERATION

MINIMUM DEPTH VALUE (km):  0.0
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EARTHQUAKE SEARCH RESULTS

Page 1

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	35.3000	119.8000	01/09/1857	16 0 0.0	0.0	7.90	0.239	IX	19.2(30.9)
GSP	35.1490	119.1040	05/28/1993	044740.6	21.0	5.20	0.052	VI	21.9(35.2)
DMG	35.0000	119.0330	07/21/1952	12 2 0.0	0.0	5.60	0.050	VI	30.7(49.4)
DMG	35.3330	118.9170	08/22/1952	224124.0	0.0	5.80	0.055	VI	30.8(49.6)
DMG	35.0000	119.0170	07/21/1952	115214.0	0.0	7.70	0.148	VIII	31.4(50.6)
DMG	35.0000	119.0170	01/12/1954	233349.0	0.0	5.90	0.057	VI	31.4(50.6)
DMG	35.0000	119.0000	07/21/1952	12 531.0	0.0	6.40	0.073	VII	32.2(51.8)
DMG	35.0000	119.0000	02/16/1919	1557 0.0	0.0	5.00	0.035	V	32.2(51.8)
DMG	34.9830	118.9830	05/23/1954	235243.0	0.0	5.10	0.036	V	33.7(54.2)
DMG	35.3830	118.8500	07/29/1952	7 347.0	0.0	6.10	0.058	VI	35.1(56.6)
DMG	34.9410	118.9870	11/15/1961	53855.5	10.7	5.00	0.033	V	35.3(56.8)
DMG	34.9320	118.9760	03/01/1963	02557.9	13.9	5.00	0.032	V	36.2(58.3)
DMG	35.2170	118.8170	07/23/1952	1317 5.0	0.0	5.70	0.046	VI	36.5(58.7)
DMG	35.4000	118.8170	07/29/1952	8 146.0	0.0	5.10	0.033	V	37.2(59.9)
DMG	35.3000	118.8000	12/23/1905	2223 0.0	0.0	5.00	0.031	V	37.2(59.9)
DMG	34.8000	119.1000	09/05/1883	1230 0.0	0.0	6.00	0.051	VI	38.6(62.2)
DMG	34.9000	118.9500	08/01/1952	13 430.0	0.0	5.10	0.032	V	38.8(62.4)
T-A	34.9200	118.9200	01/20/1857	0 0 0.0	0.0	5.00	0.030	V	39.2(63.0)
T-A	34.9200	118.9200	05/23/1857	0 0 0.0	0.0	5.00	0.030	V	39.2(63.0)
DMG	35.0000	118.8330	07/23/1952	75319.0	0.0	5.40	0.036	V	40.2(64.7)
DMG	35.0000	118.8330	07/23/1952	181351.0	0.0	5.20	0.033	V	40.2(64.7)
DMG	35.1330	118.7670	07/21/1952	194122.0	0.0	5.50	0.038	V	40.3(64.9)
DMG	34.9500	118.8670	07/21/1952	121936.0	0.0	5.30	0.034	V	40.3(64.9)
DMG	34.9000	118.9000	10/23/1916	244 0.0	0.0	6.00	0.049	VI	40.9(65.8)
DMG	34.8670	118.9330	09/21/1941	1953 7.2	0.0	5.20	0.032	V	41.0(66.0)
DMG	35.6000	118.8000	06/30/1926	1331 0.0	0.0	5.00	0.028	V	43.4(69.8)
DMG	35.5000	118.7000	01/06/1905	1430 0.0	0.0	5.00	0.027	V	45.5(73.2)
DMG	35.1830	118.6500	07/21/1952	151358.0	0.0	5.10	0.028	V	46.1(74.2)
PAS	34.9430	118.7430	06/10/1988	23 643.0	6.8	5.40	0.032	V	46.6(74.9)
DMG	35.1500	118.6330	01/27/1954	141948.0	0.0	5.00	0.026	V	47.4(76.4)
DMG	34.7000	119.0000	10/23/1916	254 0.0	0.0	5.50	0.034	V	47.5(76.4)
DMG	35.3330	118.6000	07/31/1952	12 9 9.0	0.0	5.80	0.039	V	48.6(78.2)
DMG	35.3670	118.5830	07/23/1952	03832.0	0.0	6.10	0.045	VI	49.8(80.1)
DMG	35.3670	118.5830	07/23/1952	31923.0	0.0	5.00	0.025	V	49.8(80.1)
T-A	34.8300	118.7500	11/27/1852	0 0 0.0	0.0	7.00	0.071	VI	50.6(81.4)
DMG	35.2330	118.5330	07/21/1952	174244.0	0.0	5.10	0.025	V	52.3(84.2)
DMG	35.3150	118.5160	07/25/1952	194323.7	11.2	5.70	0.034	V	53.3(85.7)
DMG	34.5000	119.5000	08/05/1930	1125 0.0	0.0	5.00	0.024	IV	53.6(86.3)
DMG	34.5000	119.5000	06/29/1926	2321 0.0	0.0	5.50	0.031	V	53.6(86.3)
DMG	35.3110	118.4990	07/25/1952	1313 8.2	2.8	5.00	0.023	IV	54.2(87.2)
DMG	35.3170	118.4940	07/25/1952	19 944.6	5.5	5.70	0.034	V	54.5(87.7)
T-A	34.5000	119.6700	06/01/1893	12 0 0.0	0.0	5.00	0.023	IV	54.9(88.3)
DMG	35.7500	120.2500	03/10/1922	112120.0	0.0	6.50	0.051	VI	55.2(88.8)
MGI	35.2500	120.5000	07/10/1917	043 0.0	0.0	5.30	0.026	V	58.7(94.4)
MGI	35.2500	120.5000	07/09/1917	2222 0.0	0.0	5.00	0.022	IV	58.7(94.4)
MGI	35.2500	120.5000	07/09/1917	2238 0.0	0.0	5.30	0.026	V	58.7(94.4)
MGI	35.2500	120.5000	07/10/1917	045 0.0	0.0	5.30	0.026	V	58.7(94.4)
DMG	35.7500	120.3300	08/18/1922	512 0.0	0.0	5.00	0.022	IV	58.8(94.7)
MGI	34.9000	120.4000	03/29/1928	625 0.0	0.0	5.30	0.026	V	59.1(95.1)
DMG	35.8000	120.3300	06/08/1934	447 0.0	0.0	6.00	0.036	V	60.8(97.9)
DMG	35.8000	120.3300	12/28/1939	121538.0	0.0	5.00	0.021	IV	60.8(97.9)
DMG	35.8000	120.3300	06/08/1934	430 0.0	0.0	5.00	0.021	IV	60.8(97.9)
DMG	35.8000	120.3300	06/05/1934	2148 0.0	0.0	5.00	0.021	IV	60.8(97.

EARTHQUAKE SEARCH RESULTS

FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
MGI	35.0000	120.5000	11/19/1927	332 0.0	0.0	5.00	0.021	IV	61.7(99.3)
DMG	34.7000	120.3000	07/31/1902	920 0.0	0.0	5.50	0.027	V	61.9(99.7)
DMG	34.7000	120.3000	01/12/1915	431 0.0	0.0	5.50	0.027	V	61.9(99.7)
MGI	34.4000	119.7000	03/25/1806	8 0 0.0	0.0	5.00	0.021	IV	62.0(99.7)
T-A	36.1700	119.3200	07/25/1868	230 0.0	0.0	5.00	0.021	IV	62.2(100.2)
MGI	34.8000	120.4000	12/12/1902	0 0 0.0	0.0	5.70	0.030	V	62.5(100.5)
T-A	34.4200	119.8200	00/00/1862	0 0 0.0	0.0	5.70	0.030	V	62.5(100.6)
DMG	34.3670	119.5830	07/01/1941	75054.8	0.0	5.90	0.033	V	63.1(101.6)
PAS	34.3470	119.6960	08/13/1978	225453.4	12.8	5.10	0.021	IV	65.5(105.4)
MGI	35.5000	120.6000	01/01/1830	0 0 0.0	0.0	5.00	0.020	IV	66.0(106.2)
DMG	36.0800	118.8200	05/29/1915	646 0.0	0.0	5.00	0.020	IV	66.1(106.4)
T-A	35.2500	120.6700	00/00/1830	0 0 0.0	0.0	5.70	0.028	V	68.2(109.8)
T-A	35.2500	120.6700	12/17/1852	0 0 0.0	0.0	5.70	0.028	V	68.2(109.8)
PAS	36.1510	120.0490	08/04/1985	12 156.0	6.0	5.80	0.030	V	68.9(110.8)
MGI	35.3000	120.7000	12/07/1906	640 0.0	0.0	5.90	0.031	V	69.9(112.5)
MGI	34.3000	119.8000	07/03/1925	1638 0.0	0.0	5.30	0.022	IV	70.1(112.8)
DMG	34.3000	119.8000	06/29/1925	144216.0	0.0	6.25	0.037	V	70.1(112.8)
MGI	34.3000	119.8000	07/03/1925	1821 0.0	0.0	5.30	0.022	IV	70.1(112.8)
MGI	34.6000	120.4000	07/28/1902	657 0.0	0.0	6.30	0.038	V	70.8(113.9)
MGI	34.6000	120.4000	08/01/1902	330 0.0	0.0	6.30	0.038	V	70.8(113.9)
GSB	35.9170	120.4650	12/20/1994	102747.2	8.0	5.00	0.019	IV	71.7(115.4)
DMG	35.9300	120.4800	12/24/1934	1626 0.0	0.0	5.00	0.019	IV	72.9(117.4)
MGI	35.1700	120.7500	12/01/1916	2253 0.0	0.0	5.70	0.027	V	73.1(117.7)
DMG	35.9500	120.4700	11/16/1956	323 9.0	0.0	5.00	0.018	IV	73.4(118.0)
DMG	35.9500	120.5000	06/28/1966	42613.4	0.0	5.50	0.024	IV	74.7(120.2)
DMG	34.9000	120.7000	11/04/1927	135053.0	0.0	7.50	0.068	VI	74.7(120.2)
GSB	34.3790	118.7110	01/19/1994	210928.6	14.0	5.50	0.024	IV	75.1(120.8)
DMG	35.9700	120.5000	06/28/1966	4 856.2	0.0	5.10	0.019	IV	75.5(121.5)
GSP	34.3940	118.6690	06/26/1995	084028.9	13.0	5.00	0.018	IV	75.6(121.7)
GSP	34.3770	118.6980	01/18/1994	004308.9	11.0	5.20	0.020	IV	75.6(121.7)
DMG	35.9500	120.5300	06/29/1966	195325.9	0.0	5.00	0.018	IV	76.0(122.3)
DMG	34.2000	119.8000	12/21/1812	19 0 0.0	0.0	7.00	0.051	VI	76.7(123.5)
DMG	36.0000	120.5000	03/03/1901	745 0.0	0.0	5.50	0.023	IV	76.9(123.7)
DMG	36.0000	120.5000	02/02/1881	011 0.0	0.0	5.60	0.024	V	76.9(123.7)
GSP	34.3690	118.6720	04/26/1997	103730.7	16.0	5.10	0.019	IV	76.9(123.8)
PAS	36.1820	120.2680	02/14/1987	72650.8	6.0	5.10	0.019	IV	77.2(124.3)
GSP	34.3780	118.6180	01/19/1994	211144.9	11.0	5.10	0.019	IV	78.2(125.9)
DMG	36.1700	120.3200	12/27/1926	919 0.0	0.0	5.00	0.018	IV	78.3(126.1)
GSP	34.3260	118.6980	01/17/1994	233330.7	9.0	5.60	0.024	V	78.5(126.4)
GSP	35.2100	118.0660	07/11/1992	181416.2	10.0	5.70	0.025	V	78.7(126.7)
BRK	36.2200	120.2600	09/09/1983	91614.0	0.0	5.40	0.022	IV	79.1(127.3)
BRK	36.2200	120.2900	05/02/1983	234239.0	0.0	6.70	0.042	VI	80.1(128.9)
BRK	36.2200	120.2900	05/02/1983	2346 6.0	0.0	5.60	0.024	IV	80.1(128.9)
DMG	34.1180	119.7020	07/05/1968	04517.2	5.9	5.20	0.019	IV	81.1(130.5)
BRK	36.2400	120.2900	05/09/1983	24912.0	0.0	5.20	0.019	IV	81.2(130.7)
DMG	34.1000	119.4000	05/19/1893	035 0.0	0.0	5.50	0.022	IV	81.2(130.7)
BRK	36.2100	120.3800	07/25/1983	223140.0	0.0	5.10	0.018	IV	82.6(132.9)
BRK	36.2000	120.4000	07/22/1983	343 2.0	0.0	5.00	0.017	IV	82.7(133.2)
DMG	34.3000	118.6000	04/04/1893	1940 0.0	0.0	6.00	0.028	V	83.2(133.8)
GSP	34.3050	118.5790	01/29/1994	112036.0	1.0	5.10	0.018	IV	83.6(134.5)
DMG	35.7150	118.0740	03/15/1946	14 035.4	0.0	5.30	0.020	IV	83.6(134.5)
BRK	36.2200	120.4000	07/22/1983	23955.0	0.0	6.00	0.028	V	83.8(134.9)
GSB	34.3010	118.5650	01/17/1994	204602.4	9.0	5.20	0.018	IV	84.3(135.6)

EARTHQUAKE SEARCH RESULTS

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FILE CODE	LAT. NORTH	LONG. WEST	DATE	TIME (UTC) H M Sec	DEPTH (km)	QUAKE MAG.	SITE ACC. g	SITE MM INT.	APPROX. DISTANCE mi [km]
DMG	34.4110	118.4010	02/09/1971	14 244.0	8.0	5.80	0.025	V	84.6(136.2)
DMG	34.4110	118.4010	02/09/1971	14 1 8.0	8.0	5.80	0.025	V	84.6(136.2)
DMG	34.4110	118.4010	02/09/1971	14 041.8	8.4	6.40	0.035	V	84.6(136.2)
DMG	34.4110	118.4010	02/09/1971	141028.0	8.0	5.30	0.019	IV	84.6(136.2)
DMG	35.7250	118.0550	03/15/1946	134935.9	22.0	6.30	0.033	V	84.8(136.5)
BRK	36.2600	120.4000	07/09/1983	74052.0	0.0	5.30	0.019	IV	86.0(138.4)
DMG	35.7450	118.0390	03/16/1946	94617.9	0.0	5.10	0.017	IV	86.2(138.7)
DMG	35.7780	118.0490	01/28/1961	81246.2	5.5	5.30	0.019	IV	86.5(139.3)
DMG	35.7510	118.0290	03/15/1946	215433.4	0.0	5.20	0.018	IV	86.9(139.8)
DMG	34.0650	119.0350	02/21/1973	144557.3	8.0	5.90	0.026	V	87.0(140.0)
PAS	36.2860	120.4130	10/25/1982	2226 4.0	6.0	5.60	0.022	IV	87.8(141.3)
DMG	34.3080	118.4540	02/09/1971	144346.7	6.2	5.20	0.018	IV	87.8(141.4)
BRK	36.2500	120.4700	06/11/1983	3 954.0	0.0	5.10	0.017	IV	87.9(141.5)
DMG	34.0000	119.5000	02/18/1926	1818 0.0	0.0	5.00	0.016	IV	88.1(141.8)
DMG	34.5190	118.1980	08/23/1952	10 9 7.1	13.1	5.00	0.016	IV	88.5(142.5)
DMG	35.7140	117.9770	03/15/1946	191853.6	0.0	5.40	0.020	IV	88.7(142.7)
DMG	33.9860	119.4750	08/06/1973	232917.0	16.9	5.00	0.016	IV	89.0(143.3)
DMG	35.7530	117.9860	03/15/1946	1321 0.9	0.0	5.20	0.018	IV	89.1(143.5)
GSP	34.2130	118.5370	01/17/1994	123055.4	18.0	6.70	0.039	V	90.1(145.1)
GSP	34.2310	118.4750	03/20/1994	212012.3	13.0	5.30	0.018	IV	91.2(146.8)
DMG	34.0000	119.0000	09/24/1827	4 0 0.0	0.0	7.00	0.045	VI	91.9(147.8)
MGI	34.0000	119.0000	12/14/1912	0 0 0.0	0.0	5.70	0.022	IV	91.9(147.8)
DMG	35.7470	117.9080	03/18/1946	155042.6	4.4	5.30	0.018	IV	93.1(149.8)
DMG	34.0000	120.0170	04/01/1945	234342.0	0.0	5.40	0.019	IV	93.6(150.6)
DMG	36.2300	120.6500	02/05/1947	614 0.0	0.0	5.00	0.015	IV	93.7(150.8)
MGI	35.6000	121.1000	02/01/1853	21 0 0.0	0.0	5.00	0.015	IV	94.9(152.8)
DMG	36.0000	120.9200	11/02/1955	1940 6.0	0.0	5.20	0.017	IV	96.0(154.5)
DMG	36.0000	121.0000	02/26/1932	1658 0.0	0.0	5.00	0.015	IV	99.8(160.7)

****

-END OF SEARCH- 134 EARTHQUAKES FOUND WITHIN THE SPECIFIED SEARCH AREA.

TIME PERIOD OF SEARCH: 1800 TO 2010

LENGTH OF SEARCH TIME: 211 years

THE EARTHQUAKE CLOSEST TO THE SITE IS ABOUT 19.2 MILES (30.9 km) AWAY.

LARGEST EARTHQUAKE MAGNITUDE FOUND IN THE SEARCH RADIUS: 7.9

LARGEST EARTHQUAKE SITE ACCELERATION FROM THIS SEARCH: 0.239 g

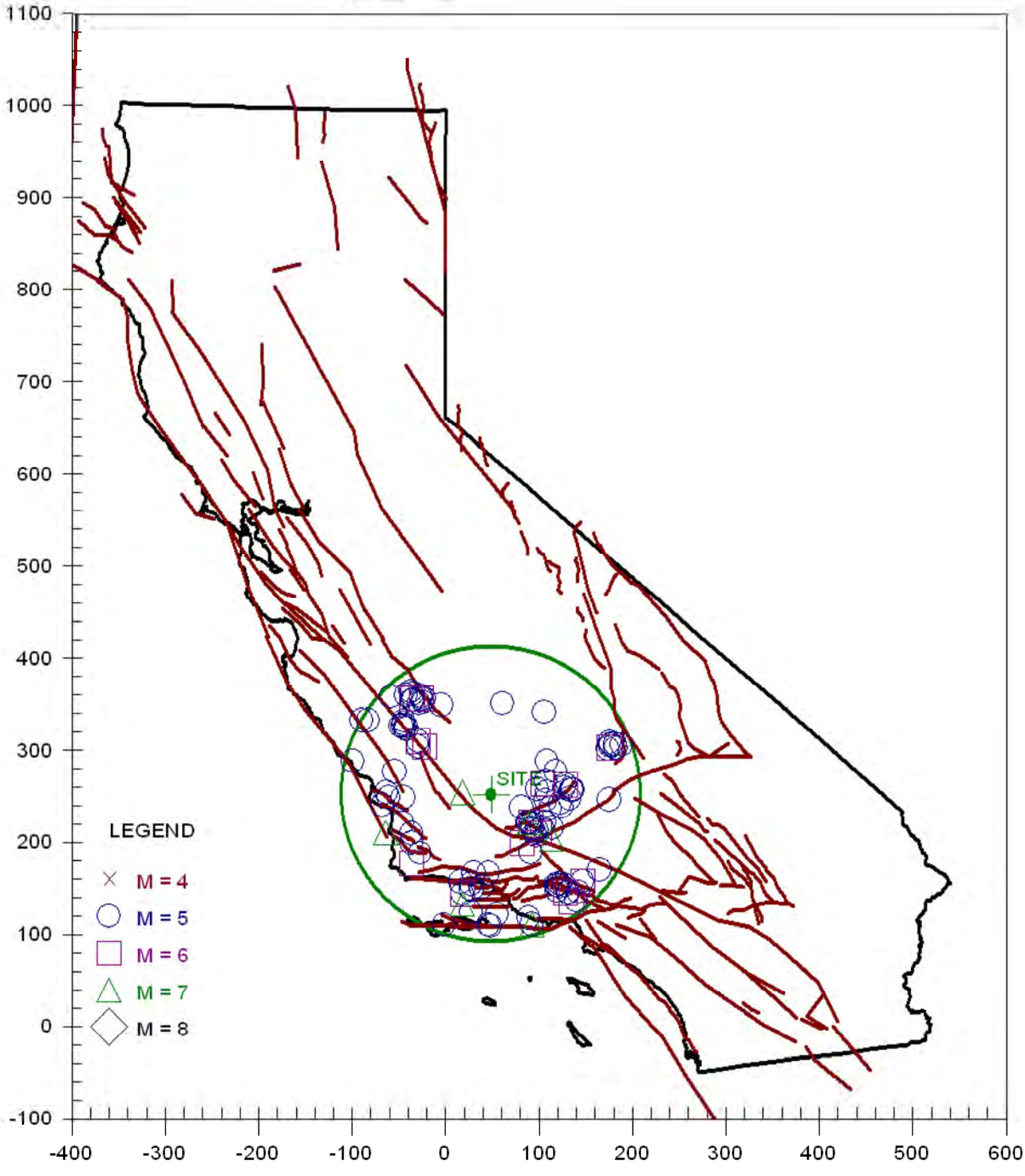
COEFFICIENTS FOR GUTENBERG & RICHTER RECURRENCE RELATION:
a-value= 1.525
b-value= 0.391
beta-value= 0.901

TABLE OF MAGNITUDES AND EXCEEDANCES:

Earthquake Magnitude	Number of Times Exceeded	Cumulative No. / Year
4.0	134	0.63810
4.5	134	0.63810
5.0	134	0.63810
5.5	55	0.26190
6.0	22	0.10476
6.5	9	0.04286
7.0	6	0.02857
7.5	3	0.01429

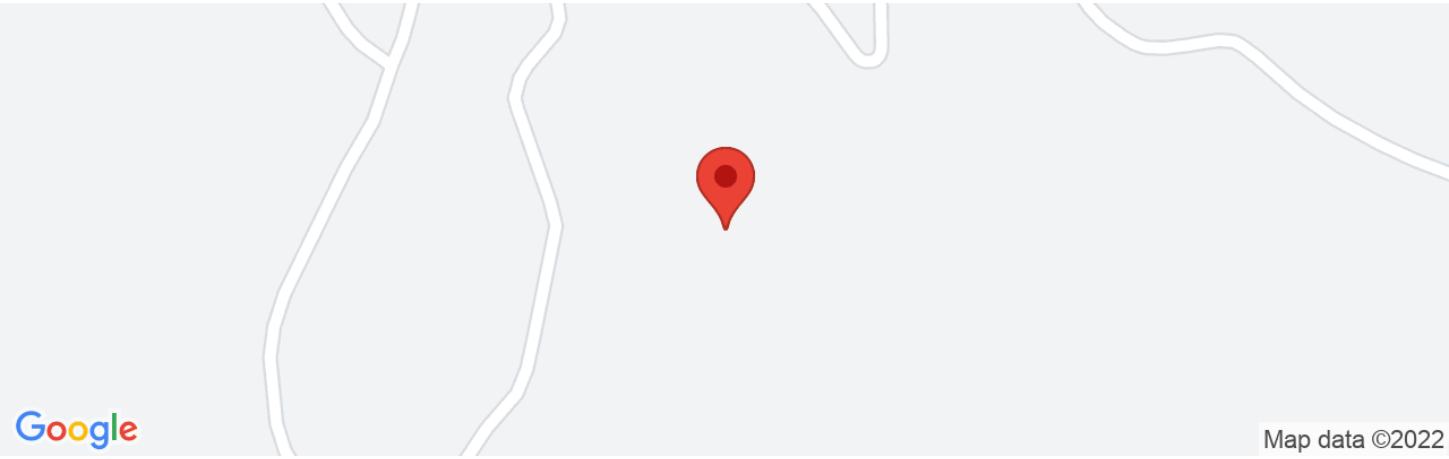
EARTHQUAKE EPICENTER MAP

18566 - 36



18566 7

Latitude, Longitude: 35.329491, -119.544847



Date	11/8/2022, 7:30:39 AM
Design Code Reference Document	ASCE7-16
Risk Category	II
Site Class	C - Very Dense Soil and Soft Rock

Type	Value	Description
S_S	1.183	MCE_R ground motion. (for 0.2 second period)
S_1	0.47	MCE_R ground motion. (for 1.0s period)
S_{MS}	1.419	Site-modified spectral acceleration value
S_{M1}	0.705	Site-modified spectral acceleration value
S_{DS}	0.946	Numeric seismic design value at 0.2 second SA
S_{D1}	0.47	Numeric seismic design value at 1.0 second SA

Type	Value	Description
SDC	D	Seismic design category
F_a	1.2	Site amplification factor at 0.2 second
F_v	1.5	Site amplification factor at 1.0 second
PGA	0.5	MCE_G peak ground acceleration
F_{PGA}	1.2	Site amplification factor at PGA
PGA_M	0.6	Site modified peak ground acceleration
T_L	12	Long-period transition period in seconds
SsRT	1.183	Probabilistic risk-targeted ground motion. (0.2 second)
SsUH	1.314	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration
SsD	1.5	Factored deterministic acceleration value. (0.2 second)
S1RT	0.47	Probabilistic risk-targeted ground motion. (1.0 second)
S1UH	0.529	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration.
S1D	0.6	Factored deterministic acceleration value. (1.0 second)
PGAd	0.5	Factored deterministic acceleration value. (Peak Ground Acceleration)
PGA_{UH}	0.534	Uniform-hazard (2% probability of exceedance in 50 years) Peak Ground Acceleration
C_{RS}	0.9	Mapped value of the risk coefficient at short periods

Type	Value	Description
C_{R1}	0.889	Mapped value of the risk coefficient at a period of 1 s
C_V	1.137	Vertical coefficient

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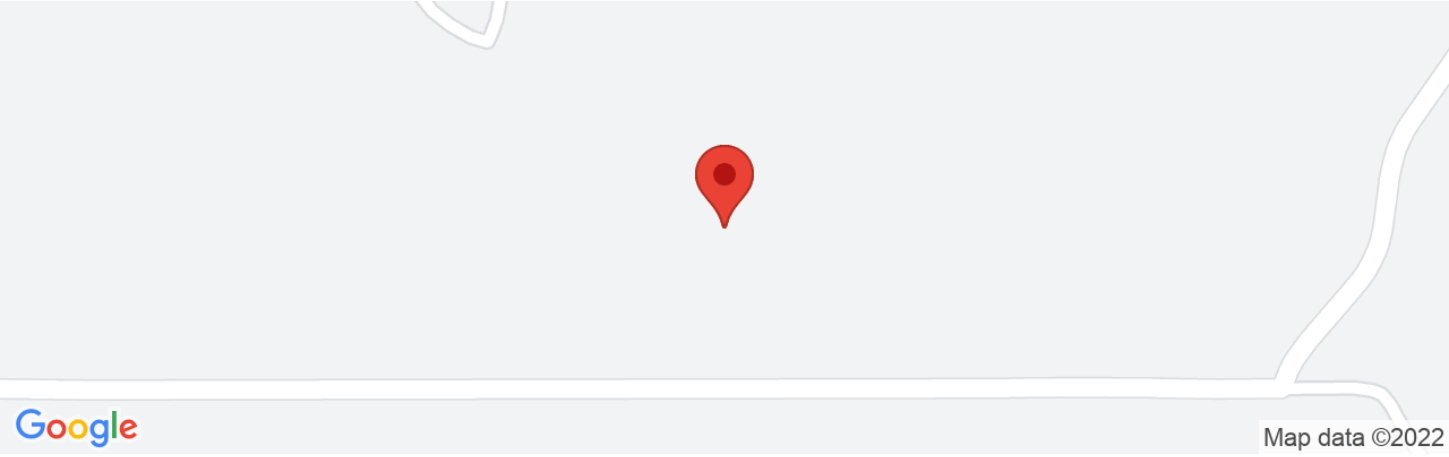
18566 7/18

Latitude, Longitude: 35.325027, -119.544935



Date	11/8/2022, 7:40:03 AM
Design Code Reference Document	ASCE7-16
Risk Category	II
Site Class	C - Very Dense Soil and Soft Rock

Type	Value	Description
S_S	1.191	MCE_R ground motion. (for 0.2 second period)
S_1	0.474	MCE_R ground motion. (for 1.0s period)
S_{MS}	1.43	Site-modified spectral acceleration value
S_{M1}	0.711	Site-modified spectral acceleration value
S_{DS}	0.953	Numeric seismic design value at 0.2 second SA
S_{D1}	0.474	Numeric seismic design value at 1.0 second SA

Type	Value	Description
SDC	D	Seismic design category
F_a	1.2	Site amplification factor at 0.2 second
F_v	1.5	Site amplification factor at 1.0 second
PGA	0.5	MCE_G peak ground acceleration
F_{PGA}	1.2	Site amplification factor at PGA
PGA_M	0.6	Site modified peak ground acceleration
T_L	12	Long-period transition period in seconds
SsRT	1.191	Probabilistic risk-targeted ground motion. (0.2 second)
SsUH	1.324	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration
SsD	1.5	Factored deterministic acceleration value. (0.2 second)
S1RT	0.474	Probabilistic risk-targeted ground motion. (1.0 second)
S1UH	0.534	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration.
S1D	0.6	Factored deterministic acceleration value. (1.0 second)
PGAd	0.5	Factored deterministic acceleration value. (Peak Ground Acceleration)
PGA_{UH}	0.539	Uniform-hazard (2% probability of exceedance in 50 years) Peak Ground Acceleration
C_{RS}	0.9	Mapped value of the risk coefficient at short periods

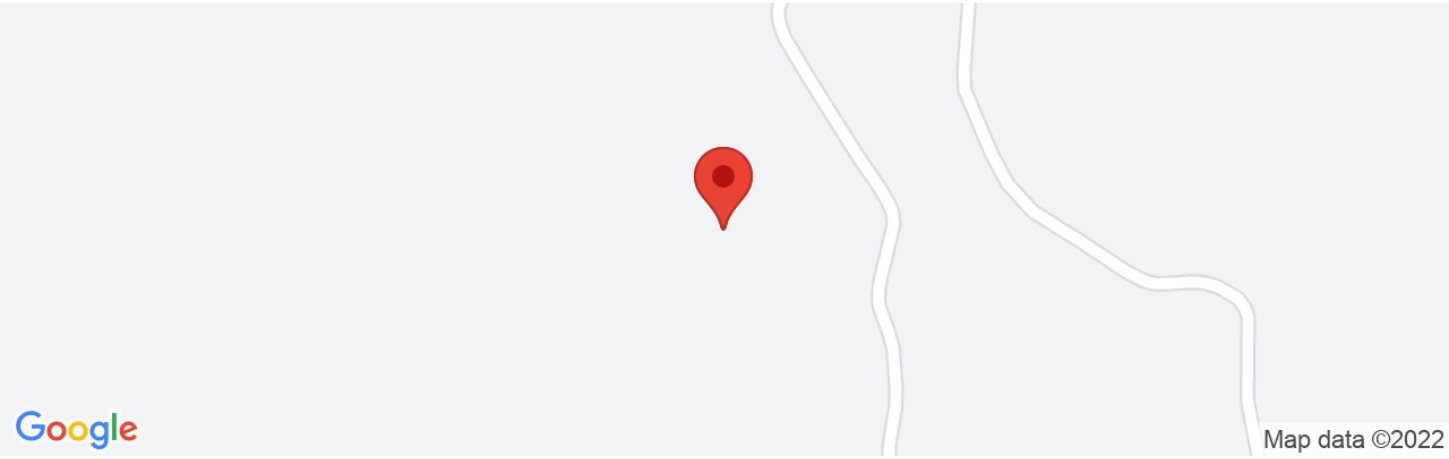
Type	Value	Description
C_{R1}	0.888	Mapped value of the risk coefficient at a period of 1 s
C_V	1.138	Vertical coefficient

DISCLAIMER

While the information presented on this website is believed to be correct, SEAOC /OSHPD and its sponsors and contributors assume no responsibility or liability for its accuracy. The material presented in this web application should not be used or relied upon for any specific application without competent examination and verification of its accuracy, suitability and applicability by engineers or other licensed professionals. SEAOC / OSHPD do not intend that the use of this information replace the sound judgment of such competent professionals, having experience and knowledge in the field of practice, nor to substitute for the standard of care required of such professionals in interpreting and applying the results of the seismic data provided by this website. Users of the information from this website assume all liability arising from such use. Use of the output of this website does not imply approval by the governing building code bodies responsible for building code approval and interpretation for the building site described by latitude/longitude location in the search results of this website.

18566 27

Latitude, Longitude: 35.293161, -119.489566



Date	11/8/2022, 8:06:12 AM
Design Code Reference Document	ASCE7-16
Risk Category	II
Site Class	C - Very Dense Soil and Soft Rock

Type	Value	Description
S_S	1.168	MCE_R ground motion. (for 0.2 second period)
S_1	0.463	MCE_R ground motion. (for 1.0s period)
S_{MS}	1.402	Site-modified spectral acceleration value
S_{M1}	0.694	Site-modified spectral acceleration value
S_{DS}	0.934	Numeric seismic design value at 0.2 second SA
S_{D1}	0.463	Numeric seismic design value at 1.0 second SA

Type	Value	Description
SDC	D	Seismic design category
F_a	1.2	Site amplification factor at 0.2 second
F_v	1.5	Site amplification factor at 1.0 second
PGA	0.5	MCE_G peak ground acceleration
F_{PGA}	1.2	Site amplification factor at PGA
PGA_M	0.6	Site modified peak ground acceleration
T_L	12	Long-period transition period in seconds
SsRT	1.168	Probabilistic risk-targeted ground motion. (0.2 second)
SsUH	1.295	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration
SsD	1.5	Factored deterministic acceleration value. (0.2 second)
S1RT	0.463	Probabilistic risk-targeted ground motion. (1.0 second)
S1UH	0.519	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration.
S1D	0.6	Factored deterministic acceleration value. (1.0 second)
PGAd	0.5	Factored deterministic acceleration value. (Peak Ground Acceleration)
PGA_{UH}	0.526	Uniform-hazard (2% probability of exceedance in 50 years) Peak Ground Acceleration
C_{RS}	0.902	Mapped value of the risk coefficient at short periods

Type	Value	Description
C_{R1}	0.891	Mapped value of the risk coefficient at a period of 1 s
C_V	1.134	Vertical coefficient

DISCLAIMER

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18566 35

Latitude, Longitude: 35.275656, -119.471325



Date	11/8/2022, 8:12:39 AM
Design Code Reference Document	ASCE7-16
Risk Category	II
Site Class	C - Very Dense Soil and Soft Rock

Type	Value	Description
S_S	1.181	MCE_R ground motion. (for 0.2 second period)
S_1	0.468	MCE_R ground motion. (for 1.0s period)
S_{MS}	1.417	Site-modified spectral acceleration value
S_{M1}	0.702	Site-modified spectral acceleration value
S_{DS}	0.945	Numeric seismic design value at 0.2 second SA
S_{D1}	0.468	Numeric seismic design value at 1.0 second SA

Type	Value	Description
SDC	D	Seismic design category
F_a	1.2	Site amplification factor at 0.2 second
F_v	1.5	Site amplification factor at 1.0 second
PGA	0.5	MCE_G peak ground acceleration
F_{PGA}	1.2	Site amplification factor at PGA
PGA_M	0.6	Site modified peak ground acceleration
T_L	12	Long-period transition period in seconds
SsRT	1.181	Probabilistic risk-targeted ground motion. (0.2 second)
SsUH	1.31	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration
SsD	1.5	Factored deterministic acceleration value. (0.2 second)
S1RT	0.468	Probabilistic risk-targeted ground motion. (1.0 second)
S1UH	0.525	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration.
S1D	0.6	Factored deterministic acceleration value. (1.0 second)
PGAd	0.5	Factored deterministic acceleration value. (Peak Ground Acceleration)
PGA_{UH}	0.532	Uniform-hazard (2% probability of exceedance in 50 years) Peak Ground Acceleration
C_{RS}	0.902	Mapped value of the risk coefficient at short periods

Type	Value	Description
C_{R1}	0.891	Mapped value of the risk coefficient at a period of 1 s
C_V	1.136	Vertical coefficient

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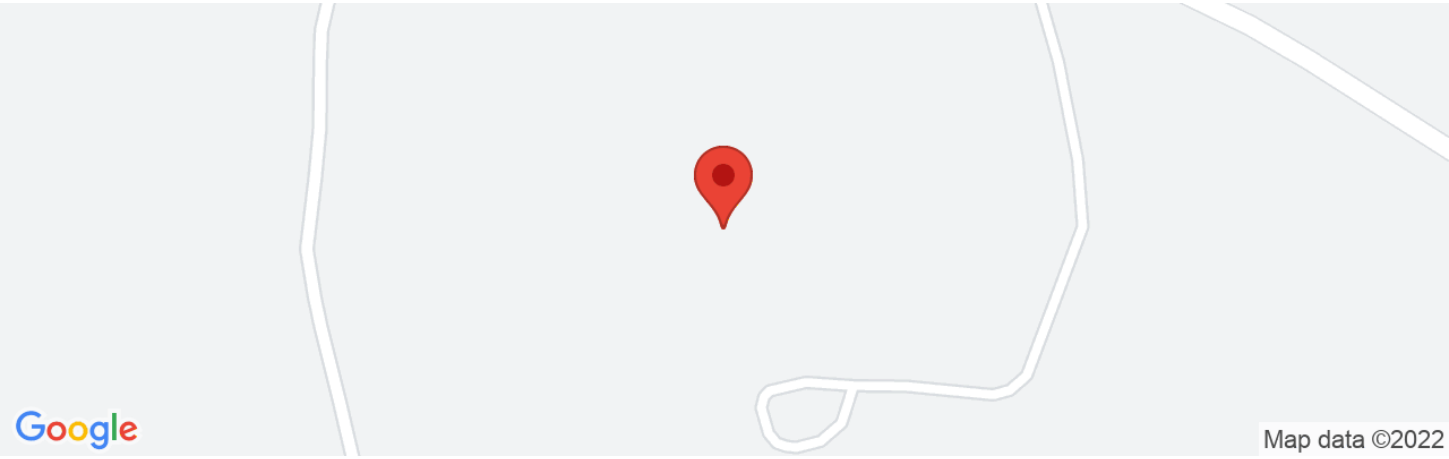
18566 36

Latitude, Longitude: 35.275718, -119.459997



Date	11/8/2022, 8:36:03 AM
Design Code Reference Document	ASCE7-16
Risk Category	II
Site Class	C - Very Dense Soil and Soft Rock

Type	Value	Description
S_S	1.166	MCE_R ground motion. (for 0.2 second period)
S_1	0.46	MCE_R ground motion. (for 1.0s period)
S_{MS}	1.399	Site-modified spectral acceleration value
S_{M1}	0.69	Site-modified spectral acceleration value
S_{DS}	0.933	Numeric seismic design value at 0.2 second SA
S_{D1}	0.46	Numeric seismic design value at 1.0 second SA

Type	Value	Description
SDC	D	Seismic design category
F_a	1.2	Site amplification factor at 0.2 second
F_v	1.5	Site amplification factor at 1.0 second
PGA	0.5	MCE_G peak ground acceleration
F_{PGA}	1.2	Site amplification factor at PGA
PGA_M	0.6	Site modified peak ground acceleration
T_L	12	Long-period transition period in seconds
SsRT	1.166	Probabilistic risk-targeted ground motion. (0.2 second)
SsUH	1.291	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration
SsD	1.5	Factored deterministic acceleration value. (0.2 second)
S1RT	0.46	Probabilistic risk-targeted ground motion. (1.0 second)
S1UH	0.516	Factored uniform-hazard (2% probability of exceedance in 50 years) spectral acceleration.
S1D	0.6	Factored deterministic acceleration value. (1.0 second)
PGAd	0.5	Factored deterministic acceleration value. (Peak Ground Acceleration)
PGA_{UH}	0.525	Uniform-hazard (2% probability of exceedance in 50 years) Peak Ground Acceleration
C_{RS}	0.903	Mapped value of the risk coefficient at short periods

Type	Value	Description
C_{R1}	0.892	Mapped value of the risk coefficient at a period of 1 s
C_V	1.133	Vertical coefficient

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U.S. Geological Survey - Earthquake Hazards Program

Unified Hazard Tool

Please do not use this tool to obtain ground motion parameter values for the design code reference documents covered by the U.S. Seismic Design Maps web tools (e.g., the International Building Code and the ASCE 7 or 41 Standard). The values returned by the two applications are not identical.

Input

Edition

Dynamic: Conterminous U.S. 2014 (u…

Spectral Period

Peak Ground Acceleration

Latitude

Decimal degrees

35.325027

Time Horizon

Return period in years

975

Longitude

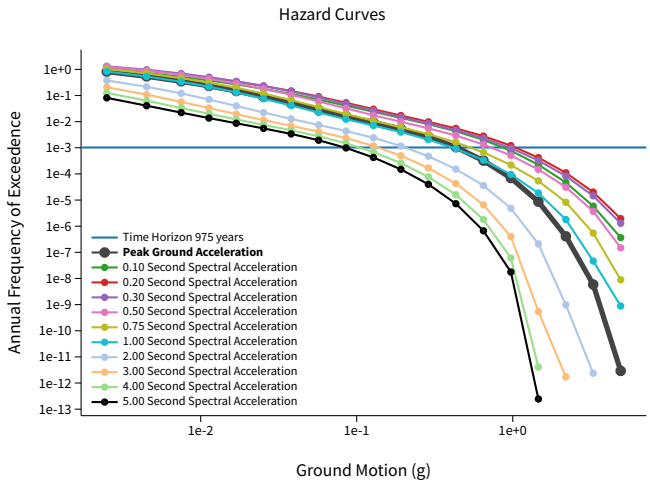
Decimal degrees, negative values for western longitudes

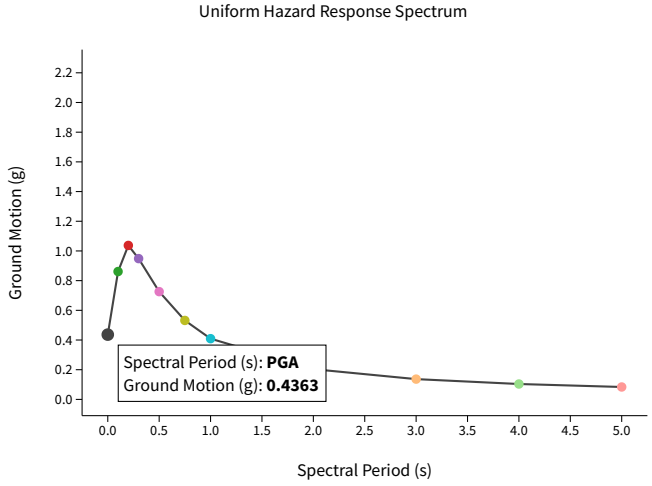
-119.544935

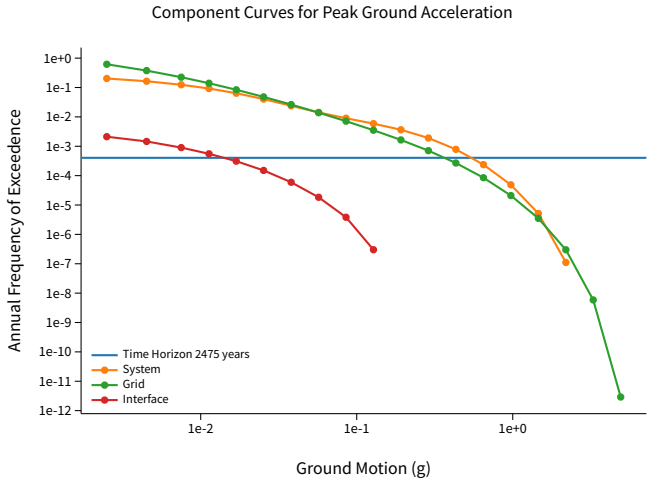
Site Class

537 m/s (Site class C)

Hazard Curve





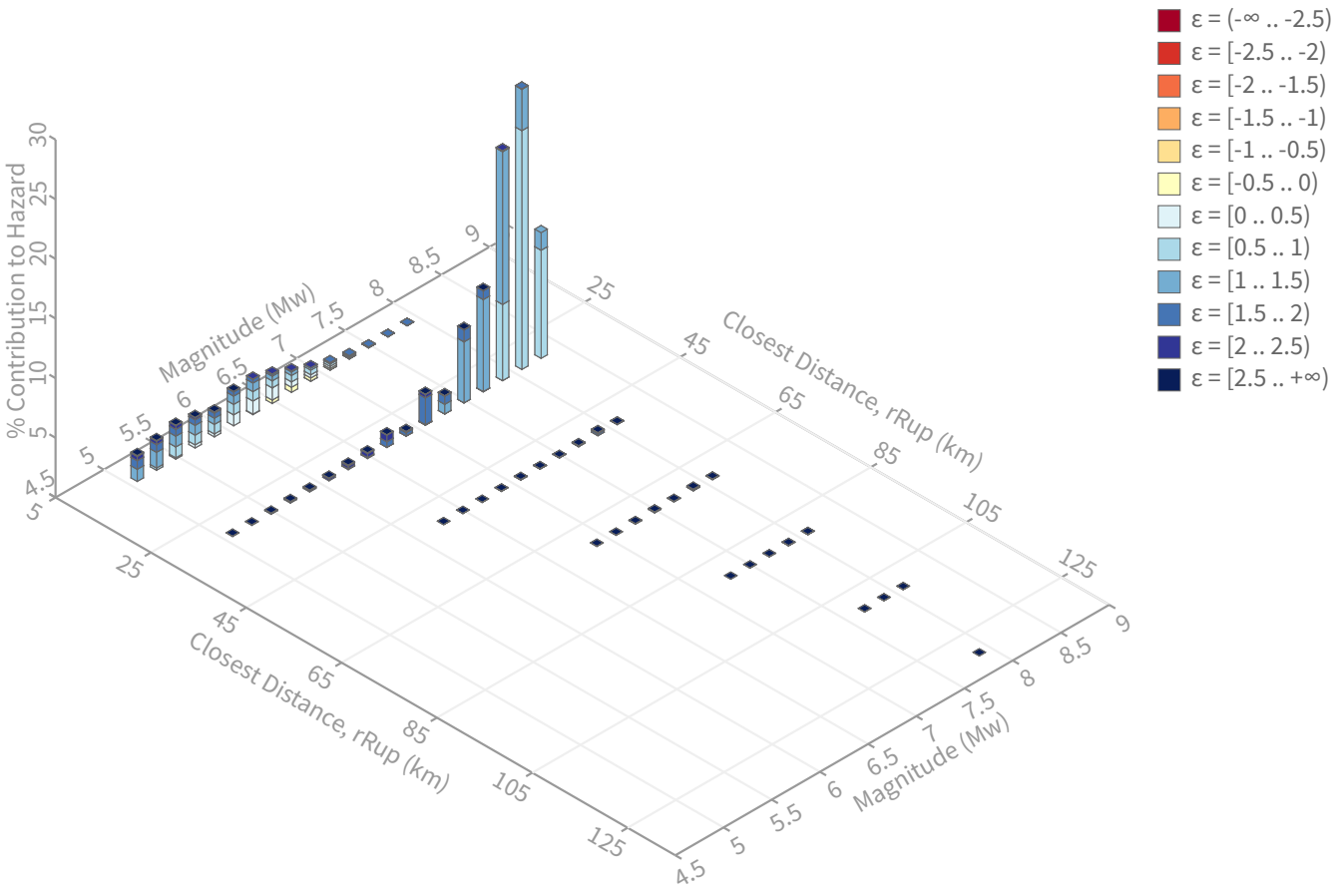


View Raw Data

Deaggregation

Component

Total


% Contribution to Hazard
0
5
10
15
20
25
30
Magnitude (Mw)
4.5
5
5.5
6
6.5
7
7.5
8
8.5
9
Closest Distance, rRup (km)
25
45
65
85
105
125
ε = (-∞ .. -2.5)
ε = [-2.5 .. -2)
ε = [-2 .. -1.5)
ε = [-1.5 .. -1)
ε = [-1 .. -0.5)
ε = [-0.5 .. 0)
ε = [0 .. 0.5)
ε = [0.5 .. 1)
ε = [1 .. 1.5)
ε = [1.5 .. 2)
ε = [2 .. 2.5)
ε = [2.5 .. +∞)

Summary statistics for, Deaggregation: Total

Deaggregation targets

Return period: 975 yrs
Exceedance rate: 0.001025641 yr^{-1}
PGA ground motion: 0.43629858 g

Recovered targets

Return period: 1084.3794 yrs
Exceedance rate: 0.00092218646 yr^{-1}

Totals

Binned: 100 %
Residual: 0 %
Trace: 0.13 %

Mean (over all sources)

m: 7.4
r: 20.21 km
ε_0: 1.09 σ

Mode (largest m-r bin)

m: 8.1
r: 23.04 km
ε_0: 0.93 σ
Contribution: 23.5 %

Mode (largest m-r-ε_0 bin)

m: 8.1
r: 23.02 km
ε_0: 0.86 σ
Contribution: 20.03 %

Discretization

r: min = 0.0, max = 1000.0, Δ = 20.0 km
m: min = 4.4, max = 9.4, Δ = 0.2
ε: min = -3.0, max = 3.0, Δ = 0.5 σ

Epsilon keys

ε0: [-∞ .. -2.5)
ε1: [-2.5 .. -2.0)
ε2: [-2.0 .. -1.5)
ε3: [-1.5 .. -1.0)
ε4: [-1.0 .. -0.5)
ε5: [-0.5 .. 0.0)
ε6: [0.0 .. 0.5)
ε7: [0.5 .. 1.0)
ε8: [1.0 .. 1.5)
ε9: [1.5 .. 2.0)
ε10: [2.0 .. 2.5)
ε11: [2.5 .. +∞]

Deaggregation Contributors

Source Set ↳ Source	Type	r	m	ε_0	lon	lat	az	%
UC33brAvg_FM31	System							37.03
San Andreas (Carrizo) rev [2]		23.02	7.92	1.05	119.741°W	35.194°N	230.74	34.97
UC33brAvg_FM32	System							36.86
San Andreas (Carrizo) rev [2]		23.02	7.92	1.06	119.741°W	35.194°N	230.74	34.86
UC33brAvg_FM31 (opt)	Grid							13.06
PointSourceFinite: -119.545, 35.365		6.57	5.79	0.70	119.545°W	35.365°N	0.00	1.71
PointSourceFinite: -119.545, 35.365		6.57	5.79	0.70	119.545°W	35.365°N	0.00	1.71
PointSourceFinite: -119.545, 35.410		9.56	6.00	1.04	119.545°W	35.410°N	0.00	1.32
PointSourceFinite: -119.545, 35.410		9.56	6.00	1.04	119.545°W	35.410°N	0.00	1.32
PointSourceFinite: -119.545, 35.374		7.14	5.82	0.78	119.545°W	35.374°N	0.00	1.27
PointSourceFinite: -119.545, 35.374		7.14	5.82	0.78	119.545°W	35.374°N	0.00	1.27
UC33brAvg_FM32 (opt)	Grid							13.04
PointSourceFinite: -119.545, 35.365		6.57	5.79	0.70	119.545°W	35.365°N	0.00	1.71
PointSourceFinite: -119.545, 35.365		6.57	5.79	0.70	119.545°W	35.365°N	0.00	1.71
PointSourceFinite: -119.545, 35.410		9.56	6.00	1.04	119.545°W	35.410°N	0.00	1.32
PointSourceFinite: -119.545, 35.410		9.56	6.00	1.04	119.545°W	35.410°N	0.00	1.32
PointSourceFinite: -119.545, 35.374		7.14	5.82	0.78	119.545°W	35.374°N	0.00	1.27
PointSourceFinite: -119.545, 35.374		7.14	5.82	0.78	119.545°W	35.374°N	0.00	1.27

U.S. Geological Survey - Earthquake Hazards Program

Unified Hazard Tool

Please do not use this tool to obtain ground motion parameter values for the design code reference documents covered by the U.S. Seismic Design Maps web tools (e.g., the International Building Code and the ASCE 7 or 41 Standard). The values returned by the two applications are not identical.

Input

Edition

Dynamic: Conterminous U.S. 2014 (u…

Spectral Period

Peak Ground Acceleration

Latitude

Decimal degrees

35.275656

Time Horizon

Return period in years

975

Longitude

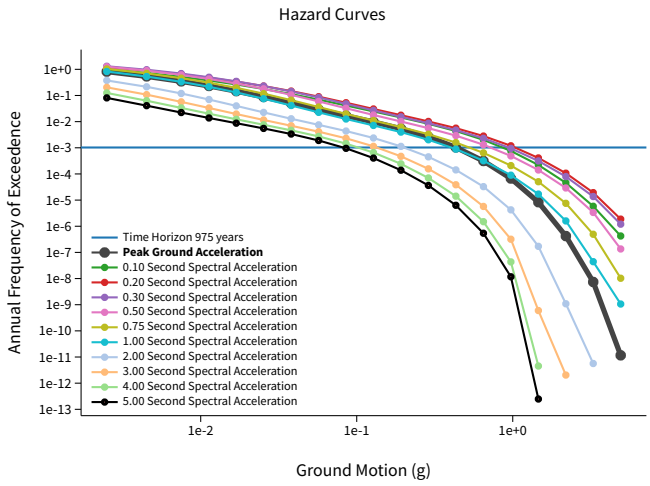
Decimal degrees, negative values for western longitudes

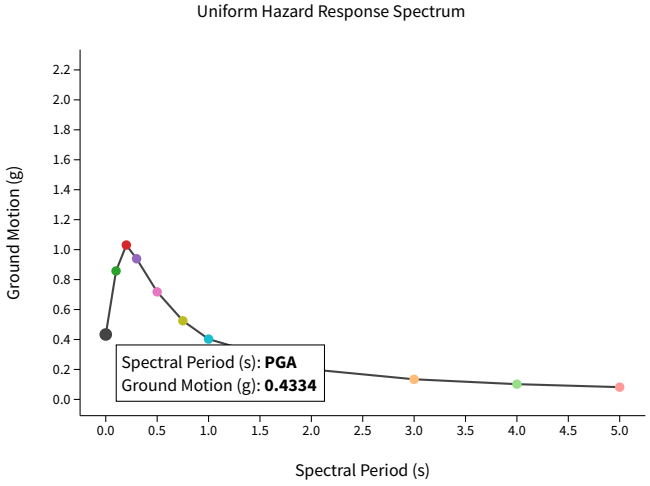
-119.471325

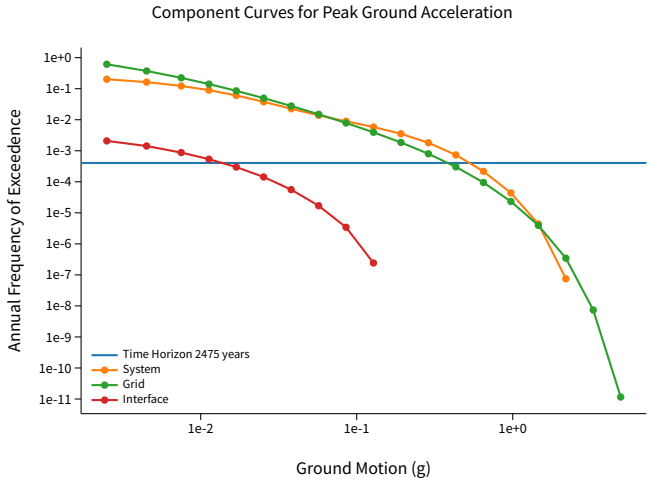
Site Class

537 m/s (Site class C)

Hazard Curve





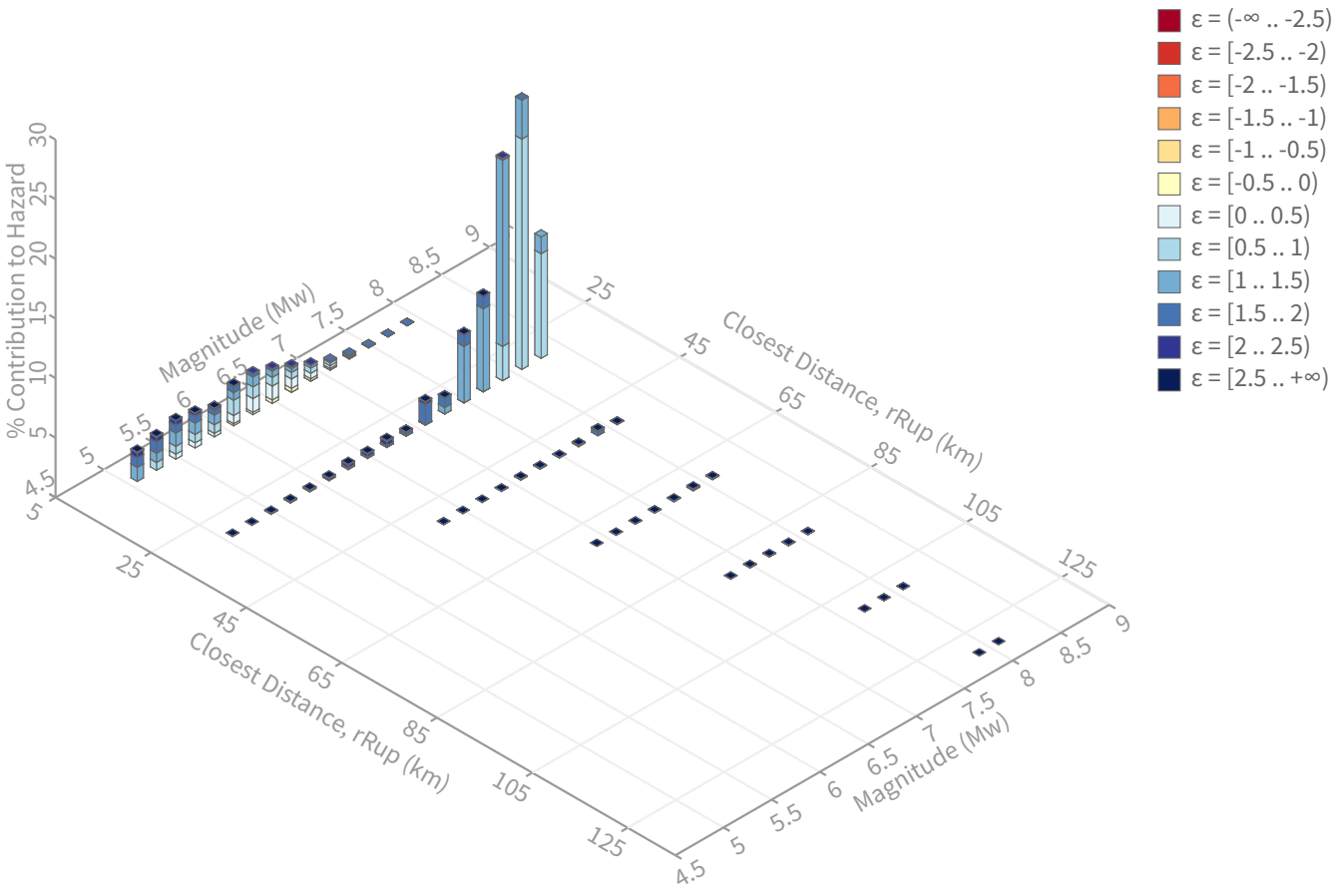


View Raw Data

Deaggregation

Component

Total


ε = (-∞ .. -2.5)
ε = [-2.5 .. -2)
ε = [-2 .. -1.5)
ε = [-1.5 .. -1)
ε = [-1 .. -0.5)
ε = [-0.5 .. 0)
ε = [0 .. 0.5)
ε = [0.5 .. 1)
ε = [1 .. 1.5)
ε = [1.5 .. 2)
ε = [2 .. 2.5)
ε = [2.5 .. +∞)
% Contribution to Hazard
Magnitude (Mw)
Closest Distance, rRup (km)
Closest Distance, rRup (km)
Magnitude (Mw)

Summary statistics for, Deaggregation: Total

Deaggregation targets

Return period: 975 yrs
Exceedance rate: 0.001025641 yr^{-1}
PGA ground motion: 0.43340673 g

Recovered targets

Return period: 1087.5806 yrs
Exceedance rate: 0.0009194721 yr^{-1}

Totals

Binned: 100 %
Residual: 0 %
Trace: 0.12 %

Mean (over all sources)

m: 7.35
r: 20.45 km
ε_0: 1.1 σ

Mode (largest m-r bin)

m: 8.1
r: 23.96 km
ε_0: 0.95 σ
Contribution: 22.59 %

Mode (largest m-r-ε_0 bin)

m: 8.1
r: 23.94 km
ε_0: 0.89 σ
Contribution: 19.32 %

Discretization

r: min = 0.0, max = 1000.0, Δ = 20.0 km
m: min = 4.4, max = 9.4, Δ = 0.2
ε: min = -3.0, max = 3.0, Δ = 0.5 σ

Epsilon keys

ε0: [-∞ .. -2.5)
ε1: [-2.5 .. -2.0)
ε2: [-2.0 .. -1.5)
ε3: [-1.5 .. -1.0)
ε4: [-1.0 .. -0.5)
ε5: [-0.5 .. 0.0)
ε6: [0.0 .. 0.5)
ε7: [0.5 .. 1.0)
ε8: [1.0 .. 1.5)
ε9: [1.5 .. 2.0)
ε10: [2.0 .. 2.5)
ε11: [2.5 .. +∞]

Deaggregation Contributors

Source Set ↳ Source	Type	r	m	ε_0	lon	lat	az	%
UC33brAvg_FM31	System							35.03
San Andreas (Carrizo) rev [4]		23.94	7.94	1.07	119.649°W	35.117°N	222.49	33.07
UC33brAvg_FM32	System							34.88
San Andreas (Carrizo) rev [4]		23.94	7.94	1.07	119.649°W	35.117°N	222.49	32.98
UC33brAvg_FM31 (opt)	Grid							15.05
PointSourceFinite: -119.471, 35.307		6.04	5.75	0.61	119.471°W	35.307°N	0.00	2.02
PointSourceFinite: -119.471, 35.307		6.04	5.75	0.61	119.471°W	35.307°N	0.00	2.02
PointSourceFinite: -119.471, 35.343		8.32	5.91	0.91	119.471°W	35.343°N	0.00	1.19
PointSourceFinite: -119.471, 35.343		8.32	5.91	0.91	119.471°W	35.343°N	0.00	1.19
UC33brAvg_FM32 (opt)	Grid							15.03
PointSourceFinite: -119.471, 35.307		6.05	5.75	0.61	119.471°W	35.307°N	0.00	2.02
PointSourceFinite: -119.471, 35.307		6.05	5.75	0.61	119.471°W	35.307°N	0.00	2.02
PointSourceFinite: -119.471, 35.343		8.32	5.91	0.91	119.471°W	35.343°N	0.00	1.19
PointSourceFinite: -119.471, 35.343		8.32	5.91	0.91	119.471°W	35.343°N	0.00	1.19

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E.2 U.S. Environmental Protection Agency Class VI Underground Injection Control (UIC) Permit Application Narratives for the Elk Hills 26R Storage Project and the A1A2 Storage Project

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26R Storage Project

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ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills 26R Storage Project

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate four CO_2 geologic sequestration wells at the Elk Hills Oil Field (EHOF) 26R reservoir located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO_2 stored in the 26R Monterey Formation reservoir up to 1.46 million tonnes annually for 26 years with injection starting in 2025. The anthropogenic CO_2 will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. The project will consist of four injectors, surface facilities, and monitoring wells. This supporting documentation applies to the four injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

   Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

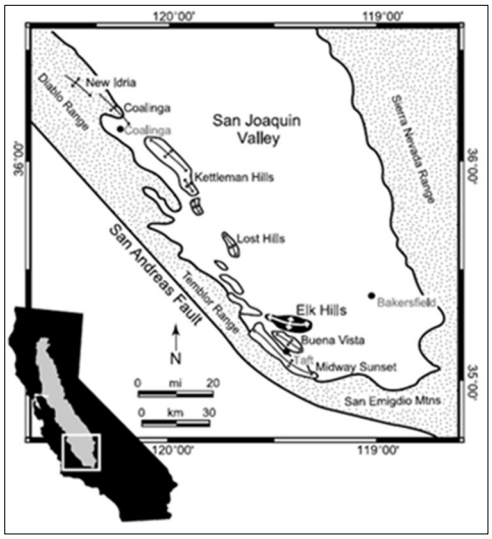
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation 26R sequestration reservoir was discovered in the 1940's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

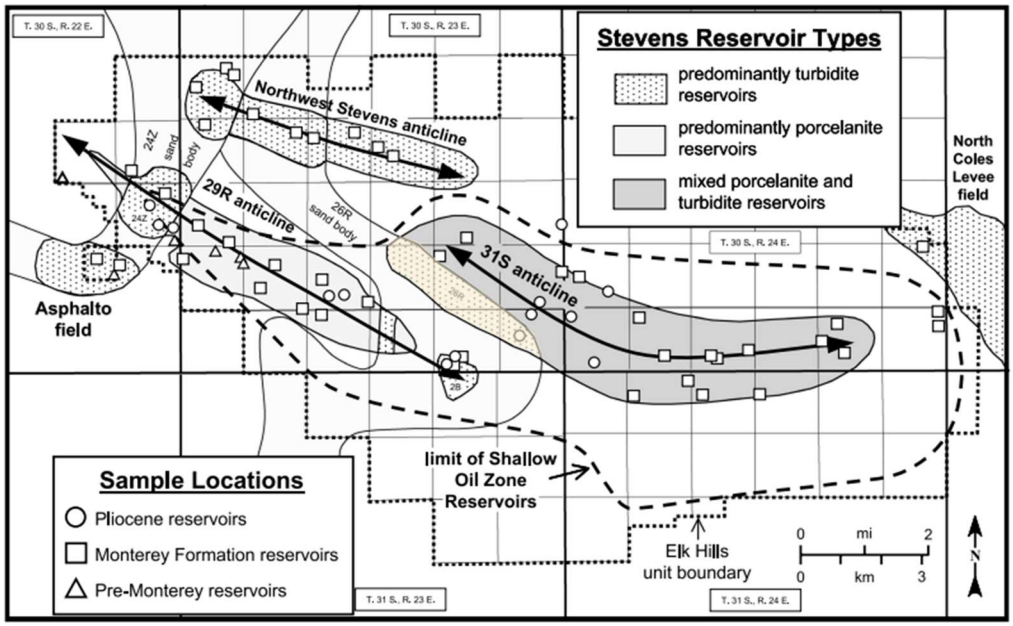
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide. With increasing depth, the structure sub-divides into three distinct anticlines (Figure 2), separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

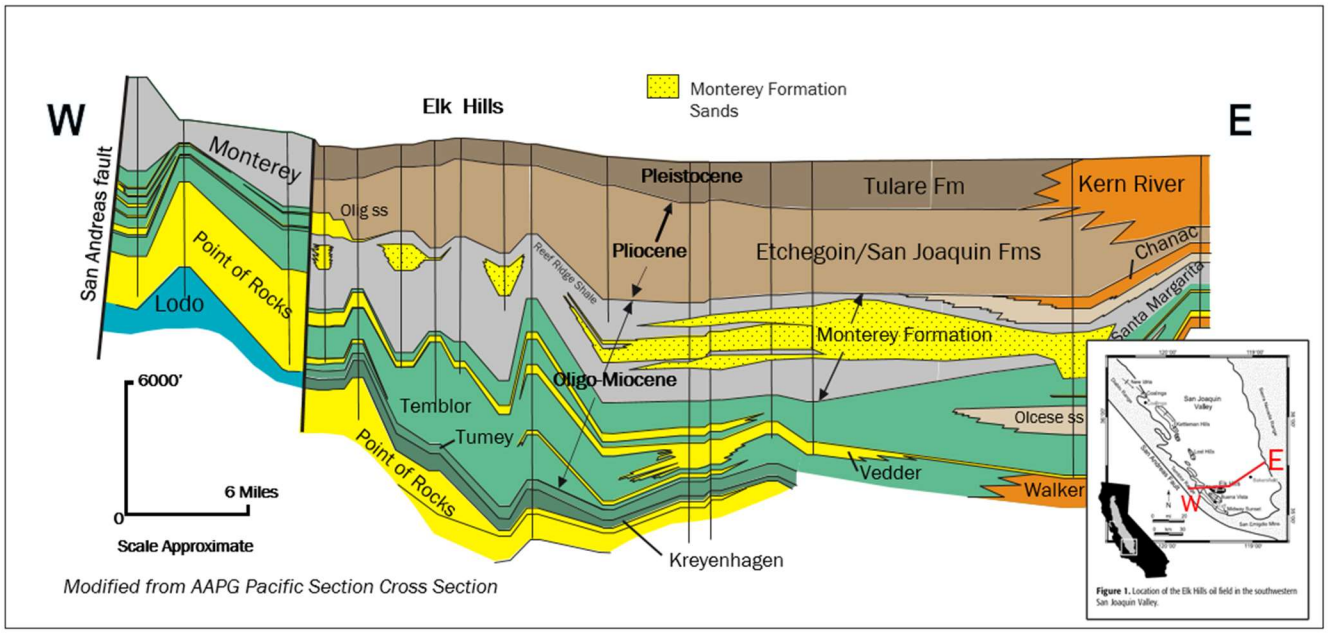
Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation 26R CO_2 sequestration reservoir is located in the 31S anticline (Zumberge, 2005).



Geological Sequence

Figure 3 shows the stratigraphy of the EHOF. The Miocene aged Monterey Formation 26R reservoir at the 31S anticline is approximately 6,000 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by over 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



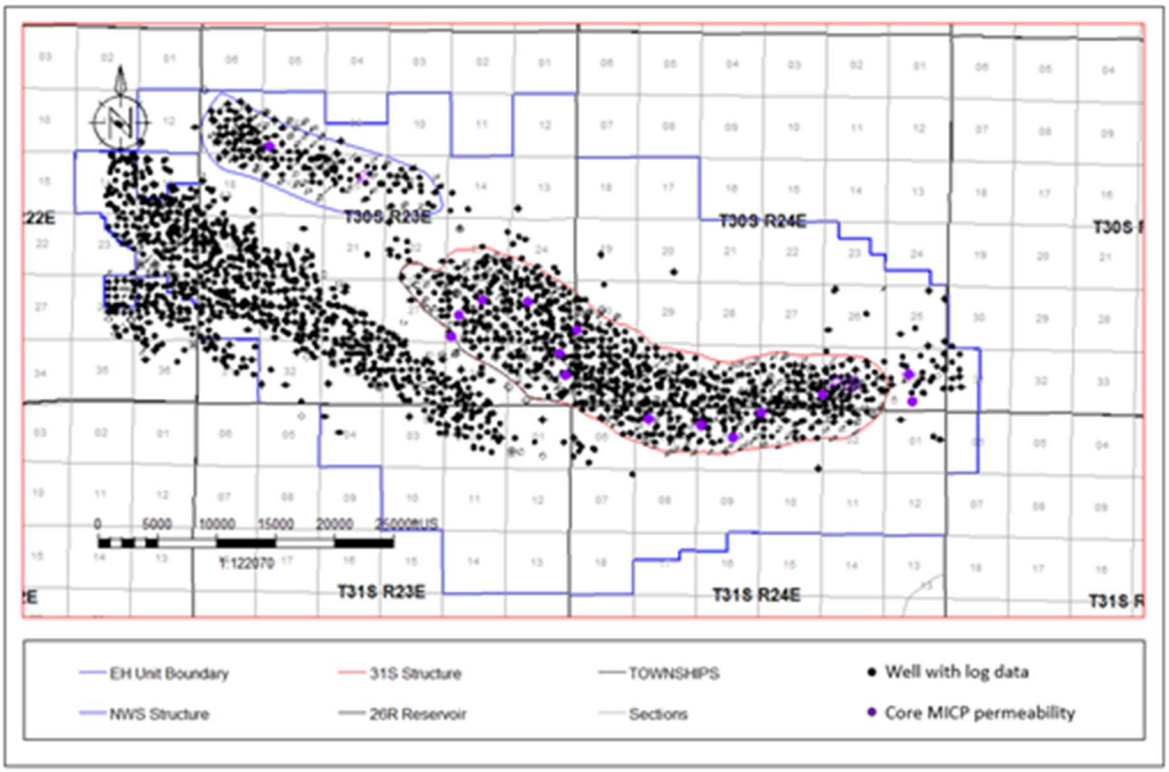
Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin and serves as the primary confining layer for the Monterey Formation 26R reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 4), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

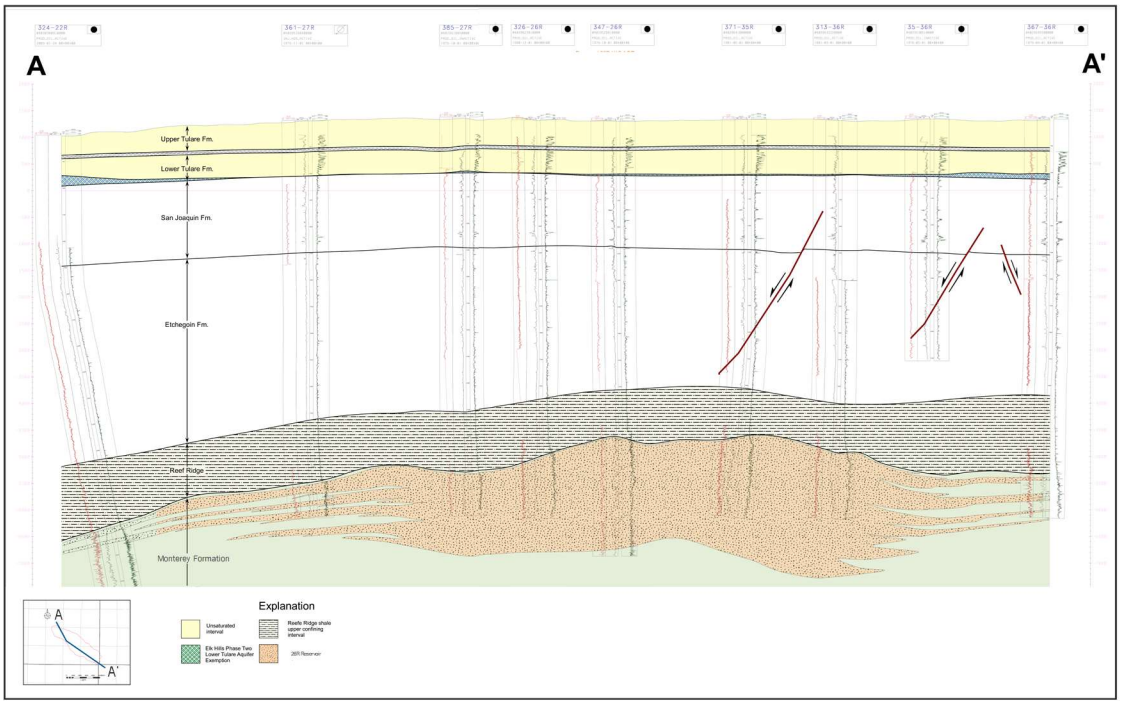
Figure 4: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core from the Monterey Formation are shown in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 5 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 5: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the 31S anticline.



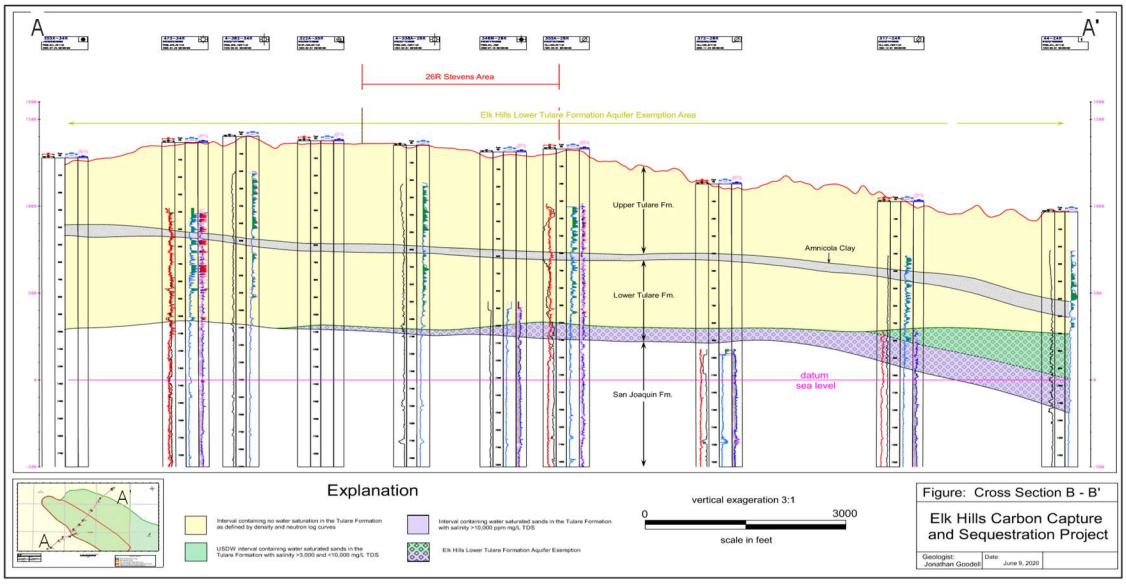
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 6), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare is an unsaturated air sand above the Monterey Formation 26R reservoir. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 6: The Tulare Formation consists of the Upper Tulare and Lower Tulare separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer and the Upper Tulare is an unsaturated air sand.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and conglomerate of the Tulare Formation interfinger with the San Joaquin beds (Maher et al., 1975). The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000' in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

The Etchegoin Formation will dissipate CO2 and CTV will drill and equip a monitoring well to assess formation pressure and water quality changes during the project.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 5,000 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

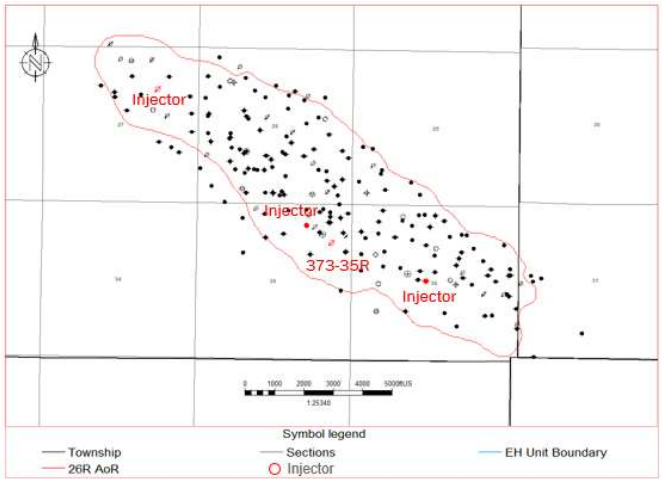
The Reef Ridge directly overlies the 26R Monterey Formation sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

The 26R Monterey Formation sequestration reservoir is approximately 6,000 feet deep and produces from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 25% and 45 mD, respectively.

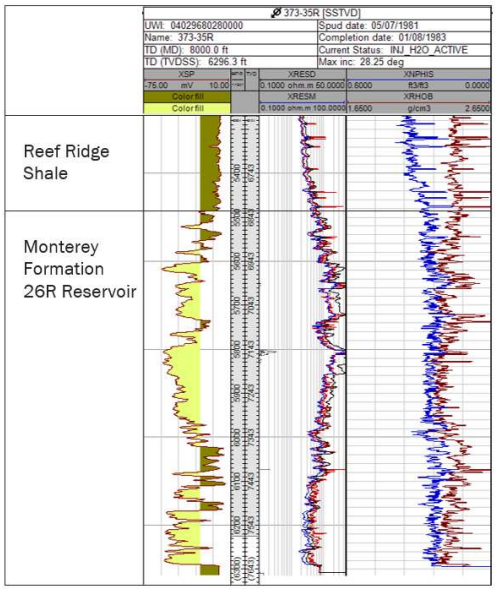
The 26R Monterey Formation sands were deposited as a turbidite channel influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. The turbidite sands were largely aggregational with minimal erosive deposition.

Figure 7: AoR and injection well location map for the Elk Hills 26R project. Well location shown is defined by the well path intersection with the Monterey Formation.



The reservoir is continuous across the AoR and the sands pinch-out up-dip and on the channel edges (Figure 5). As such, the 26R Monterey Formation sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

Figure 8: 373-35R injector showing the Monterey Formation 26R reservoir.



Summary:

The Monterey Formation 26R project will be developed with four injectors (Figure 7), three wells to be drilled prior to the initiation of injection and the existing 373-35R well (Figure 8).

The storage reservoir depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as vertical confinement by the Reef Ridge Shale and lateral reservoir confinement.

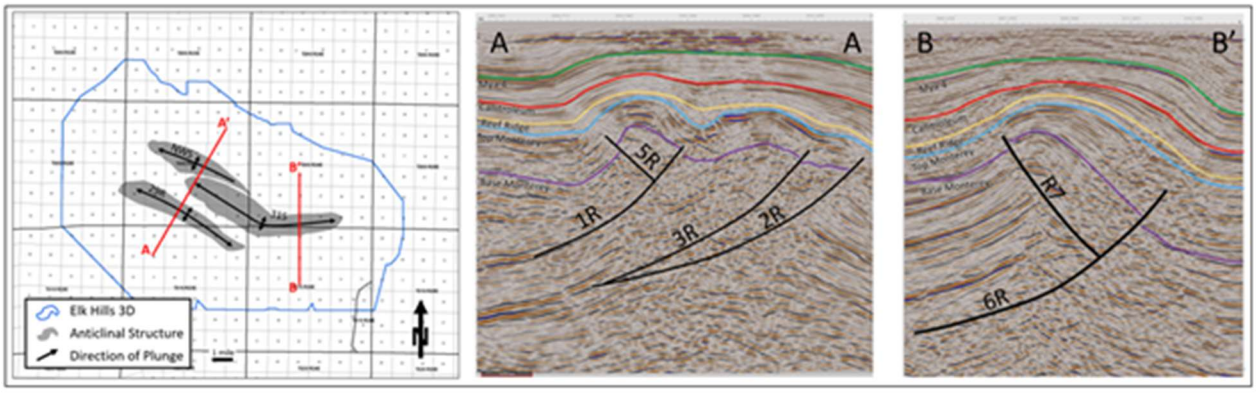
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 9 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the 26R anticline are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale.

Figure 9: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.



Fluid Confinement

Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO_2 injectate in the 26R Monterey Formation sands:

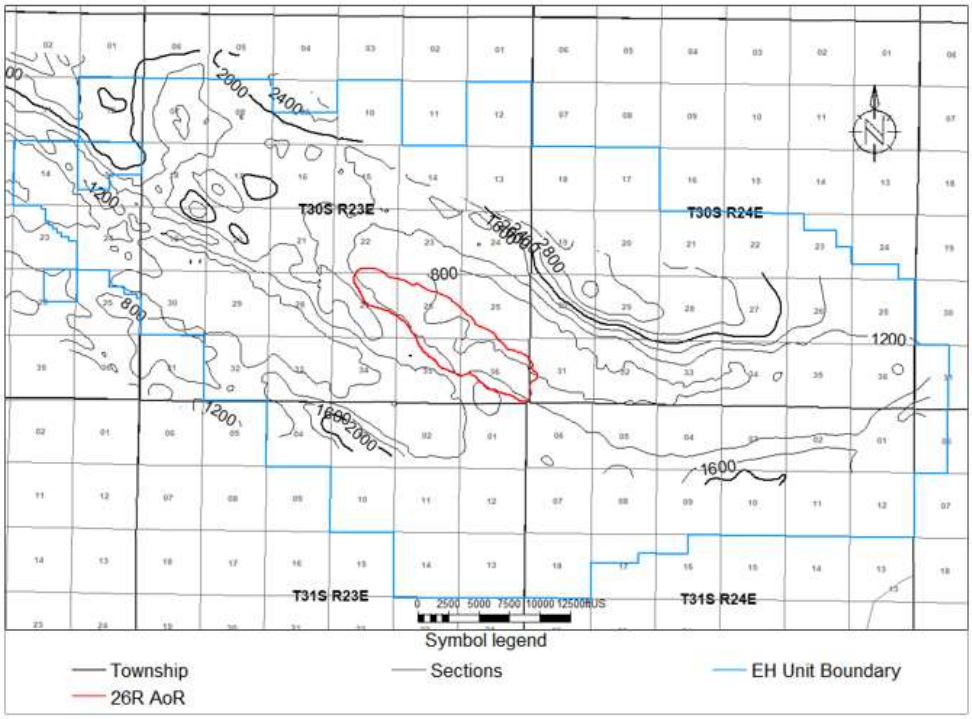
1. There are no faults that extend into the confining Reef Ridge Shale (refer to Figure 9).

2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,000 feet (Figure 10) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 10: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



2. Waterflooding and Gas Injection

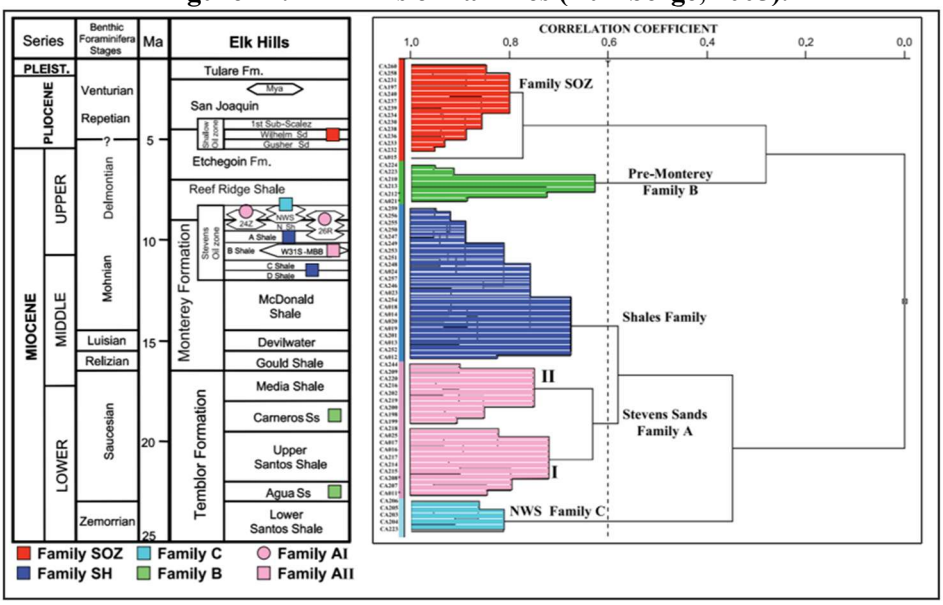
Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control Board. To date, more than 114 million barrels of water and 841 billion cubic feet of gas have been injected into the 26R Monterey Formation sands. There has been no evidence of water or gas

migrating through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically confined.

3. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 11) sourced from the Miocene Monterey Formation and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests "minimal up-section, [and] cross stratigraphic migration". The authors conclude that the hydrocarbons present in the overlying formations are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

Figure 11: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

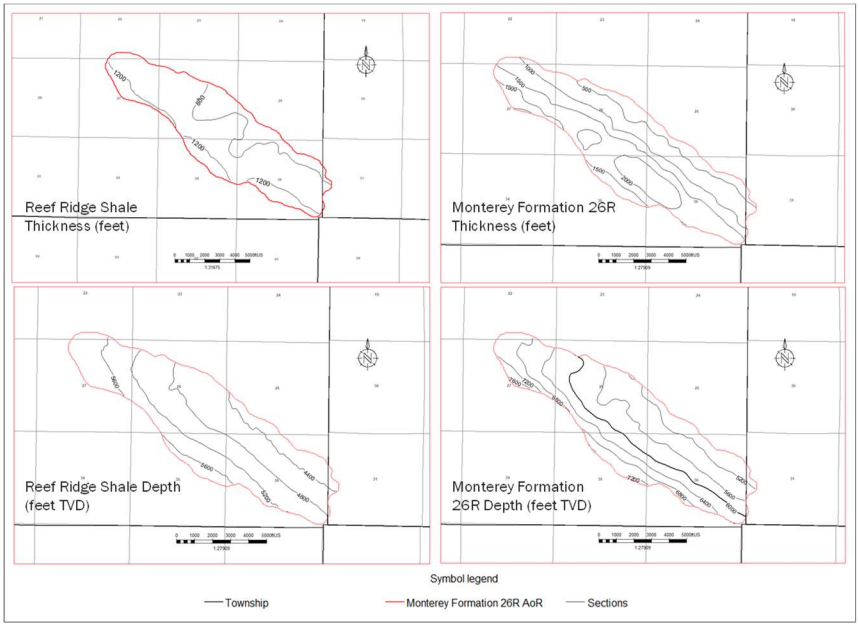
Depths and thickness of the 26R Monterey Formation reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 12) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability is due to deposition of the Monterey Formation sands.
3. Monterey Formation thickness variability is from pinch-out of the reservoir on the 31S structure.

Table 1: Reef Ridge Shale and Monterey Formation 26R thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone Reef Ridge Shale	Thickness (feet)	640	1,598	985.1
	Depth (feet TVD)	4,084	5,949	4,992
Reservoir Monterey Formation 26R Reservoir	Thickness (feet)	255	2,497	1,283
	Depth (feet TVD)	4,828	7,827	6,014

Figure 12: Reef Ridge Shale and Monterey Formation 26R thickness and depth maps.



Variability in the thickness and depth of the either the Reef Ridge Shale or the 26R Monterey Formation sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

Mineralogy

Monterey Formation 26R:

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the AoR. Well 377H-26R (Figure 13) provides an example of the mineralogy for the reservoir interval in 373-35R. Clean reservoir sand intervals have an average of 39% quartz, 49% potassium feldspar, albite and oligoclase as well as 12% total clay.

Figure 13: Monterey Formation 26R sand mineralogy from well 377H-26R.

	Whole Rock Mineralogy (Weight %)							Relative Clay Abundance (Normalized to 100%)			
Depth	Quartz	K-Feldspar	Plagioclase	Siderite	Pyrite	Gypsum	Total Clay	Illite / Smectite *	Fe-Illite & Mica	Kaolinite	Chlorite
5912.5	38	15	32	0	1	1	13	28	65	4	3
5981.5	40	16	32	0	1	1	10	29	56	11	4
6046.0	40	14	29	0	2	0	15	32	45	20	3
6046.9	37	17	37	0	1	Tr	8	36	45	15	4
6066.4	41	18	32	0	1	0	8	30	41	26	3
6097.1	41	16	34	0	0	0	9	19	53	25	3
6113.3	35	19	34	0	1	0	11	16	46	33	5
6141.0	44	6	17	3	3	1	26	75	22	3	0

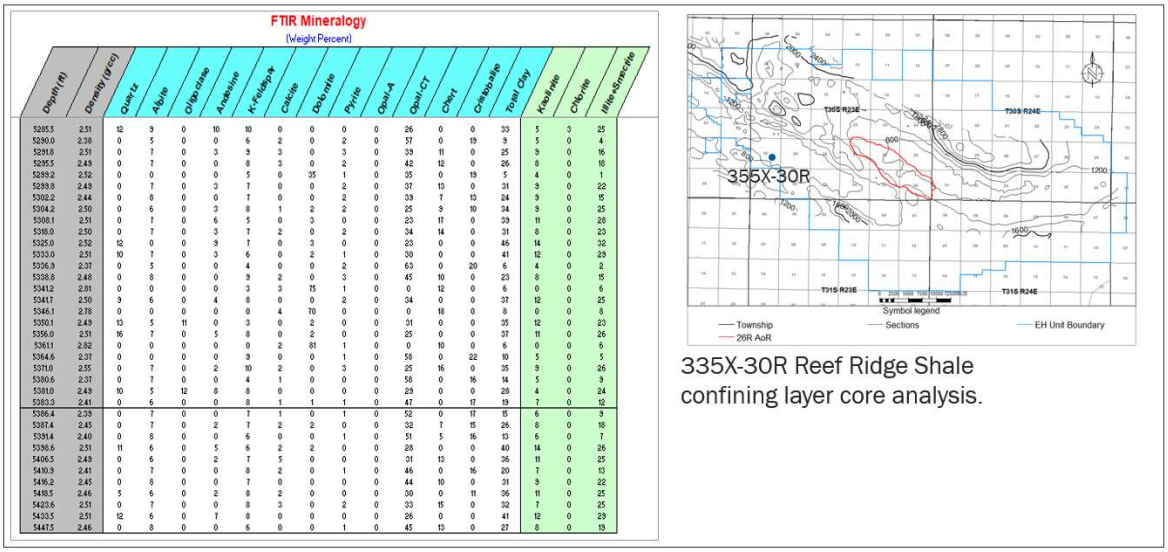


Reef Ridge Shale:

Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 14). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AoR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 14: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.



FTIR Mineralogy
(Weight Percent)

Depth (ft)	Density (g/cc)	Quartz	Albite	Oligoclase	Anorthite	K-Feldspar	Calcite	Dolomite	Pyrite	Opal-A	Opal-CT	Chert	Cristobalite	Total Clay	Kaolinite	Chlorite	Illite-Smectite
5285.5	2.51	12	9	0	10	10	0	0	0	0	26	0	0	33	5	3	25
5290.0	2.38	0	5	0	0	6	2	0	2	0	57	0	13	9	5	0	4
5291.8	2.51	0	7	0	3	9	3	0	3	0	39	11	0	25	9	0	16
5295.5	2.43	0	7	0	0	8	3	0	2	0	42	12	0	26	8	0	18
5299.2	2.52	0	0	0	0	5	0	35	1	0	35	0	19	5	4	0	1
5299.8	2.43	0	7	0	3	7	0	0	2	0	37	13	0	31	9	0	22
5302.2	2.44	0	8	0	0	7	0	0	2	0	39	7	13	24	9	0	15
5304.2	2.50	0	6	0	3	8	1	2	2	0	25	9	10	34	9	0	25
5308.1	2.51	0	7	0	6	5	0	3	0	0	23	17	0	39	11	0	28
5310.0	2.50	0	7	0	3	7	2	0	2	0	34	14	0	31	8	0	23
5325.0	2.52	12	0	0	9	7	0	3	0	0	23	0	0	46	14	0	32
5333.0	2.51	10	7	0	3	6	0	2	1	0	30	0	0	41	12	0	29
5336.9	2.37	0	5	0	0	4	0	0	2	0	63	0	20	6	4	0	2
5338.8	2.48	0	8	0	0	9	2	0	3	0	45	10	0	23	8	0	15
5341.2	2.81	0	0	0	0	3	3	75	1	0	0	12	0	6	0	0	6
5341.7	2.50	9	6	0	4	8	0	0	2	0	34	0	0	37	12	0	25
5346.1	2.78	0	0	0	0	0	4	70	0	0	0	18	0	8	0	0	8
5350.1	2.43	13	5	11	0	3	0	2	0	0	31	0	0	35	12	0	23
5356.0	2.51	16	7	0	5	8	0	2	0	0	25	0	0	37	11	0	26
5361.1	2.82	0	0	0	0	0	2	81	1	0	0	10	0	6	0	0	6
5364.6	2.37	0	0	0	0	3	0	0	1	0	59	0	22	10	5	0	5
5371.0	2.55	0	7	0	2	10	2	0	3	0	25	16	0	35	9	0	26
5380.6	2.37	0	7	0	0	4	1	0	0	0	58	0	16	14	5	0	9
5381.0	2.43	10	5	12	8	8	0	0	0	0	29	0	0	28	4	0	24
5383.3	2.41	0	6	0	0	8	1	1	1	0	47	0	17	19	7	0	12
5386.4	2.39	0	7	0	0	7	1	0	1	0	52	0	17	15	6	0	9
5387.4	2.45	0	7	0	2	7	2	2	0	0	32	7	15	26	8	0	18
5391.4	2.40	0	8	0	0	6	0	0	1	0	51	5	16	13	6	0	7
5398.6	2.51	11	6	0	5	6	2	2	0	0	28	0	0	40	14	0	26
5406.5	2.43	0	6	0	2	7	5	0	0	0	31	13	0	36	11	0	25
5410.9	2.41	0	7	0	0	8	2	0	1	0	46	0	16	20	7	0	13
5416.2	2.45	0	8	0	0	7	0	0	0	0	44	10	0	31	9	0	22
5418.5	2.46	5	6	0	2	8	2	0	0	0	30	0	11	36	11	0	25
5423.6	2.51	0	7	0	0	8	3	0	2	0	33	15	0	32	7	0	25
5433.5	2.51	12	6	0	7	8	0	0	0	0	26	0	0	41	12	0	29
5447.5	2.46	0	8	0	0	6	0	0	1	0	45	13	0	27	8	0	19

335X-30R Reef Ridge Shale confining layer core analysis.

Porosity and Permeability

26R Monterey Formation:

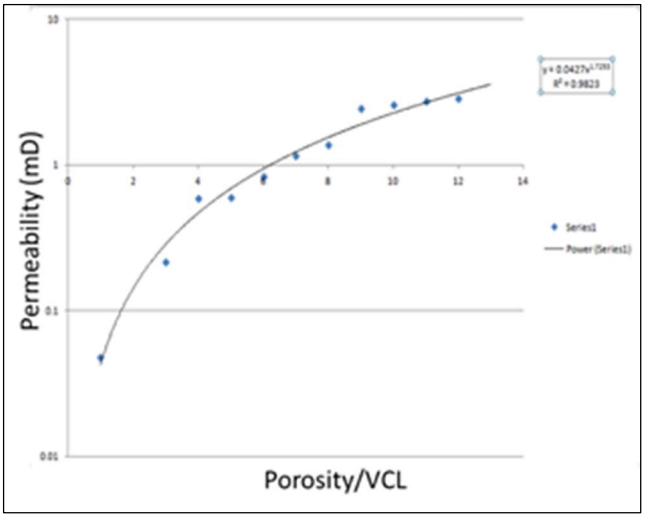
Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.

Volume of clay is determined by neutron-density separation and is calibrated to core data.

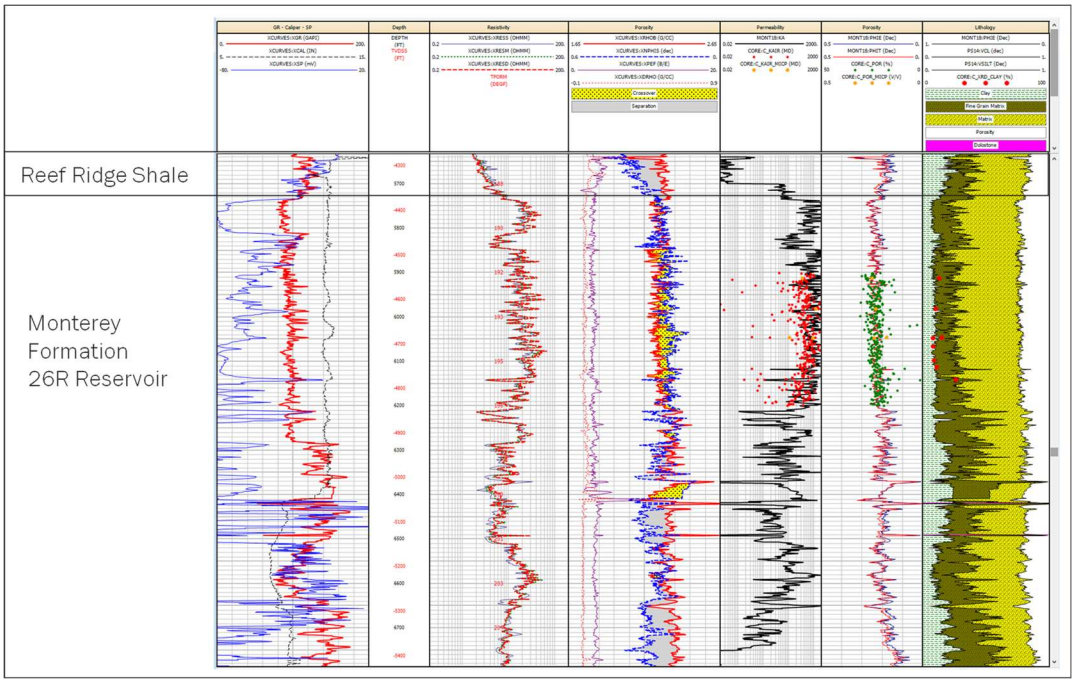
Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated in Figure 15 below.

Figure 15: Permeability function developed based on mercury injection capitally pressure data and calculated from log derived porosity and clay volume.



In the example below for the 26R Monterey Formation sands, the porosity ranges from 20% - 30% with a mean of 24%. The permeability ranges from 3 mD – 1,500 mD with a log mean of 45 mD (Figure 16).

Figure 16: Porosity and permeability for well 377H-26R, showing the distribution and the input and output log curves.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2).

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006
TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

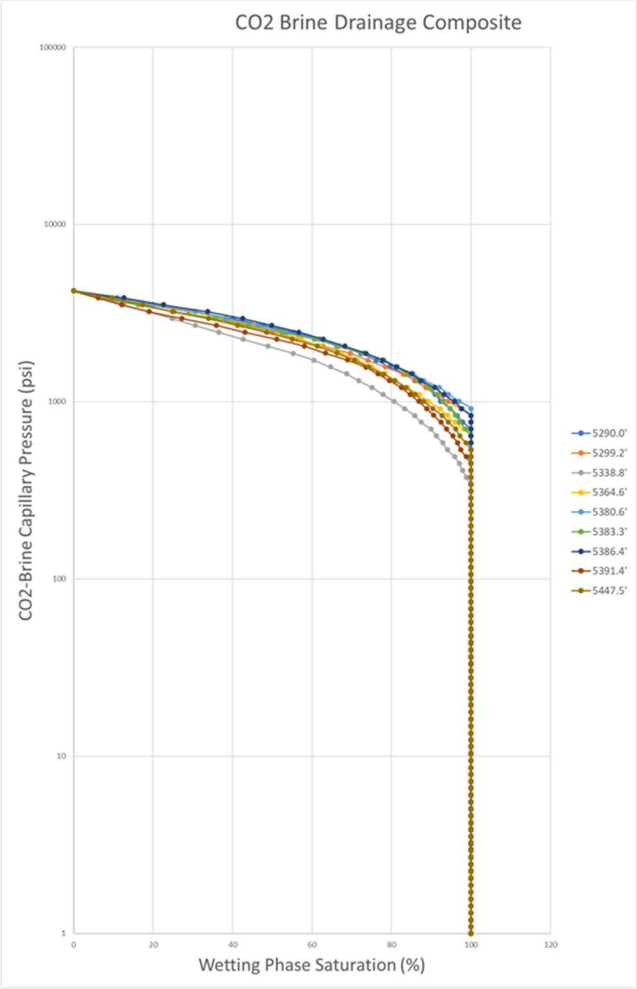
Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 17). The capillary pressure was determined by applying CO_2-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-

brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO_2-brine, respectively.

Figure 17: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR, 11 wells had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 22,592 individual logging data points.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

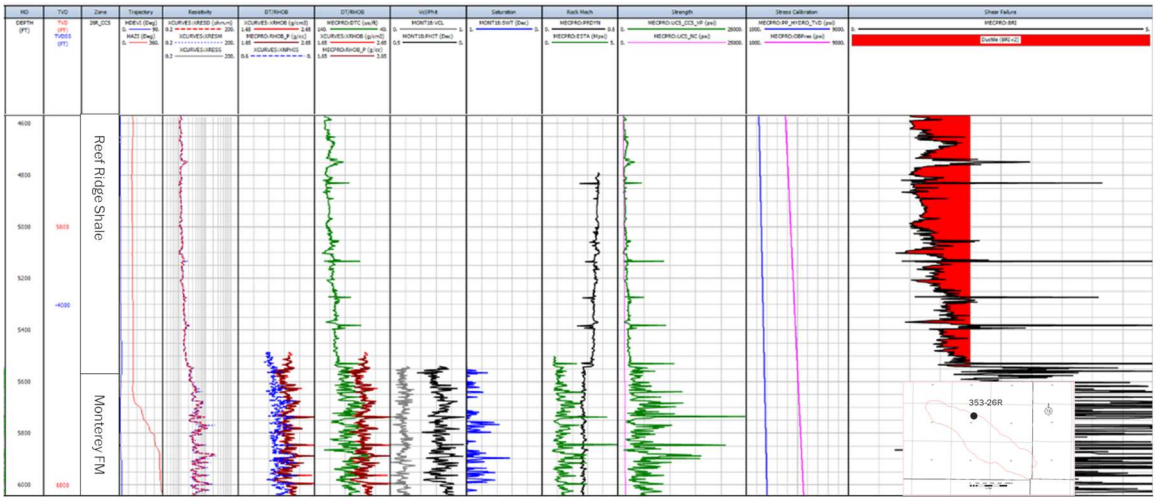
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 353-26R is shown below (Figure 18). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method.

Figure 18: Unconfined compressive strength and ductility calculations for well 353-26R. The Reef Ridge Shale ductility is shaded where less than two.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than two, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to anneal discontinuities. The BRI less than two confirms that the Reef Ridge is a ductile confining layer.

The average ductility of the confining zone based on data from 11 wells is 1.59.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,385 PSI.

As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the 26R Monterey Formation reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 20 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

Figure 19: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).

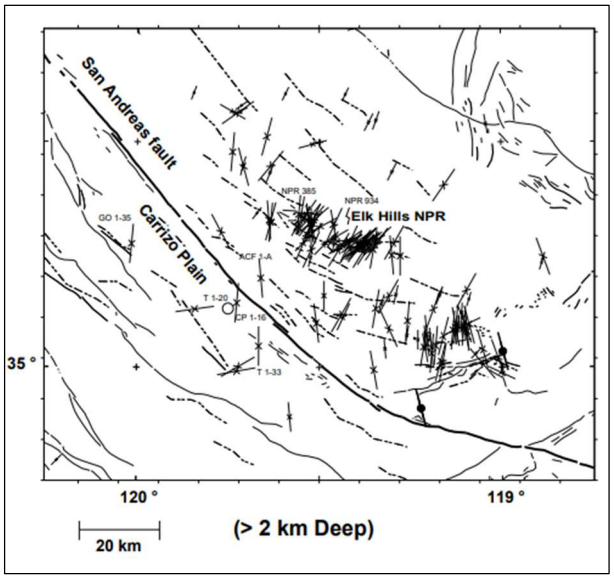


Table 3 shows the horizontal fracture gradients for the Reef Ridge Shale and the Monterey Formation 26R reservoir.

Table 3: Pressure gradients for the Monterey Formation 26R reservoir and Reef Ridge Shale.

Stress	Reef Ridge Confining Layer	Monterey Formation
Pore Pressure Gradient (psi/ft)	0.433	0.5
Overburden Gradient (psi/ft)	0.91	0.92
Breakdown Gradient (psi/ft)	1.12	1.03

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOME0.CH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO_2 injection. A modified Barton-Bandis model can be used to allow CO_2 to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO_2 is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO_2 to leak from the storage reservoir.

Description:

A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 21.

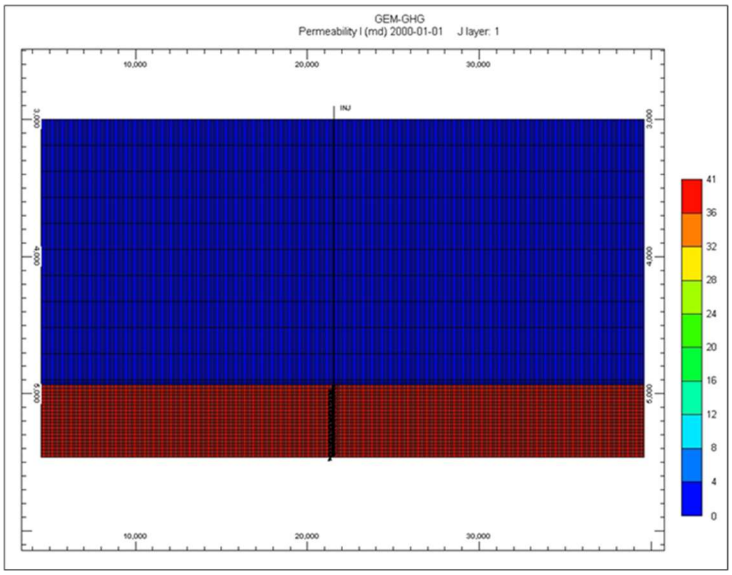
In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the

reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO_2 with a maximum injection pressure of 10,000 PSI.

Figure 20: Geomechanics Model.



Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 22 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO_2 bleeding into the cap rock despite the very low vertical permeability.

Figure 21: Normal Fracture Stress and Pressure for Geomechanics Cases.

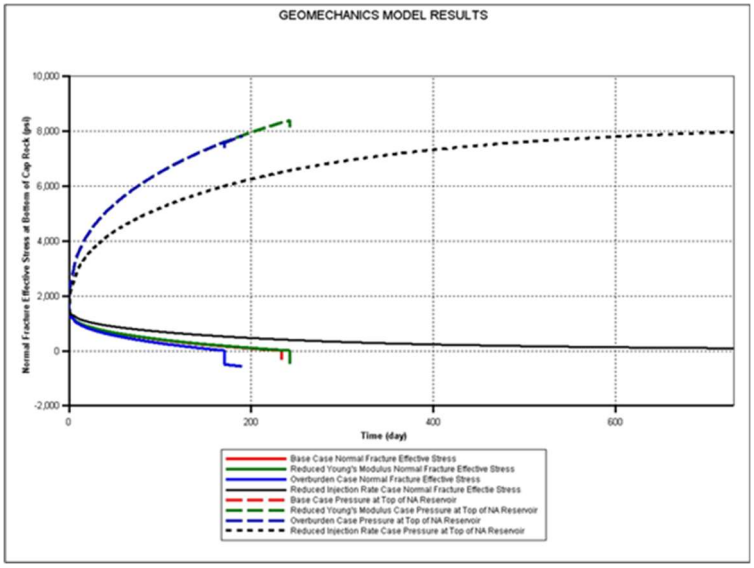


Table 4: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	**FAILURE PRESSURE, psia**
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Results:

Failure pressures for the four scenarios are given in Table 4. These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,600 PSI or more without tensile failure.

Seismic History [40 CFR 146.82(a)(3)(v)]

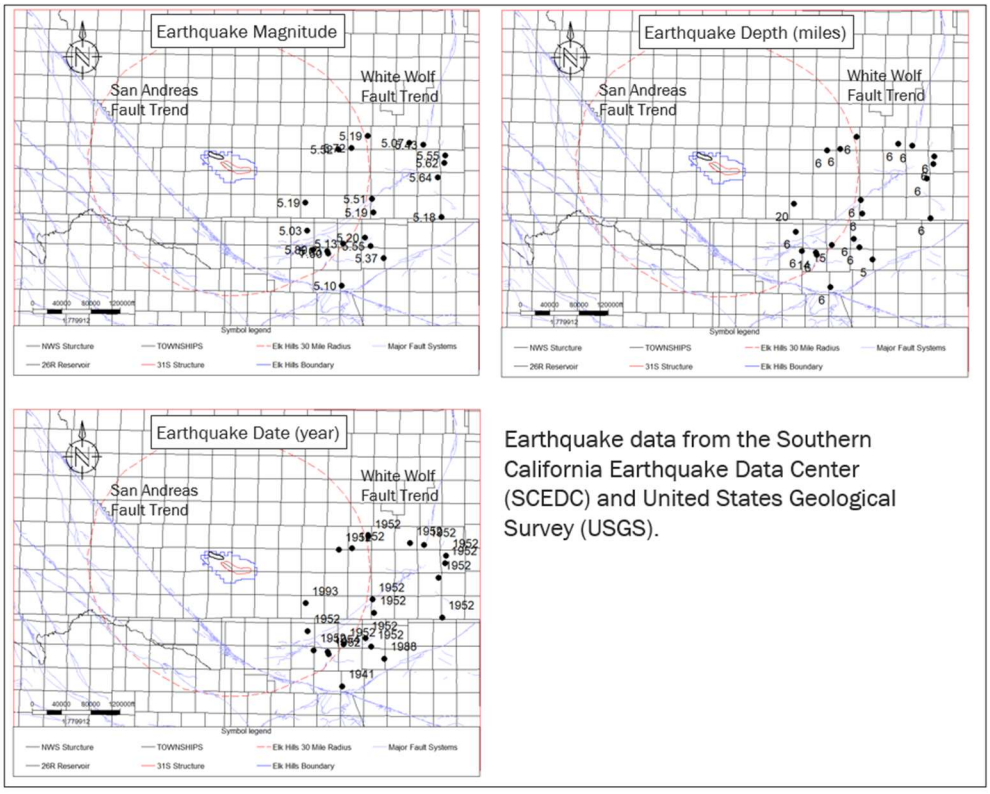
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

Within the EHOF there have been no earthquakes recorded greater than 3.0. In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF (Figure 23). The average depth of these earthquakes is 6.3 miles.

Figure 22: Earthquakes in the San Joaquin Basin with a magnitude greater than 5 since 1932. The White Wolf Fault is active in the southern San Joaquin Basin.



Seismic Risk:

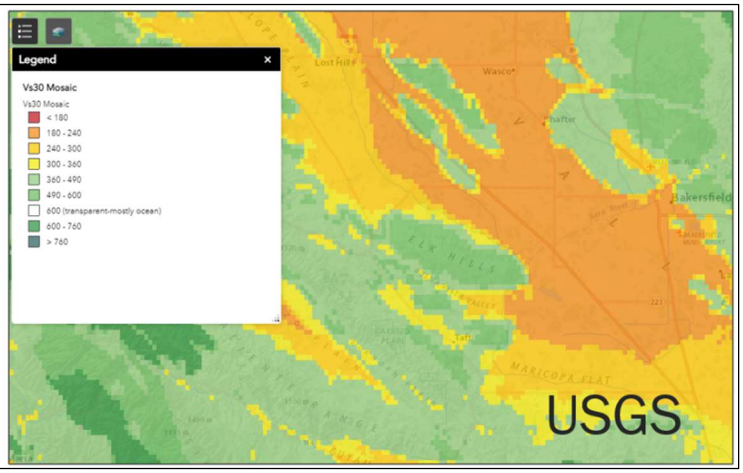
The EHOF has been closely monitored for the effects of seismicity by CTV and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

1. No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
2. VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high VS30 means (Figure 24) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
3. The 1952 Kern County earthquake, the largest in the region, occurred southeast of the EHOF near Frazier Park with an estimated magnitude of 7.5. Effects of the earthquake were catastrophic with loss of life, and significant property damage (SCEDC). Regionally there were no reservoir containment issues associated with oil and gas operations and the Reef Ridge Shale. Moreover, there was no impact to Elk Hills infrastructure (Jenkins, 1955).

Figure 23: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.

Table: NEHRP seismic site classification based on shear-wave velocity (Vs) ranges.

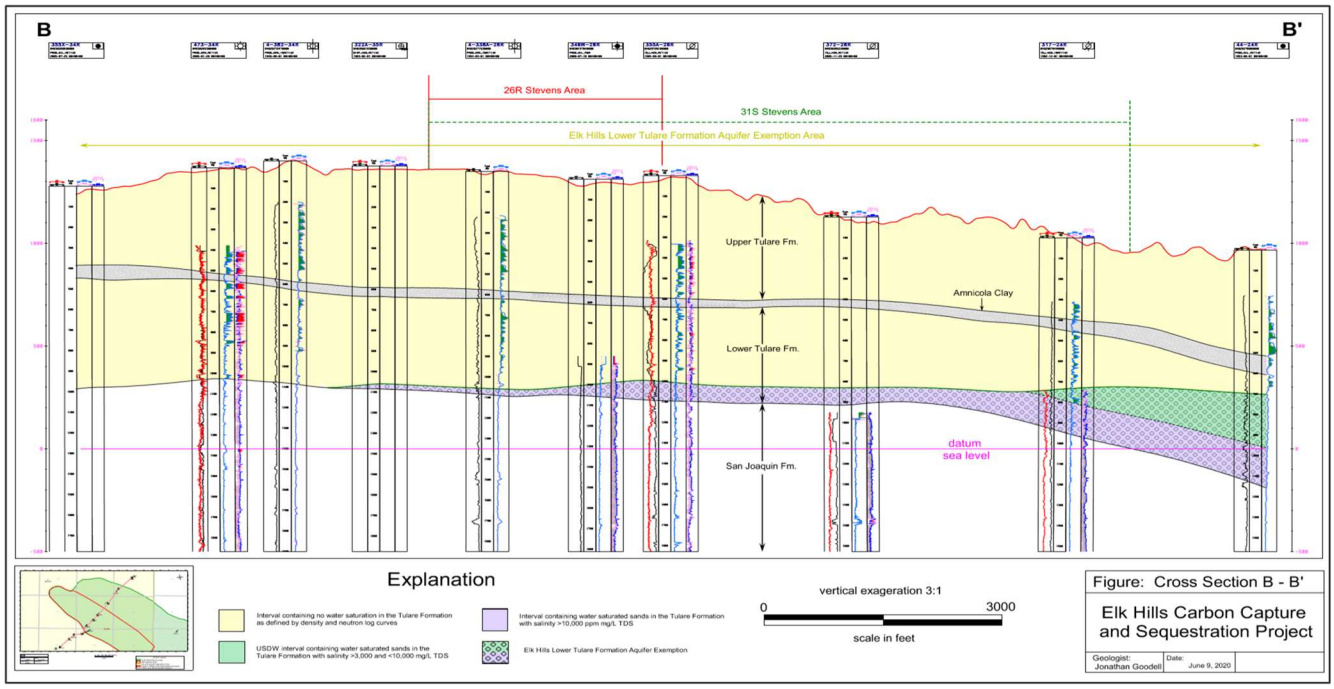
Site Class	S-Velocity (Vs) (ft/sec)	S-Velocity (Vs) (m/sec)
A (Hard Rock)	> 5,000	> 1500
B (Rock)	2,500 – 5000	760 – 1500
C (Very Dense Soil and Soft Rock)	1,200 – 2,500	360 – 760
D (Stiff Soil)	600 – 1,200	180 – 360
E (Soft Clay Soil)	< 600	< 180
F (Soils requiring additional response)	< 600, and meeting some additional conditions.	< 180, and meeting some additional conditions.



Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

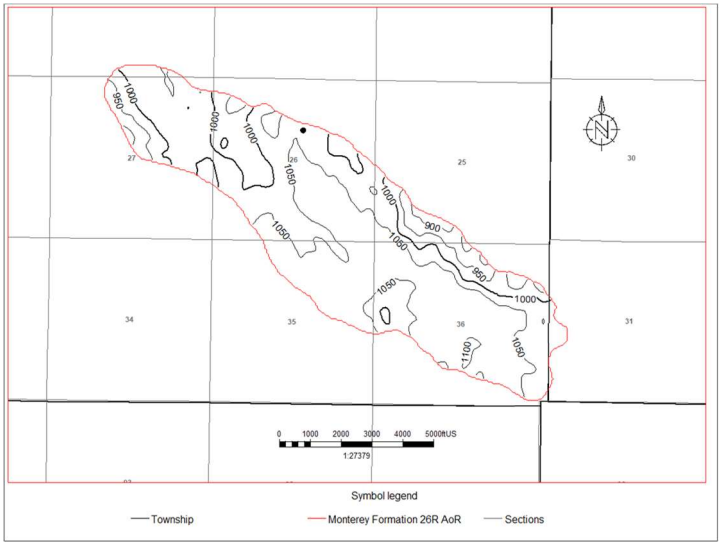
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 25). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 24: The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands are unsaturated in the 26R area.



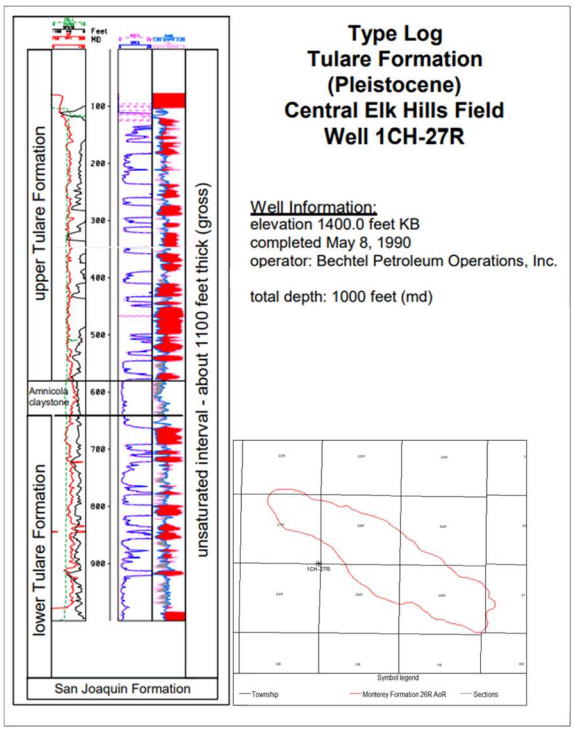
The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 25). The depth is 900 - 1,000 feet and the thickness ranges from 900 – 1,000 feet (Figure 26).

Figure 25: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 27). The characteristic density-neutron crossover (red-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity.

Figure 26: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, and Lower Tulare exempt aquifer.



Tulare Formation (Figure 28) water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum contaminant levels (MCL).

In 2018 the Lower Tulare aquifer was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and
2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

Figure 27: Upper Tulare and Lower Tulare Formation water analysis.

Upper Tulare

Table 6a. WATER SOURCE WELL #43WS-133
WATER ANALYSIS DATA (mg/kg)

DATE	6-95	7-95	8-95	9-95
SAMPLE #	95094	95150	95182	95189
CONSTITUENTS:				
Calcium, Ca	230	230	220	220
Magnesium, Mg	85	85	92	93
Sodium, Na	1280	1300	1200	1300
Potassium, K	9.2	9.8	8.8	8.6
Iron, Fe	0.4	0.51	0.38	0.54
Hydroxide, OH	0	0	0	0
Carbonate, CO3	0	0	0	0
Bicarb, HCO3	180	190	190	180
Chloride, Cl	1360	1400	1300	1400
Sulfate, SO4	1600	1600	1500	1600
Sulfide, S	<5.0	<5.0	<5.0	<5.0
Totals	4660	4700	4480	4700
Boron, B	4.7	4.6	4.7	4.7
TDS (Grav)	4890	4800	4900	4900
Hardness, CaCO3	920	920	930	930
Alkalinity, CaCO3	150	160	160	150
Sodium Chloride	3690	3700	3500	3800
pH	7.8	8.1	8.0	7.9
Electrical Conductivity	6.99 mmhos/cm	7.02 mmhos/cm	6.99 mmhos/cm	6.99 mmhos/cm
Specific Gravity	1.003	1.003	1.004	1.003
Resistivity	1.43 ohmm	1.43 ohmm	1.43 ohmm	1.43 ohmm

NOTE: Sample analysis is from Zalco Laboratory.

(Source: NPR-1 Ground Water Monitoring Plan, 1995)

Lower Tulare

Water Analysis (General Chemistry)

BCL Sample ID: 1411064-01 | Client Sample Name: Elk Hills Well 82-2B, 5/17/2014 4:05:00PM, Rick Ogletree

Constituent	Result	Units	PQL	MDL	Method	MB Bias	Lab Quals
Electrical Conductivity @ 25 C (Field Test)	27000	umhos/cm	1.0	1.0	EPA-120.1		
pH (Field Test)	7.23	pH Units	0.05	0.05	EPA-150.1		
Temperature (Field Test)	87.6	F	32.0	32.0	SM-2550B		
Total Calcium	650	mg/L	2.0	0.30	EPA-6010B	ND	A10
Total Magnesium	230	mg/L	1.0	0.38	EPA-6010B	0.75	A10
Total Sodium	4700	mg/L	10	1.0	EPA-6010B	ND	A01
Total Potassium	31	mg/L	20	2.6	EPA-6010B	ND	A10
Bicarbonate Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Carbonate Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Hydroxide Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Total Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Bromide	50	mg/L	5.0	2.2	EPA-300.0	ND	A01
Chloride	10000	mg/L	50	6.7	EPA-300.0	20	A01
Fluoride	ND	mg/L	2.5	0.70	EPA-300.0	ND	A10
Nitrate as NO3	ND	mg/L	22	5.5	EPA-300.0	ND	A10
Sulfate	320	mg/L	50	9.0	EPA-300.0	19	A01
pH	7.47	pH Units	0.05	0.05	EPA-150.1		S05
Electrical Conductivity @ 25 C	26100	umhos/cm	1.00	1.00	EPA-120.1		
Total Dissolved Solids @ 180 C	20000	mg/L	1000	1000	EPA-160.1	ND	

Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the

Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

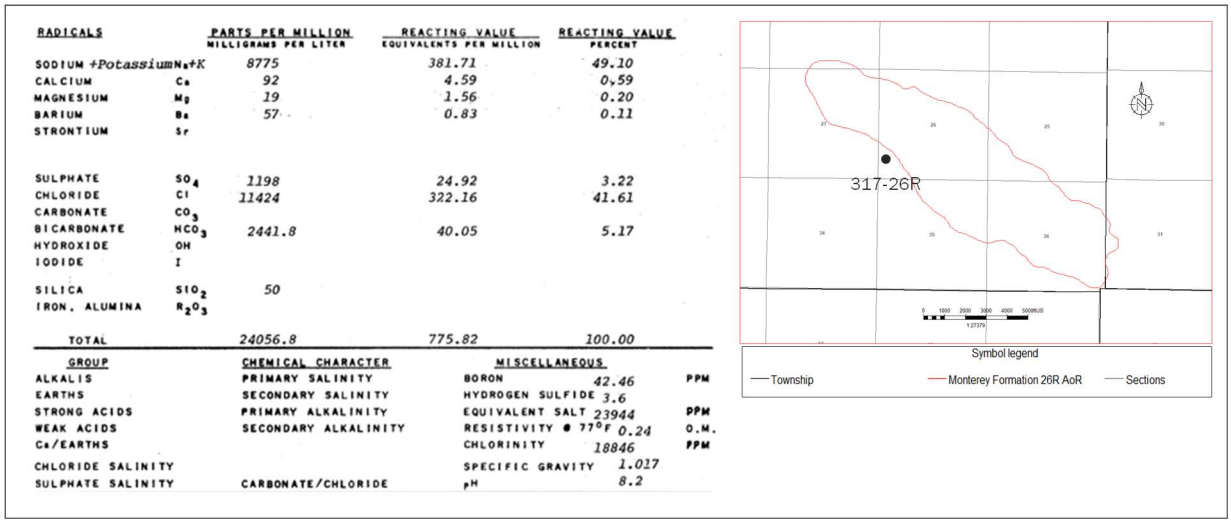
Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry 26R Reservoir:

The 26R Monterey Formation reservoir has a gas cap that overlies a thin oil band and a basal water zone. CTV and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Geochemical water analysis for the 26R Monterey Formation reservoir has been completed across the AoR and collected since reservoir discovery as part of routine surveillance. This data is consistent through time and over the AoR, Figure 29 shows the geochemical water analysis for well 317-26R.

Figure 28: Monterey Formation 26R reservoir water geochemistry from well 317-26R.



RADICALS		PARTS PER MILLION MILLIGRAMS PER LITER	REACTING VALUE EQUIVALENTS PER MILLION	REACTING VALUE PERCENT
SODIUM +Potassium	$Na+K$	8775	381.71	49.10
CALCIUM	Ca	92	4.59	0.59
MAGNESIUM	Mg	19	1.56	0.20
BARIUM	Ba	57	0.83	0.11
STRONTIUM	Sr			
SULPHATE	SO_4	1198	24.92	3.22
CHLORIDE	Cl	11424	322.16	41.61
CARBONATE	CO_3			
BICARBONATE	HCO_3	2441.8	40.05	5.17
HYDROXIDE	OH			
IODIDE	I			
SILICA	SiO_2	50		
IRON, ALUMINA	R_2O_3			
TOTAL		24056.8	775.82	100.00

GROUP	CHEMICAL CHARACTER	MISCELLANEOUS		
ALKALIS	PRIMARY SALINITY	BORON	42.46	PPM
EARTHS	SECONDARY SALINITY	HYDROGEN SULFIDE	3.6	
STRONG ACIDS	PRIMARY ALKALINITY	EQUIVALENT SALT	23944	PPM
WEAK ACIDS	SECONDARY ALKALINITY	RESISTIVITY @ 77°F	0.24	O.M.
Ca/EARTHS		CHLORINITY	18846	PPM
CHLORIDE SALINITY		SPECIFIC GRAVITY	1.017	
SULPHATE SALINITY	CARBONATE/CHLORIDE	pH	8.2	

The hydrocarbon composition for the Monterey Formation 26R reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 30 shows the results of the hydrocarbon composition for well 356-26R within the AoR. Oil composition analysis was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

Figure 29: Monterey Formation reservoir hydrocarbon analysis from well 356-26R.

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	MOL PERCENT	WEIGHT PERCENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide	Nil	Nil			
Carbon Dioxide	1.29	0.65			
Nitrogen	0.07	0.02			
Methane	38.83	7.16			
Ethane	8.38	2.89			
Propane	7.05	3.57			
iso-Butane	1.38	0.92			
n-Butane	3.92	2.61			
iso-Pentane	1.50	1.24			
n-Pentane	1.72	1.42			
Hexanes	2.15	2.12			
Heptanes plus	33.71	77.40	0.8516	34.5	200
	100.00	100.00			

26R Monterey Formation Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO_2 injectate:

1. The 26R Monterey Formation reservoir will store 7% of the injectate CO_2 in aqueous phase with water saturations of 34% saturation in the gas cap, 25% in the oil band and 100% in the basal water.
2. Residual oil saturation (15- 37%) in the 26R Monterey Formation reservoir will dissolve 20% of the CO_2 injectate.
3. The Monterey Formation has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO_2 and carbonic acid and any dissolution or changes that occur will stay on grain surfaces.

The oil and water CO_2 trapping mechanisms have been incorporated in the computational modeling and is discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO_2 injectate.

Site Suitability [40 CFR 146.83]

The 26R Monterey Formation reservoir in the 26R anticline was discovered in the 1940's and developed in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the 26R Monterey Formation reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

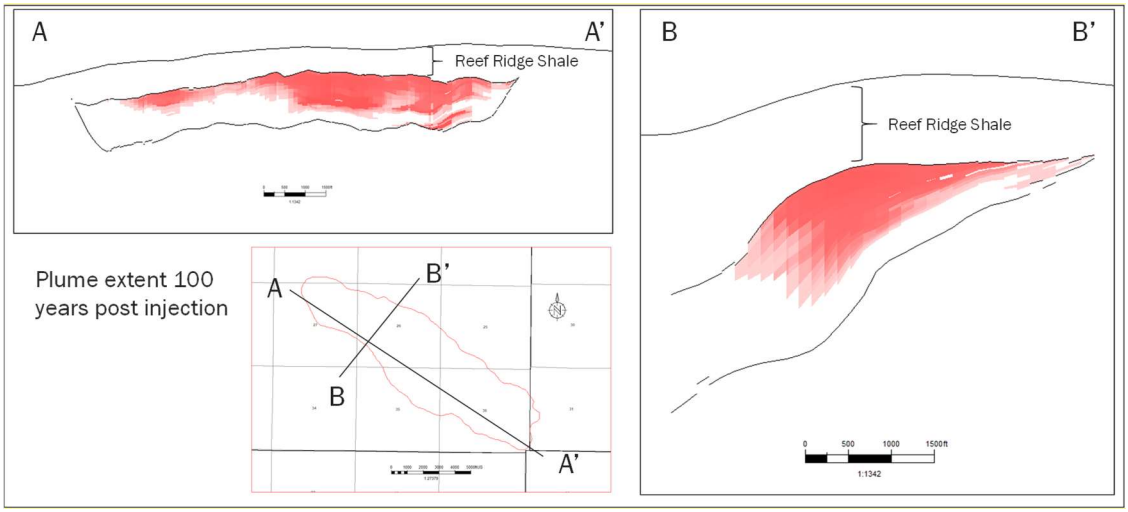
A key component of the 26R Monterey Formation reservoir characterization was the development of a geo-cellular model, which is used to assess CO_2 plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement, and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale).

CO2 Injectate Confinement:

Confinement of CO_2 injected into the storage reservoir is supported by the following:

1. Monterey Formation 26R reservoir hydrocarbons were confined for several million years.
2. The Reef Ridge Shale primary confining layer is 800-1,000 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 841 billion cubic feet of gas and 114 million barrels of water with no leakage.
3. Cross section A-A' (Figure 31) shows confinement of the injected CO_2 plume by up-dip pinch-out of the reservoir on the anticline structure and lateral confinement by reservoir edges. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does not migrate beyond the edges of the anticline structure or into the Reef Ridge Shale.

Figure 31: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the Monterey Formation 26R sand facies and the edges of the reservoir.



Storage capacity for the Monterey Formation 26R storage reservoir based on computational modeling results is up to 38 million tonnes of CO_2. This is sufficient capacity for the total proposed injectate volume.

AoR and Corrective Action

CTV's AoR and Corrective Action plan pursuant to 40 CFR 146.82(a)(4), 40 CFR 146.82(a)(13) and 146.84(b), and 40 CFR 146.84(c) describes the process, software, and results to establish the AoR, and the wells that require corrective action.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

Financial Responsibility

CTV's Financial Responsibility demonstration pursuant to 140 CFR 146.82(a)(14) and 40 CFR 146.85 is met with a line of credit for Injection Well Plugging and Post-Injection Site Care and Site Closure and insurance to cover Emergency and Remedial Responses.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

Injection Well Construction

CTV plans to repurpose existing injector 373-35R and drill three new injectors for the Elk Hills 26R storage project. Well 373-35R is currently approved by CalGEM for Class II injection of water for the purpose of reservoir pressure maintenance.

Construction Procedures [40 CFR 146.82(a)(12)]

Injectate Migration Prevention:

373-35R was drilled in 1981, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing
3. All casing strings were cemented in place with cement to surface using industry-proven recommended practices for slurry design and placement
4. Cement bond log indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results
5. Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and Mechanical Integrity Testing (MIT) to be conducted
6. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Materials:

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

1. Tubing –13 CR-95 or other corrosion resistant alloy
2. Wellhead – stainless steel or other corrosion resistant alloy
3. Packer – corrosion resistant alloy and hardened rubber
4. Casing and Cement - N-80 and K-55 casing with Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 with good cement bond between formation and casing into the Reef Ridge Shale

The well will be tested for mechanical integrity prior to injection.

Standards:

Well materials follow the following standards:

1. API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

Casing:

26R Monterey Formation temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity.

Casing specifications are presented in Table 5. These specifications show that the well was engineered to standards that allow for the safe operation at a bottomhole injection pressure that will not be greater than 4,900 PSI (0.71 PSI per foot). Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues attributed to the casing design.

Table 5: Casing construction data for the 373-35R injector.

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14-53	20.000	19.5	52	H-40	Short	31	875	90
Surface	14-331	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14-3,006	9.625	8.835	40	K-55	Long	31	3,950	2,570
Long-string	14-7,988	7.000	6.276 6.276 6.366	26 26 23	N-80 K-55 K-55	Long	31	7,240 4,980 4,360	5,410 4,320 3,270

Casing below injection packer and exposed to CO2 injectate.

Table 6. Casing details.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	53	24	0.25	20	H40	52
Surface	331	17.5	0.33	13.375	H40	48
Intermediate	3,006	12.25	0.395	9.625	K-55	40
Long String	7,988	8.75	6.276 6.276 6.366	7.0	N-80 K-55 K-55	26 26 23

Tubing and Packer

The information in this table meets the minimum requirements at 40 CFR 146.86(c).

CTV plans to use the following and will update the EPA as part of pre-operational testing.

Table 7. Tubing and packer details.

Component	Setting Depth (ft)	Min Yield Strength (psi)	Burst Pressure (psi)	Collapse Pressure (psi)	Material
Tubing	7,043	80,000	10,480	11,080	13CR L-80
Packer	7,049	80,000	7,500	7,500	13CR L-80 or other CRA

Pre-Operational Logging and Testing

CTV has provided operational and testing data to support the Elk Hills 26R project. Data and information provided meets the requirements pursuant to 40 CFR 146.82(a)(8) and 40 CFR 146.87.

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational Testing
Tab(s): Welcome tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

373-35R Well Operation

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of super-critical (SC) phase CO_2. For attaining SC flow, surface injection pressure will be a minimum of 1,200 PSI. As the depleted oil reservoir fills up, a higher surface injection pressure will likely be required. Final reservoir pressure target is 3,250 PSI. It is assumed that at shut-in, the downhole injection pressure will be 4,010 PSI (0.59 PSI/FT) for well 373-35R.

Table 8 values shown below for average injection pressure are an average of initial conditions and final conditions. As the reservoir fills up with CO_2 it will pressure up, thus creating a continually changing reservoir and injector condition over injection life. A downhole injection pressure of 4,010 PSI is assumed to occur at shut-in timing when reservoir pressure has reached its final level at 3,250 PSI. This translates to a surface injection pressure of ~1,600 PSI, which will be achieved via a surface booster pump.

The final/maximum values for surface and downhole injection pressures are far below those associated with the Class II permitted fracture gradients of 0.8 psi/foot. Over 40 years of gas and water injection experience into the Monterey Formation supports that these operating limits are appropriate and effective. Additionally, the final reservoir pressure target of 3,250 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical tensile failure pressure of ~7,500 PSI.

As mentioned above, as the reservoir fills up with CO_2, the reservoir pore pressure will increase. A surface booster pump will be needed to supplement surface injection pressure from the initial value of ~1,200 PSI to the final requirement of ~1,600 PSI.

Table 8. Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface	2,300	psig
Downhole	4,900	psig
Average Injection Pressure	Average over time	
Surface	1,375	psig
Downhole	3,699	psig
Maximum Injection Rate	30 per well	mmscfpd
Average Injection Rate	15-25 per well	mmscfpd
Maximum Injection Volume and/or Mass	38 million	tonnes
Average Injection Volume and/or Mass	38 million	tonnes
Annulus Pressure	2,984 @ packer	psig
Annulus Pressure/Tubing Differential	715 @ packer @ average injection condition	psig

Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

There are currently multiple sources of anthropogenic CO_2 being considered for 26R Monterey Formation sequestration. These include capture off of the Elk Hills NGCC Power Plant as well as 3rd party existing and proposed industrial sources in the Southern San Joaquin Valley area. The carbon dioxide stream will consist of a minimum of 95% CO_2 by volume. Other key constituents that will be controlled for corrosion mitigation include water content (<50ppmv) and oxygen level (<50 ppm)

Corrosiveness of the CO_2 stream is very low as long as the entrained water is kept in solution with the CO_2. This is ensured by the < 50ppmv injectate specification referred to above. Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. In early injection time, it is likely that gas phase CO_2 will exist towards the lower depths of the tubing string. Stainless steel (13 CR L-80) tubing will be used in the injection wells to mitigate this

potential corrosion impact should free-phase water be present. CTV may optimize the maximum water content specification prior to injection based on technical analysis.

Testing and Monitoring

CTV's Testing and Monitoring plan pursuant to 40 CFR 146.82 (a) (15) and 40 CFR 146.90 describes the strategies for testing and monitoring to ensure protection of the USDW, injection well mechanical integrity, and plume monitoring.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

Post-Injection Site Care (PISC) and Site Closure

CTV has developed a Post-Injection Site Care and Site Closure plan pursuant to 40 CFR 146.93 (a) to define post-injection testing and monitoring.

At this time CTV is not proposing an alternative PISC timeframe.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***

PISC and Site Closure GSDT Submissions

GSDT Module: Alternative PISC Timeframe Demonstration
Tab(s): All tabs (only if an alternative PISC timeframe is requested)

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

Emergency and Remedial Response

CTV's Emergency and Remedial Response plan pursuant to 40 CFR 164.94 describes the process and response to emergencies to ensure USDW protection.

Emergency and Remedial Response GSDT Submissions

GSDT Module: Project Plan Submissions
Tab(s): Emergency and Remedial Response tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

References:

1. Callaway, D.C., and Rennie, E.W., Jr., 1991, San Joaquin Basin, California, in Gluskoter, H.J., Rice, D.D., and Taylor, R. B., eds., Economic geology, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. P-2, p. 417-430.
2. Zumberge, John, Russell, Just and Reid, Stephen, Charging of Elk Hills reservoirs as determined by oil geochemistry, AAPG Bulletin, v. 89, no. 10 (October 2005), pp. 1347–1371.
3. Hosford, Allegra and Magoon, Les, 2007 Age, U.S. Geological Survey Professional Paper 1713, California Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, Chapter 5.
4. Castilla, Davis and Younker, Leland, 1997, David A. Castillo Leland W. Younker A High Shear Stress Segment along the San Andreas Fault: Inferences Based on Near-Field Stress Direction and Stress Magnitude Observations in the Carrizo Plain Area, Lawrence Livermore National Laboratory.

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ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project
373-35R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35°19'40.9189"N / 119°32'37.9057"W

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery

pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.

2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al

2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al

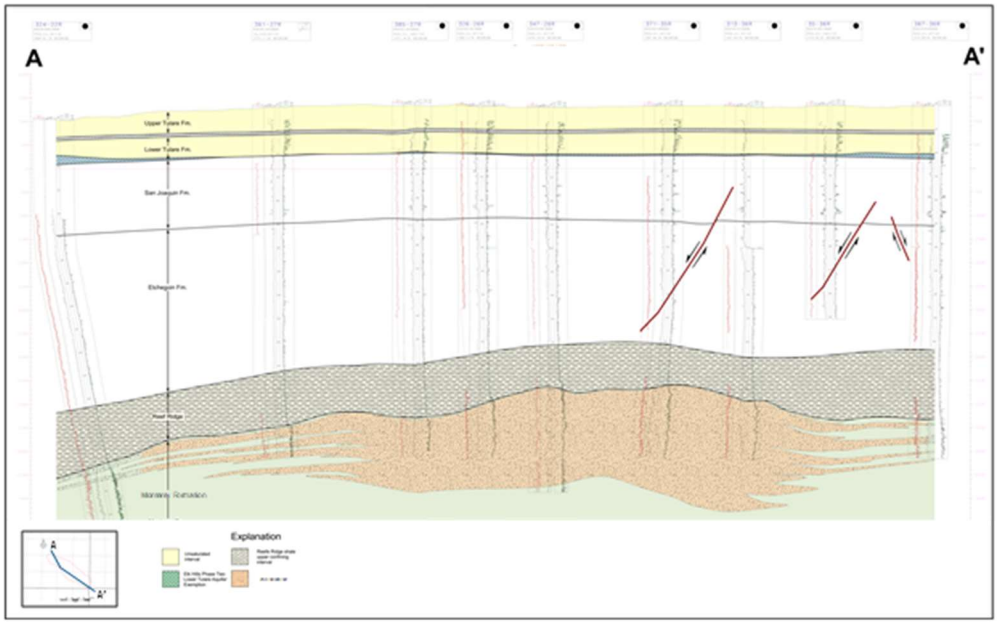
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation (Figure 8, Type Log). The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir

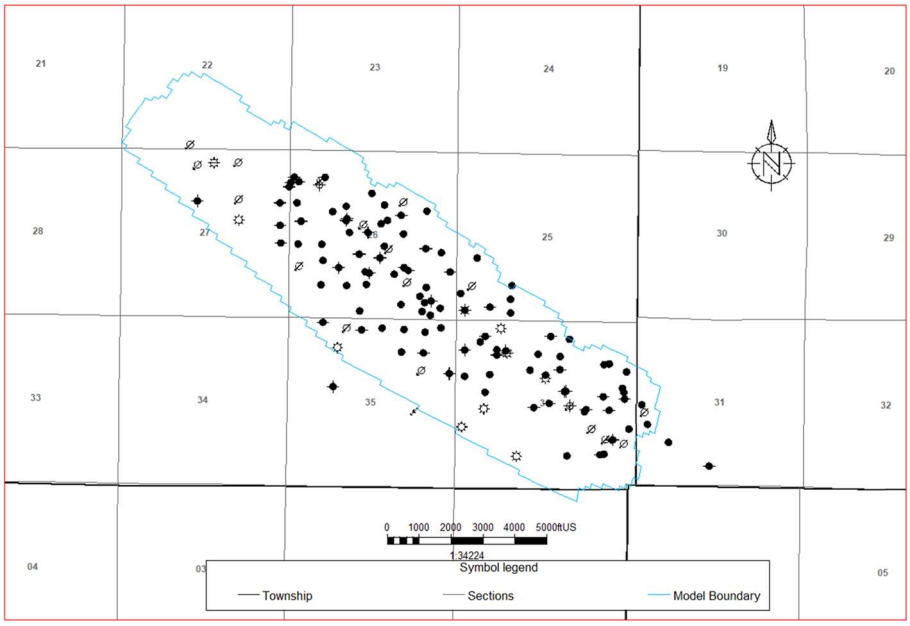
pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows

the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2.

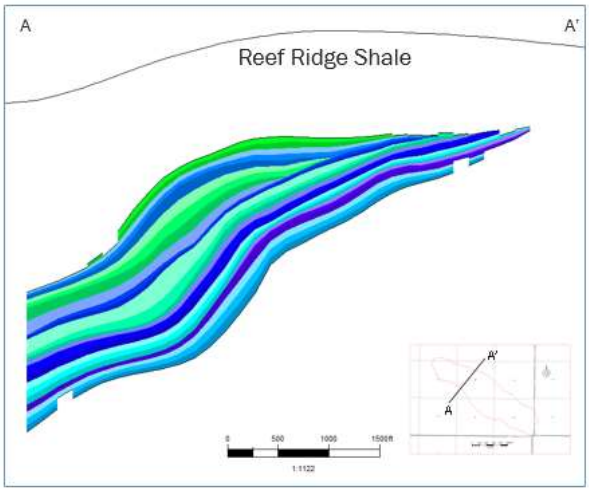
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4) that is dependent on porosity and clay volume.

Figure 4: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

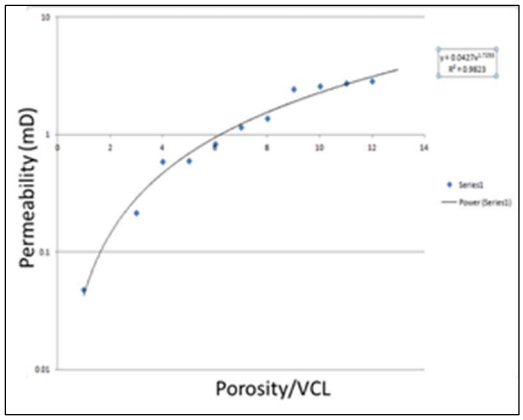


Figure 5: Monterey Formation 26R sands porosity and permeability distribution in the static model.

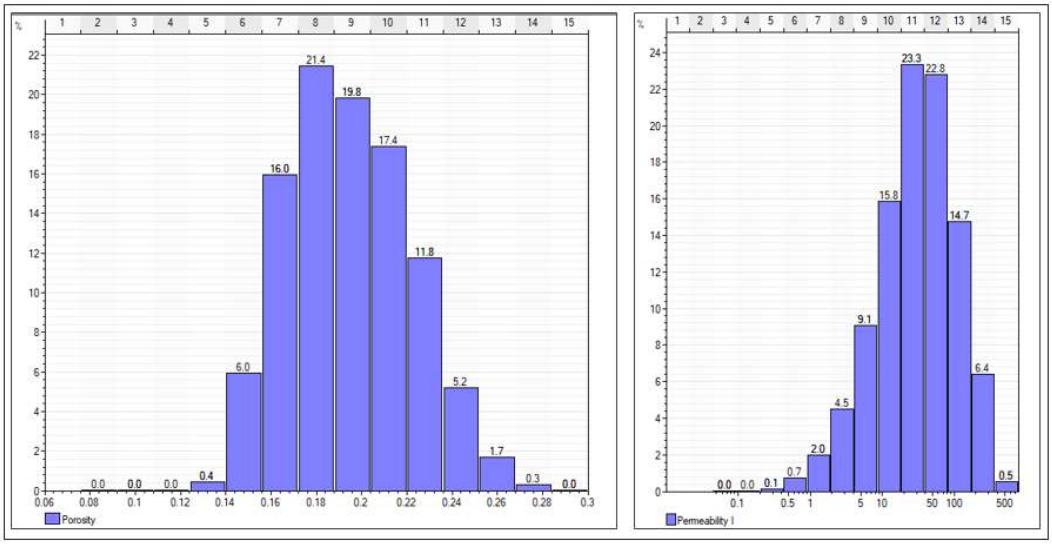
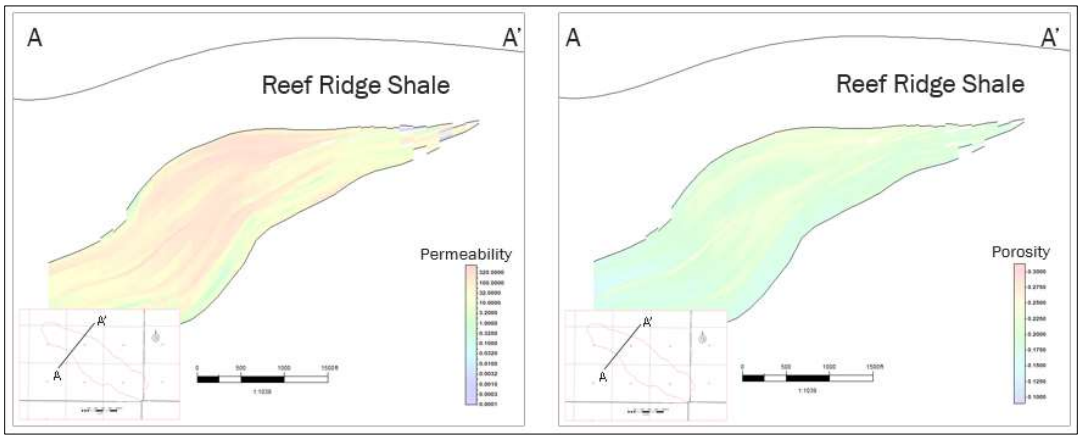


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 6: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



Constitutive Relationships and Other Rock Properties

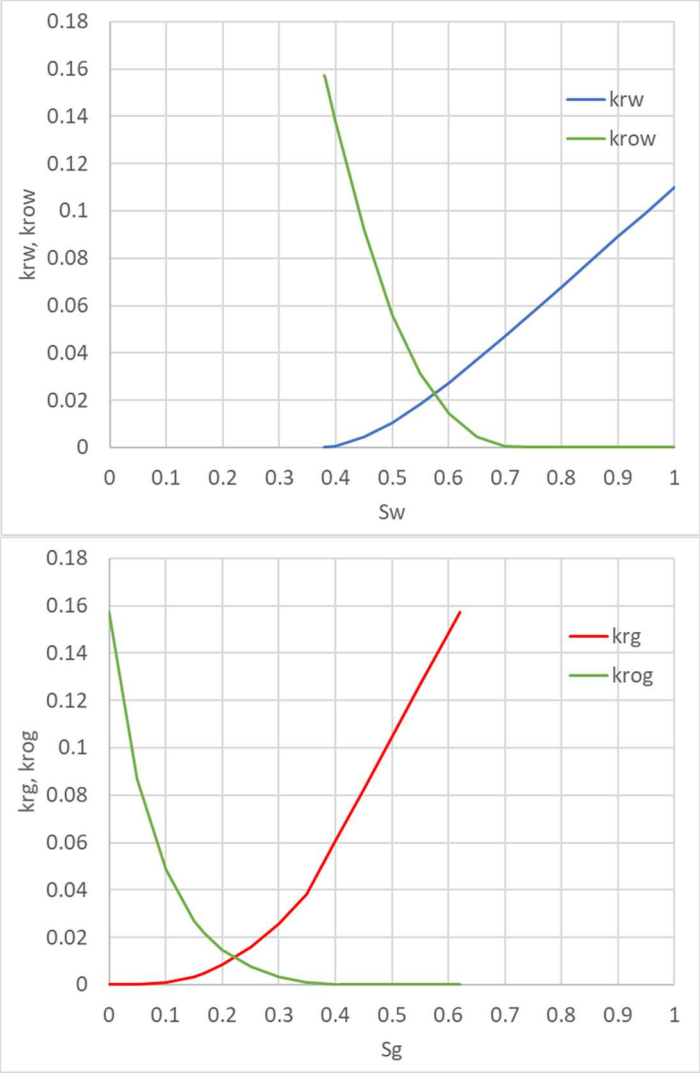
The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 7 shows the relative permeability curves used in the computational modeling.

Figure 7: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study.



Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

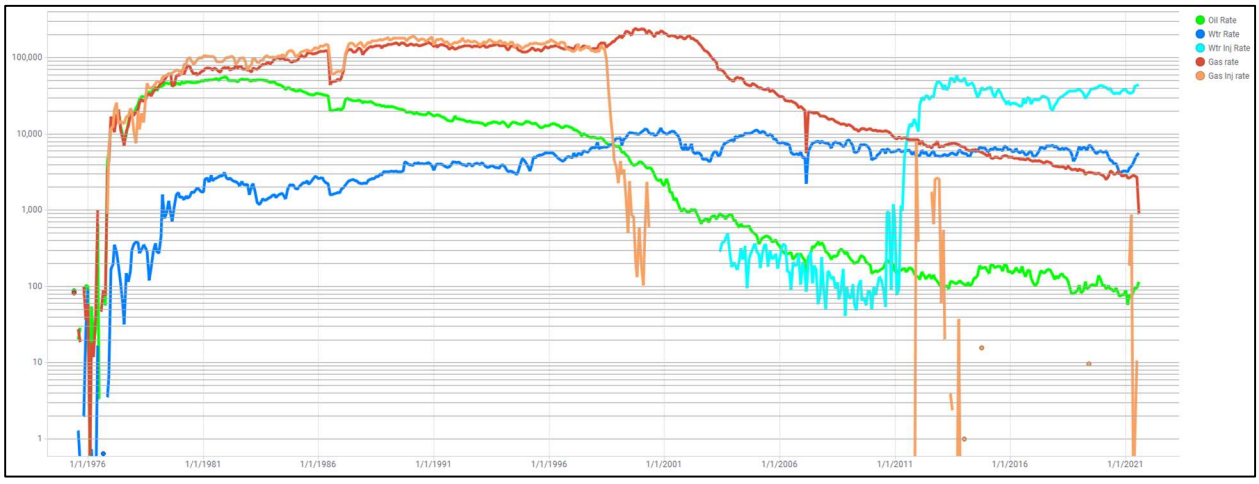
2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 8) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 8) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

Figure 8: Monterey Formation 26R production and injection data.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150-300	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	**Injection Well 1 373-35R**
Location (global coordinates) X Y	 35°16'34.5276"N 119°28'24.1836"W
Model coordinates (ft) X Y	 6121906 2290081
No. of perforated intervals	13
Perforated interval (ft MSL) Z top Z bottom	 -5,484 -6,289
Wellbore diameter (in.)	7
Planned injection period Start End	 2044 2070
Injection duration (years)	26
Injection rate (t/day)*	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are given in Table 6.

The Monterey Formation 26R reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process there is Class II UIC approval from CalGEM. The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate. With over 40 years of injection that includes 114 million barrels of oil and 841 billion cubic feet of gas, there are no recorded incidents of fluid migration out of the Monterey Formation.

Table 6: Summary of the fracture pressure data for the Monterey Formation 26R reservoir at the 373-35R well.

Interval	Breakdown Fracture Gradient PSI/foot	Fracture Pressure (PSI) at base of Reef Ridge Shale (6826.6 feet TVD)
Monterey Formation 26R	1.03	7,031

CTV will ensure that the injection pressure is beneath 90% of the fracture gradient at the base of the Reef Ridge Shale for each injection well using the Monterey Formation 26R breakdown fracture gradient. The planned maximum subsurface wellbore injection gradient for the project is 0.71 PSI per foot. Well 373-35R injection pressure details are shown in Table 7.

Table 7. Injection pressure details.

Injection Pressure Details	**Injection Well 1 373-35R**
Depth corresponding to maximum injection pressure (ft TVD)	6,826.6
Breakdown Fracture gradient (psi/ft)	1.03
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,031
Maximum injection pressure (90% of fracture pressure) (psi)	6,327.9
Elevation at the top of the perforated interval (ft MSL)	-5,484
Planned maximum injection pressure / gradient (top of perforations)	4,900 / 0.71

Computational Modeling Results

Predictions of System Behavior

The following maps (Figure 9) and cross-sections (Figure 10) show the computational modeling results and development of the CO_2 plume at four –time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. Within the first 15 years of injection, the AoR extent is largely defined. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

Figure 9: Plan view showing the plume development through time.

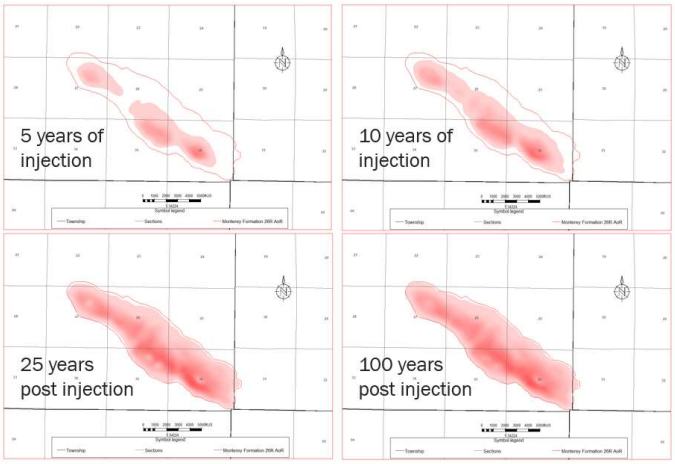
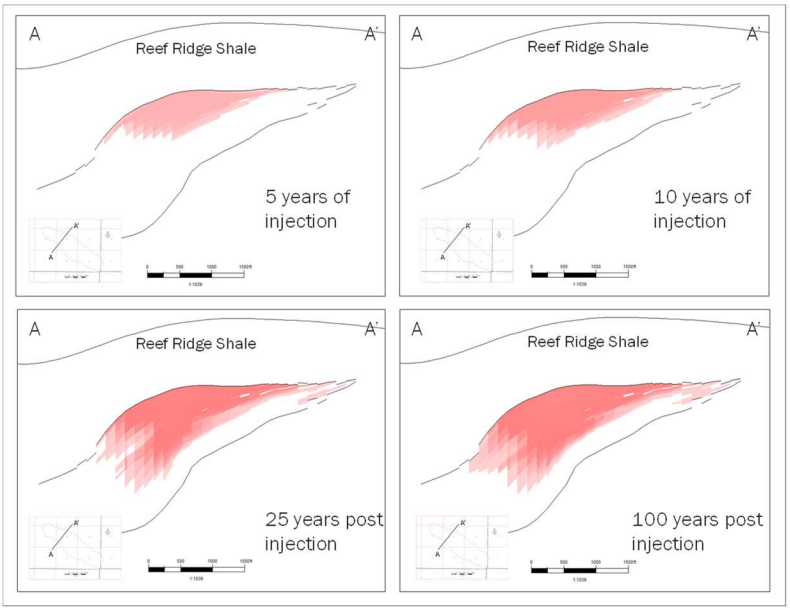
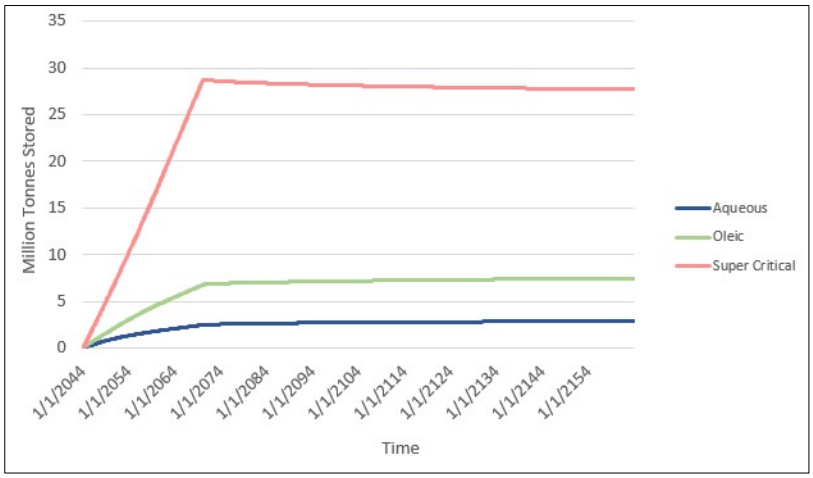


Figure 10: Cross-sections showing the plume development through varying times through the project. Note that the plume does not change from 50 years post injection to 100 years post injection.



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 11 shows the cumulative storage for each of the mechanisms.

Figure 11: CO2 storage mechanisms in the reservoir.



Model Calibration and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables.

These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

AoR Delineation

The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.

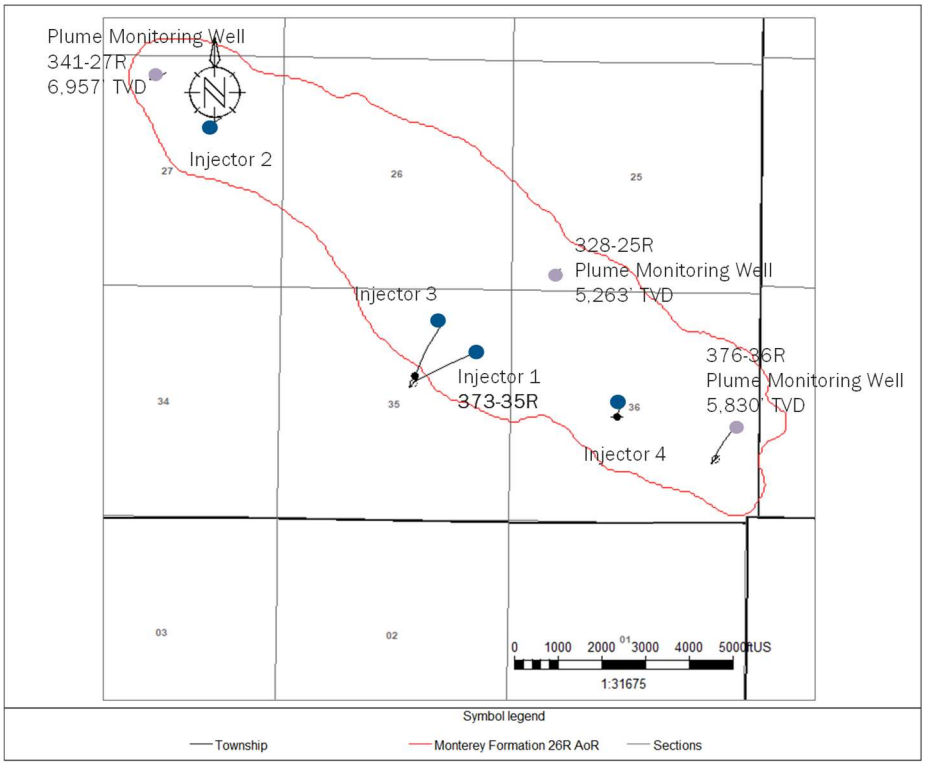
Figure 12 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 12: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

Tabulation of Wells within the AoR

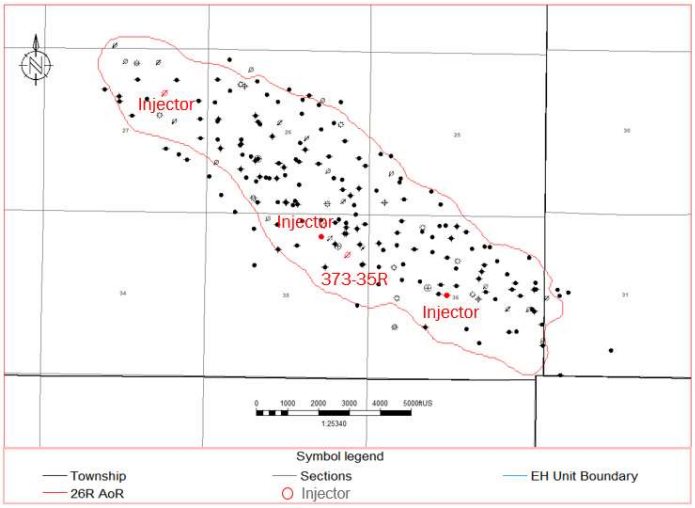
Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 8 is a summary of the AoR wells by type. Figure 13 displays the AoR wells' surface locations in map view. Appendix 1 lists the wells individually and provides information including well name, API-12, well type, status, spud date, surface coordinates, and pre-operational requirements.

Table 8: Wellbores in the AoR by Well Type

Well Type	Well Count
Oil & Gas Producing Wells	143
Class II Injection/Disposal Wells	23
Pressure Observation wells	2
Plugged back	36
Total	**204**

Figure 13: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Wells Penetrating the Confining Zone

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021.

The corrective action assessment included the generation of detailed wellbore/casing diagrams for each well. The wellbore diagrams include depths and dimensions of all hole sections, casing strings cement plugs and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination results are provided to support review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment and monitoring, the CO2 injected will be confined to the Monterey Formation 26R reservoir.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Monterey Formation 26R Isolation

A well is a penetration of the Reef Ridge Shale or Monterey Formation that may have wellbore sidetracks. These wellbore sidetracks can be abandoned without abandoning the main well. Abandonment will be considered at the wellbore (sidetrack) level.

Table 9: Wells to be abandoned prior to injection as part of asset retirement obligations.

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	168

Of the 204 wells penetrating the Reef Ridge formation (Table 9), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells,

and the application subject well will be repurposed as a CO_2 injector. Of the remaining, 164 wells require standard plugging procedures, are considered pre-operational abandonment and will be abandoned under the asset retirement obligation plan (ARO) prior to CO_2 injection. 36 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore. Appendix 1 provides well-specific information for all AoR wells including the pre-operational requirements mentioned above.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be mechanically pressure tested, abandoned, re-abandoned, monitored or have a technical demonstration showing adequate zonal confinement prior to the commencement of CO2 injection or based on an agreed upon phased scheduled post CO2 injection if conditions allow.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will

develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Change in operations such as an increase in injection rates, or injection pressure.
2. Difference between the computation modeling and observed plume development:
    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation 26R reservoir that are not related to well integrity.
    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.
3. Seismic monitoring anomalies that are indicative of:
    a. The presence of faults near the confining zone that indicates propagation into the confining zone.
    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

CTV will discuss any such events with the UIC Program Director to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.

ATTACHMENT C: TESTING AND MONITORING PLAN
40 CFR 146.90

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage
373-35R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills 26R storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality assurance procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the date of authorization of injection and every three months thereafter.

CTV is evaluating several sources of CO_2 as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling location and frequency

CO_2 injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the date of authorization of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and

2. Facility or injector downtime is greater than thirty days.

Analytical parameters

CTV will analyze the CO_2 for the constituents identified in Table 1 using the methods listed.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen	ASTM D1945
Nitrogen	ASTM D1945
Carbon Monoxide	ASTM D1945
Total hydrocarbons	ASTM D1945
Methane	ASTM D1945
Hydrogen Sulfide	ASTM D1945/D6228
CO_2 purity	ASTM D1945
Total Sulfur	ASTM 3246

Sampling methods

CO_2 stream sampling will occur in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory to be used/chain of custody and analysis procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date.
2. Sample description.
3. Sample type.
4. Relinquished by and received by signature.
5. Sampler name.
6. Location information.

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring location and frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table.

All monitoring will be continuous with a 30 second sampling and recording frequency for both active and shut-in periods.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	30 seconds	30 seconds
Injection rate	Flowmeter	Surface	30 seconds	30 seconds
Injection volume	Calculated	Surface	30 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	30 seconds	30 seconds
CO_2 stream temperature	Temperature gauge	Surface and Downhole	30 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Monitoring details

Injection Rate and Pressure Monitoring

Injection pressure (gauge), temperature (gauge) and flow rate (flow meter) will be continuously monitored by the Elk Hills Central Command Facility (CCF). Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable injection pressure of 90% of the injection zone's fracture pressure.

Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

Calculation of Injection Volume and Mass

The volume of CO_2 injected into the Monterey Formation 26R reservoir will be calculated from the injection flow rate, CO_2 density, and composition. Density will be determined from the Massachusetts Institute of Technology's CO_2 Thermophysical Calculator.

https://sequestration.mit.edu/tools/index.html

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the down-hole packer and tubing. Pressure will be read at the surface via a pressure gauge. The annulus will be filled with a non-corrosive fluid. Any deviations in the annular pressure may indicate a well integrity issue that will be investigated.

Injection Rate

The injection rate will be monitored with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent.

Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring location and frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7).

CTV will continually update the corrosion monitoring plan as data is acquired.

Sample description

Samples of the materials used in the construction of the pipeline, and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials (Table 3) will be weighed, measured, and photographed prior to installation.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	CS A106B
Casing	N80 and K55 Steel

Equipment Coupon	Material of Construction
Tubing	13 CR L-80
Wellhead	Stainless steel

Monitoring details

The corrosion coupons will be located in the pipeline that feeds CO_2 injectate to the injectors. Every six months the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram.

A corrosion rate of greater than 0.3 mils/year will initiate consultation with the regulatory agencies. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year.

Above Confining Zone Monitoring

CTV will monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

Monitoring above the confining zone will include the following:

1. Tulare Formation – Upper Tulare Formation unsaturated zone will be monitored from the proposed Shallow Monitoring Well from 0 – 1,100 feet TVD.

2. Etchegoin Formation – between the confining layer and USDW in well 355X-26R.

Monitoring location and frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well locations with respect to the AoR. The wells are located within the Elk Hills Oil Field, CTV owns the mineral rights and has guaranteed surface right access.

Etchegoin Formation

The Etchegoin Formation zone between the confining zone and Upper Tulare unsaturated zone will dissipate any CO_2 injectate that migrates upward through the confining zone. The Etchegoin will be monitored continuously for pressure and temperature changes. Leakage from the Monterey Formation to the Etchegoin Formation will increase the reservoir pressure.

The 355X-26R Etchegoin Formation monitor well is located in the middle of the AoR (Figure 1). The Etchegoin zone is continuous across the AoR. As such, 355X-26R will adequately monitor for pressure and temperature changes.

Tulare Formation

Monitoring in the Tulare Formation will include pressure and fluid sampling. Leakage to the Tulare Formation may increase the reservoir pressure and change the composition of the formation (increased CO_2 concentration).

Prior to injection a shallow Upper Tulare Formation monitoring well will be drilled and baseline analysis will be completed. Future results will be compared against these baseline results for significant changes or anomalies.

Additional shallow monitoring wells will be drilled to assess and monitor if the following occurs:

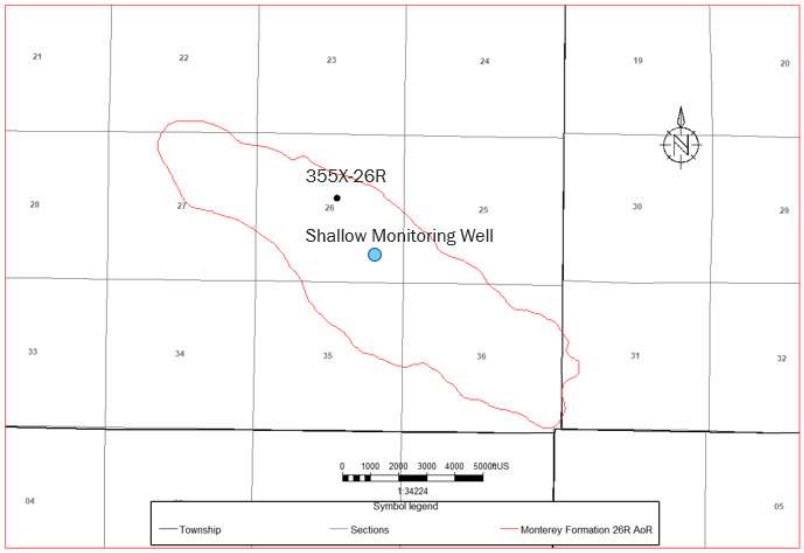
1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation 26R CO_2 injection.

2. Tulare Formation pressure or composition changes due to Monterey Formation 26R CO_2 injection.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
Tulare Formation	Fluid Sampling	Shallow Monitoring Well	Annually
	Pressure/Temperature	Shallow Monitoring Well	Continuously
Etchegoin Formation	Pressure/Temperature	355X-26R	Continuously

Figure 1: Above confining zone monitoring wells.



Analytical parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Tulare Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	SM 4500-CO2-C
Total Dissolved Solids	SM 2540 C
Alkalinity	SM 2320 B
pH (field)	EPA 150.1 / SM4500-H+B
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple
Dissolved Methane	RSK-175/Gas Chromatography

Sampling methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory to be used/chain of custody procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment,

experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

External Mechanical Integrity Testing

CTV will conduct at least one test periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90. MITs will be performed annually, within 30 days of the injection authorization date.

CTV will run a temperature log via wireline to ensure mechanical integrity of the tubing and downhole packer. If CTV elects to conduct an alternate MIT, notification that includes the test and a description will be sent to the EPA for approval.

Testing location and frequency

Table 6. MITs.

Test Description	Location
Temperature Log	Along wellbore via wireline well log
Radioactive Tracer	Along wellbore via iodine

Testing details

CTV will follow the following procedures for MIT temperature logging:

1. Stabilize injection for 24 hours prior to running the temperature log. If possible, the wireline speed will be limited to 20 feet per minute or less.
2. Run a temperature survey from 200 feet above the Reef Ridge Shale base to the deepest point reachable in the well, while injecting at a rate that allows for safe operations.

3. Shut-in well and run multiple temperature surveys with 1-2 hours between runs.

4. Assess the acquired time lapse temperature profiles. As the well cools, the temperature profile is compared to the baseline. External integrity issues present themselves anomalies when compared to the baseline.

Pressure Fall-Off Testing

CTV will meet the requirements of 40 CFR 146.90(f) as discussed below.

Testing location and frequency

The main benefit of pressure fall-off testing is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation 26R reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

Testing details

The following procedure will be followed:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Carbon Dioxide Plume and Pressure Front Tracking

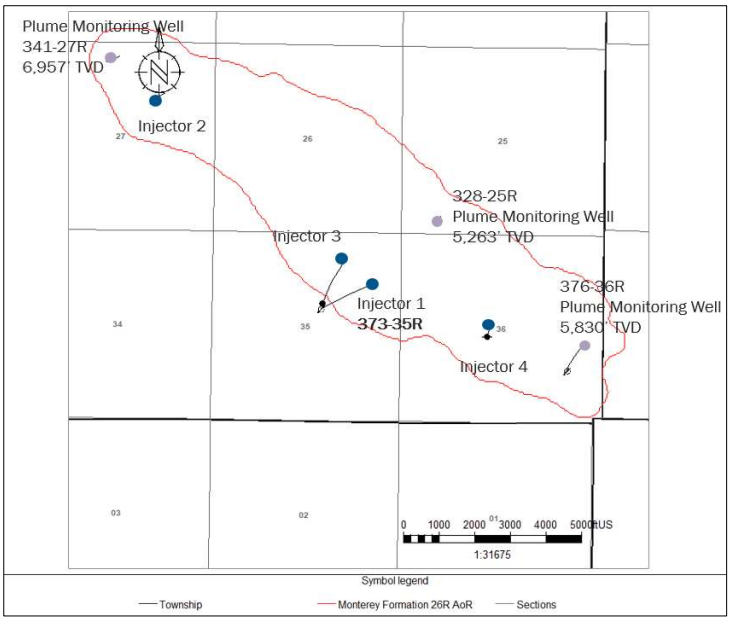
CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume monitoring location and frequency

Table 7 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 8. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Figure 2 shows the location and depth of the wells that will monitor the CO_2 plume directly in the targeted Monterey Formation 26R zone. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary.

Figure 2: Monterey Formation 26R sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.



Plume monitoring details

Fluid sampling and pressure monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 8.

As discussed in the AoR and Corrective Action Plan, 72% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and formation fluid density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

Table 7. Plume monitoring activities.

DIRECT PLUME MONITORING			
Monterey Formation 26R2	Fluid Sampling	341-27R, 328-25R and 376-36R	Annual
INDIRECT PLUME MONITORING			
Monterey Formation 26R	Pulse Neutron Logging	341-27R, 328-25R and 376-36R	Every two years from start of injection.

Table 8. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Tulare Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO2	SM 4500-CO2-C
Total Dissolved Solids	SM 2540 C
Alkalinity	SM 2320 B
pH (field)	EPA 150.1 / SM4500-H+B
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple
Dissolved Methane	RSK-175/Gas Chromatography

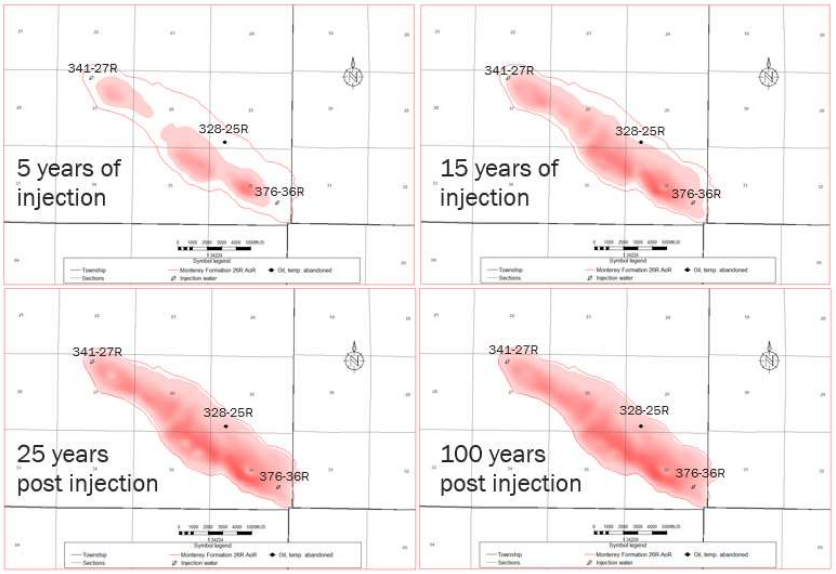
Pressure-front monitoring location and frequency

Table 9 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ.

Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

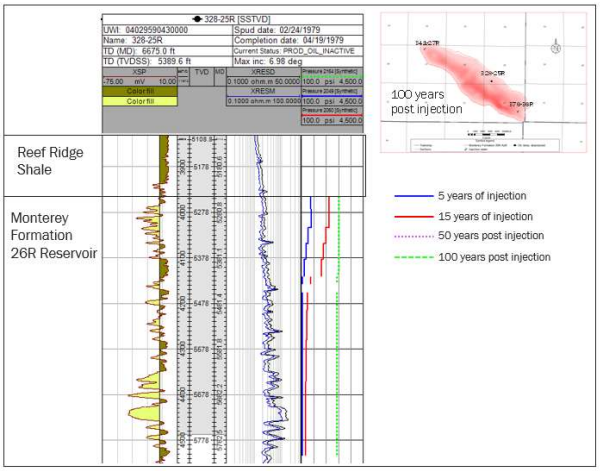
The aerial extent of plume development in the Monterey Formation 26R reservoir will reach the AoR boundaries early in the injection phase. Because the reservoir is pressure depleted, injected CO_2 will quickly fill the available pore space. Monitoring well locations with respect to plume development through time are shown in Figure 3.

Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.



Monitoring well 328-25R pressure development based on computational is modeled in Figure 4. Note that the reservoir pressure between 50- and 100-years post injection is the same, indicating plume stabilization.

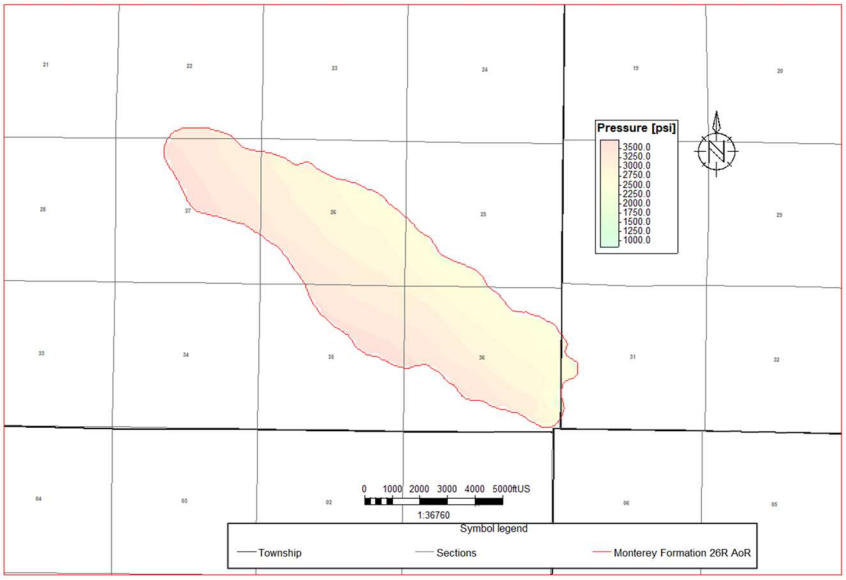
Figure 4: Monitoring well 328-25R showing the pressure increase through time from the computational modeling results.



Pressure-front monitoring details

Direct pressure monitoring of the plume will be achieved through installation of pressure gauges in monitoring wells 341-27R, 328-25R and 376-36R. The depleted Monterey Formation 26R oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

Figure 5: Monterey Formation 26R pressure 50 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.



The modeled pressure increases at monitoring well 328-25R are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 9. Pressure-front monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FRONT MONITORING			
Monterey Formation 26R	Pressure and temperature monitoring	341-27R, 328-25R and 376-36R	Continuous
INDIRECT PRESSURE-FRONT MONITORING			
All formations	Seismicity	AoR	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with surface and shallow borehole seismometers in the AoR. The seismometers will be tied in with the regional network to increase resolution and assess natural versus induced seismicity. The seismometers will be able to detect events with a magnitude 0 to 1.0 and will be installed pre-injection to provide baseline seismicity. In addition, CTV will monitor the Southern California Earthquake Data Center (SCEDC) network for seismic events.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

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ATTACHMMENT D: INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
373-35R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Carbon TerraVault 1 LLC (CTV) will conduct injection well plugging and abandonment according to the procedures below.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity survey prior to plugging the injection well as required by 40 CFR 146.92(a).

A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 1 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Class G cement blend will be utilized that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The wells will have this cement placed inside casing from total depth (TD) of the well to surface. The cement will be set in plug segments per CTV's standard procedures.

Table 1: Plugging details.

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.276	6.276 and 6.366	6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	7,871	6,800	972	25
Sacks of cement to be used (each plug)	200	1111	182	5
Slurry volume to be pumped (ft^3)	230	1277	209	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	6,800	972	25	0
Bottom of plug (ft)	7,871	6,800	972	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

Narrative Description of Plugging Procedures

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following procedures are planned for plugging:

1. Bottom hole pressure from downhole pressure gauge is recorded and kill fluid density is calculated.

2. Well equipment is removed from the casing and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

3. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up-hole while cementing operations continue. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up-hole while operations are paused to wait on cement. Once the cement has "set", the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval. This process is repeated until cement is placed to surface.

CTV follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L DTS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

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ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
373-35R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize one year after injection ceases. Final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

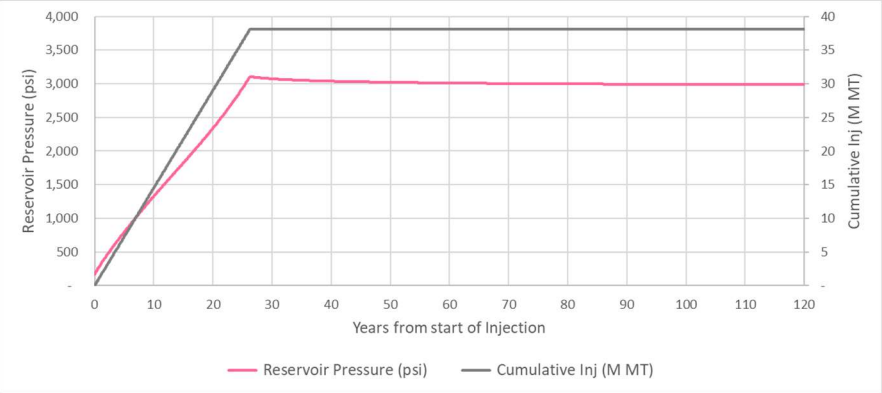
Discussion

The Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation 26R storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when

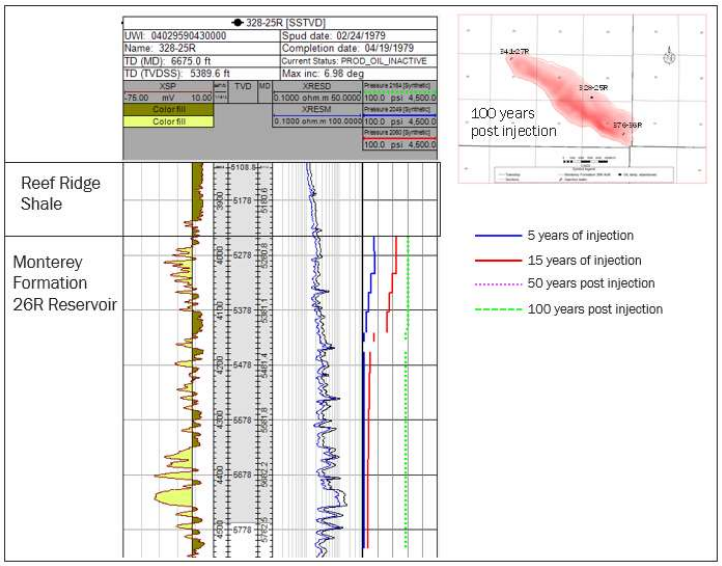
the reservoir pressure will be at the initial conditions of the reservoir. Figure 1 shows the pressure of the Monterey Formation 26R reservoir through time from computational modeling.

Figure 1: Reservoir pressure and Cumulative injection.



Pressure at 50 and 100 years post injection are the same in monitoring well 328-25R (Figure 2) indicating plume stabilization. The low water saturation within the Monterey Formation 26R storage reservoir results in 72% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

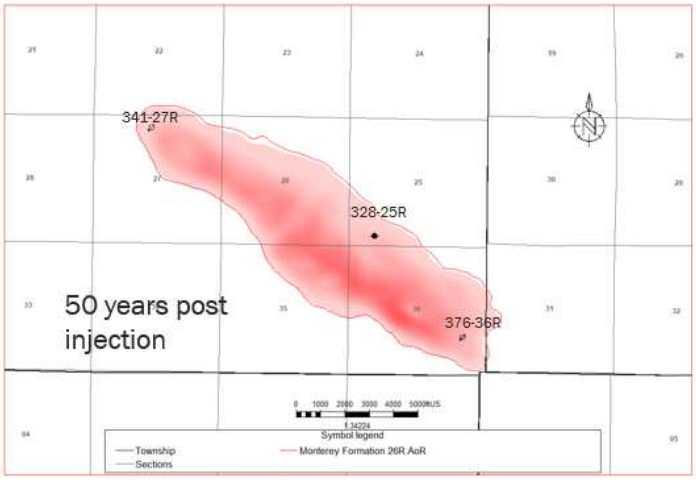
Figure 2: Pressure at the 328-25R monitoring well. Pressure at 50 and 100 years post injection are the same indicating plume stabilization.



Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 3: Map of the predicted extent of the CO2 plume 50 years post injection with plume monitoring well locations . The pressure of the 26R reservoir will be at or beneath the initial pressure at the time of discovery.



Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include a combination of groundwater pressure, fluid composition and storage zone pressure as described in the following sections and will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Post-injection monitoring will include a combination of groundwater monitoring, and storage zone pressure monitoring.

> Pressure monitoring of the Monterey Formation 26R storage reservoir will monitor for pressure stabilization. This is the best method to confirm confinement of the reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

Throughout the AoR there is no USDW but a zone of unsaturated sands in the Upper Tulare. A shallow groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed every five years for indicators of CO_2 movement into the formation.

CTV own the mineral rights for the Monterey Formation 26R reservoir. Surface access is guaranteed for the life of the project as CTV is a wholly owned subsidiary of California Resources Corporation, owner of the surface rights.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ.

The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Tulare Formation	Fluid sampling	Shallow Monitoring Well	AoR	Annual
	Pressure Monitoring	Shallow Monitoring Well	AoR	Continuously

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Tulare Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1)	ICP-OEC EPA 200.7/6010B
Cations (Ca, FE, K, Mg, Na and Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300
Dissolved CO2	SM 4500-CO2-C
Alkalinity	SM 2510 B
pH	EPA 150.1 / SM4500-H+B
Total Dissolved Solids (TDS)	SM 4500 C
Specific Conductance (field)	SM 2510 B
Dissolved Methane	RSK – 175 / Gas Chromatography
Temperature (field)	Thermocouple
Pressure	Pressure Gauge

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	Shallow Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	Shallow Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation 26R (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

Table 4. Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PLUME MONITORING			
Monterey Formation 26R	Fluid Sampling	341-27R, 328-25R and 376-36R	Annual
INDIRECT PLUME MONITORING			
Monterey Formation 26R	Pulse neutron logging	341-27R, 328-25R and 376-36R	Every five years

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Monterey Formation 26R	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1)	ICP-OEC EPA 200.7/6010B
Cations (Ca, FE, K, Mg, Na and Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300
Dissolved CO2	SM 4500-CO2-C
Alkalinity	SM 2510 B
pH	EPA 150.1 / SM4500-H+B
Total Dissolved Solids (TDS)	SM 4500 C
Specific Conductance (field)	SM 2510 B
Dissolved Methane	RSK – 175 / Gas Chromatography
Temperature (field)	Thermocouple
Pressure	Pressure Gauge

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the three Monterey Formation 26R monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro-seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in plan view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FRONT MONITORING			
Monterey Formation 26R	Pressure	341-27R, 328-25R and 376-36R	Continuous
INDIRECT PRESSURE-FRONT MONITORING			
All strata	Seismicity	AoR	Continuous

Figure 4: Map showing AoR and well locations for post-injection plume monitoring.

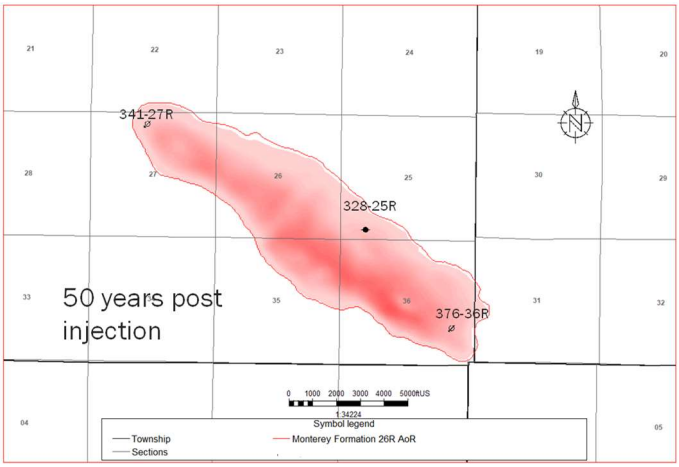
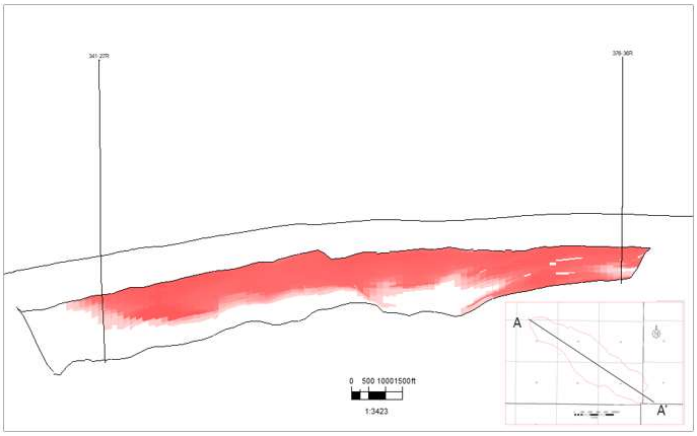


Figure 5: Cross-section showing plume CO2 plume 100 years post injection and 341-27R and 376-36R monitoring wells for post-injection monitoring.



Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

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ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
373-35R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault 1 LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the Elk Hills 26R Storage facility that may be affected as a result of an emergency event at the project site include:

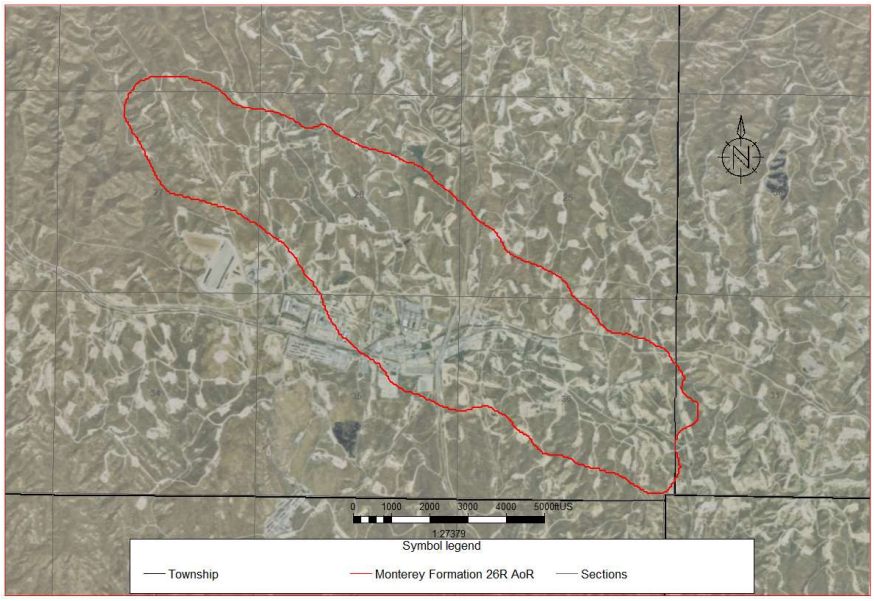
1. Elk Hills oil and gas production resources not associated with the Elk Hills 26R Storage project. These oil and gas operations are operated by California Resources Corporation (CRC), an owner of the Elk Hills 26R Storage project.

Infrastructure in the vicinity of the Elk Hills 26R Storage facility that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CRC that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure.



Potential Risk Scenarios

The following events related to the Elk Hills 26R facility that could potentially result in an emergency response:

- Injection or monitoring (verification) well integrity failure;
- Injection well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike);
- Fluid (e.g. brine) leakage to a USDW;
- CO_2 leakage to USDW or land surface; or
- Induced seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).

- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW.

Severity: Low

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in USDW monitoring well.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

Severity: Low

Timing of event: Injection

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.

- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within the AoR, inclusive of a ¼ mile buffer.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills 26R storage site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Low

Timing of event: Injection

An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase.

Avoidance measures: N/A

Detection methods: The seismic monitoring wells

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.0 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Review seismic and operational data. 4. Report findings to the UIC Program Director and issue corrective actions.
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate rate reduction plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 9. Review seismic and operational data. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and issue corrective actions.

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4] Seismic event >M3.5	1. Initiate shutdown plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 9. Review seismic and operational data. 10. Report findings to the UIC Program Director and issue corrective actions.

Response personnel: Emergency response personnel, California Geological Survey, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Will Chessum (562-999-8380)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director

Bill Blair (562-743-8336)

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	Phone Number
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (CalGEM)	661-322-4031
EPA National Response Center (24 hours)	800-424-8802
California Geological Survey	(916) 322-1080
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within three months following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilites, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintainence, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintainence of personal monitors, portable multi-gas monitors and stationary montiors throughout thefacility.

Carbon Dioxide Haxards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercies and drills simulating potential emergency situations.

ATTACHMENT G: CONSTRUCTION DETAILS

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
373-35R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35°19'40.9189"N / 119°32'41.9057"W

Introduction

The testing activities at the 373-35R described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

Injection well 373-35R is an existing well approved for water injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 4.7 million barrels of water. As part of the UIC approval, California Resources Corporation (CRC) has conducted mechanical integrity (MIT) and standard annular pressure (SAPT) tests to ensure internal and external mechanical integrity.

Injection Well Construction Details

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14-53	20.000	19.5	52	H-40	Short	31	875	90
Surface	14-331	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14-3,006	9.625	8.835	40	K-55	Long	31	3,950	2,570
Long-string	14-7,988	7.000	6.276 6.276 6.366	26 26 23	N-80 K-55 K-55	Long	31	7,240 4,980 4,360	5,410 4,320 3,270

Tubing Specifications

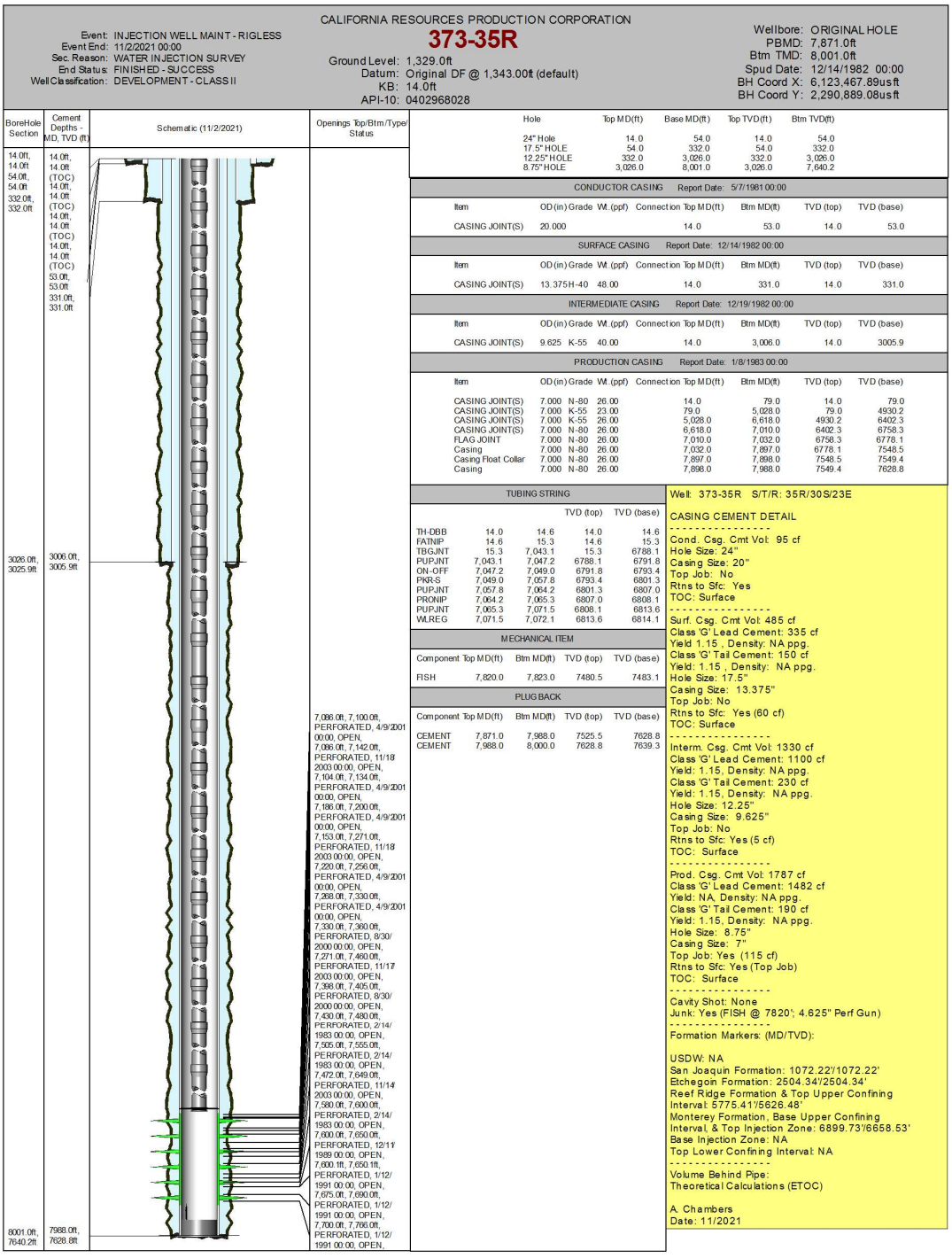
Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Internal Yield Pressure (psi)	Collapse Pressure (psi)
Injection tubing	7,043	4.500	4.000	11.6	13CR L-80	Long (premium)	7,780	6,350

Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Retrievable Packer, CRA	7,049	~120	23-26	6.000	3.875

Tensile Rating (lbs)	Internal Yield Pressure (psi)	Collapse Pressure (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
150,000	7,500	7,500	6.366	6.151

Figure 1: Injection well 373-35R casing diagram.



CALIFORNIA RESOURCES PRODUCTION CORPORATION

373-35R

Event: INJECTION WELL MAINT - RIGLESS
Event End: 11/2/2021 00:00
Sec. Reason: WATER INJECTION SURVEY
End Status: FINISHED - SUCCESS
Well Classification: DEVELOPMENT - CLASS II

Ground Level: 1,329.0ft
Datum: Original DF @ 1,343.00ft (default)
KB: 14.0ft
API-10: 0402968028

Wellbore: ORIGINAL HOLE
PBMD: 7,871.0ft
Btm TMD: 8,001.0ft
Spud Date: 12/14/1982 00:00
BH Coord X: 6,123,467.89usft
BH Coord Y: 2,290,889.08usft

BoreHole Section | Cement Depths - MD, TVD (ft) | Schematic (11/2/2021) | Openings Top/Btm/Type/ Status

14.0ft, 14.0ft
54.0ft, 54.0ft
332.0ft, 332.0ft
3026.0ft, 3025.9ft
8001.0ft, 7640.2ft

14.0ft, 14.0ft (TOC)
14.0ft, 14.0ft (TOC)
14.0ft, 14.0ft (TOC)
14.0ft, 14.0ft (TOC)
53.0ft, 53.0ft
331.0ft, 331.0ft
3006.0ft, 3005.9ft
7988.0ft, 7628.8ft

7,086.0ft, 7,100.0ft, PERFORATED, 4/9/2001 00:00, OPEN,
7,086.0ft, 7,142.0ft, PERFORATED, 11/18/2003 00:00, OPEN,
7,104.0ft, 7,134.0ft, PERFORATED, 4/9/2001 00:00, OPEN,
7,186.0ft, 7,200.0ft, PERFORATED, 4/9/2001 00:00, OPEN,
7,153.0ft, 7,271.0ft, PERFORATED, 11/18/2003 00:00, OPEN,
7,220.0ft, 7,256.0ft, PERFORATED, 4/9/2001 00:00, OPEN,
7,268.0ft, 7,330.0ft, PERFORATED, 4/9/2001 00:00, OPEN,
7,330.0ft, 7,360.0ft, PERFORATED, 8/30/2000 00:00, OPEN,
7,271.0ft, 7,460.0ft, PERFORATED, 11/17/2003 00:00, OPEN,
7,398.0ft, 7,405.0ft, PERFORATED, 8/30/2000 00:00, OPEN,
7,430.0ft, 7,480.0ft, PERFORATED, 2/14/1983 00:00, OPEN,
7,505.0ft, 7,555.0ft, PERFORATED, 2/14/1983 00:00, OPEN,
7,472.0ft, 7,649.0ft, PERFORATED, 11/14/2003 00:00, OPEN,
7,580.0ft, 7,600.0ft, PERFORATED, 2/14/1983 00:00, OPEN,
7,600.0ft, 7,650.0ft, PERFORATED, 12/11/1989 00:00, OPEN,
7,600.1ft, 7,650.1ft, PERFORATED, 1/12/1991 00:00, OPEN,
7,675.0ft, 7,690.0ft, PERFORATED, 1/12/1991 00:00, OPEN,
7,700.0ft, 7,766.0ft, PERFORATED, 1/12/1991 00:00, OPEN,

Hole	Top MD(ft)	Base MD(ft)	Top TVD(ft)	Btm TVD(ft)
24" Hole	14.0	54.0	14.0	54.0
17.5" HOLE	54.0	332.0	54.0	332.0
12.25" HOLE	332.0	3,026.0	332.0	3,026.0
8.75" HOLE	3,026.0	8,001.0	3,026.0	7,640.2

CONDUCTOR CASING Report Date: 5/7/1981 00:00

Item	OD (in)	Grade	Wt. (ppf)	Connection	Top MD(ft)	Btm MD(ft)	TVD (top)	TVD (base)
CASING JOINT(S)	20.000				14.0	53.0	14.0	53.0

SURFACE CASING Report Date: 12/14/1982 00:00

Item	OD (in)	Grade	Wt. (ppf)	Connection	Top MD(ft)	Btm MD(ft)	TVD (top)	TVD (base)
CASING JOINT(S)	13.375	H-40	48.00		14.0	331.0	14.0	331.0

INTERMEDIATE CASING Report Date: 12/19/1982 00:00

Item	OD (in)	Grade	Wt. (ppf)	Connection	Top MD(ft)	Btm MD(ft)	TVD (top)	TVD (base)
CASING JOINT(S)	9.625	K-55	40.00		14.0	3,006.0	14.0	3005.9

PRODUCTION CASING Report Date: 1/8/1983 00:00

Item	OD (in)	Grade	Wt. (ppf)	Connection	Top MD(ft)	Btm MD(ft)	TVD (top)	TVD (base)
CASING JOINT(S)	7.000	N-80	26.00		14.0	79.0	14.0	79.0
CASING JOINT(S)	7.000	K-55	23.00		79.0	5,028.0	79.0	4930.2
CASING JOINT(S)	7.000	K-55	26.00		5,028.0	6,618.0	4930.2	6402.3
CASING JOINT(S)	7.000	N-80	26.00		6,618.0	7,010.0	6402.3	6758.3
FLAG JOINT	7.000	N-80	26.00		7,010.0	7,032.0	6758.3	6778.1
Casing	7.000	N-80	26.00		7,032.0	7,897.0	6778.1	7548.5
Casing Float Collar	7.000	N-80	26.00		7,897.0	7,898.0	7548.5	7549.4
Casing	7.000	N-80	26.00		7,898.0	7,988.0	7549.4	7628.8

TUBING STRING

			TVD (top)	TVD (base)
TH-DBB	14.0	14.6	14.0	14.6
FATNIP	14.6	15.3	14.6	15.3
TBGJNT	15.3	7,043.1	15.3	6788.1
PUPJNT	7,043.1	7,047.2	6788.1	6791.8
ON-OFF	7,047.2	7,049.0	6791.8	6793.4
PKR-S	7,049.0	7,057.8	6793.4	6801.3
PUPJNT	7,057.8	7,064.2	6801.3	6807.0
PRONIP	7,064.2	7,065.3	6807.0	6808.1
PUPJNT	7,065.3	7,071.5	6808.1	6813.6
WLREG	7,071.5	7,072.1	6813.6	6814.1

MECHANICAL ITEM

Component	Top MD(ft)	Btm MD(ft)	TVD (top)	TVD (base)
FISH	7,820.0	7,823.0	7480.5	7483.1

PLUG BACK

Component	Top MD(ft)	Btm MD(ft)	TVD (top)	TVD (base)
CEMENT	7,871.0	7,988.0	7525.5	7628.8
CEMENT	7,988.0	8,000.0	7628.8	7639.3

Well: 373-35R S/T/R: 35R/30S/23E

CASING CEMENT DETAIL
- - - - - - - - - - - - - - - -
Cond. Csg. Cmt Vol: 95 cf
Hole Size: 24"
Casing Size: 20"
Top Job: No
Rtns to Sfc: Yes
TOC: Surface
- - - - - - - - - - - - - - - -
Surf. Csg. Cmt Vol: 485 cf
Class 'G' Lead Cement: 335 cf
Yield: 1.15 , Density: NA ppg.
Class 'G' Tail Cement: 150 cf
Yield: 1.15 , Density: NA ppg.
Hole Size: 17.5"
Casing Size: 13.375"
Top Job: No
Rtns to Sfc: Yes (60 cf)
TOC: Surface
- - - - - - - - - - - - - - - -
Interm. Csg. Cmt Vol: 1330 cf
Class 'G' Lead Cement: 1100 cf
Yield: 1.15, Density: NA ppg.
Class 'G' Tail Cement: 230 cf
Yield: 1.15, Density: NA ppg.
Hole Size: 12.25"
Casing Size: 9.625"
Top Job: No
Rtns to Sfc: Yes (5 cf)
TOC: Surface
- - - - - - - - - - - - - - - -
Prod. Csg. Cmt Vol: 1787 cf
Class 'G' Lead Cement: 1482 cf
Yield: NA, Density: NA ppg.
Class 'G' Tail Cement: 190 cf
Yield: 1.15, Density: NA ppg.
Hole Size: 8.75"
Casing Size: 7"
Top Job: Yes (115 cf)
Rtns to Sfc: Yes (Top Job)
TOC: Surface
- - - - - - - - - - - - - - - -
Cavity Shot: None
Junk: Yes (FISH @ 7820'; 4.625" Perf Gun)
- - - - - - - - - - - - - - - -
Formation Markers: (MD/TVD):

USDW: NA
San Joaquin Formation: 1072.22'/1072.22'
Etchegoin Formation: 2504.34'/2504.34'
Reef Ridge Formation & Top Upper Confining Interval: 5775.41'/5626.48'
Monterey Formation, Base Upper Confining Interval, & Top Injection Zone: 6899.73'/6658.53'
Base Injection Zone: NA
Top Lower Confining Interval: NA
- - - - - - - - - - - - - - - -
Volume Behind Pipe:
Theoretical Calculations (ETOC)

A. Chambers
Date: 11/2021

Pre-Injection Testing Plan – Injection Well

The following tests and logs have been acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

Deviation Checks

Deviation measurements were conducted approximately every 120 feet during construction of the well.

Tests and Logs

The following logs were acquired during the drilling and prior to the completion of the 373-35R well:

- Dual Induction SFL
- Microlog
- Spontaneous Potential
- Bulk Density / Density Porosity
- Neutron Porosity
- Four-Arm Dipmeter
- Gamma Ray
- Caliper Log
- Mud Log

The following cased-hole logs were acquired after the drilling and completion of the 373-35R well:

- Acoustic Cement Bond Log
- Mechanical Integrity Tests

Demonstration of mechanical integrity

Below is a summary of the tests to be performed prior to injection:

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Radioactive Tracer	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Pre-Injection Testing Plan – Deep Monitoring Wells 341-27R, 328-25R, and 376-36R

Deep monitoring wells proposed for the Elk Hills 26R Storage project have already been drilled. Prior to injection the wells will be re-worked to install monitoring equipment and ensure well integrity.

Deviation Checks

Deviation measurements for 341-27R, 328-25R, and 376-36R were recorded approximately every 100, 10 and 10 feet respectively, during construction of the well.

Tests and Logs

The following logs were acquired during the drilling and prior to the completion of the 341-27R, 328-25R, and 376-36R wells:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density

Demonstration of mechanical integrity

CTV will run mechanical integrity logs and tests prior to injection operations.

Annulus Pressure Test Procedures for Injection Well 373-35R:

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

Annulus Pressure Test Procedures for Monitoring Wells 341-27R, 328-25R, and 376-36R:

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source(annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

Pressure Fall-Off Test Procedures:

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation 26R reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

Testing details

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

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FINANCIAL RESPONSIBILITY

CLASS VI EMERGENCY AND REMEDIAL RESPONSE INSUREANCE
40 CFR 146.85

Elk Hills 26R Storage Project

Emergency and Remedial Response Insurance

Carbon TerraVault 1 LLC (CTV) will provide financial assurance for **Emergency and Remedial Response** by procuring an environmental insurance policy. The limits will be re-determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills 26R project environmental insurance policy will be placed with an A.M. Best A or higher rated carrier and will cover all emergency and remedial response activities arising from the assets. The selected insurance carrier will issue a financial assurance certificate in compliance with state and federal regulations.

CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

COST ESTIMATES DESCRIPTION
40 CFR 146.85

Elk Hills 26R Storage Project

Description of Financial Responsibility Cost Estimates

Carbon TerraVault 1 LLC (CTV) will provide updated estimates that are verified with a third party contractor.

CTV utilized the EPA Cost Estimation Tool for initial estimates.

Financial responsibility will be covered by the following:

1. **Letter of Credit** for Post-Injection Site Care and Closure and Injection Well Plugging.

2. **Insurance** coverage for Emergency and Remedial Response.

FINANCIAL RESPONSIBILITY

CLASS VI INJECTION WELL PLUGGING AND POST-INJECTION SITE CARE AND CLOSURE LETTER OF CREDIT
40 CFR 146.85

Elk Hills 26R Storage Project

Letter of Credit Description

Carbon TerraVault 1 LLC (CTV) will provide financial assurance for Injection Well Plugging and Post-injection Site Care and Site Closure by posting a letter of credit. The amount of each letter of credit would be determined by a reasonable estimate of the cost of these activities. CTV will provide an updated estimate from a third party prior to project approval.

The letter of credit will be backed by California Resources Corporation's (CRC) Credit Agreement with Citibank, N.A., as administrative agent, and certain other lenders as participants. This credit agreement consists of a senior revolving loan facility (Revolving Credit Facility) with an aggregate commitment of $492 million, which CRC is permitted to increase if CRC obtains additional commitments from new or existing lenders. The Revolving Credit Facility also includes a sub-limit of $200 million for the issuance of letters of credit. The letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

As of June 30, 2021, CRC had an undrawn Revolving Credit Facility, approximately $75 million available in letter of credit issuance capacity and $151 million of cash. CRC is currently making efforts to add to the aggregate commitment and the sub-limit for letters of credit.

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A1A2 Storage Project

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ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills A1-A2 Storage Project

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate two CO_2 geologic sequestration wells at the Elk Hills Oil Field (EHOF) located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO_2 stored in the Monterey Formation at 0.25 - 0.75 million tonnes annually for 15 years with injection starting in 2025. The anthropogenic CO_2 will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. The project will consist of two existing injectors, surface facilities, and monitoring wells. This supporting documentation applies to the two injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

   Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

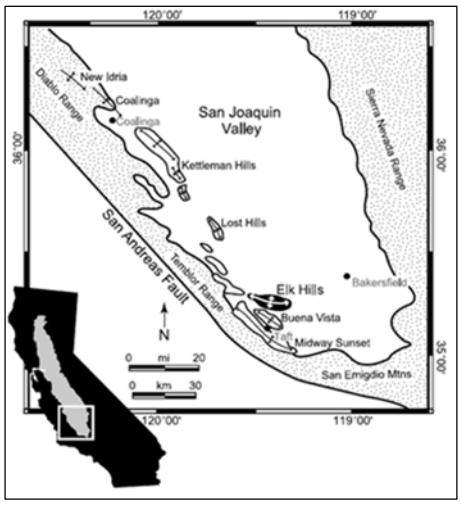
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation A1-A2 sequestration reservoir was discovered in the 1970's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

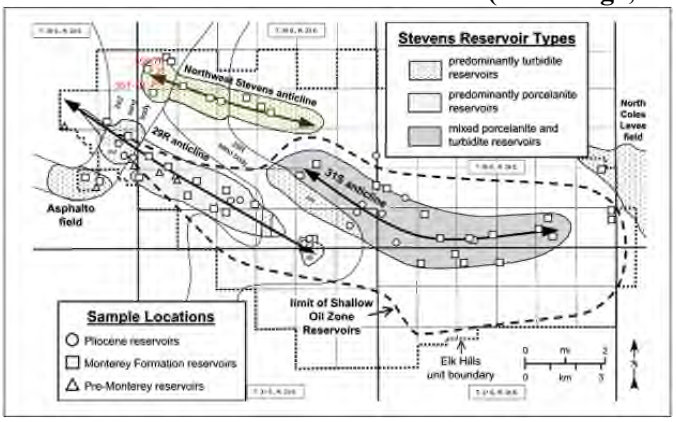
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide. With increasing depth, the structure sub-divides into three distinct anticlines (Figure 2), separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

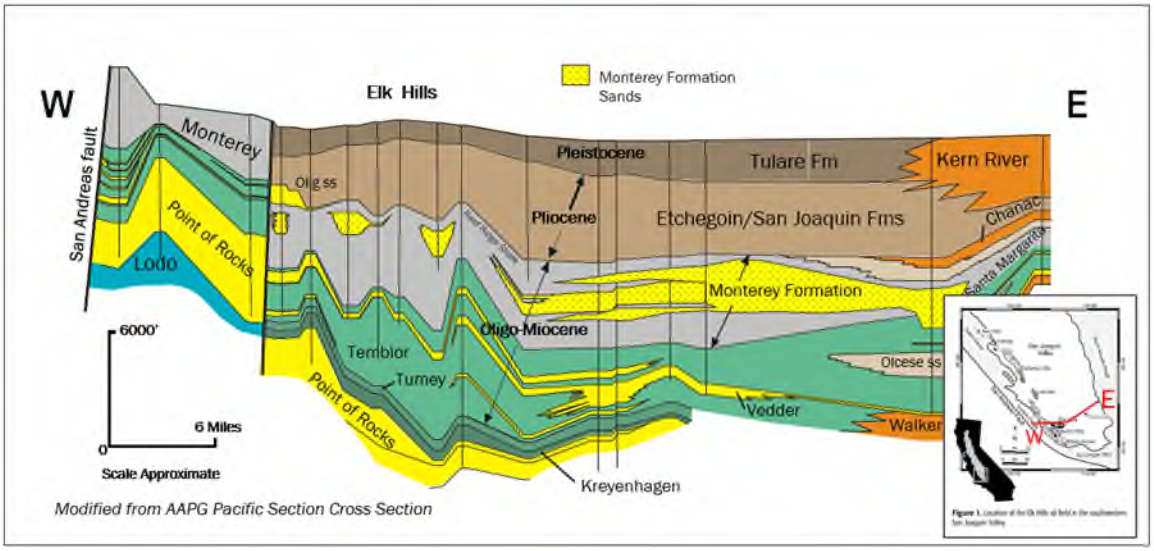
Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation A1-A2 CO2 sequestration reservoir is located in the Northwest Stevens anticline (Zumberge, 2005).



Geological Sequence

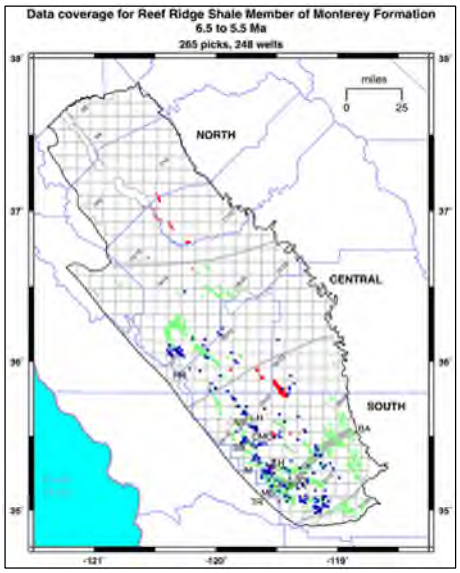
Figure 3 shows the stratigraphy of the EHOF. The two injection wells will inject CO_2 into the Miocene aged Monterey Formation A1-A2 at the Northwest Stevens anticline approximately 8,500 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin (Figure 4) and serves as the primary confining layer for the Monterey Formation A1-A2 reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Figure 4: Reef Ridge Shale data coverage over the San Joaquin Basin (Hosford, 2007).

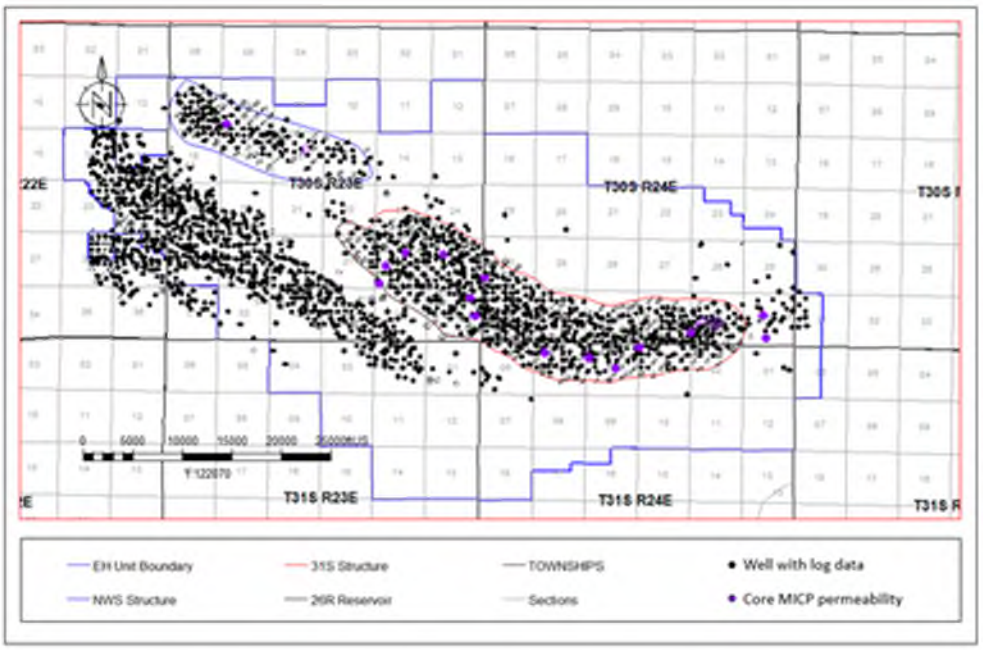


Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 5), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

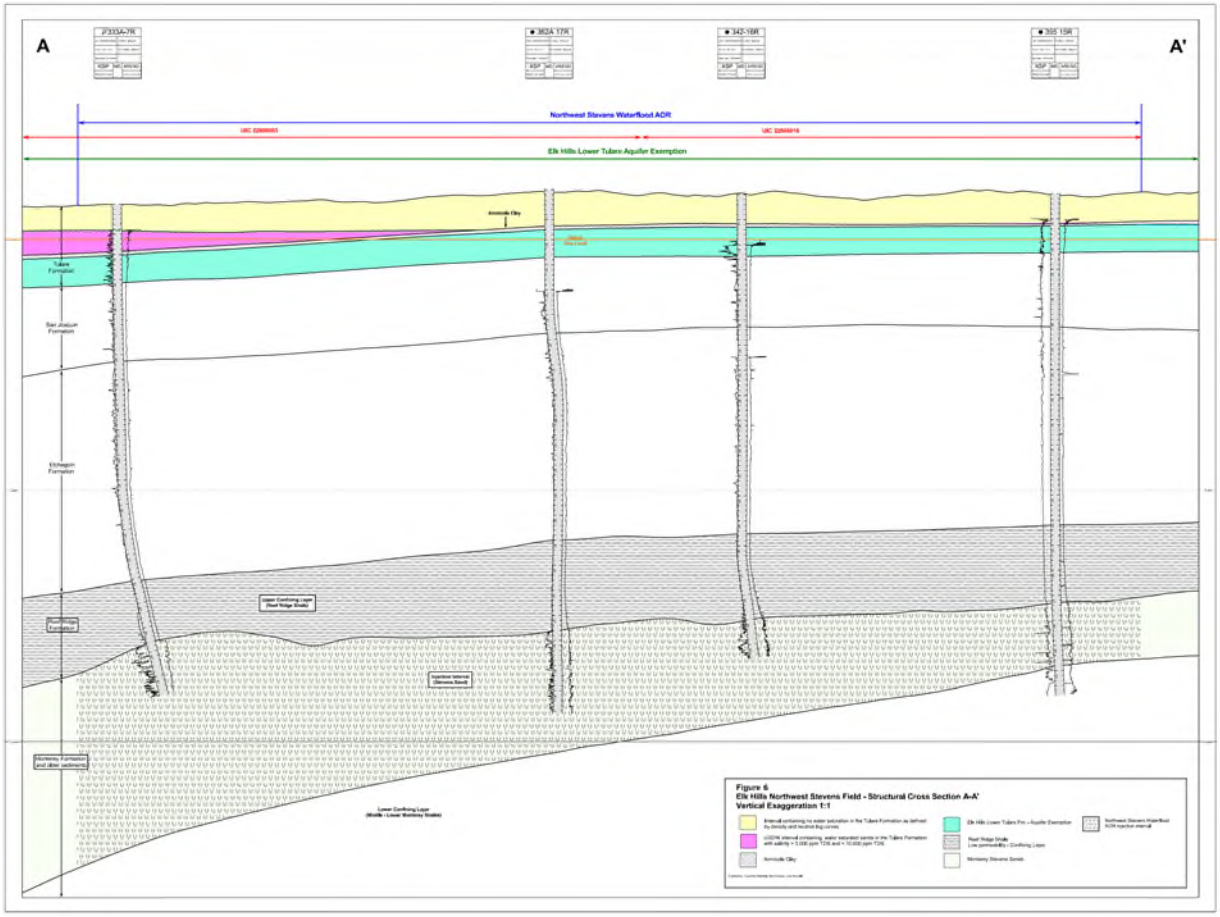
Figure 5: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core from the Monterey Formation are in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 6 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 6: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the Northwest Stevens anticline.



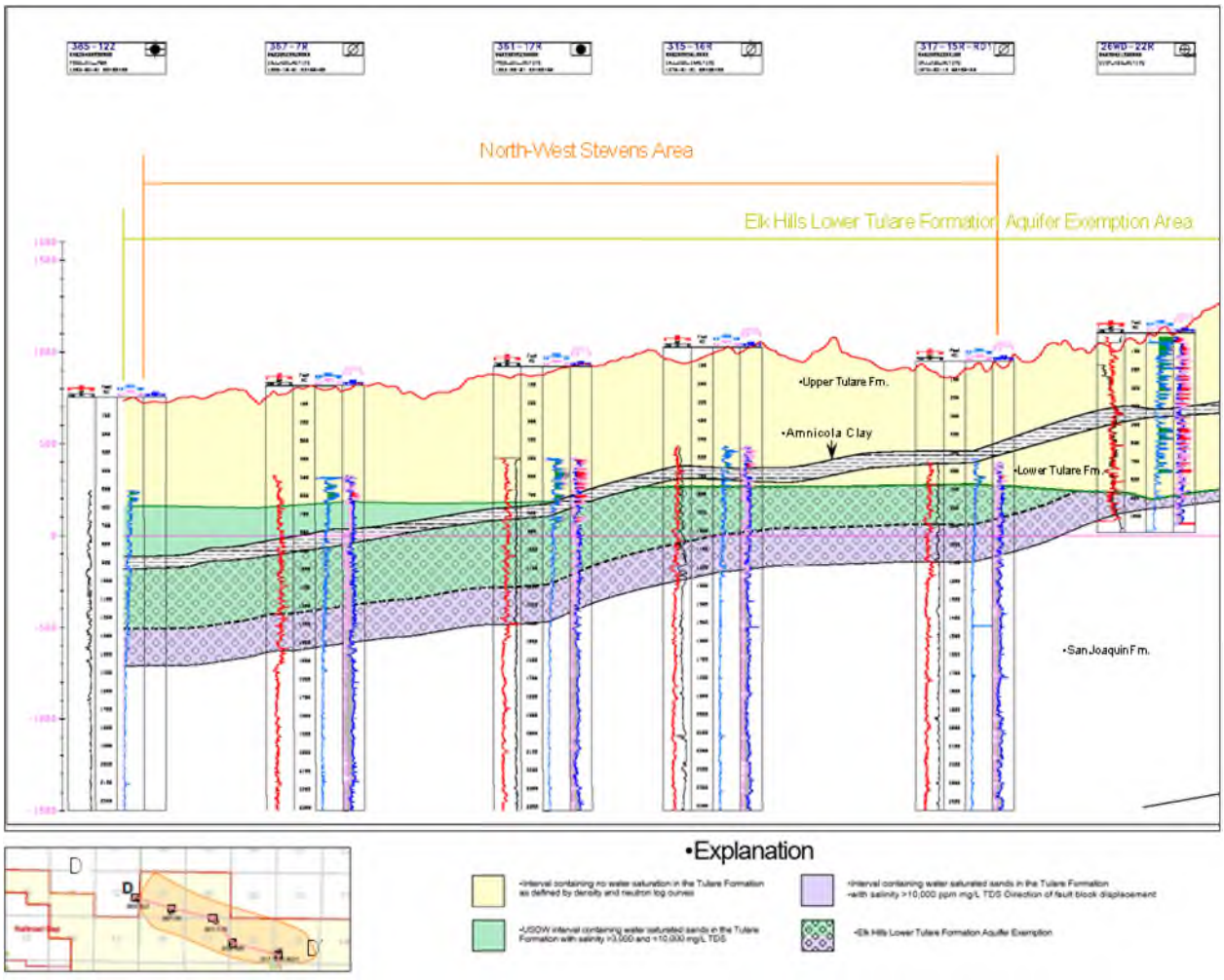
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 7), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare contains 3,000 - 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) water and is the only USDW in the AoR. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 7: The Tulare Formation consists of the Upper Tulare USDW and Lower Tulare and is separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer. The Upper Tulare USDW has formation water 3,000 - 10,000 mg/l TDS.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and

conglomerate of the Tulare Formation interfinger with the San Joaquin beds. The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000' in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 6,929-7,962 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

The Reef Ridge directly overlies the Monterey Formation A1-A2 sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

The Monterey Formation A1-A2 sequestration zone is approximately 8,500 feet deep and produces from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 16% and 60 mD, respectively.

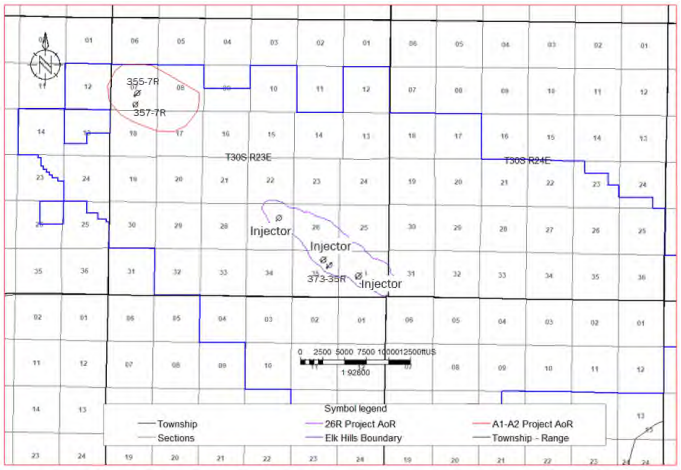
The Monterey Formation A1-A2 sands were deposited in two coalescing turbidite channels which were influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. Figure 2 shows the orientation and depositional fairways for these channels in the Northwest Stevens anticline. The sands were largely aggregational with minimal erosive deposition.

The reservoir is continuous across the AoR and sands pinch-out on the channel edges. The Monterey Formation A1-A2 sequestration reservoir has minimal connection outside the AoR,

creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

The Monterey Formation will be developed with the Elk Hills A1-A2 and the Elk Hills 26R reservoir projects. The AoR and injectors for each project is shown in Figure 8.

Figure 8: AoR and injection well location map for Elk Hills A1-A2 project. The injection wells, 355-7R and 357-7R are 1,250 feet apart. Also shown is the Elk Hills 26R AOR and injection wells.



Underlying Monterey Formation A3-A11:

Underlying the Monterey A1-A2 Formation is the Monterey Formation A3-A11 reservoir. This stratigraphic package is not in communication with the A1-A2, as indicated by the following:

1. The two packages have been developed separately. The A1-A2 reservoir was previously pressure supported by gas injection (175 billion cubic feet injected) while the A3-A11 reservoir is currently pressure supported by waterflood (449 million barrels of water injected).
2. The Monterey Formation A1-A2 reservoir is at 200-300 PSI and the A3-A11 reservoir is much higher at approximately 1,700 PSI. This pressure differential is maintained due to hydraulic confinement between the two reservoirs. Pressure data obtained using Repeat Formation Testers (RFT) during the drilling of Oil & Gas wells in the project area has shown a clear separation in the pressure and pressure gradients in the A1-A2 reservoir in comparison to the A3-A11 reservoir. RFT data from two wells in the project area drilled in 2014 is shown below in Figure 10.
3. The laterally continuous A2 shale separates the reservoirs (Figure 9). This shale is greater than 20 feet thick across the AoR and prevents communication between the Monterey Formation A1-A2 reservoir and the Monterey Formation A3-A11 reservoir.

   The permeability function (Figure 19) is constrained with high clay content samples that enable the function to characterize the A2 shale permeability. Based on the 357-7R well,

the A2 shale is 8900'-8920 feet in depth, 20 feet thick and has a permeability of 0.05 millidarcies. The derived permeability is shown in Figure 9.

Figure 9: 357-7R injector showing the Monterey Formation A1-A2 reservoir and the laterally continuous A2 Shale above the Monterey Formation A3-A11 reservoir. The depths shown are for feet subsea true vertical depth and feet measured depth.

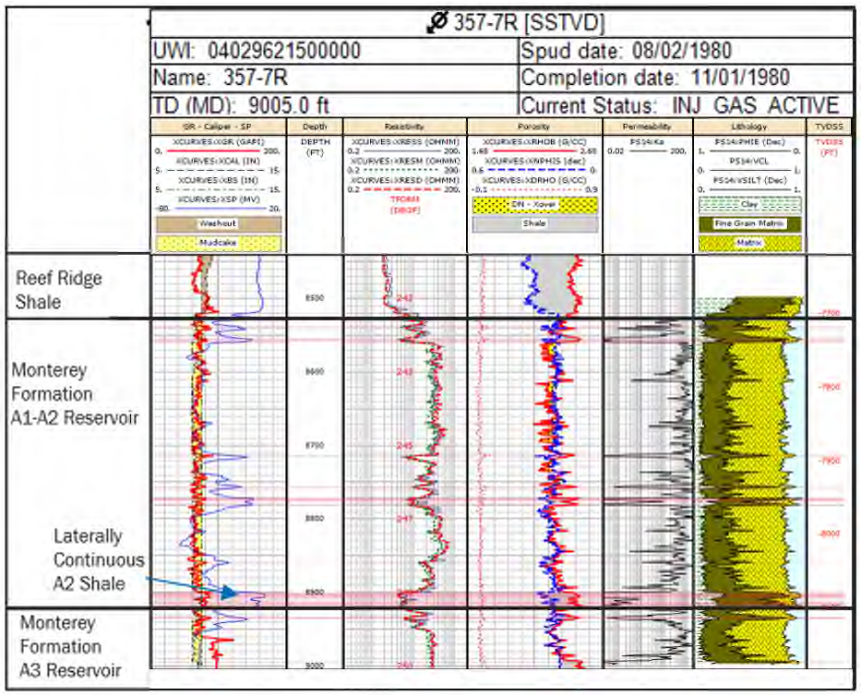
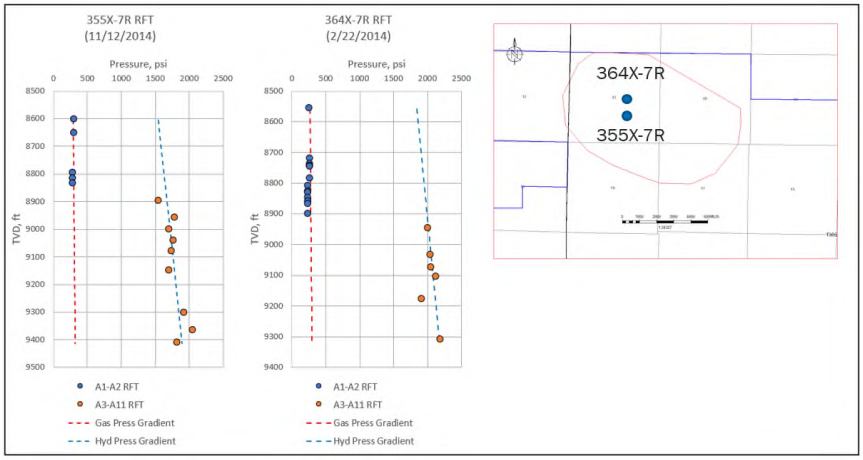


Figure 10: Repeat formation pressure data readings showing hydraulic separation between the A1-A2 and A3-A11 reservoirs. Large pressure difference between the two reservoirs and different fluid gradients as indicated by the red and blue dotted lines



CTV will monitor the Monterey Formation A3-A11 reservoir and wellbores for CO_2 migration. Waterflood producers will be monitored via fluid sampling once per quarter for changes in

composition. In addition, Monterey Formation A3-A11 waterflood injectors will have mechanical integrity tests (MIT) and standard annular pressure tests (SAPT) to ensure internal and external mechanical integrity. This monitoring will be discussed in more detail within the Testing and Monitoring Plan. Additionally, due to its waterflood infrastructure and high reservoir pressure, the A3-A6 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

Summary:

The Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as confinement by the Reef Ridge Shale.

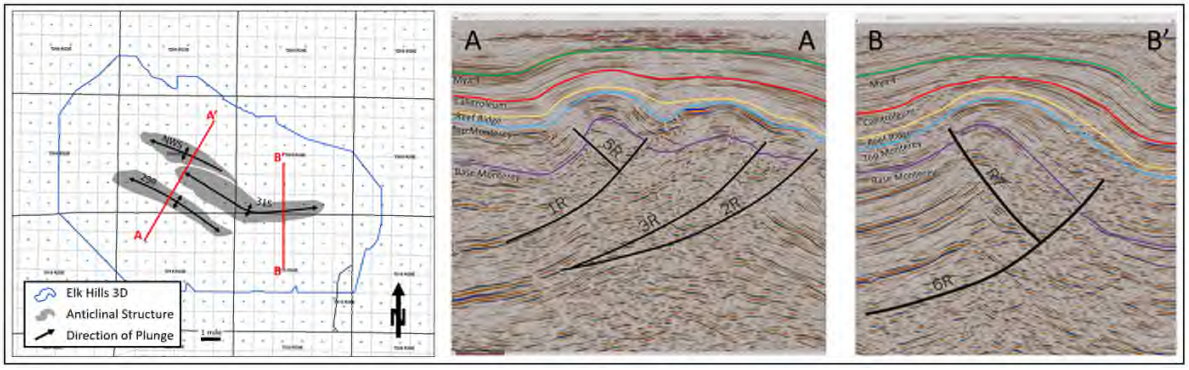
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 11 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the NWS anticlines are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale.

Figure 11: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.



Fluid Confinement

Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO_2 injectate in the Monterey Formation A1-A2 sands:

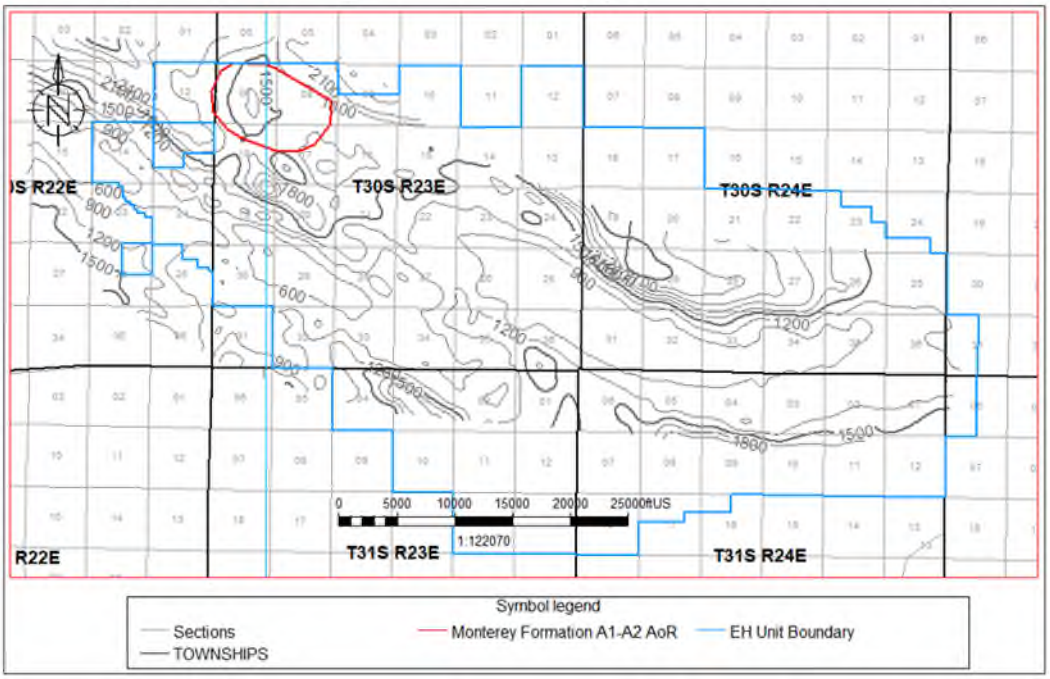
1. There are no faults that extend into the confining Reef Ridge Shale.
2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. A pressure differential exists above and below the Reef Ridge confining interval, confirming lack of communication.

4. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,100 feet (Figure 12) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 12: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



2. Waterflooding and Gas Injection

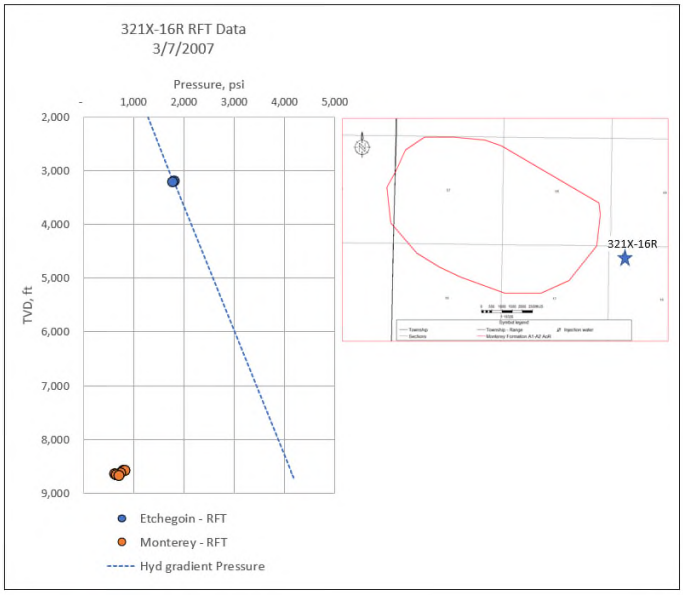
Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control Board. To date, more than five million barrels of water and 175 billion cubic feet of gas have been injected into the Monterey Formation A1-A2 sands. There has been no evidence of water or gas migrating out of the reservoir or through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically and aerially

confined.

3. Pressure Differentials

The Monterey Formation A1-A2 sequestration zone average current pressure is approximately 230 PSI. Overlying the sequestration zone, and separated by the confining Reef Ridge Shale, the Etchegoin Formation aquifer sands are at a much higher pressure of 1,500 PSI (0.43 PSI/foot gradient at 3,600 feet depth). This pressure differential of 1,300 PSI between the overlying Etchegoin Formation and Monterey Formation is maintained because the Reef Ridge is sealing and there are no transmissive features. Figure 13 shows an example of RFT pressure data collected in 2004 during the drilling of an Oil & Gas well near the project area. The RFT data shows that the Etchegoin is hydraulically separated from the deeper Monterey formation and at a much higher pressure.

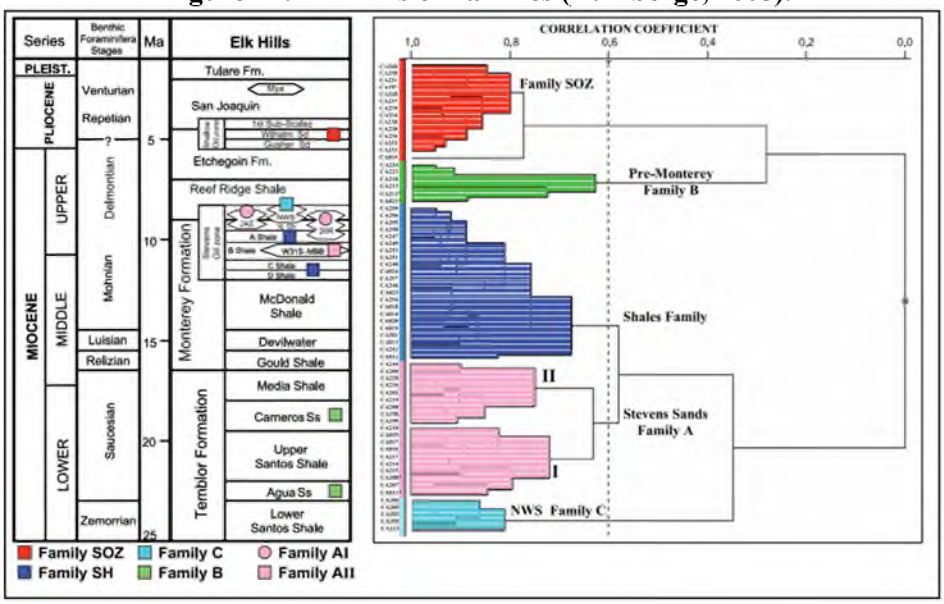
Figure 13: Etchegoin and Monterey RFT data collected during the drilling of Oil & Gas well 321X-16R near the project area showing hydraulic separation between the two formations



4. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 14) sourced from the Miocene Monterey Formation and tied to stratigraphic intervals (sample locations shown on Figure 2). The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests "minimal up-section, [and] cross stratigraphic migration". The authors conclude that the hydrocarbons present in the overlying formations are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

Figure 14: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

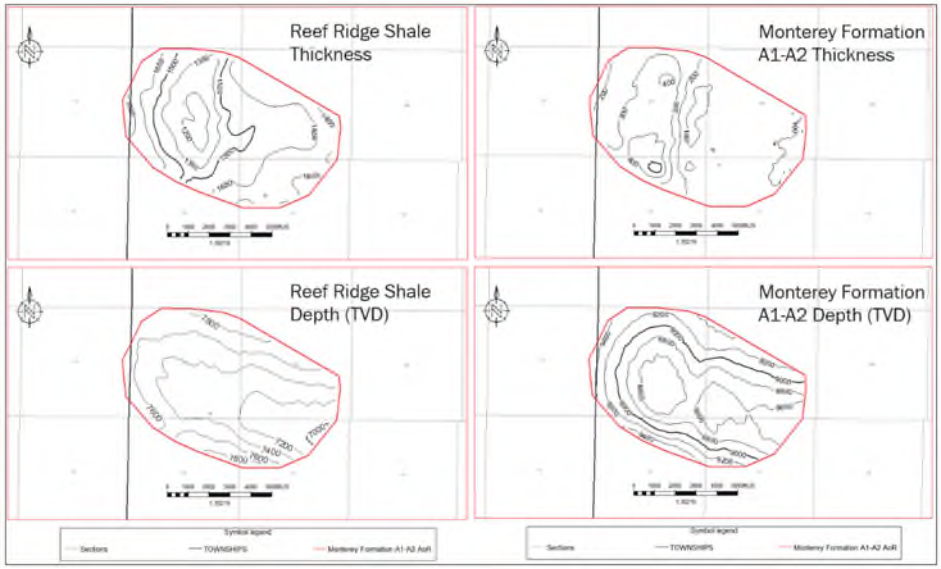
Depths and thickness of the Monterey Formation A1-A2 reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 15) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability due to deposition of the Monterey Formation sands. In the AoR, the Reef Ridge Shale minimum thickness corresponds to a high in Monterey Formation A1-A2 sand thickness.
3. Monterey Formation A1-A2 thickness variability is from pinch-out of the reservoir on the structure.

Table 1: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone Reef Ridge Shale	Thickness (feet)	1,122	1,892	1,555
	Depth (feet TVD)	6,929	7,962	7,441
Reservoir Monterey Formation A1-A2 Sand	Thickness (feet)	27	548	204
	Depth (feet TVD)	8,403	9,598	8,907

Figure 15: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth maps.

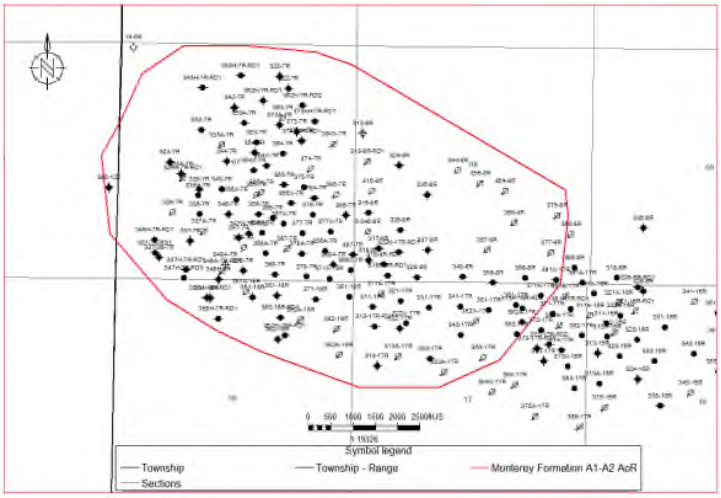


Variability in the thickness and depth of the either the Reef Ridge Shale or the Monterey Formation A1-A2 sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

Facies Changes in the Injection or Confining Zone

The Monterey Formation A1-A2 reservoir and Reef Ridge Shale has been defined with extensive data (Figure 16), with a total of 255 well and spacing of 400-800 feet. Each of these wells is used to define stratigraphy, lithology/facies and reservoir properties for the static geological model and the maps shown in Figure 15. This quantity and spacing of data is more than sufficient to generate a data driven static model that define facies changes in for the reservoir and confining zone. Based on Monterey Formation A1-A2 operational experience and plume modeling results, there are no facies changes that will either impact injection operations or confinement.

Figure 16: Well data used to define the Monterey Formation A1-A2 injection reservoir and confining zone. These wells have open-hole log data that is used to establish, clay volume, porosity, permeability, and facies (sand and shale) that are used in the static geological model.



Mineralogy

Monterey Formation A1-A2:

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the AoR. Offset well 367-7R (Figure 17) provides an example of the mineralogy for the reservoir interval in 357-7R. Clean reservoir sand intervals have an average of 43% quartz, 38% potassium feldspar, albite and oligoclase as well as 7% total clay.

Figure 17: Monterey Formation A1-A2 sand mineralogy from well 367-7R. The map shows the location for 367R and the other wells with XRD in the Elk Hills field.

DEPTH	GDI	SAMP/ WT	QTZ	CHRT	OP-A	OP-CT	ALB	OLIG	AND	KSPAR	CALC	DOLO	PYR	KAOL	CHLOR	ILL/SMEC
8551.9	2.62	8.34	30	13	0	0	17	0	2	21	2	0	1	0	0	14
8552	2.62	9.41	29	13	0	0	14	10	0	15	3	0	0	0	3	14
8554.1	2.62	10.73	45	0	0	0	19	0	2	20	4	0	0	0	0	10
8560.6	2.62	11.37	44	0	0	0	15	11	0	17	5	0	0	2	0	6
8570	2.62	8.32	33	0	0	0	17	8	4	17	3	0	0	0	0	8
8583	2.6	14.88	45	0	0	0	15	11	0	18	4	0	0	0	0	7
8604.3	2.6	18.83	21	21	0	0	15	0	10	14	2	0	0	0	0	17
8634.3	2.52	12.65	44	0	0	0	14	13	1	17	3	0	0	0	0	6
8648.6	2.52	14.16	47	0	0	0	14	3	5	19	3	0	0	0	0	5
8649.2	2.42	15.58	49	0	0	0	18	0	4	14	3	0	0	2	0	6
8649.8	2.42	8.76	50	0	0	0	17	0	4	17	1	2	0	3	0	6
8660.9	2.42	11.24	45	0	0	0	14	9	4	17	2	1	0	2	0	6
8651.4	2.42	8.75	45	0	0	0	14	0	4	19	3	0	0	0	0	10
8656	2.43	23.41	38	0	0	0	14	10	4	14	12	2	0	0	0	6
8702.5	2.41	10.58	40	13	0	0	15	0	5	18	2	0	0	0	0	7

GDI = Grain Density
Sample WT = Weight of Fresh Sample Crushed For Analysis
QTZ = Quartz
CHRT = Chert
OP-A = Opal-A
OP-CT = Opal-CT
ALB = Albite
OLIG = Oligoclase
AND = Andesine
KSPAR = Potassium Feldspar
CALC = Calcite
DOLO = Dolomite
PYR = Pyrite
CHLOR = Chlorite
Ill/SMEC = Illite - Smectite

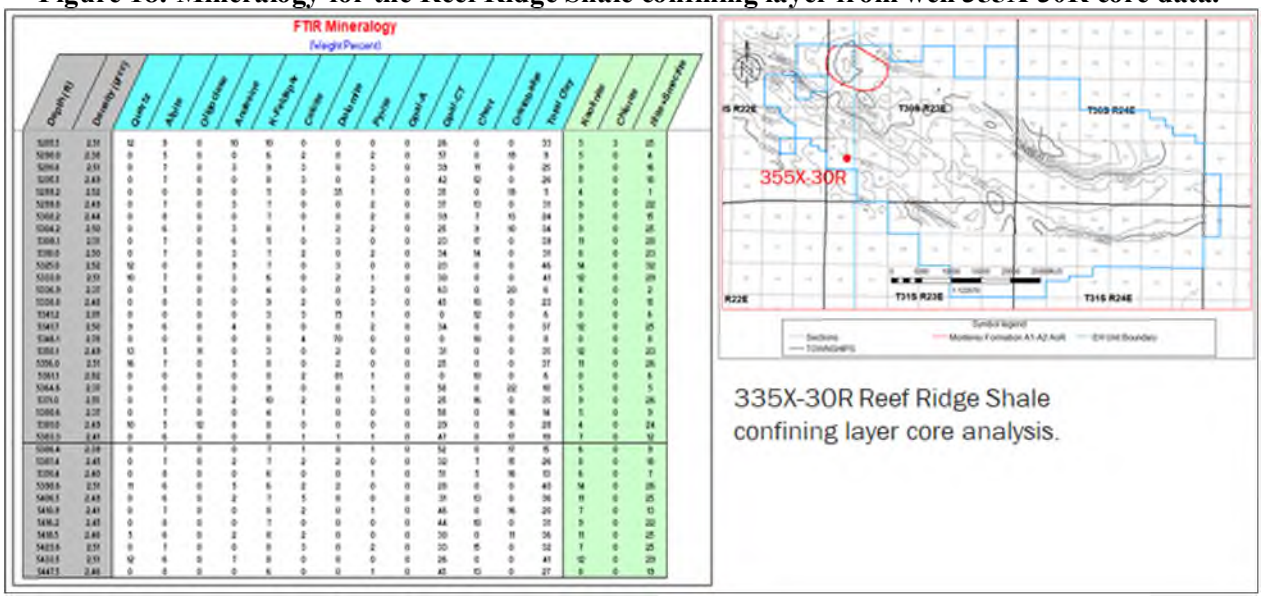


Reef Ridge Shale:

Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 18). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AOR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 18: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.



Porosity and Permeability

Monterey Formation A1-A2:

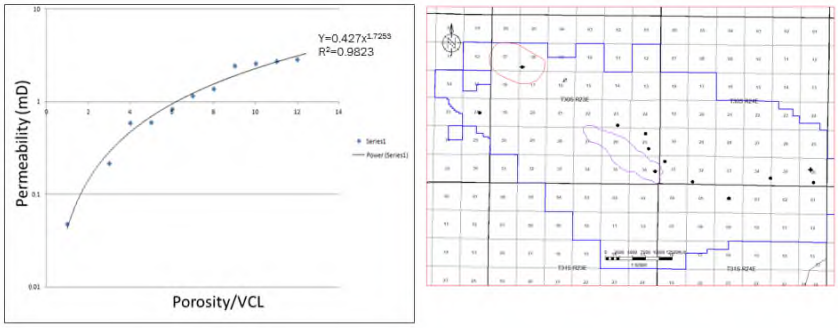
Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.

Volume of clay is determined by neutron-density separation and is calibrated to core data.

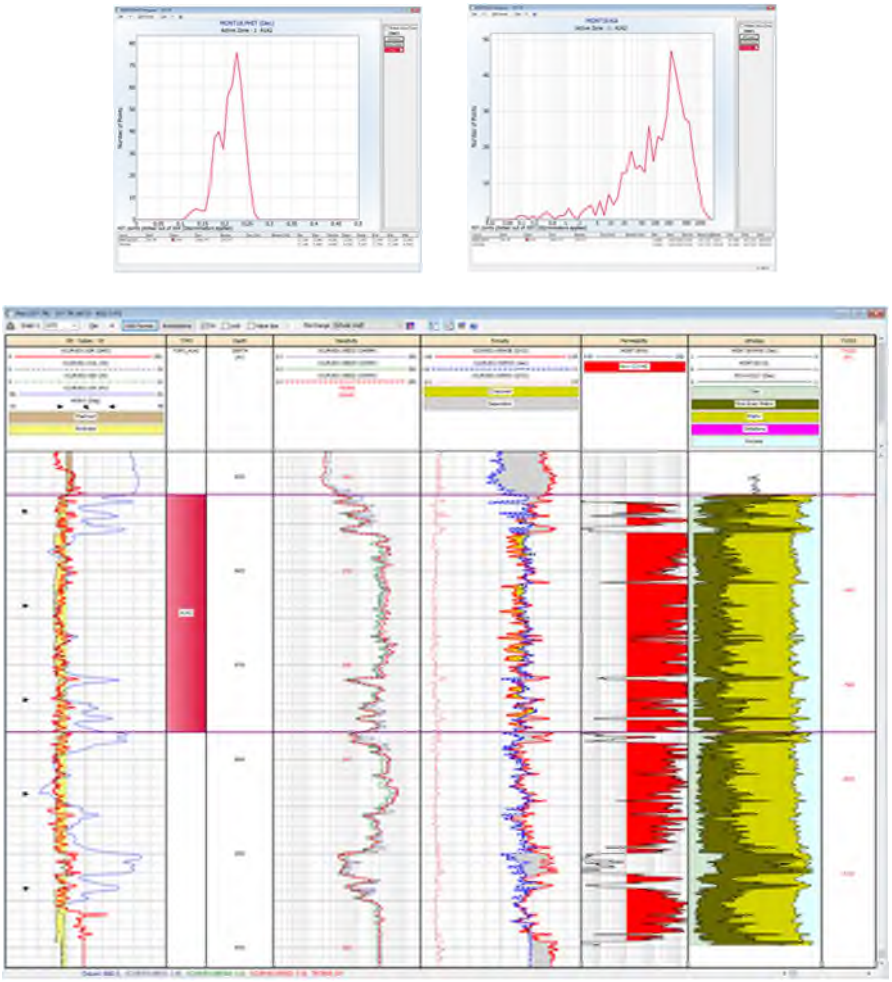
Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells (Figure 19) with 175 data points were used to calibrate log porosity and to develop a permeability transform. This distribution of wells and data points covers Monterey Formation sands in the Elk Hills field and ensures coverage of the porosity-permeability range in the storage reservoir. An example of the transform from core data is illustrated in Figure 19 below.

Figure 19: Permeability function developed based on mercury injection capillary pressure data and calculated from log derived porosity and clay volume. Map shows the locations for wells with Monterey Formation sand core data used in the function.



In the example below for the Monterey Formation A1-A2 sands, the porosity ranges from 11% - 27% with a mean of 21%. The permeability ranges from 0.1 mD - 1300 mD with a log mean of 108 mD (Figure 20).

Figure 20: Porosity and permeability for well 357-7R, showing the distribution and the input and output log curves.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2).

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

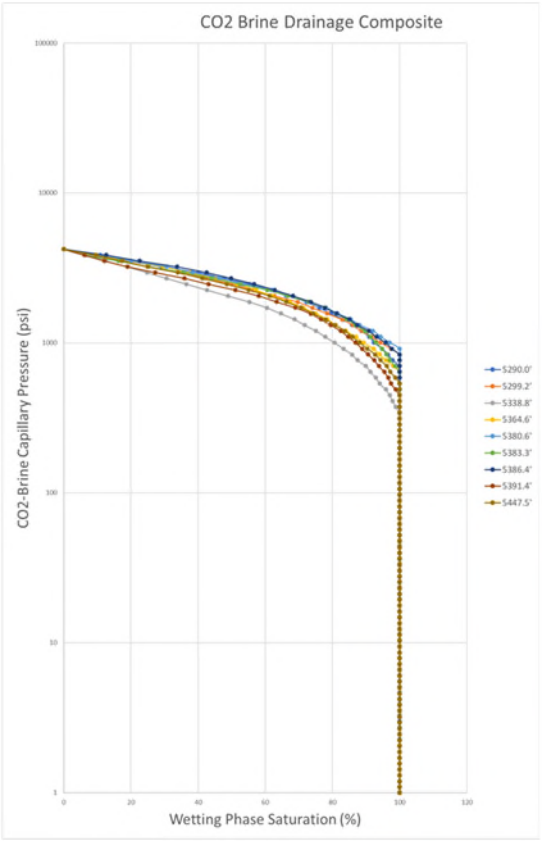
Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006
TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 21). The capillary pressure was determined by applying CO_2-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO_2-brine, respectively.

Figure 21: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR, 18 wells had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 59,214 individual logging data points.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

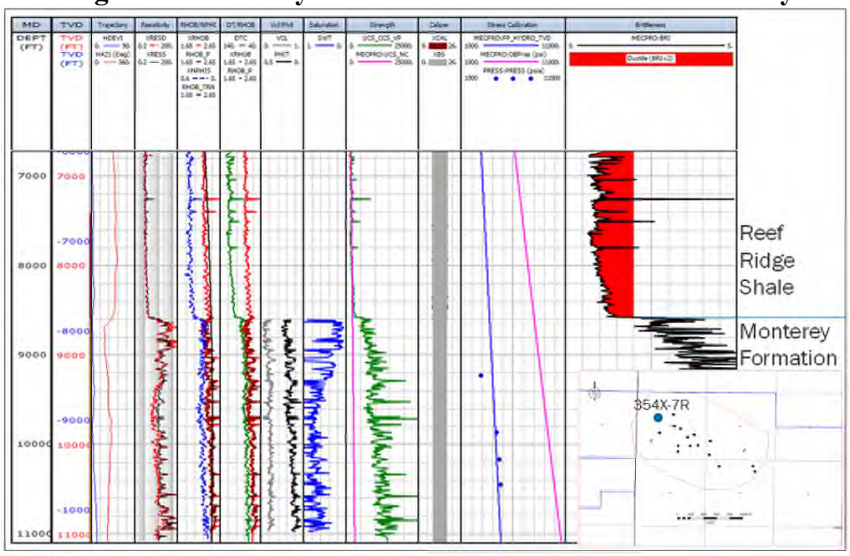
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 354X-7R is shown below (Figure 22). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method. Ductility less than two is shaded red.

Figure 22: Unconfined compressive strength and ductility calculations for well 354X-7R. The Reef Ridge Shale ductility is less than two and will be sufficiently.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to accommodate large amounts of strain without undergoing brittle failure.

The average ductility of the confining zone based on the mean value from 18 wells is 1.24.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,452 psi.

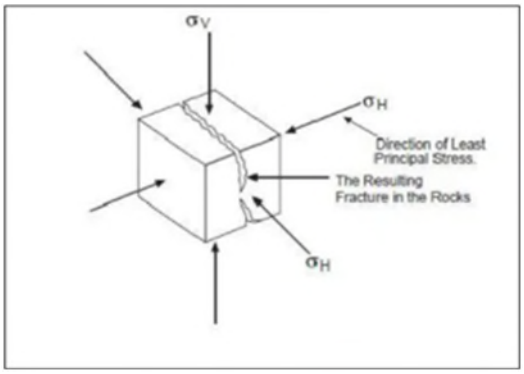
As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the Monterey Formation A1-A2 reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

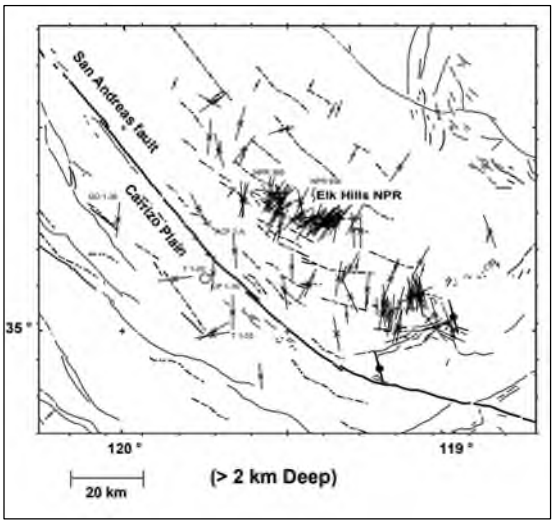
The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. in this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (Figure 23).

Figure 23: Stress diagram showing the three principal stresses and the fracturing that will occur perpendicular to the minimum principal stress.



Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 24 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

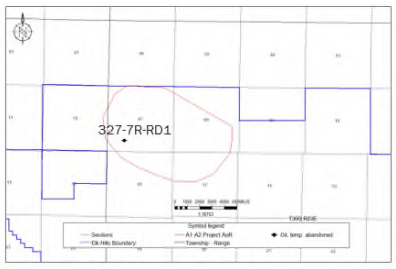
Figure 24: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).



From a fracture test in well 327-7R-RD1, the Monterey Formation A1-A2 has a fracture gradient of 0.82psi/ft, based on the initial shut-in pressure with an overburden gradient of 0.94psi/ft and pore pressure gradient of 0.2psi/ft. Using this gradient, the injectors are planned to be operated such that they will not exceed 90% of the fracture pressure, which equates to a maximum allowable bottomhole gradient of 0.9*0.82 psi/ft = 0.738psi/ft. Applying this gradient to the two injector locations, the maximum bottom injection pressures are shown in table 3.

Table 3: Injectors 355-7R and 357-7R maximum allowable bottom hole injection pressure (psi) for the Monterey Formation A1-A2 injection zone.

Stress	357-7R	355-7R
Reservoir Fracture Gradient with Safety Factore (psi/foot)	0.738	0.738
Montery Formation A1-A2 Injection Zone Top (feet TVD)	8,485	8,462
Fracture Pressure (psi)	6261.9	62,44.9



In the project AoR there is no site specific Reef Ridge Shale fracture pressure or fracture gradient. A Reef Ridge Shale step rate test will be conducted as per the preoperational testing plan. In the interim, CTV is making the assumption that the Reef Ridge Shale will have a similar fracture gradient as the Monterey Formation.

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO_2 injection. A modified Barton-Bandis model can be used to allow CO_2 to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO_2 is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO_2 to leak from the storage reservoir.

Results:

Failure pressures for the four scenarios are given in Table 4. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

Table 4: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	**FAILURE PRESSURE, PSI**
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Description:

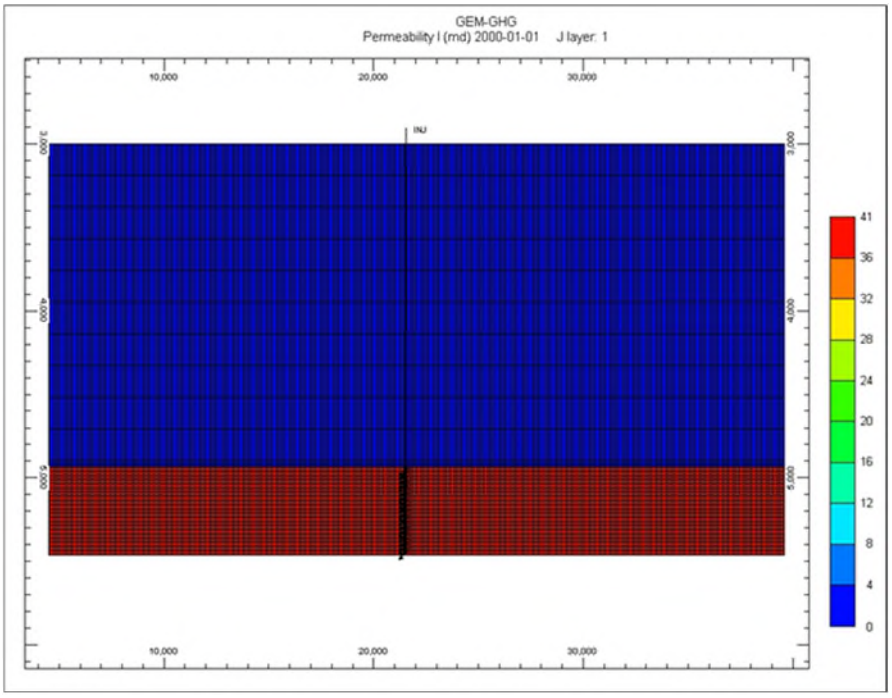
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 25.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO_2 with a maximum injection pressure of 10,000 PSI.

Figure 25: Geomechanics Model.

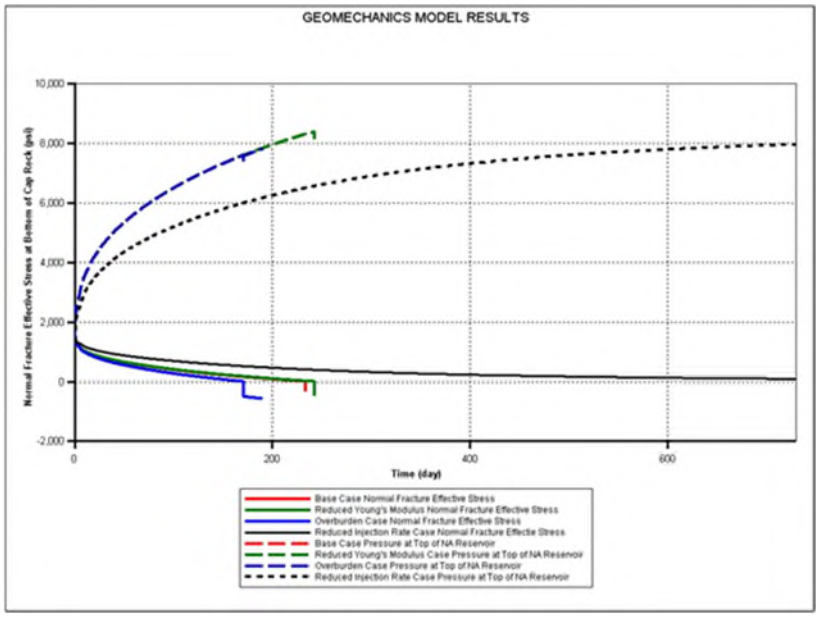


Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 26 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO_2 bleeding into the cap rock despite the very low vertical permeability.

Figure 26: Normal Fracture Stress and Pressure for Geomechanics Cases. Base case follows the reduced Young's Modulus case.



Geomechanical Modeling Parameters

The geomechanical parameters used in the modeling were selected to represent a range of values for thickness, poisons ratio and Youngs Modulus. The following is a short description for parameter variability selection:

> **Thickness:** Reef Ridge thickness scenarios for the geomechanical modeling was 795 feet and 1,935 feet. The mean thickness of the Reef Ridge Shale confining layer overlying the Monterey Formation A1-A2 AoR is 1,555 feet thick (Figure 12) as derived from open-hole log interpretation, which is between the parameters modeled.

Poisson's Ratio: Compressional and shear sonic logs were used to calculate Poisson's Ratio (Yale, 2017).

$$\nu_{dyn} = \nu_{stat} = \frac{V_p^2 - 2V_s^2}{2\left(V_p^2 - V_s^2\right)}$$

The following table shows the range of values determined for Poisons Ratio and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case (1140' of Caprock)	P10	P50	P90
Caprock Reef Ridge	0.23	0.23	0.23	0.24	0.28	0.32
Reservoir A1-A2	0.25			0.19	0.25	0.3

Young's Modulus: Young's Modulus was calculated using compressional and shear sonic and bulk density logs. The dynamic to static correction applied was the Lacy shale method (Lacy, 1997):

$$E_{dyn} = \frac{\rho V_s^2\left(3V_p^2 - 4V_s^2\right)}{\left(V_p^2 - V_s^2\right)}$$

- See equation 8.1 in Fjaer et. al, 2008

$$E_{stat} = 0.0428E_{dyn}^2 + 0.2334E_{dyn}$$

- See equation 2 in Lacy, 1997.

The following table shows the range of values determined for Young's Modulus and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case (Top 1140' of Caprock)	P10 E	P50 E	P90 E
Caprock Reef Ridge	0.9	0.8	0.6	0.66	0.91	1.36
Reservoir A1-A2	0.725			0.79	0.85	0.92

Seismic History [40 CFR 146.82(a)(3)(v)]

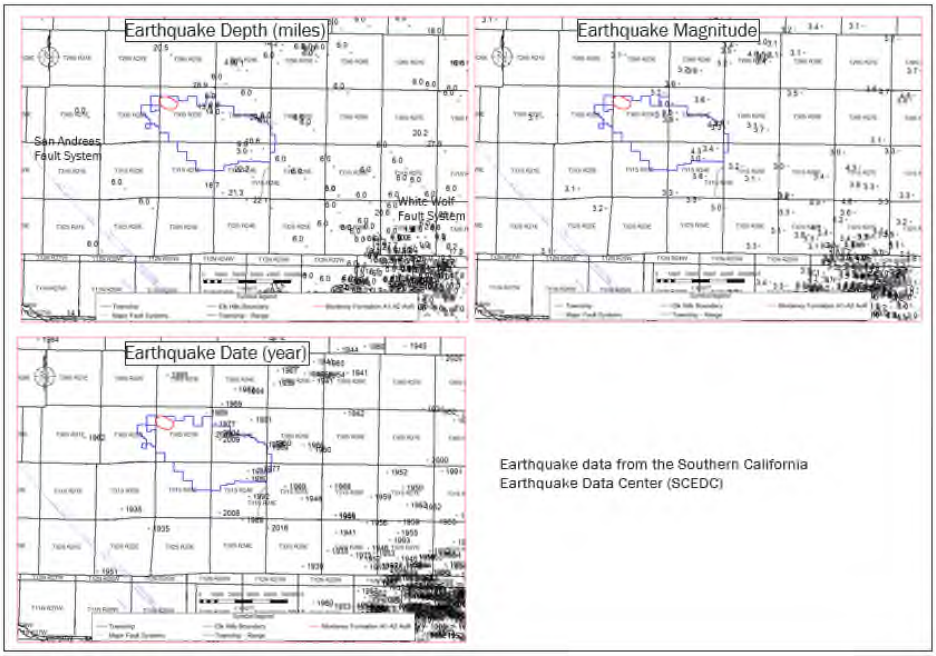
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

There have been no earthquakes in the AoR (Figure 27). In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF. The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, CTV will establish a baseline and assess natural versus induced seismicity.

Figure 27: Earthquakes in the southern San Joaquin Basin with a magnitude greater than 3 since 1932. The White Wolf Fault is active in the southern San Joaquin Basin.



Seismic Risk:

The EHOF has been closely monitored for the effects of seismicity by CRC and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

The following is a summary of CTVs seismic risk:

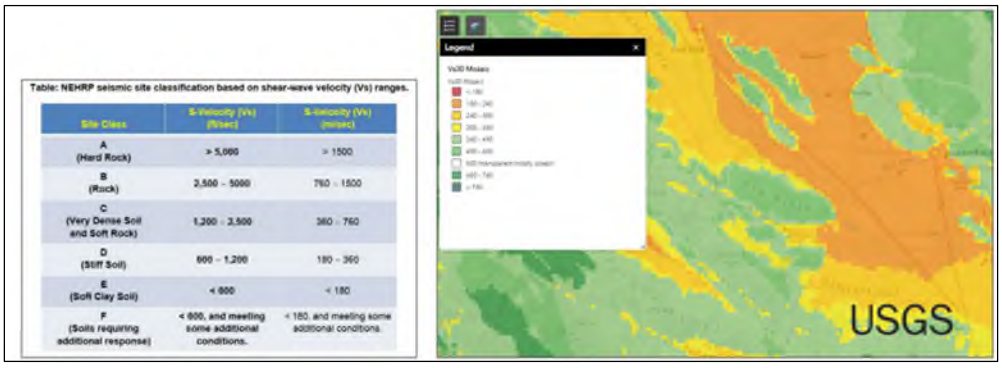
Has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO2 proposed to be injected.

- Extensive historical operations in the Monterey Formation A1-A2 reservoir is valuable experience to understand operating conditions such as injection volumes and reservoir containment. The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
- VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high Vs30means (Figure 28) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
- There are no faults or fractures identified in the AoR that will impact the confinement of CO2 injectate.

Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;

- The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- Injection and monitoring well pressure monitoring will ensure that pressures are beneath the fracture pressure of the sequestration reservoir and confining zone. Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.

Figure 28: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.



Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV personnel will be notified of events that are considered an early warning sign. Early warning signs will be addressed to ensure that more significant events do not occur.
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations.

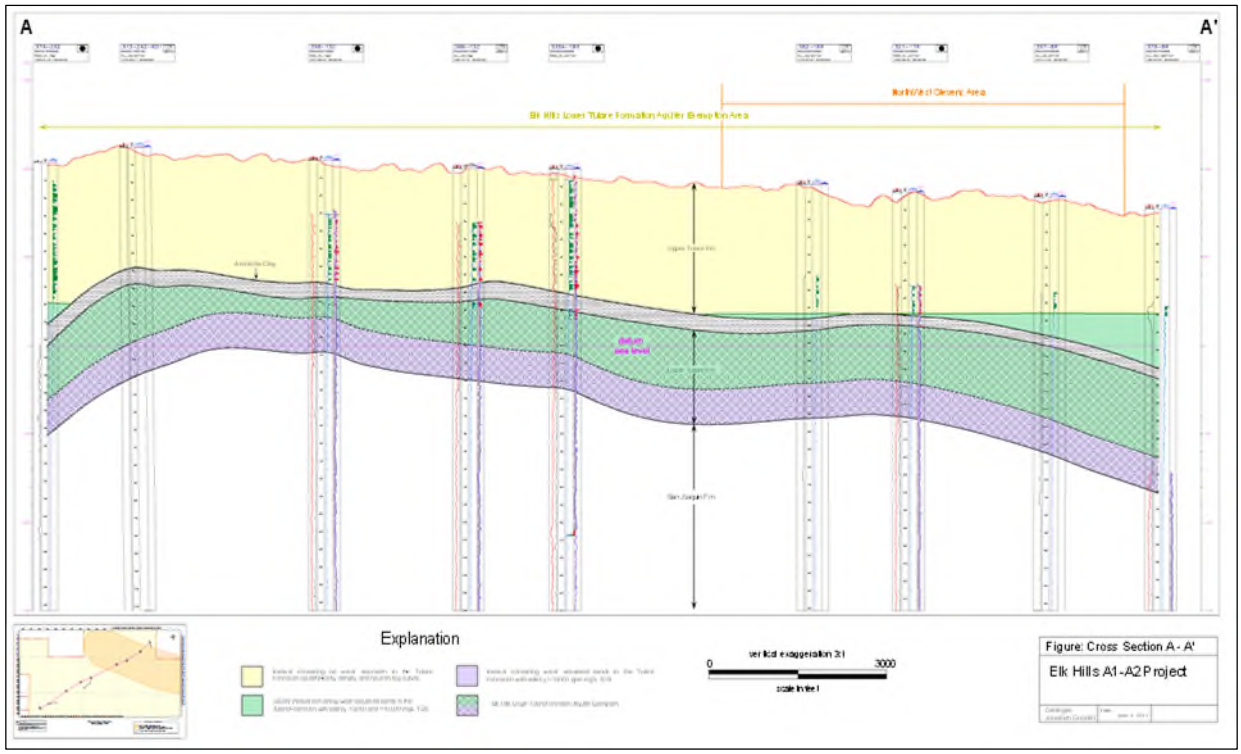
Poses a low risk of inducing a felt seismic event.

- Pressure will be monitored in each injector and sequestration monitoring well to ensure that pressure does not exceed the fracture pressure of the reservoir or confining layer.
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.
- The operational strategy of keeping the reservoir pressure at or beneath the initial pressure of the reservoir has been designed to reduce the risk for seismic events.

Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

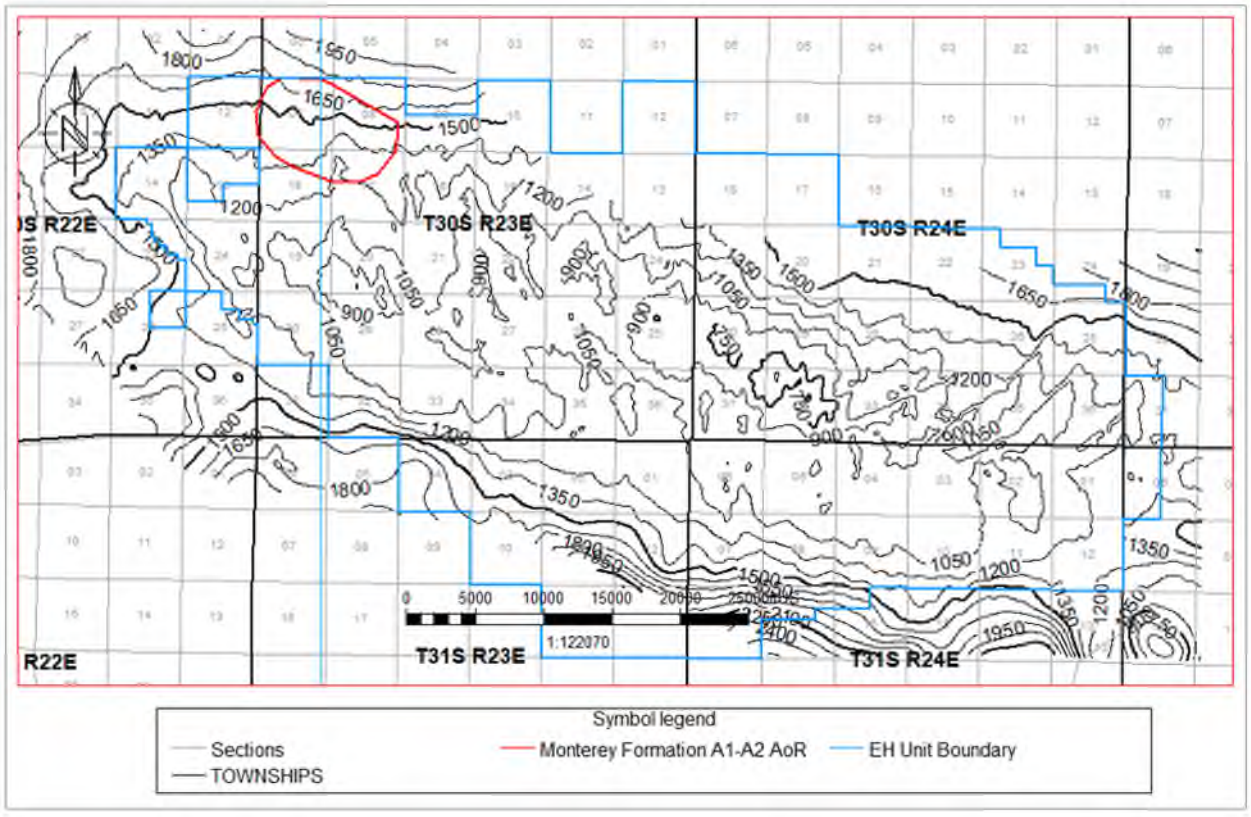
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 29). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 29: Cross-section showing the Tulare Formation USDW. The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands have 3,000 – 10,000 TDS water at the base, on the edges of the Northwest Stevens anticline.



The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 29). The depth is 600 - 2,500 feet and the thickness ranges from 1,200 - 1,500 feet (Figure 30).

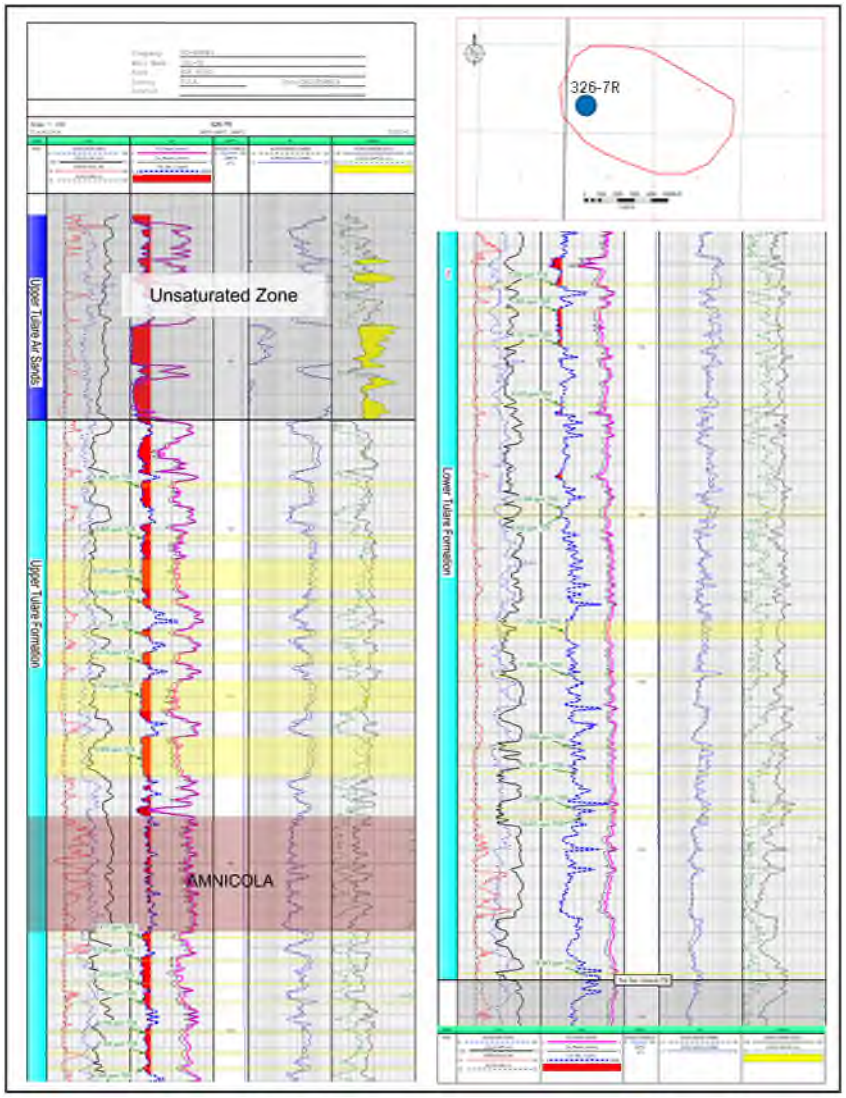
Figure 30: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare USDW. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 31). The characteristic density-neutron crossover (orange-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity.

Figure 31 shows the Upper Tulare USDW overlain by the Upper Tulare air sands. The Upper Tulare is 850 feet in depth and is separated from the underlying Reef Ridge Shale confining layer by 6,450 feet and the Monterey Formation A1-A2 sequestration reservoir by 7,650 feet.

Figure 31: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, Upper Tulare USDW and Lower Tulare exempt aquifer.



Salinity Calculation

Calculation of salinity as shown in Figure 31 is a four step process:

(1) converting measured density to formation porosity

The equation to convert measured density to porosity is:

$$POR = (Rhom - RHOB) / (Rhom-Rhof)$$

Parameter definitions for the equation are:

POR is formation porosity

Rhom is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones

RHOB is calibrated bulk density taken from well log measurements (g/cc)

Rhof is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

(2) calculation of apparent water resistivity using the Humble equation,

The Humble equation calculates apparent water resistivity. The equation is:

Rwah = ((POR**m) * XRESD)/a

Parameter definitions for the equation are:

Rwah is apparent water resistivity (ohmm)

POR is formation porosity as derived from the density conversion formula

m is the cementation factor; 2.15 is the standard value

XRESD is deep reading resistivity taken from well log measurements (ohmm)

a is the archie constant; 0.62 is the standard value

(3) correcting apparent water resistivity to a standard temperature

Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

Rwahc = Rwah * ((TEMP)+6.77)/(75+6.77)

Parameter definitions for the equation are:

Rwahc is apparent water resistivity (ohmm), corrected to surface temperature

TEMP is down hole temperature based on temperature gradient (DegF)

(4) converting temperature corrected apparent water resistivity to salinity.

The following formular was used:

SAL_h = 10 ** ((3.562-(Log10(Rwahc-0.0123)))/.955)

Parameter definitions for the equation are:

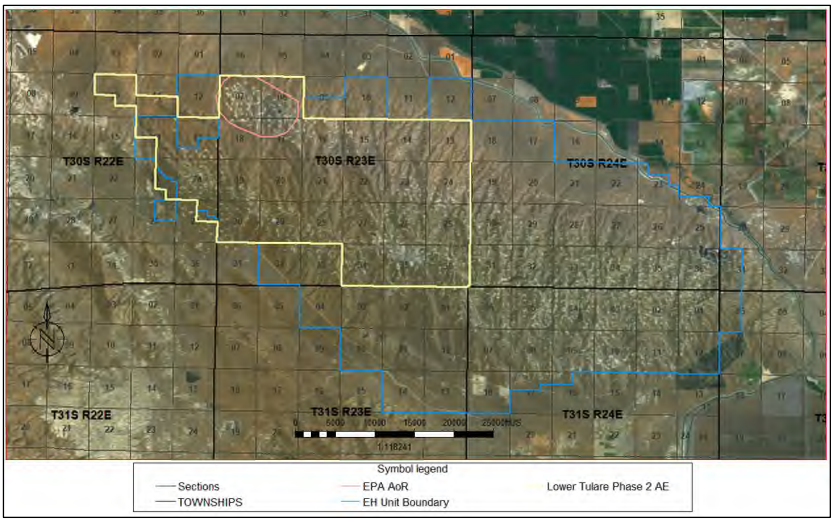
SAL_h is salinity from corrected Rwahc (ppm)

Rwahc is apparent water resistivity, corrected to surface temperature (ohmm),

Water Samples

Tulare Formation water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum containment levels (MCL).

Figure 32: Lower Tulare aquifer exemption boundary.

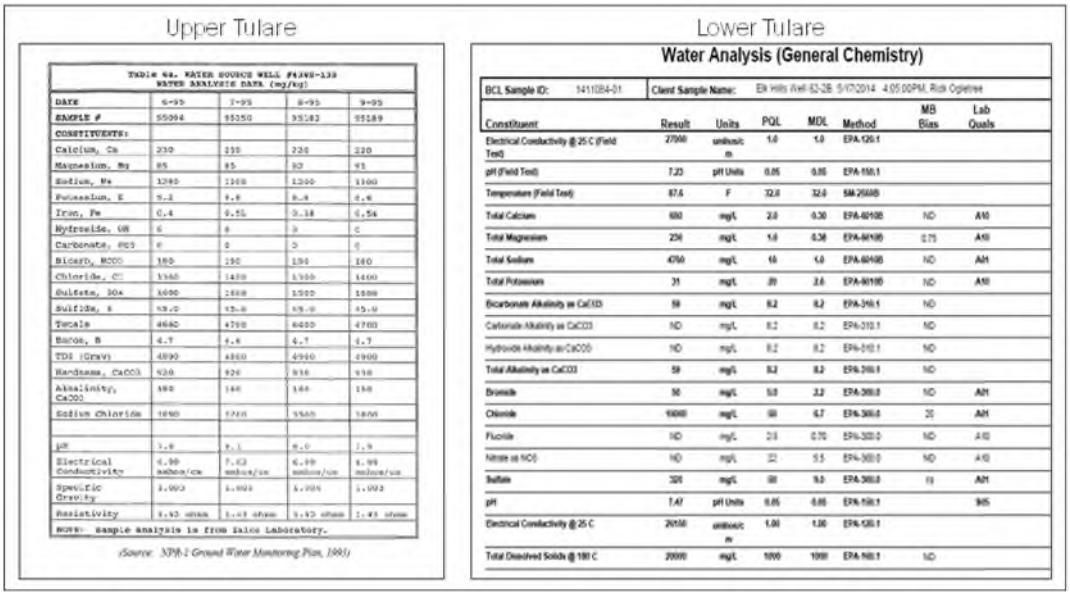


In 2018 the Lower Tulare aquifer (boundary shown on map in Figure 32) was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and
2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

The Upper Tulare USDW has 3,000-10,000 mg/l TDS on the edges of the NWS anticline. Water quality for the Upper Tulare USDW is shown in Figure 33. The water is not used within the AoR or the EHOF.

Figure 33: Upper Tulare USDW and Lower Tulare Formation water analysis.



Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

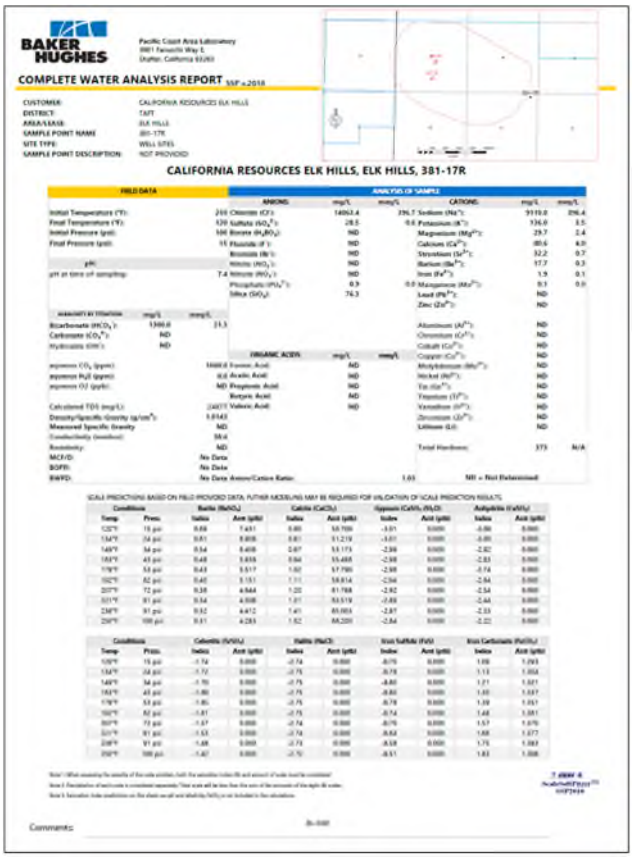
Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry A1-A2 Reservoir:

The Monterey Formation A1-A2 reservoir has a gas cap that overlies a thin oil band and a basal water zone. CRC and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation A1-A2 geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Figure 34 shows the water chemistry from well 381-17R, taken from a sand underlying the Monterey Formation A1-A2 reservoir. Reservoir depletion of the Monterey Formation A1-A2 has reduced the water saturation to residual, preventing representative water sampling.

Figure 34: Monterey Formation A1-A2 reservoir water geochemistry from well 381-17R. Monterey Formation total dissolved solids based on well 381-17R is 24,877, well above USDW standards.


BAKER HUGHES

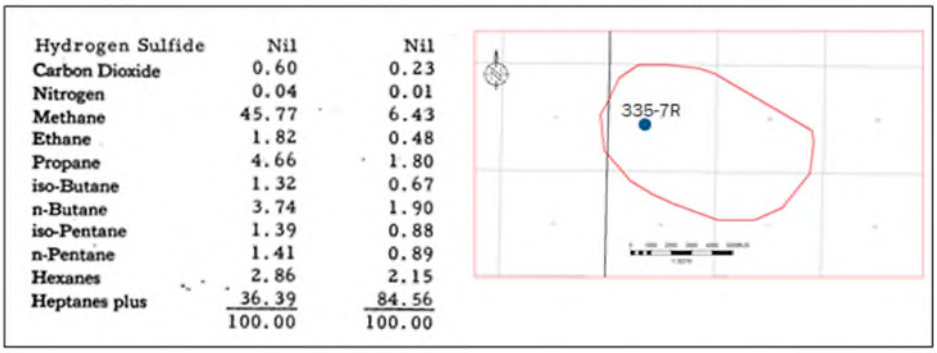
COMPLETE WATER ANALYSIS REPORT

CALIFORNIA RESOURCES ELK HILLS, ELK HILLS, 381-17R

The hydrocarbon composition for the Monterey Formation A1-A2 reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 35 shows the

results of the hydrocarbon composition for well 335-7R within the AoR. Oil composition analysis was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

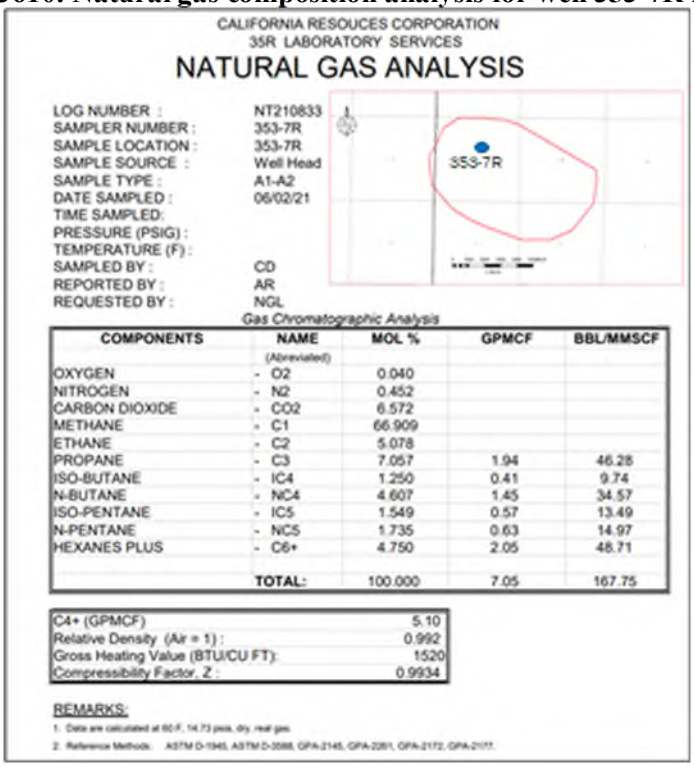
Figure 35: Monterey Formation A1-A2 hydrocarbon geochemistry from well 335-7R in 1974.



Hydrogen Sulfide	Nil	Nil
Carbon Dioxide	0.60	0.23
Nitrogen	0.04	0.01
Methane	45.77	6.43
Ethane	1.82	0.48
Propane	4.66	1.80
iso-Butane	1.32	0.67
n-Butane	3.74	1.90
iso-Pentane	1.39	0.88
n-Pentane	1.41	0.89
Hexanes	2.86	2.15
Heptanes plus	36.39	84.56
	100.00	100.00

Gas composition for the Monterey Formation A1-A2 is collected to assess the changing concentration of key components. Since 2011, CTV has used two injectors for reservoir pressure support; 357-7R and 355-7R to inject gas containing up to 44% CO_2. Figure 36 shows the produced natural gas analysis for 353-7R in 2021. Note that the composition has 6.5 mole % CO_2.

Figure 3610: Natural gas composition analysis for well 353-7R in 2021.



CALIFORNIA RESOUCES CORPORATION
35R LABORATORY SERVICES

NATURAL GAS ANALYSIS

LOG NUMBER :	NT210833
SAMPLER NUMBER :	353-7R
SAMPLE LOCATION :	353-7R
SAMPLE SOURCE :	Well Head
SAMPLE TYPE :	A1-A2
DATE SAMPLED :	06/02/21
TIME SAMPLED:	
PRESSURE (PSIG) :	
TEMPERATURE (F) :	
SAMPLED BY :	CD
REPORTED BY :	AR
REQUESTED BY :	NGL

Gas Chromatographic Analysis

COMPONENTS	NAME (Abreviated)	MOL %	GPMCF	BBL/MMSCF
OXYGEN	- O2	0.040		
NITROGEN	- N2	0.452		
CARBON DIOXIDE	- CO2	6.572		
METHANE	- C1	66.909		
ETHANE	- C2	5.078		
PROPANE	- C3	7.057	1.94	46.28
ISO-BUTANE	- IC4	1.250	0.41	9.74
N-BUTANE	- NC4	4.607	1.45	34.57
ISO-PENTANE	- IC5	1.549	0.57	13.49
N-PENTANE	- NC5	1.735	0.63	14.97
HEXANES PLUS	- C6+	4.750	2.05	48.71
	TOTAL:	100.000	7.05	167.75

C4+ (GPMCF)	5.10
Relative Density (Air = 1) :	0.992
Gross Heating Value (BTU/CU FT):	1520
Compressibility Factor, Z :	0.9934

REMARKS:

1. Data are calculated at 60 F, 14.73 psia, dry, real gas.
2. Reference Methods: ASTM D-1945, ASTM D-3588, GPA-2145, GPA-2261, GPA-2172, GPA-2177.

Monterey Formation A1-A2 Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO_2 injectate:

1. The Monterey Formation A1-A2 reservoir has a low current water volume (~15% saturation in the gas cap and 85% in the thin oil leg) due to production related to oil and gas operations, where four million net barrels of water have been produced. This low volume of water will minimize both the quantity of CO_2 that will dissolve in solution and the quantity of carbonic acid formed in-situ.
2. Residual oil saturation (15%) in the Monterey Formation A1-A2 reservoir will also dissolve only a small amount of CO_2.
3. The Monterey Formation A1-A2 has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO_2 and carbonic acid and any dissolution or changes that occur will be on grain surfaces.
4. Since 2011 6.3 billion cubic feet of gas has been injected in the 357-7R and 355-7R wells, consisting of up to 44% CO_2. Injectivity of the reservoir has not changed.

The oil and water CO_2 trapping mechanisms have been incorporated in the computational modeling and will be discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO_2 injectate.

Site Suitability [40 CFR 146.83]

The Monterey Formation A1-A2 reservoir in the Northwest Stevens anticline was discovered in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the Monterey Formation A1-A2 reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

A key component of the A1-A2 reservoir characterization was the development of a geo-cellular model, which is used to assess CO_2 plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement, and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale). Cross-sections in Figures 37 and 38 shows the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers supports predictable plume development.

CO2 Injectate Confinement:

Confinement of CO_2 injected into the storage reservoir is supported by the following:

1. Prior to discovery of the Monterey Formation A1-A2 reservoir, a gas cap with underlying oil was confined for several million years.
2. The Reef Ridge Shale primary confining layer is 1,500 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 175 billion cubic feet of gas and five million barrels of water with no leakage.
3. Cross section A-A' (Figure 37) shows the lateral confinement of the injected CO_2 plume by the anticline structure. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does migrate beyond the edges of the anticline structure or into the Reef Ridge shale.
4. In Cross section B-B' (Figure 38) the up-dip CO_2 plume is confined by shale and the non-deposition of reservoir sands.

Figure 37: Plume modeling results showing lateral confinement of the CO2 plume by the edges of the anticline structure.

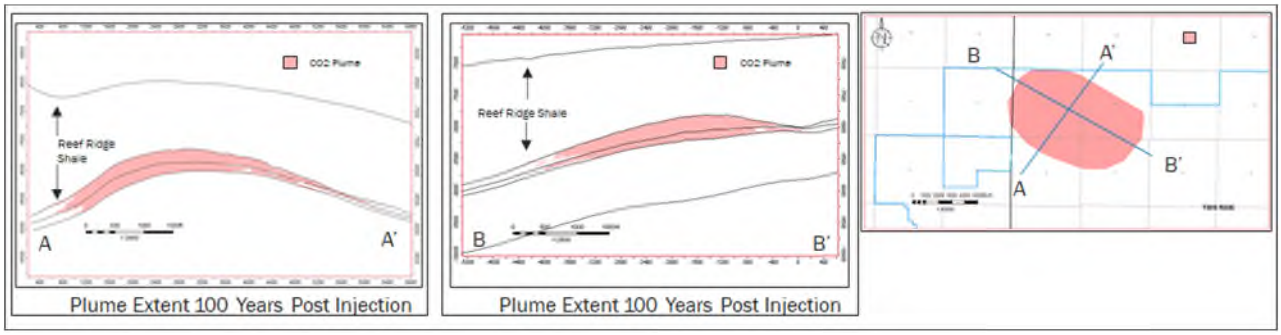
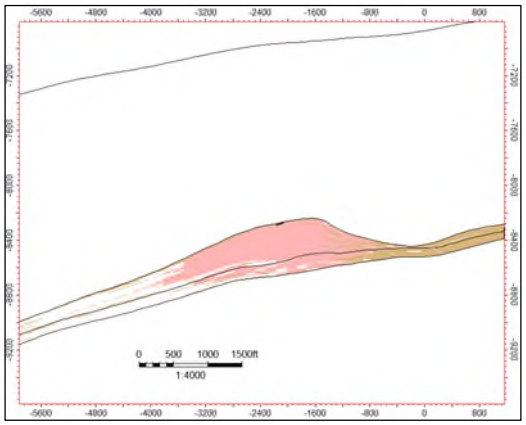


Figure 38: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the A1-A2 sand facies and the increasing shale facies.



Storage capacity for the Monterey Formation A1-A2 storage reservoir based on computational modeling results is approximately 8 -10 million tonnes of CO_2. This is sufficient capacity for the total proposed injectate.

References:

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ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills A1-A2 Storage Project

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate two CO_2 geologic sequestration wells at the Elk Hills Oil Field (EHOF) located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO_2 stored in the Monterey Formation at 0.25 - 0.75 million tonnes annually for 15 years with injection starting in 2024. The anthropogenic CO_2 will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. CTV operates and owns ~100% of the surface, mineral and pore space rights at the EHOF. The project will consist of two existing injectors, surface facilities, and monitoring wells. This supporting documentation applies to the two injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

   Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

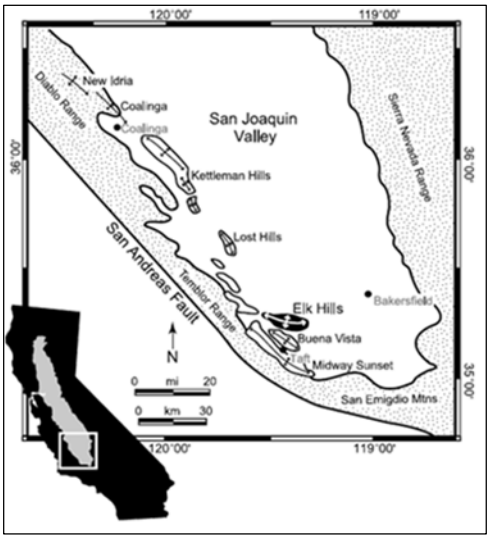
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation A1-A2 sequestration reservoir was discovered in the 1970's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

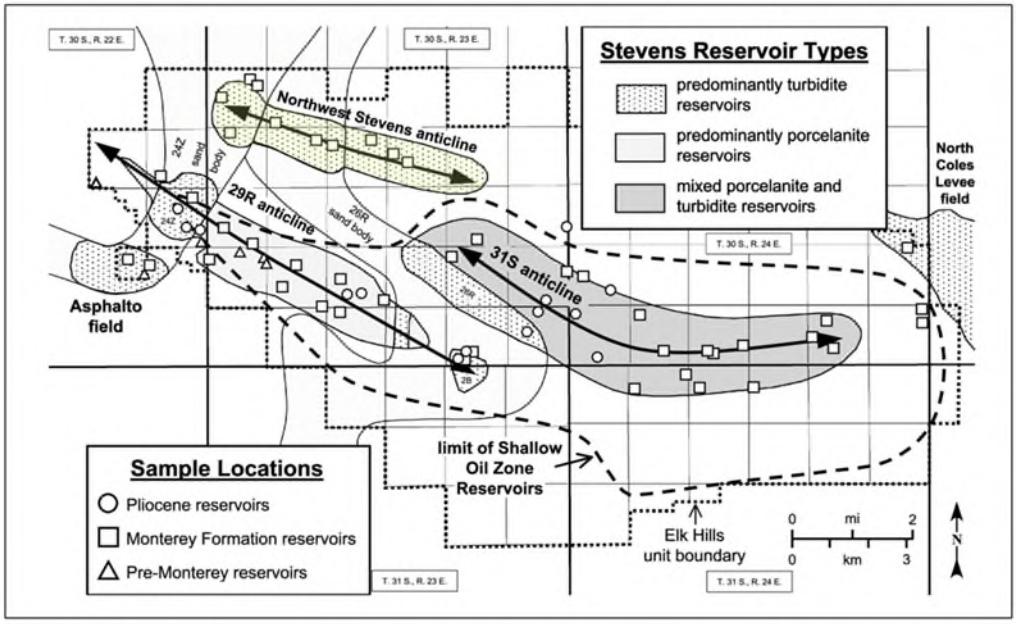
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide. With increasing depth, the structure sub-divides into three distinct anticlines (Figure 2), separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

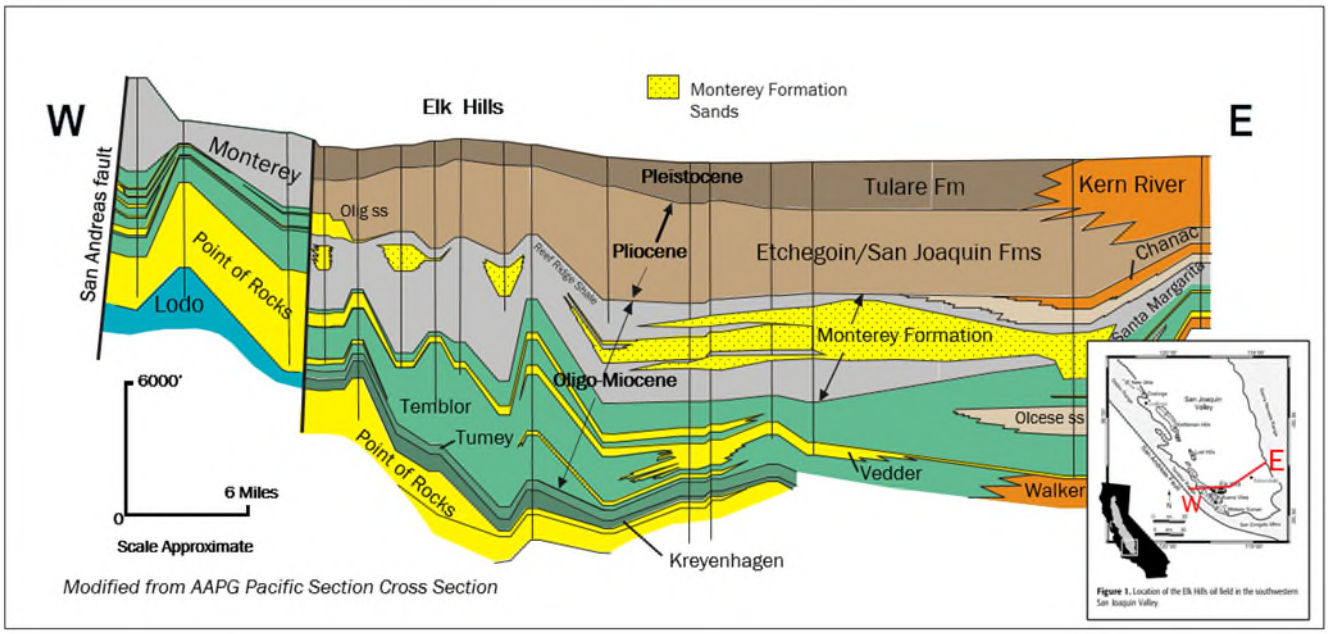
Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation A1-A2 CO2 sequestration reservoir is located in the Northwest Stevens anticline (Zumberge, 2005).



Geological Sequence

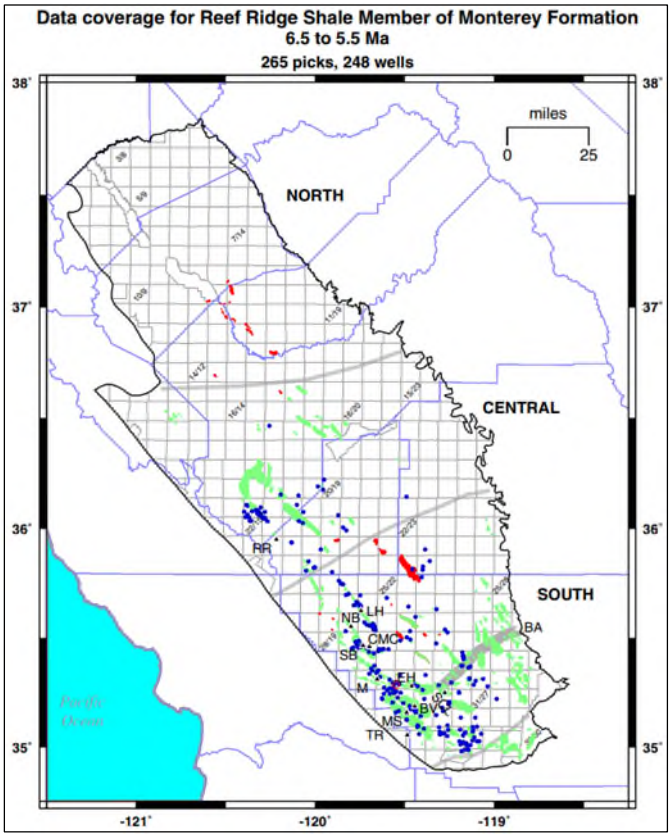
Figure 3 shows the stratigraphy of the EHOF. The two injection wells will inject CO_2 into the Miocene aged Monterey Formation A1-A2 at the Northwest Stevens anticline approximately 8,500 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin (Figure 4) and serves as the primary confining layer for the Monterey Formation A1-A2 reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Figure 4: Reef Ridge Shale data coverage over the San Joaquin Basin (Hosford, 2007).

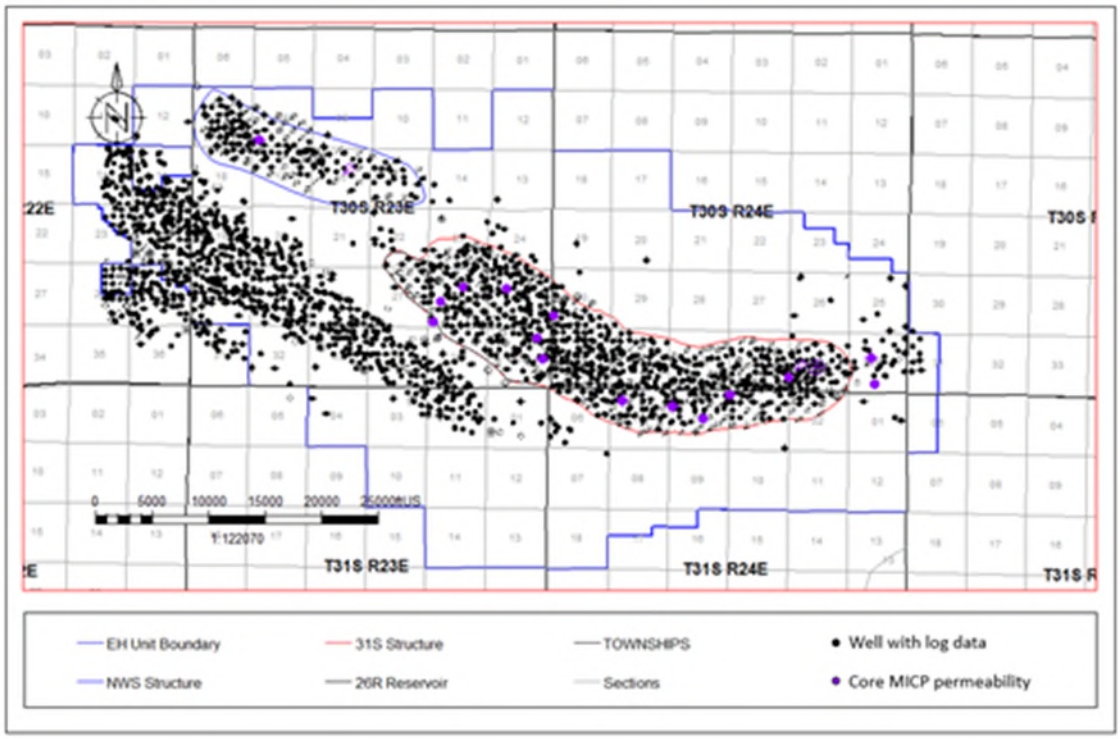


Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 5), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

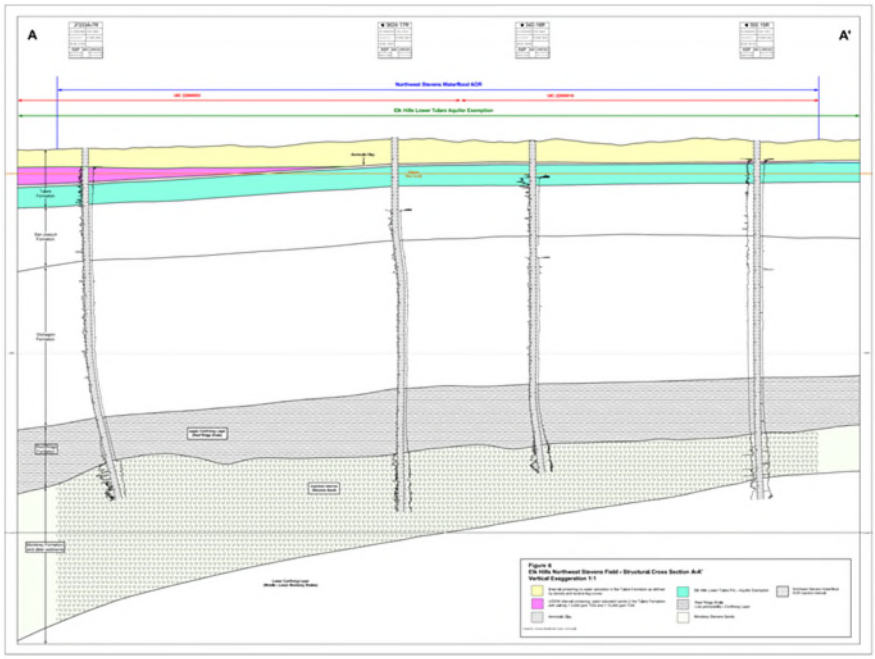
Figure 5: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core from the Monterey Formation are in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 6 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 6: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the Northwest Stevens anticline.



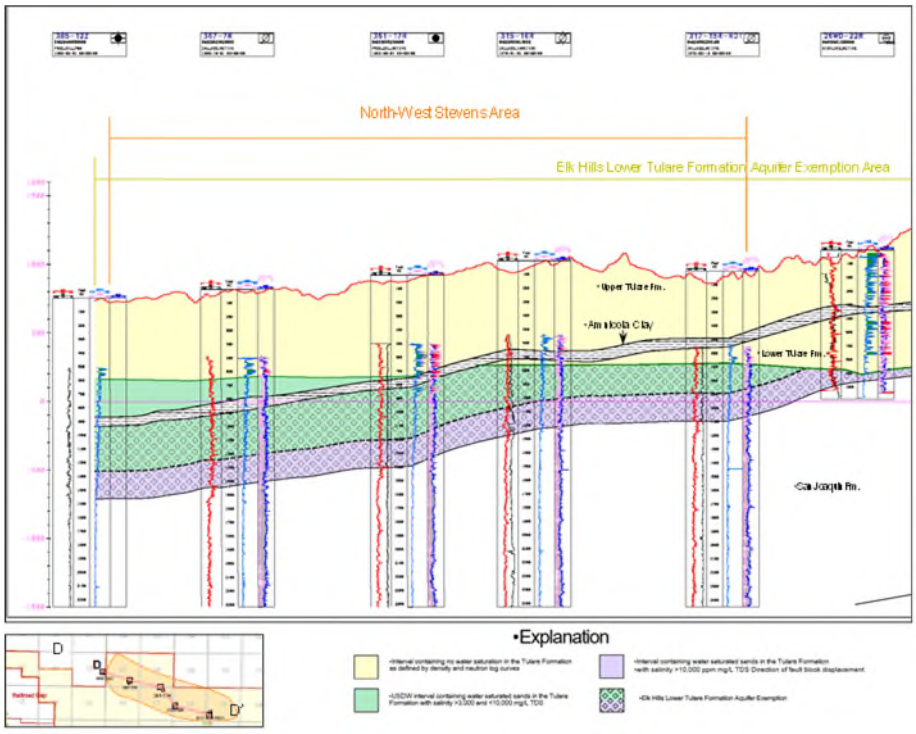
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 7), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare contains 3,000 - 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) water and is the only USDW in the AoR. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 7: The Tulare Formation consists of the Upper Tulare USDW and Lower Tulare and is separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer. The Upper Tulare USDW has formation water 3,000 - 10,000 mg/l TDS.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and conglomerate of the Tulare Formation interfinger with the San Joaquin beds. The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000’ in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand

dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 6,929-7,962 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

The Reef Ridge directly overlies the Monterey Formation A1-A2 sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

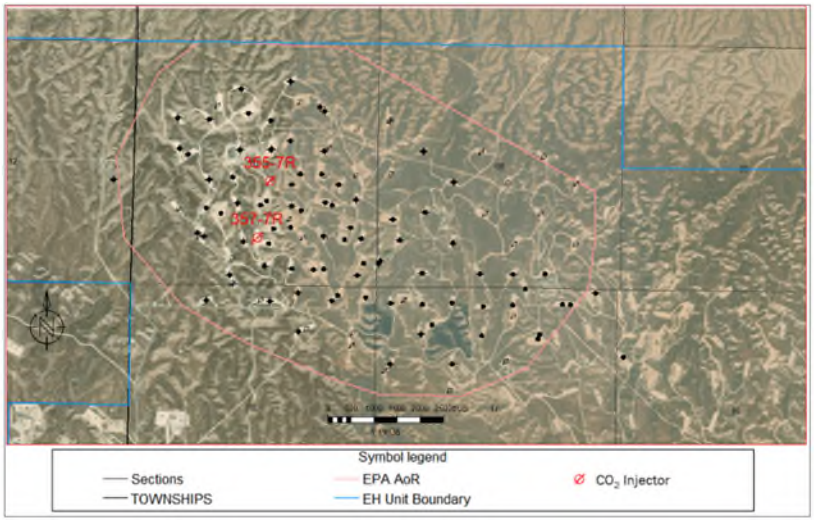
The Monterey Formation A1-A2 sequestration zone is approximately 8,500 feet deep and produces from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 16% and 60 mD, respectively.

The Monterey Formation A1-A2 sands were deposited in two coalescing turbidite channels which were influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. Figure 2 shows the orientation and depositional fairways for these channels in the Northwest Stevens anticline. The sands were largely aggregational with minimal erosive deposition.

The reservoir is continuous across the AoR and sands pinch-out on the channel edges. The Monterey Formation A1-A2 sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no

evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

Figure 8: AoR and injection well location map for Elk Hills A1-A2 project. The injection wells, 355-7R and 357-7R are 1,250 feet apart. Also shown are the wells that penetrate the confining Reef Ridge Shale.

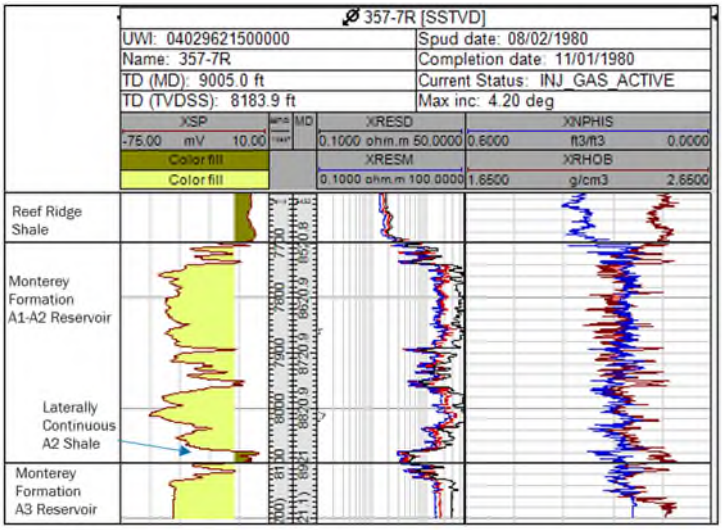


Underlying Monterey Formation A3-A11:

Underlying the Monterey A1-A2 Formation is the Monterey Formation A3-A11 reservoir. This stratigraphic package is not in communication with the A1-A2, as indicated by the following:

1. The two packages have been developed separately. The A1-A2 reservoir was previously pressure supported by gas injection (175 billion cubic feet injected) while the A3-A11 reservoir is currently pressure supported by waterflood (449 million barrels of water injected).
2. The Monterey Formation A1-A2 reservoir is at 200-300 PSI and the A3-A11 reservoir is much higher at approximately 1,700 PSI. This pressure differential is maintained due to hydraulic confinement between the two reservoirs.
3. The laterally continuous A2 shale separates the reservoirs (Figure 9). This shale is greater than 20 feet thick across the AoR and prevents communication between the Monterey Formation A1-A2 reservoir and the Monterey Formation A3-A11 reservoir.

Figure 9: 357-7R injector showing the Monterey Formation A1-A2 reservoir and the laterally continuous A2 Shale above the Monterey Formation A3-A11 reservoir.



CTV will monitor the Monterey Formation A3-A11 reservoir and wellbores for CO_2 migration. Waterflood producers will be monitored via fluid sampling once per quarter for changes in composition. In addition, Monterey Formation A3-A11 waterflood injectors will have mechanical integrity tests (MIT) and standard annular pressure tests (SAPT) to ensure internal and external mechanical integrity. This monitoring will be discussed in more detail within the Testing and Monitoring Plan. Additionally, due to its waterflood infrastructure and high reservoir pressure, the A3-A6 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

Summary:

The Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as confinement by the Reef Ridge Shale.

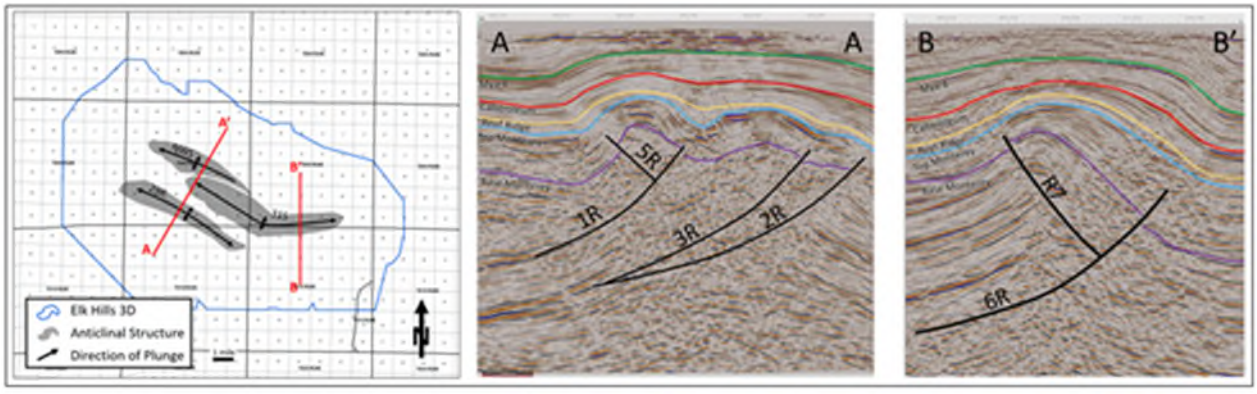
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 10 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the NWS anticlines are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale.

Figure 10: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.



Fluid Confinement

Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO_2 injectate in the Monterey Formation A1-A2 sands:

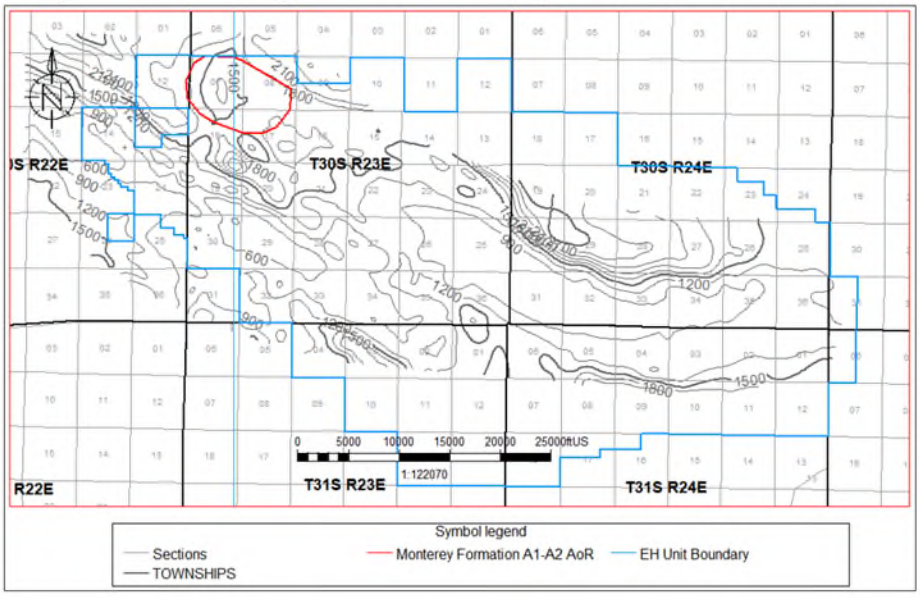
1. There are no faults that extend into the confining Reef Ridge Shale.

2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. A pressure differential exists above and below the Reef Ridge confining interval, confirming lack of communication.
4. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,100 feet (Figure 11) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 11: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



2. Waterflooding and Gas Injection

Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control Board. To date, more than five million barrels of water and 175 billion cubic feet of gas have been injected into the Monterey Formation A1-A2 sands. There has been no evidence of water or gas migrating out of the reservoir or through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically and aerially confined.

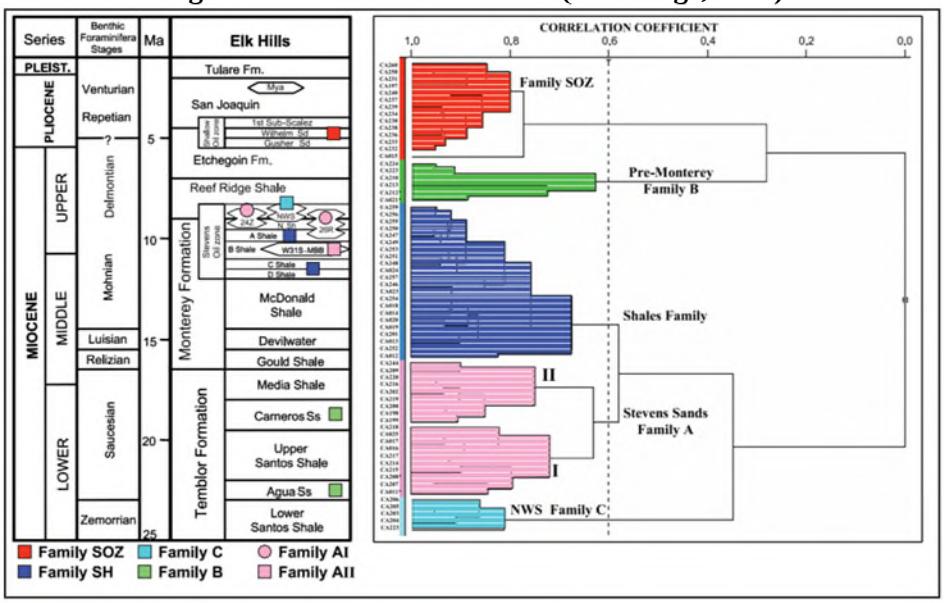
3. Pressure Differentials

The Monterey Formation A1-A2 sequestration zone average current pressure is approximately 230 PSI. Overlying the sequestration zone, and separated by the confining Reef Ridge Shale, the Etchegoin Formation aquifer sands are at a much higher pressure of 1,500 PSI (0.43 PSI/foot gradient at 3,600 feet depth). This pressure differential of 1,300 PSI between the overlying Etchegoin Formation and Monterey Formation is maintained because the Reef Ridge is sealing and there are no transmissive features.

4. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 12) sourced from the Miocene Monterey Formation and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests "minimal up-section, [and] cross stratigraphic migration". The authors conclude that the hydrocarbons present in the overlying formations are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

Figure 12: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

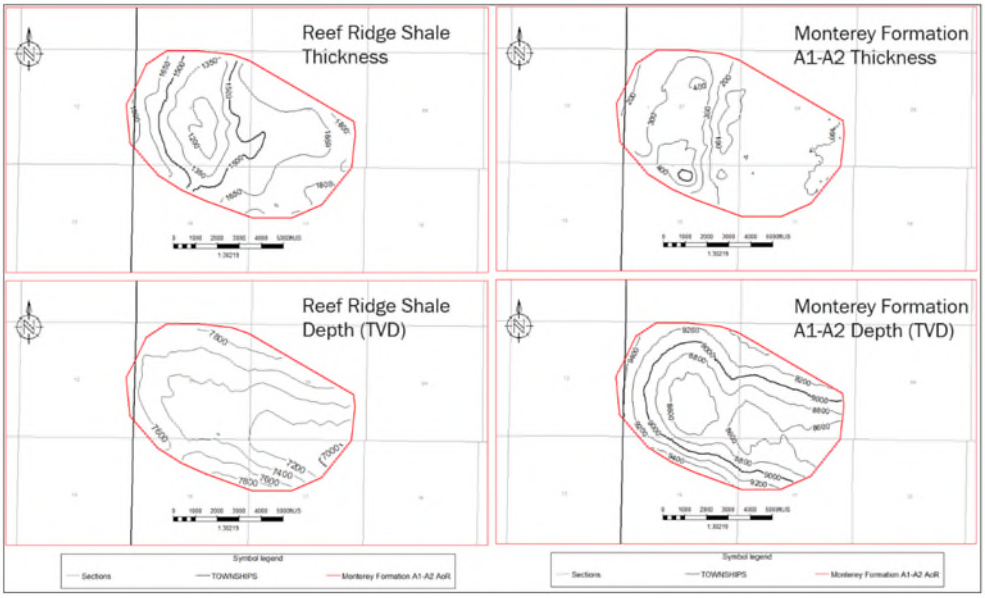
Depths and thickness of the Monterey Formation A1-A2 reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 13) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability due to deposition of the Monterey Formation sands. In the AoR, the Reef Ridge Shale minimum thickness corresponds to a high in Monterey Formation A1-A2 sand thickness.
3. Monterey Formation A1-A2 thickness variability is from pinch-out of the reservoir on the structure.

Table 1: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone Reef Ridge Shale	Thickness (feet)	1,122	1,892	1,555
	Depth (feet TVD)	6,929	7,962	7,441
Reservoir Monterey Formation A1-A2 Sand	Thickness (feet)	27	548	204
	Depth (feet TVD)	8,403	9,598	5,907

Figure 13: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth maps.



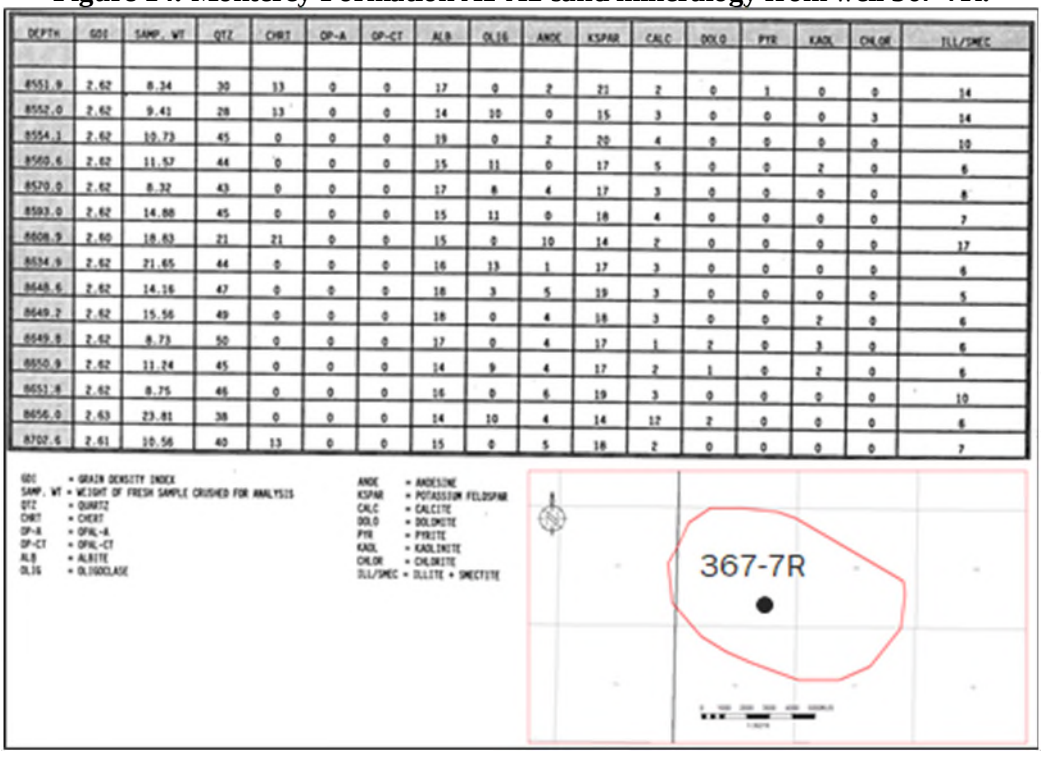
Variability in the thickness and depth of the either the Reef Ridge Shale or the Monterey Formation A1-A2 sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

Mineralogy

Monterey Formation A1-A2:

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the AoR. Offset well 367-7R (Figure 14) provides an example of the mineralogy for the reservoir interval in 357-7R. Clean reservoir sand intervals have an average of 43% quartz, 38% potassium feldspar, albite and oligoclase as well as 7% total clay.

Figure 14: Monterey Formation A1-A2 sand mineralogy from well 367-7R.

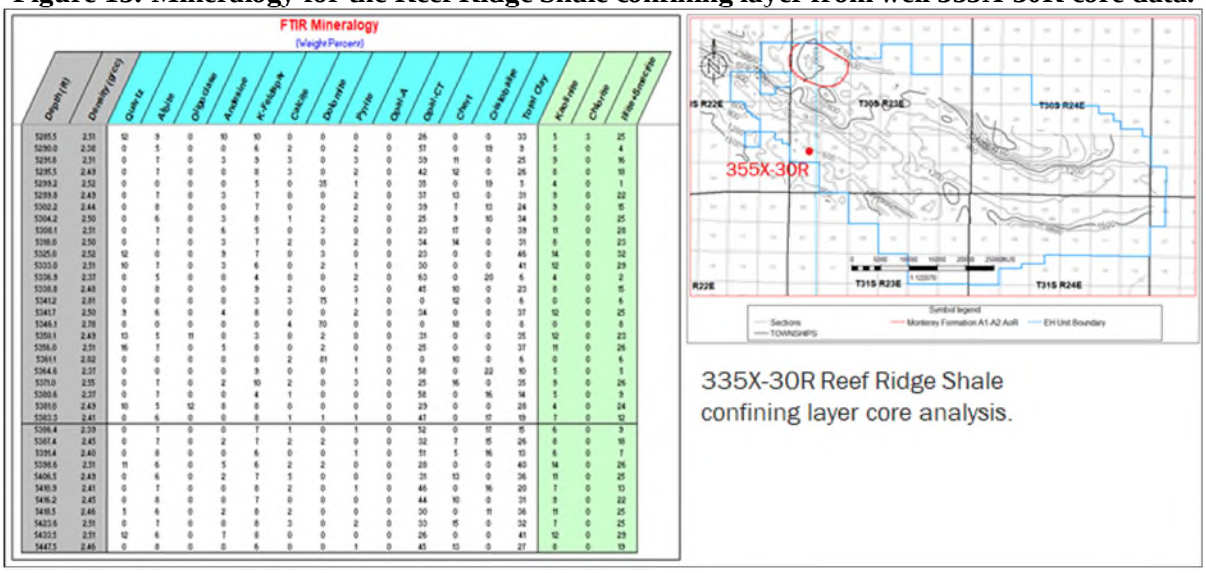


Reef Ridge Shale:

Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 15). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AOR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 15: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.



Porosity and Permeability

Monterey Formation A1-A2:

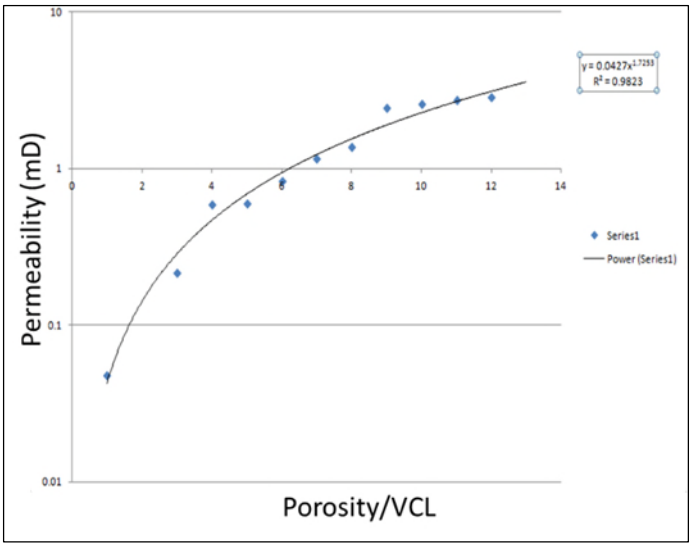
Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.

Volume of clay is determined by neutron-density separation and is calibrated to core data.

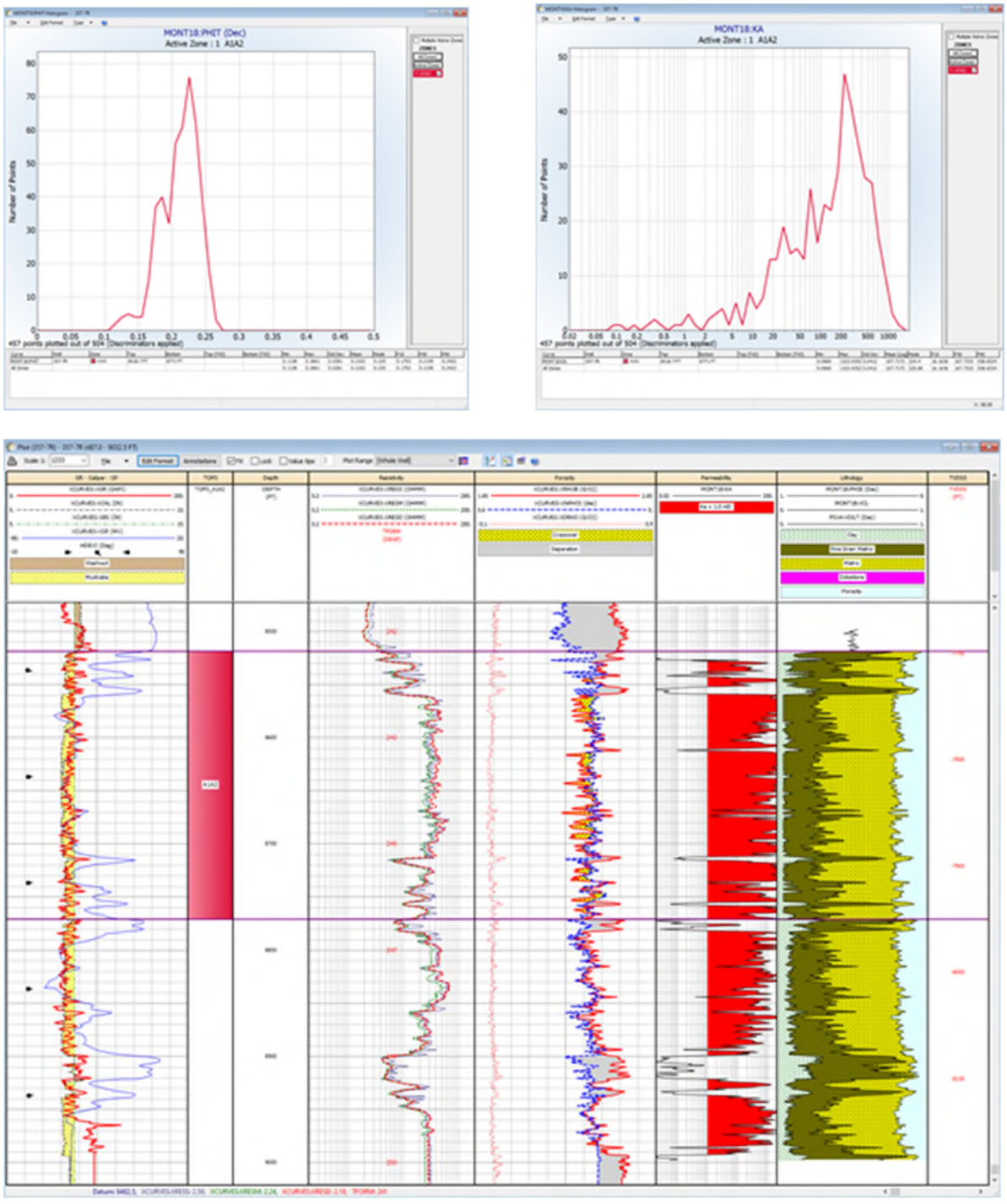
Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated in Figure 16 below.

Figure 16: Permeability function developed based on mercury injection capitally pressure data and calculated from log derived porosity and clay volume.



In the example below for the Monterey Formation A1-A2 sands, the porosity ranges from 11% - 27% with a mean of 21%. The permeability ranges from 0.1 mD - 1300 mD with a log mean of 108 mD (Figure 17).

Figure 17: Porosity and permeability for well 357-7R, showing the distribution and the input and output log curves.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2).

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006
TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

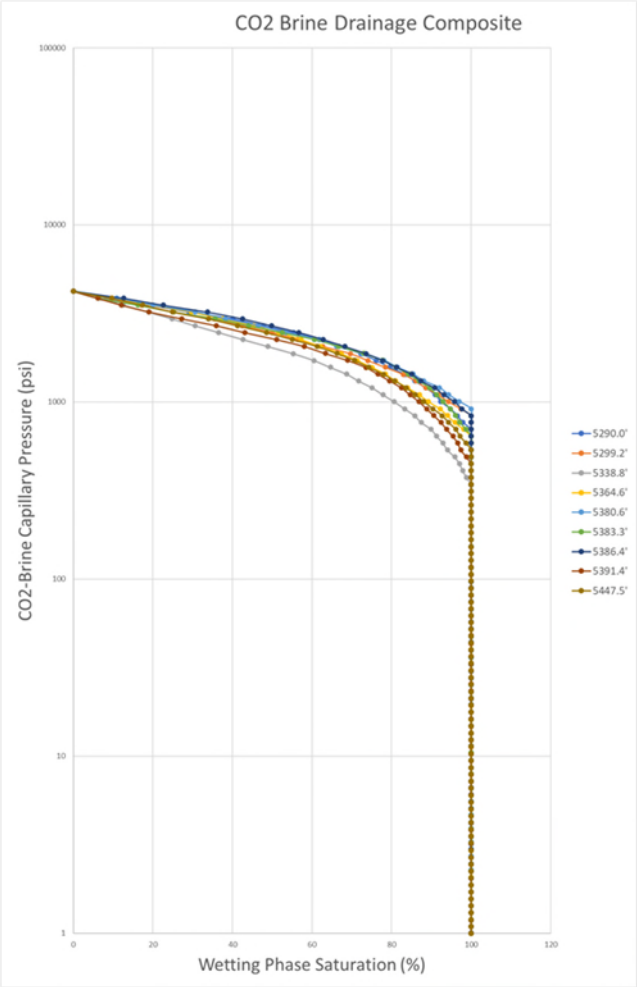
Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 18). The capillary pressure was determined by applying CO_2-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-

brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO_2-brine, respectively.

Figure 18: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR, 18 wells had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 59,214 individual logging data points.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

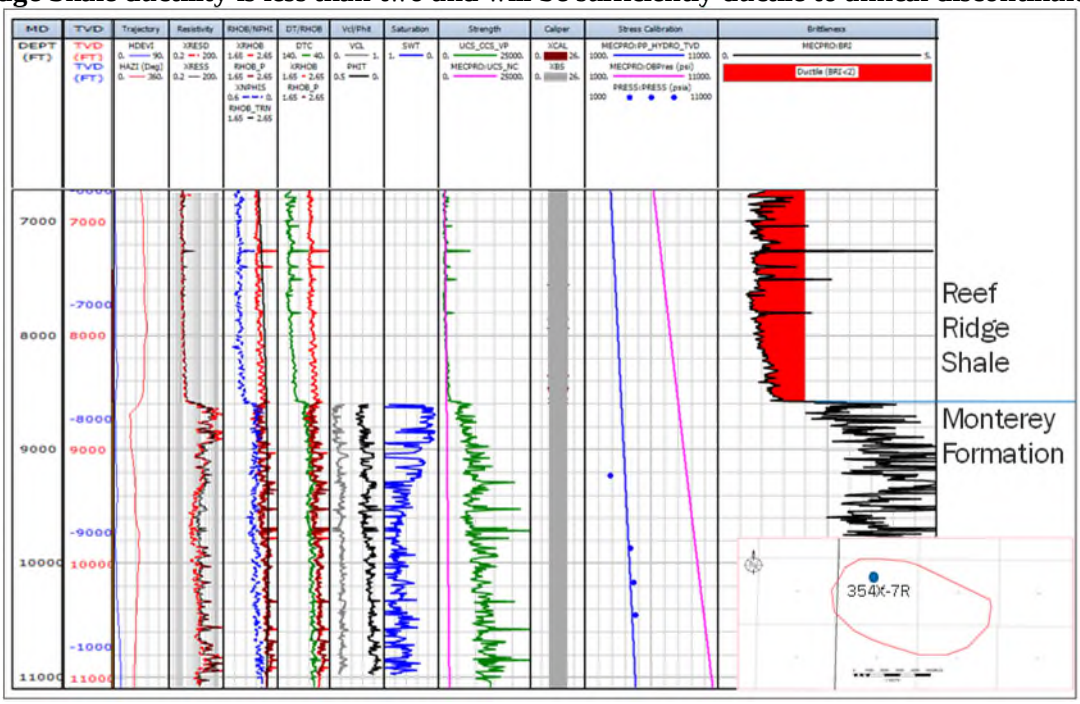
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 354X-7R is shown below (Figure 19). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method. Ductility less than two is shaded red.

Figure 19: Unconfined compressive strength and ductility calculations for well 354X-7R. The Reef Ridge Shale ductility is less than two and will be sufficiently ductile to anneal discontinuities.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to anneal discontinuities. This confirms that the Reef Ridge is a ductile confining layer.

The average ductility of the confining zone based on the mean value from 18 wells is 1.24.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,452 psi.

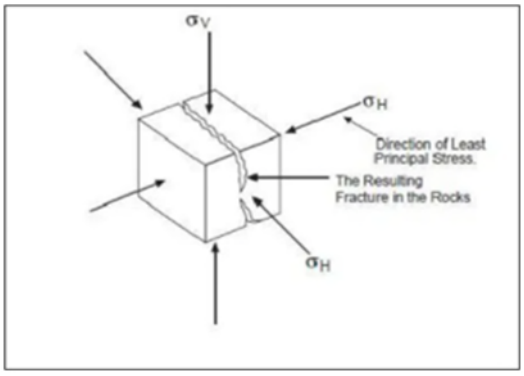
As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the Monterey Formation A1-A2 reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. in this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (Figure 20).

Figure 20: Stress diagram showing the three principal stresses and the fracturing that will occur perpendicular to the minimum principal stress.



Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 21 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

Figure 21: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).

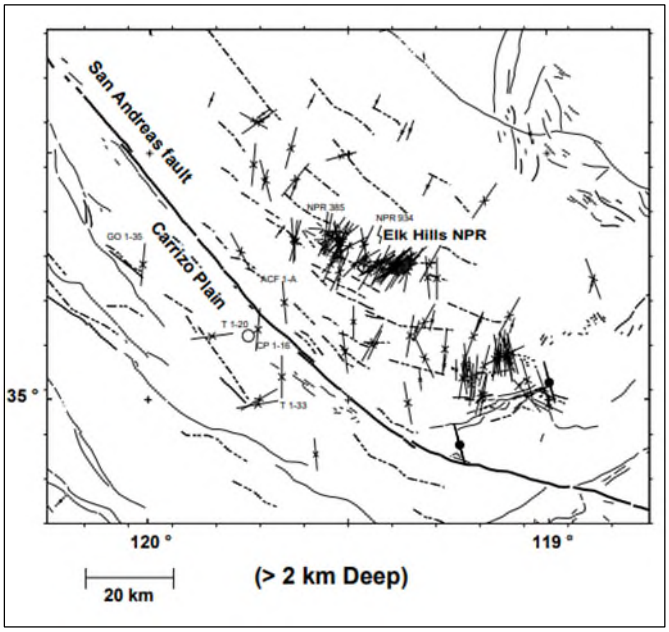


Table 3 shows the horizontal fracture gradients for the Reef Ridge Shale and the Monterey Formation A1-A2 reservoir.

Table 3: Pressure gradients and pressures for the Monterey Formation A1-A2 reservoir and the Reef Ridge Shale.

Stress	Reef Ridge Shale Confining Layer (374A-7R-RD1)	Monterey Formation A1-A2 Reservoir (372-7R-RD1)
Pore Pressure Gradient (PSI/foot)	0.433	0.2
Overburden Gradient (PSI/foot)	0.93	0.94
Minimum Horizontal Stress Gradient (PSI/foot)	0.73	0.97

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO_2 injection. A modified Barton-Bandis model can be used to allow CO_2 to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO_2 is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO_2 to leak from the storage reservoir.

Results:

Failure pressures for the four scenarios are given in Table 4. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

Table 4: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	**FAILURE PRESSURE, PSI**
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Description:

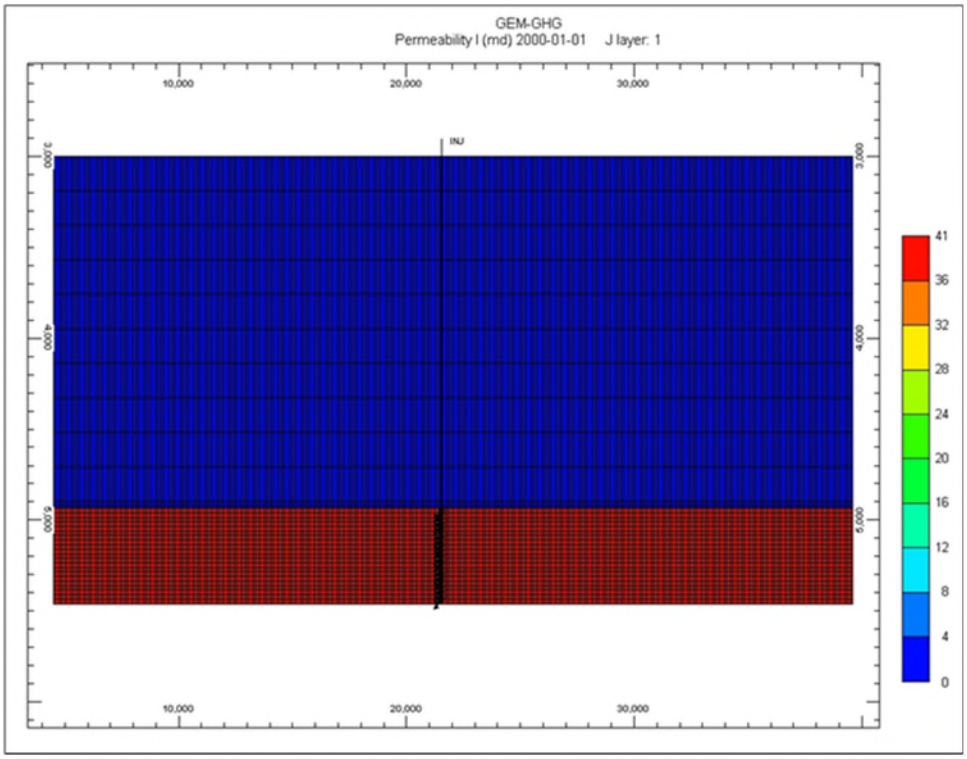
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 22.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO_2 with a maximum injection pressure of 10,000 PSI.

Figure 22: Geomechanics Model.

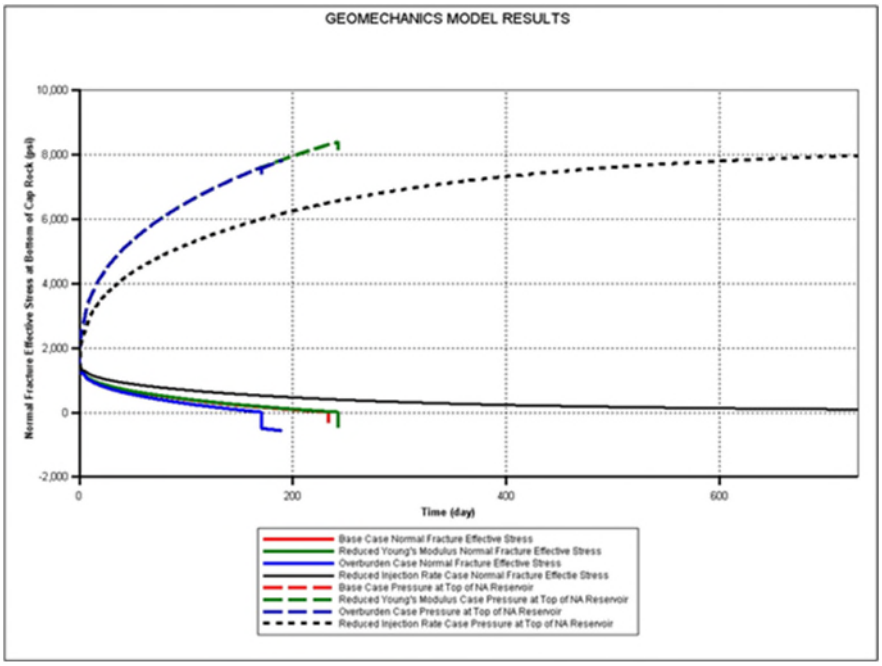


Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 23 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO_2 bleeding into the cap rock despite the very low vertical permeability.

Figure 23: Normal Fracture Stress and Pressure for Geomechanics Cases.



Seismic History [40 CFR 146.82(a)(3)(v)]

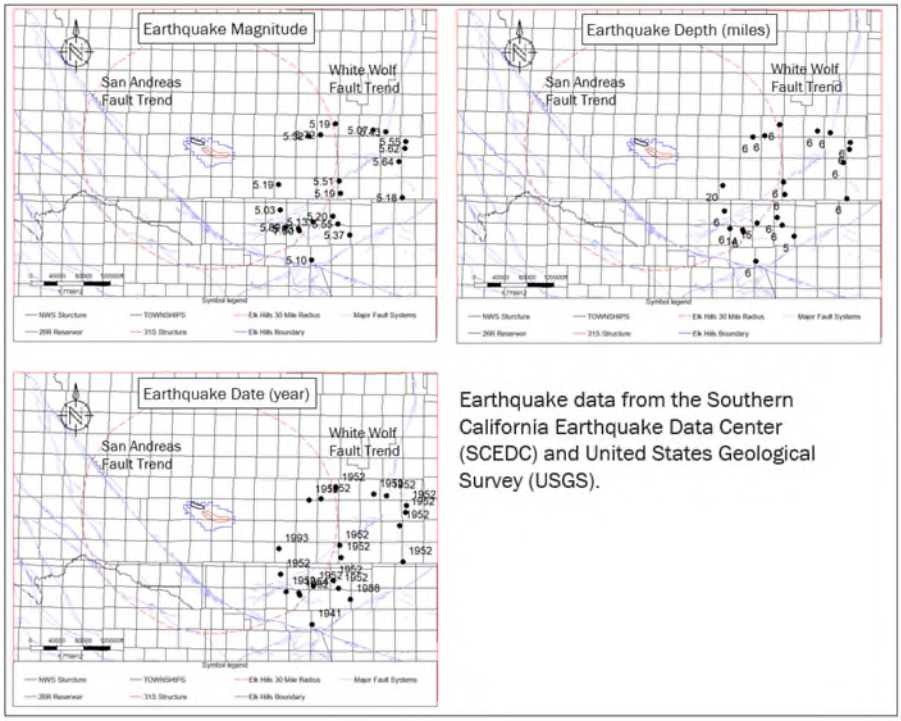
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

Within the EHOF there have been no earthquakes recorded greater than 3.0. In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF (Figure 24). The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, CTV will establish a baseline and assess natural versus induced seismicity.

Figure 24: Earthquakes in the San Joaquin Basin with a magnitude greater than 5 since 1932. The White Wolf Fault is active in the southern San Joaquin Basin.

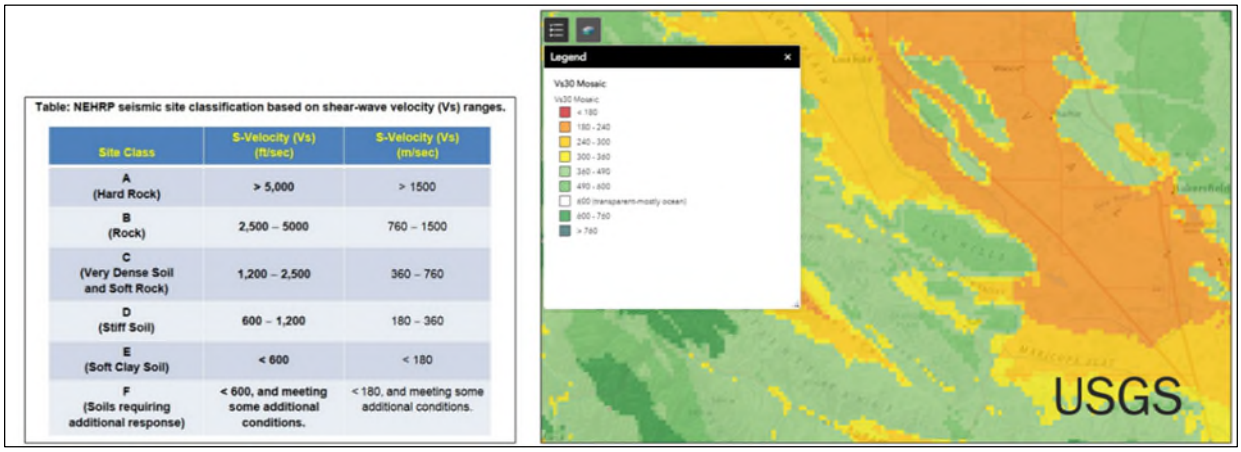


Seismic Risk:

The EHOF has been closely monitored for the effects of seismicity by CRC and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

1. No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
2. VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high Vs30means (Figure 25) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
3. The 1952 Kern County earthquake, the largest in the region, occurred southeast of the EHOF near Frazier Park with an estimated magnitude of 7.5. Effects of the earthquake were catastrophic with loss of life, and significant property damage (SCEDC). Regionally there were no reservoir containment issues associated with oil and gas operations and the Reef Ridge Shale. Moreover, there was no impact to Elk Hills infrastructure (Jenkins, 1955).

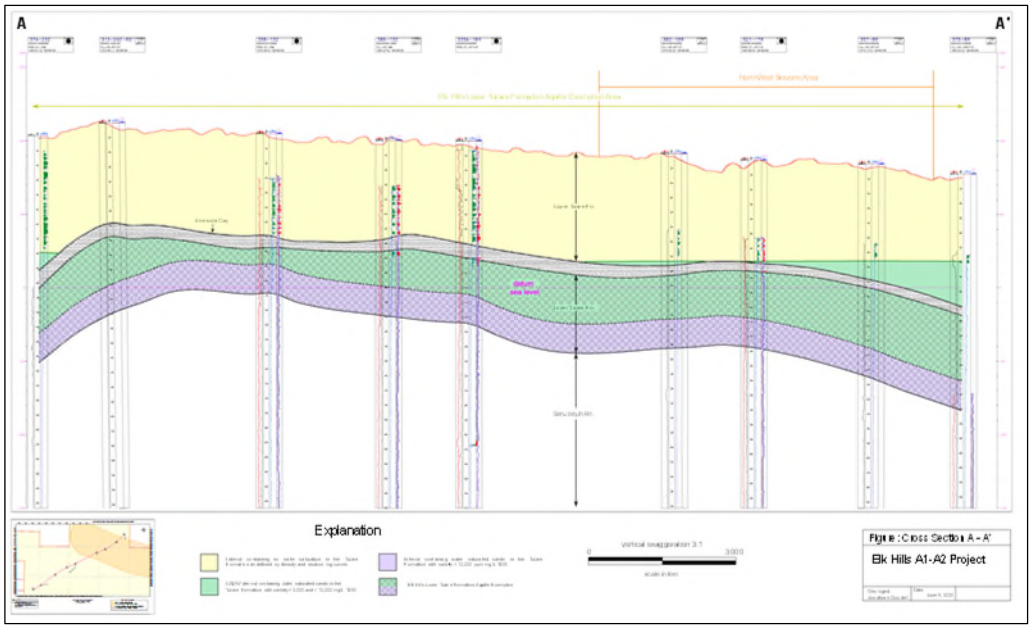
Figure 25: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.



Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

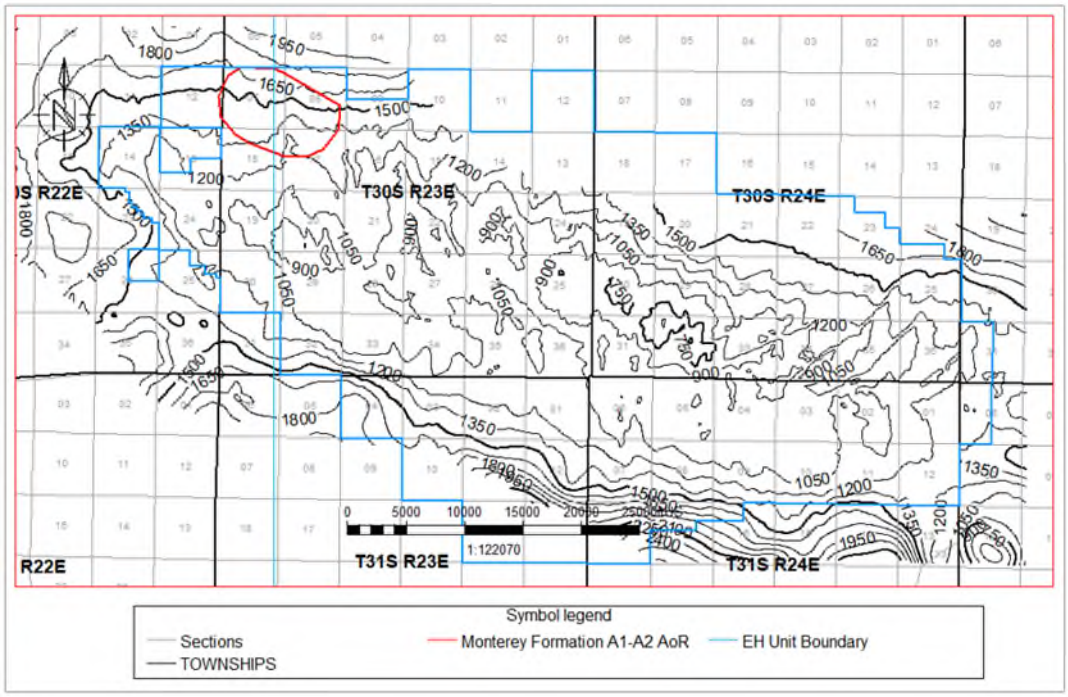
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 26). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 26: Cross-section showing the Tulare Formation USDW. The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands have 3,000 – 10,000 TDS water at the base, on the edges of the Northwest Stevens anticline.



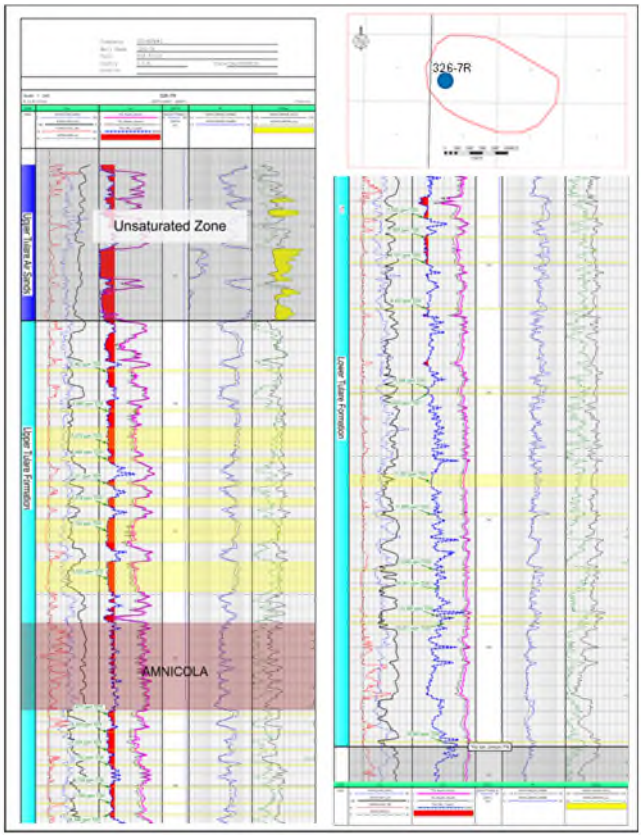
The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 26). The depth is 600 - 2,500 feet and the thickness ranges from 1,200 - 1,500 feet (Figure 27).

Figure 27: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare USDW. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 28). The characteristic density-neutron crossover (orange-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity. Figure 28 shows that the Upper Tulare USDW occupies the lowermost portion of the zone, overlain by the air sands.

Figure 28: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, Upper Tulare USDW and Lower Tulare exempt aquifer.



Salinity Calculation

Calculation of salinity as shown in Figure 28 is a four step process:

(1) converting measured density to formation porosity

The equation to convert measured density to porosity is:

POR = (Rhom - RHOB) /(Rhom-Rhof)

Parameter definitions for the equation are:

POR is formation porosity

Rhom is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones

RHOB is calibrated bulk density taken from well log measurements (g/cc)

Rhof is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

(2) calculation of apparent water resistivity using the Humble equation,

The Humble equation calculates apparent water resistivity. The equation is:

Rwah = ((POR**m) * XRESD)/a

Parameter definitions for the equation are:

Rwah is apparent water resistivity (ohmm)

POR is formation porosity as derived from the density conversion formula

m is the cementation factor; 2.15 is the standard value

XRESD is deep reading resistivity taken from well log measurements (ohmm)

a is the archie constant; 0.62 is the standard value

(3) correcting apparent water resistivity to a standard temperature

Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

Rwahc = Rwah * ((TEMP)+6.77)/(75+6.77)

Parameter definitions for the equation are:

Rwahc is apparent water resistivity (ohmm), corrected to surface temperature

TEMP is down hole temperature based on temperature gradient (DegF)

(4) converting temperature corrected apparent water resistivity to salinity.

The following formular was used:

SAL_h = 10 ** ((3.562-(Log10(Rwahc-0.0123)))/.955)

Parameter definitions for the equation are:

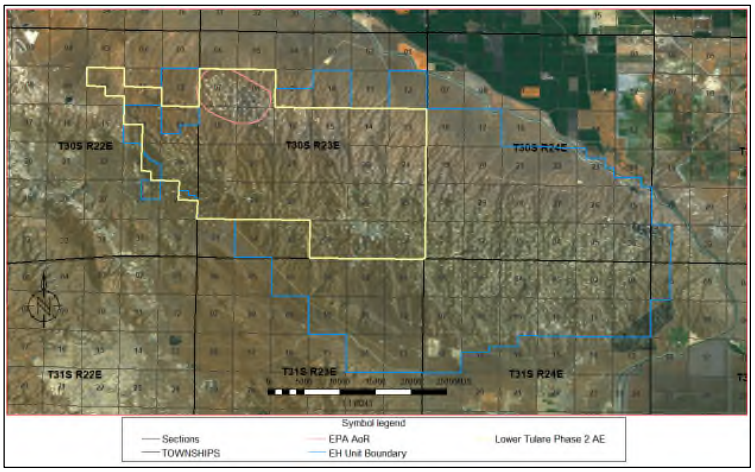
SAL_h is salinity from corrected Rwahc (ppm)

Rwahc is apparent water resistivity, corrected to surface temperature (ohmm),

Water Samples

Tulare Formation water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum containment levels (MCL).

Figure 29: Lower Tulare aquifer exemption boundary.



In 2018 the Lower Tulare aquifer (boundary shown on map in Figure 29) was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and

2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

The Upper Tulare USDW has 3,000-10,000 mg/l TDS on the edges of the NWS anticline. Water quality for the Upper Tulare USDW is shown in Figure 30. The water is not used within the AoR or the EHOF.

Figure 30: Upper Tulare USDW and Lower Tulare Formation water analysis.

Upper Tulare

Table 4a. WATER SOURCE WELL #439S-133
WATER ANALYSIS DATA (mg/kg)

DATE	6-95	7-95	8-95	9-95
SAMPLE #	95094	95150	95182	95189
CONSTITUENTS:				
Calcium, Ca	230	230	220	220
Magnesium, Mg	85	85	92	93
Sodium, Na	1280	1300	1200	1300
Potassium, K	5.2	5.8	8.8	8.6
Iron, Fe	0.4	0.51	0.38	0.54
Hydroxide, OH	0	0	0	0
Carbonate, CO3	0	0	0	0
Bicarb, HCO3	180	190	190	180
Chloride, Cl	1360	1400	1300	1400
Sulfate, SO4	1600	1600	1500	1600
Sulfide, S	<5.0	<5.0	<5.0	<5.0
Totals	4660	4700	4400	4700
Boron, B	4.7	4.6	4.7	4.7
TDS (Grav)	4890	4800	4900	4900
Hardness, CaCO3	920	920	930	930
Alkalinity, CaCO3	160	160	160	150
Sodium Chloride	3690	3700	3500	3800
pH	7.8	8.1	8.0	7.9
Electrical Conductivity	6.99 mmhos/cm	7.02 mmhos/cm	6.99 mmhos/cm	6.99 mmhos/cm
Specific Gravity	1.003	1.003	1.004	1.003
Resistivity	1.43 ohm	1.43 ohm	1.43 ohm	1.43 ohm

NOTE: Sample analysis is from Zalco Laboratory.

(Source: NPR-1 Ground Water Monitoring Plan, 1995)

Lower Tulare

Water Analysis (General Chemistry)

BCL Sample ID: 1411064-01 | Client Sample Name: Elk Hills Well 82-2B, 5/17/2014 4:05:00PM, Rick Ogletree

Constituent	Result	Units	PQL	MDL	Method	MB Bias	Lab Quals
Electrical Conductivity @ 25 C (Field Test)	27000	umhos/cm	1.0	1.0	EPA-120.1		
pH (Field Test)	7.23	pH Units	0.05	0.05	EPA-150.1		
Temperature (Field Test)	87.6	F	32.0	32.0	SM-2550B		
Total Calcium	650	mg/L	2.0	0.30	EPA-6010B	ND	A10
Total Magnesium	230	mg/L	1.0	0.38	EPA-6010B	0.75	A10
Total Sodium	4700	mg/L	10	1.0	EPA-6010B	ND	A01
Total Potassium	31	mg/L	20	2.6	EPA-6010B	ND	A10
Bicarbonate Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Carbonate Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Hydroxide Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Total Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Bromide	50	mg/L	5.0	2.2	EPA-300.0	ND	A01
Chloride	10000	mg/L	50	6.7	EPA-300.0	20	A01
Fluoride	ND	mg/L	2.5	0.70	EPA-300.0	ND	A10
Nitrate as NO3	ND	mg/L	22	5.5	EPA-300.0	ND	A10
Sulfate	320	mg/L	50	9.0	EPA-300.0	19	A01
pH	7.47	pH Units	0.05	0.05	EPA-150.1		S05
Electrical Conductivity @ 25 C	26100	umhos/cm	1.00	1.00	EPA-120.1		
Total Dissolved Solids @ 180 C	20000	mg/L	1000	1000	EPA-160.1	ND	

Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the

site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

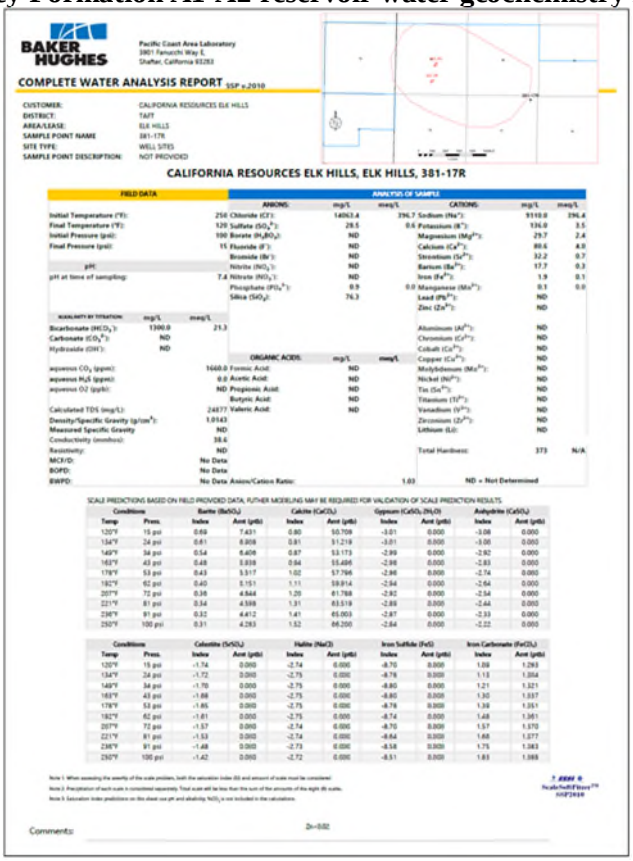
Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry A1-A2 Reservoir:

The Monterey Formation A1-A2 reservoir has a gas cap that overlies a thin oil band and a basal water zone. CRC and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation A1-A2 geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Figure 31 shows the water chemistry from well 381-17R, taken from a sand underlying the Monterey Formation A1-A2 reservoir. Reservoir depletion of the Monterey Formation A1-A2 has reduced the water saturation to residual, preventing representative water sampling.

Figure 31: Monterey Formation A1-A2 reservoir water geochemistry from well 381-17R.


BAKER HUGHES

Pacific Coast Area Laboratory
3801 Fanuchi Way E.
Shafter, California 93263

COMPLETE WATER ANALYSIS REPORT USP v.2010

CUSTOMER: CALIFORNIA RESOURCES ELK HILLS
DISTRICT: TAFT
AREA/LEASE: ELK HILLS
SAMPLE POINT NAME: 381-17R
SITE TYPE: WELL SITES
SAMPLE POINT DESCRIPTION: NOT PROVIDED

CALIFORNIA RESOURCES ELK HILLS, ELK HILLS, 381-17R

FIELD DATA

Initial Temperature (°F):	250
Final Temperature (°F):	120
Initial Pressure (psi):	100
Final Pressure (psi):	15
pH:	
pH at time of sampling:	7.4
Bicarbonate (HCO_3^-):	1300.0 / 21.3
Carbonate (CO_3^{2-}):	ND
Hydroxide (OH^-):	ND
aqueous CO_2 (ppm):	1660.0
aqueous H_2S (ppm):	0.0
aqueous O2 (ppb):	ND
Calculated TDS (mg/L):	24877
Density/Specific Gravity (g/cm³):	1.0143
Measured Specific Gravity	ND
Conductivity (mmhos):	38.6
Resistivity:	ND
MCI/D:	No Data
BOPD:	No Data
BWPD:	No Data

ANALYSIS OF SAMPLE

ANIONS:	mg/L	meq/L
Chloride (Cl^-):	14063.4	396.7
Sulfate (SO_4^{2-}):	28.5	0.6
Borate ($H_2BO_3^-$):	ND	
Fluoride (F^-):	ND	
Bromide (Br^-):	ND	
Nitrite (NO_2^-):	ND	
Nitrate (NO_3^-):	ND	
Phosphate (PO_4^{3-}):	0.9	0.0
Silica (SiO_2):	76.3	

ORGANIC ACIDS:	mg/L	meq/L
Formic Acid:	ND	
Acetic Acid:	ND	
Propionic Acid:	ND	
Butyric Acid:	ND	
Valeric Acid:	ND	

CATIONS:	mg/L	meq/L
Sodium (Na^+):	9110.0	396.4
Potassium (K^+):	136.0	3.5
Magnesium (Mg^{2+}):	29.7	2.4
Calcium (Ca^{2+}):	80.6	4.0
Strontium (Sr^{2+}):	32.2	0.7
Barium (Ba^{2+}):	17.7	0.3
Iron (Fe^{2+}):	1.9	0.1
Manganese (Mn^{2+}):	0.1	0.0
Lead (Pb^{2+}):	ND	
Zinc (Zn^{2+}):	ND	
Aluminum (Al^{3+}):	ND	
Chromium (Cr^{3+}):	ND	
Cobalt (Co^{2+}):	ND	
Copper (Cu^{2+}):	ND	
Molybdenum (Mo^{2+}):	ND	
Nickel (Ni^{2+}):	ND	
Tin (Sn^{2+}):	ND	
Titanium (Ti^{2+}):	ND	
Vanadium (V^{2+}):	ND	
Zirconium (Zr^{2+}):	ND	
Lithium (Li):	ND	
Total Hardness:	373	N/A

ND = Not Determined

SCALE PREDICTIONS BASED ON FIELD PROVIDED DATA; FURTHER MODELING MAY BE REQUIRED FOR VALIDATION OF SCALE PREDICTION RESULTS.

Conditions		Barite ($BaSO_4$)		Calcite ($CaCO_3$)		Gypsum ($CaSO_4 \cdot 2H_2O$)		Anhydrite ($CaSO_4$)	
Temp	Pres.	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)
120°F	15 psi	0.69	7.431	0.80	50.709	-3.01	0.000	-3.08	0.000
134°F	24 psi	0.61	8.808	0.91	51.219	-3.01	0.000	-3.08	0.000
149°F	34 psi	0.54	6.406	0.87	53.173	-2.99	0.000	-2.92	0.000
163°F	43 psi	0.48	5.838	0.84	55.496	-2.96	0.000	-2.83	0.000
178°F	53 psi	0.43	5.317	1.02	57.796	-2.96	0.000	-2.74	0.000
192°F	62 psi	0.40	5.151	1.11	59.914	-2.94	0.000	-2.64	0.000
207°F	72 psi	0.36	4.844	1.20	61.788	-2.92	0.000	-2.54	0.000
221°F	81 psi	0.34	4.598	1.31	63.519	-2.89	0.000	-2.44	0.000
236°F	91 psi	0.32	4.412	1.41	65.003	-2.87	0.000	-2.33	0.000
250°F	100 psi	0.31	4.283	1.52	66.200	-2.84	0.000	-2.22	0.000

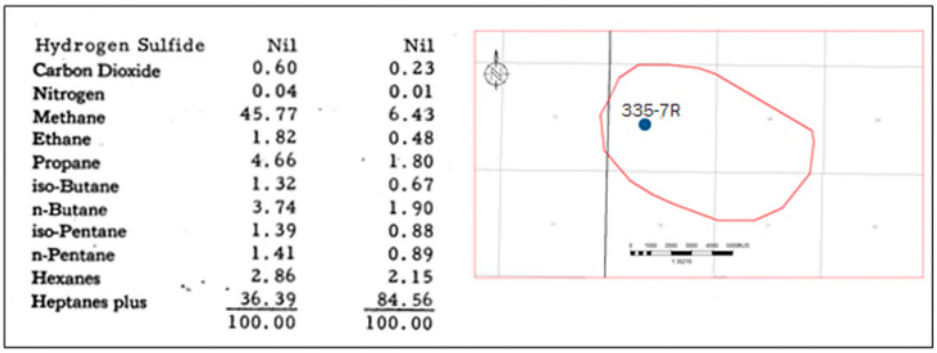
Conditions		Celestite ($SrSO_4$)		Halite ($NaCl$)		Iron Sulfide (FeS)		Iron Carbonate ($FeCO_3$)	
Temp	Pres.	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)
120°F	15 psi	-1.74	0.000	-2.74	0.000	-8.70	0.000	1.08	1.293
134°F	24 psi	-1.72	0.000	-2.75	0.000	-8.78	0.000	1.13	1.354
149°F	34 psi	-1.70	0.000	-2.75	0.000	-8.80	0.000	1.21	1.321
163°F	43 psi	-1.68	0.000	-2.75	0.000	-8.80	0.000	1.30	1.337
178°F	53 psi	-1.65	0.000	-2.75	0.000	-8.78	0.000	1.38	1.351
192°F	62 psi	-1.61	0.000	-2.75	0.000	-8.74	0.000	1.48	1.361
207°F	72 psi	-1.57	0.000	-2.74	0.000	-8.70	0.000	1.57	1.370
221°F	81 psi	-1.53	0.000	-2.74	0.000	-8.64	0.000	1.66	1.377
236°F	91 psi	-1.48	0.000	-2.73	0.000	-8.58	0.000	1.75	1.383
250°F	100 psi	-1.42	0.000	-2.72	0.000	-8.51	0.000	1.83	1.388

Comments:

The hydrocarbon composition for the Monterey Formation A1-A2 reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 32 shows the results of the hydrocarbon composition for well 335-7R within the AoR. Oil composition analysis was routinely completed upon reservoir discovery and was collected across the field. This original

dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

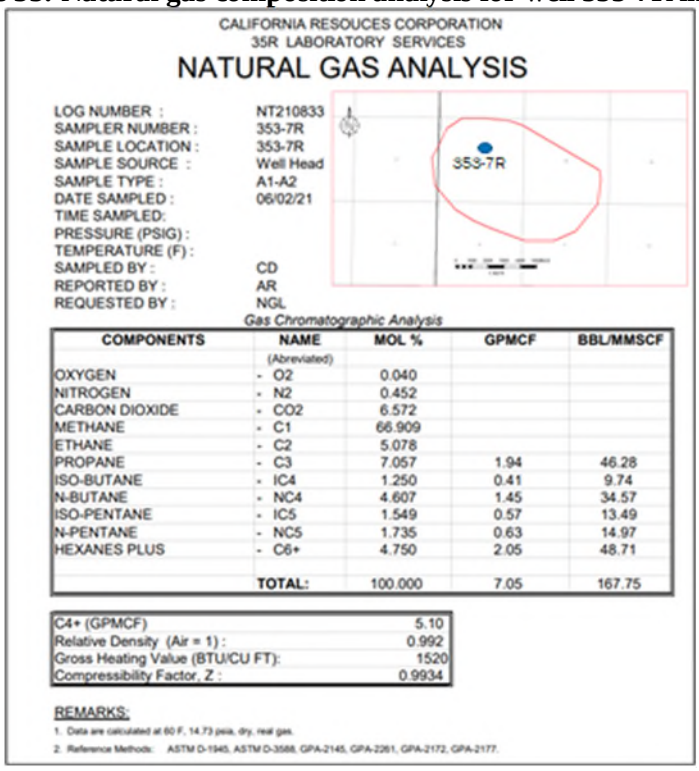
Figure 32: Monterey Formation A1-A2 hydrocarbon geochemistry from well 335-7R in 1974.



Hydrogen Sulfide	Nil	Nil
Carbon Dioxide	0.60	0.23
Nitrogen	0.04	0.01
Methane	45.77	6.43
Ethane	1.82	0.48
Propane	4.66	1.80
iso-Butane	1.32	0.67
n-Butane	3.74	1.90
iso-Pentane	1.39	0.88
n-Pentane	1.41	0.89
Hexanes	2.86	2.15
Heptanes plus	36.39	84.56
	100.00	100.00

Gas composition for the Monterey Formation A1-A2 is collected to assess the changing concentration of key components. Since 2011, CTV has used two injectors for reservoir pressure support; 357-7R and 355-7R to inject gas containing up to 44% CO_2. Figure 33 shows the produced natural gas analysis for 353-7R in 2021. Note that the composition has 6.5 mole % CO_2.

Figure 33: Natural gas composition analysis for well 353-7R in 2021.



CALIFORNIA RESOUCES CORPORATION
35R LABORATORY SERVICES

NATURAL GAS ANALYSIS

LOG NUMBER :	NT210833
SAMPLER NUMBER :	353-7R
SAMPLE LOCATION :	353-7R
SAMPLE SOURCE :	Well Head
SAMPLE TYPE :	A1-A2
DATE SAMPLED :	06/02/21
TIME SAMPLED:	
PRESSURE (PSIG) :	
TEMPERATURE (F) :	
SAMPLED BY :	CD
REPORTED BY :	AR
REQUESTED BY :	NGL

Gas Chromatographic Analysis

COMPONENTS	NAME (Abreviated)	MOL %	GPMCF	BBL/MMSCF
OXYGEN	- O2	0.040		
NITROGEN	- N2	0.452		
CARBON DIOXIDE	- CO2	6.572		
METHANE	- C1	66.909		
ETHANE	- C2	5.078		
PROPANE	- C3	7.057	1.94	46.28
ISO-BUTANE	- IC4	1.250	0.41	9.74
N-BUTANE	- NC4	4.607	1.45	34.57
ISO-PENTANE	- IC5	1.549	0.57	13.49
N-PENTANE	- NC5	1.735	0.63	14.97
HEXANES PLUS	- C6+	4.750	2.05	48.71
	TOTAL:	100.000	7.05	167.75

C4+ (GPMCF)	5.10
Relative Density (Air = 1) :	0.992
Gross Heating Value (BTU/CU FT):	1520
Compressibility Factor, Z :	0.9934

REMARKS:

1. Data are calculated at 60 F, 14.73 psia, dry, real gas.
2. Reference Methods: ASTM D-1945, ASTM D-3588, GPA-2145, GPA-2261, GPA-2172, GPA-2177.

Monterey Formation A1-A2 Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO_2 injectate:

1. The Monterey Formation A1-A2 reservoir has a low current water volume (~15% saturation in the gas cap and 85% in the thin oil leg) due to production related to oil and gas operations, where four million net barrels of water have been produced. This low volume of water will minimize both the quantity of CO_2 that will dissolve in solution and the quantity of carbonic acid formed in-situ.
2. Residual oil saturation (15%) in the Monterey Formation A1-A2 reservoir will also dissolve only a small amount of CO_2.
3. The Monterey Formation A1-A2 has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO_2 and carbonic acid and any dissolution or changes that occur will be on grain surfaces.
4. Since 2011 6.3 billion cubic feet of gas has been injected in the 357-7R and 355-7R wells, consisting of up to 44% CO_2. Injectivity of the reservoir has not changed.

The oil and water CO_2 trapping mechanisms have been incorporated in the computational modeling and will be discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO_2 injectate.

Site Suitability [40 CFR 146.83]

The Monterey Formation A1-A2 reservoir in the Northwest Stevens anticline was discovered in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the Monterey Formation A1-A2 reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

A key component of the A1-A2 reservoir characterization was the development of a geo-cellular model, which is used to assess CO_2 plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale). Cross-sections in Figures 34 and 35 shows the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers supports predictable plume development.

CO2 Injectate Confinement:

Confinement of CO_2 injected into the storage reservoir is supported by the following:

1. Prior to discovery of the Monterey Formation A1-A2 reservoir, a gas cap with underlying oil was confined for several million years.
2. The Reef Ridge Shale primary confining layer is 1,500 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 175 billion cubic feet of gas and five million barrels of water with no leakage.
3. Cross section A-A' (Figure 34) shows the lateral confinement of the injected CO_2 plume by the anticline structure. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does migrate beyond the edges of the anticline structure or into the Reef Ridge shale.
4. In Cross section B-B' (Figure 35) the up-dip CO_2 plume is confined by shale and the non-deposition of reservoir sands.

Figure 34: Plume modeling results showing lateral confinement of the CO2 plume by the edges of the anticline structure.

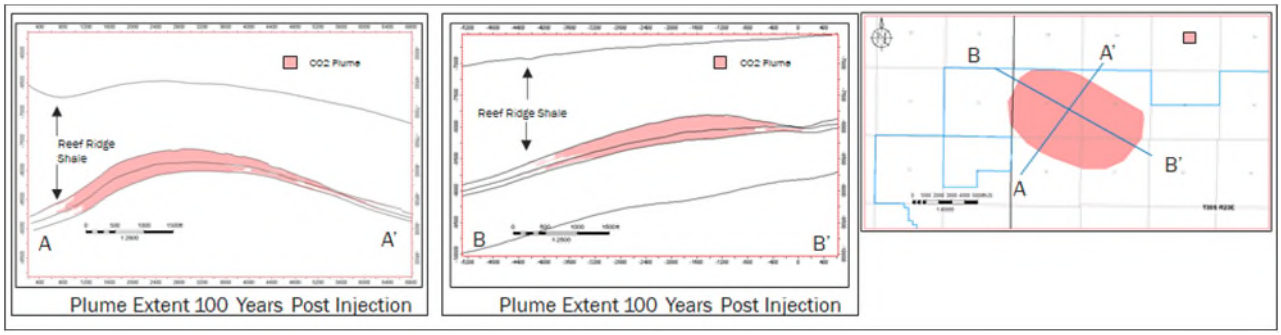
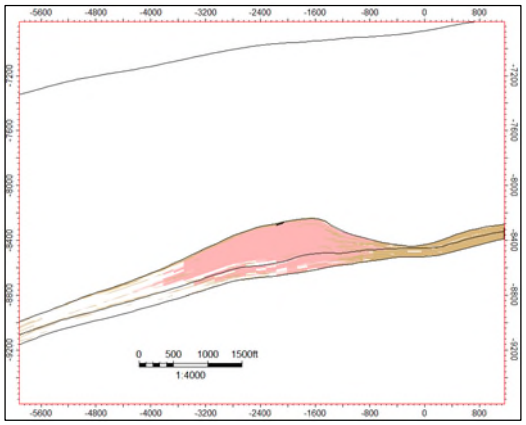


Figure 35: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the A1-A2 sand facies and the increasing shale facies.



Storage capacity for the Monterey Formation A1-A2 storage reservoir based on computational modeling results is approximately 8 -10 million tonnes of CO_2. This is sufficient capacity for the total proposed injectate.

AoR and Corrective Action

CTV's AoR and Corrective Action plan pursuant to 40 CFR 146.82(a)(4), 40 CFR 146.82(a)(13) and 146.84(b), and 40 CFR 146.84(c) describes the process, software and results to establish the AoR, and the wells that require corrective action.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

Financial Responsibility

CTV's Financial Responsibility demonstration pursuant to 140 CFR 146.82(a)(14) and 40 CFR 146.85 is met with a line of credit for Injection Well Plugging and Post-Injection Site Care and Site Closure and insurance to cover Emergency and Remedial Responses.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

Injection Well Construction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. These injectors are currently approved by CalGEM for Class II injection of gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. The approval is for four injectors at a maximum injection rate of 50 million cubic feet per day. These wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

Construction Procedures [40 CFR 146.82(a)(12)]

Injectate Migration Prevention:

357-7R was drilled in 1980, during which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the USDW and allow for monitoring:

1. Conductor, surface, and intermediate casing.
2. Cement across each casing string with cement returns to surface during completion. A cement bond log was acquired to confirm cement along the well.
3. Casing specifications exceed the operating conditions of the well (Table 5).
4. Long string casing diameter of seven inches with stainless steel tubing of 4.5 inches. This casing and tubing size will enable monitoring devices to be installed, cased hole logs to be acquired and Mechanical Integrity Testing (MIT) to be conducted.

Attachment G: Construction Details provides more detail related to the construction of well 357-7R.

Materials:

All well materials are designed to be compatible with the CO_2 injectate and will limit corrosion:

1. Tubing –13 CR-95
2. Wellhead – stainless steel
3. Packer – nickel plating and hardened rubber
4. Casing and Cement - N-80 casing with Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 with good cement bond between formation and casing. A cement bond log was acquired to ensure bond between casing and formation.

Standards:

Well materials follow the following standards:

1. Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

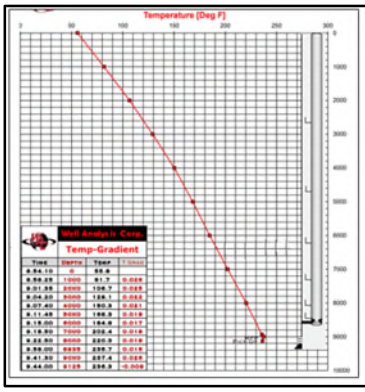
Casing and Cementing

Casing:

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity.

Casing specifications are presented in Table 5. These specifications show that the well was engineered to standards that allow for the safe operation at an injection pressure that will not be greater than 4,500 PSI. Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues related to the structural strength.

Table 5: Temperature profile and casing construction data for the 357-7R injector.



Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Cement:

Class G Portland cement has been used to complete the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The cement returns were to surface for each stage. Cementing was completed in stages to ensure cement between casing and the formation.

Protection of USDW:

The USDW and all strata overlying the injection zone will be protected by the following:

1. A cement bond log was run on the well post completion to ensure adequate bond to casing and formation.
2. Standard annular pressure test (SAPT) have been acquired through time that increases the well annulus pressure to 500 PSI for 30 minutes. All SAPT's demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPT will be acquired before the start of injection and every five years thereafter.
3. If there are mechanical integrity issues in the future, CTV will run a casing inspection log to assess casing thickness.

Table 6. Casing details.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	60	24	0.55	20	J-55	94
Surface	501	17.5	0.33	13.375	H-80	48
Intermediate	3516	12.25	0.395	9.625	N-80	40
Long String	2,953	8.75	0.317	7	N-80	23
	6,158	8.75	0.362	7	N-80	26
	6,158 – 8,990	8.75	0.408	7	N-80	29

Tubing and Packer

The information in this table meets the minimum requirements at 40 CFR 146.86(c).

Table 7. Tubing and packer details.

Material	Setting Depth	Tensile Strength	Burst Strength	Collapse Strength	Material
Tubing	8,454	105,000	12,450	12,760	13 CR-95
Packer	8,447	10,000	8,160	7,020	Baker-Hornet, Ni plated

Pre-Operational Logging and Testing

CTV has provided operational and testing data to support the Elk Hills A1-A2 project. Data and information provided meets the requirements pursuant to 40 CFR 146.82(a)(8) and 40 CFR 146.87.

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational Testing
Tab(s): Welcome tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

Well Operation

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of super-critical (SC) phase CO_2. For attaining SC flow, surface injection pressure will be a minimum of 1,200 PSI. As the depleted oil reservoir fills up, a higher surface injection pressure will likely be required. Final reservoir pressure target is 4,000 PSI. It is assumed that at time of shut-in, the downhole injection pressure will be ~4,500 PSI.

Table 8 values shown below for average injection pressure are an average of initial conditions and final conditions. As the reservoir fills up with CO_2 it will pressure up, thus creating a continually changing reservoir and injector condition over injection life. A downhole injection pressure of ~4,500 PSI is assumed to occur at shut-in timing when reservoir pressure has reached its final level at 4,000 PSI. This translates to a surface injection pressure of ~2,000 PSI, which will be achieved via a surface booster pump.

The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of .8 psi/foot. 40+ years of gas and water injection experience into A1-A2 Stevens supports that these operating limits are appropriate and effective. Additionally, the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI.

As mentioned above, as the reservoir fills up with CO_2, the reservoir pore pressure will increase. A surface booster pump will be needed to supplement surface injection pressure from the initial value of ~1,200 PSI to the final requirement of ~2,000 PSI.

Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

There are currently multiple sources of anthropogenic CO_2 being considered for Stevens A1-A2 sequestration. These include capture off of the Elk Hills NGCC Power Plant as well as 3rd party existing and proposed industrial sources in the Southern San Joaquin Valley area. The carbon dioxide stream will consist of a minimum of 95% CO_2 by volume. Other key constituents that will be controlled for corrosion mitigation include water content (25#/mmscf) and oxygen level (<50 ppm)

Corrosiveness of the CO_2 stream is very low as long as the entrained water is kept in solution with the CO_2. This is ensured by the 25#/mmscf injectate specification referred to above. Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. In early injection time, it is likely that gas phase CO_2 will exist towards the lower depths of the tubing string. Stainless steel (13 CR-95) tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present.

Table 8. Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	UIC Class II frac gradient .8 psi/ft	
Surface	3,800	psig
Downhole	6,100	psig
Average Injection Pressure	Average over time	
Surface	1,600	psig
Downhole	4,100	psig
Maximum Injection Rate	30 per well	mmscfpd
Average Injection Rate	10-15 per well	mmscfpd
Maximum Injection Volume and/or Mass	10 million	tonnes
Average Injection Volume and/or Mass	8 million	tonnes
Annulus Pressure	3,730 @ packer	psig
Annulus Pressure/Tubing Differential	370@ packer @ average injection condition	psig

Testing and Monitoring

CTV's Testing and Monitoring plan pursuant to 40 CFR 146.82 (a) (15) and 40 CFR 146.90 describes the strategies for testing and monitoring to ensure protection of the USDW, injection well mechanical integrity, and plume monitoring.

Testing and Monitoring GSDT Submissions

GSDT Module: Project Plan Submissions
Tab(s): Testing and Monitoring tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Injection Well Plugging GSDT Submissions

GSDT Module: Project Plan Submissions
Tab(s): Injection Well Plugging tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

Post-Injection Site Care (PISC) and Site Closure

CTV has developed a Post-Injection Site Care and Site Closure plan pursuant to 40 CFR 146.93 (a) to define post-injection testing and monitoring.

At this time CTV is not proposing an alternative PISC timeframe.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

Emergency and Remedial Response

CTV's Emergency and Remedial Response plan pursuant to 40 CFR 164.94 describes the process and response to emergencies to ensure USDW protection.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

References:

1. Callaway, D.C., and Rennie, E.W., Jr., 1991, San Joaquin Basin, California, in Gluskoter, H.J., Rice, D.D., and Taylor, R. B., eds., Economic geology, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. P-2, p. 417-430.
2. Zumberge, John, Russell, Just and Reid, Stephen, Charging of Elk Hills reservoirs as determined by oil geochemistry, AAPG Bulletin, v. 89, no. 10 (October 2005), pp. 1347–1371.
3. Hosford, Allegra and Magoon, Les, 2007 Age, U.S. Geological Survey Professional Paper 1713, California Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, Chapter 5.
4. Maher, J. C., R. D. Carter, and R. J. Lantz, 1975, Petroleum geology of naval petroleum reserve No. 1, Elk Hills, Kern County, California: U.S. Geological Survey Professional Paper 912, 109 p.
5. Castilla, Davis and Younker, Leland, 1997, David A. Castillo Leland W. Younker A High Shear Stress Segment along the San Andreas Fault: Inferences Based on Near-Field Stress Direction and Stress Magnitude Observations in the Carrizo Plain Area, Lawrence Livermore National Laboratory.
6. Ingram G. M., Urai J. L., Naylor M. A. (1997) in Hydrocarbon Seals: Importance for Exploration and Production, Sealing processes and top seal assessment, Norwegian Petroleum Society (NPF) Special Publication, eds Moller-Pedersen P., Koestler A. G. **7**, pp 165–175.

ATTACHMENT A2: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills A1-A2 Storage Project

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project.

Wells 357-7R and 355-7R are 1,300 feet apart and will inject CO_2 into the Monterey Formation A1-A2 reservoir. Plume development from each of the wells will coalesce into the larger Monterey Formation A1-A2 AoR. The following documents provided for injector 357-7R are valid for injector 355-7R and will not be resubmitted:

Attachment A: Narrative Site Characterization (with exception of the well construction and operating procedures.)

Attachment B: AoR and Corrective Action Plan

Attachment C: Testing and Monitoring Plan

Attachment E: Post Injection Site Care and Site Closure Plan

Attachment F: Emergency and Remedial Response Plan, and

Quality Assurance and Surveillance Plan

Submission for well 355-7R includes Attachment A2: Narrative for an overview of 355-7R well construction and operational procedures, Attachment G2: Construction Details, and Attachment D2: Injection Well Plugging Plan.

Injection Well Construction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. These injectors are currently approved by CalGEM for Class II injection of up to 50 million cubic feet per day gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. These wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

Construction Procedures [40 CFR 146.82(a)(12)]

Injectate Migration Prevention:

355-7R was drilled in 1973, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. 13-3/8" and 9-5/8" casing string were cemented with 30 cubic feet and 35 cubic feet returns to surface, respectively.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval, from base of 7" casing to ~5200 feet.
5. Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted
6. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Materials:

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

1. Tubing – material selection consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
3. Packer – corrosion resistant alloy material or coating and hardened rubber
4. Casing and Cement - N-80 and K-55 casing with Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 with good cement bond between formation and casing into the Reef Ridge Shale

The well will be reconfigured with corrosion resistant materials and will be tested for mechanical integrity prior to injection.

Standards:

Well materials follow the following standards:

1. API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

Casing:

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity.

Casing specifications are presented in Table 5. These specifications show that the well was engineered to standards that allow for the safe operation at the conditions outlined in Table 8 in operating parameters. Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues related to the structural strength.

Table 5: Casing Specifications for the 355-7R injector.

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Cement:

Class G Portland cement has been used to complete the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The cement returns were to surface for the 13-3/8" and 9-5/8" casing strings. Cement bond log

(CBL) indicates the top of cement is above 5,200 feet (top of CBL logged interval), which is well above the top of the upper confining layer.

Protection of USDW:

The USDW and all strata overlying the injection zone will be protected by the following:

1. A CBL log was run on the well post completion to ensure adequate bond to casing and formation.
2. SAPT tests that pressure the well annulus to 500 PSI for 30 minutes have been acquired through time. All SAPT's demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPT will be acquired before the start of injection and every five years thereafter.
3. If there are mechanical integrity issues in the future, CTV will run a casing inspection log to assess casing thickness.

Tubing and Packer:

The information in this table meets the minimum requirements at 40 CFR 146.86(c). Tubing specifications in Table 6 are for the current well configuration. CTV plans to configure the well with corrosion resistant tubing.

Table 6. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,398	00	3.920	135	L-80	Long	9,020	8,540

Table 7. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	8,000	8,000	6.466	6.184

Well Operation

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of super-critical (SC) phase CO_2. For attaining SC flow, surface injection pressure will be a minimum of 1,200 PSI. As the depleted oil reservoir fills up, a higher surface injection pressure will likely be required. Final reservoir pressure target is 4,000 PSI. It is assumed that at shut-in, the downhole injection pressure will be ~4,500 PSI.

Table 8 values shown below for average injection pressure are an average of initial conditions and final conditions. As the reservoir fills up with CO_2 it will pressure up, thus creating a continually changing reservoir and injector condition over injection life. A downhole injection pressure of ~4,500 PSI is assumed to occur at shut-in timing when reservoir pressure has reached its final level at 4,000 PSI. This translates to a surface injection pressure of ~1,600 PSI, which will be achieved via a surface booster pump.

The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of 0.8 psi/foot with a 10% safety factor. 40+ years of gas and water injection experience into the Monterey Formation A1-A2 reservoir supports that these operating limits are appropriate and effective. Additionally, the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI.

Table 8. Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	UIC Class II frac gradient 0.8 psi/ft (with 10% Safety factor)	
Surface	2,900	psig
Downhole	6,108	psig
Injection Pressure	Average over time	
Surface Average / Maximum	1,400 / 1,600	psig
Downhole Average/ Maximum	4,300 / 4,516	psig
Maximum Injection Rate	30 per well	mmscfpd
Average Injection Rate	10-15 per well	mmscfpd
Maximum Injection Volume and/or Mass	10 million	tonnes
Average Injection Volume and/or Mass	8 million	tonnes
Annulus Pressure	3,720 @ packer	psig
Annulus Pressure/Tubing Differential	578 @ packer @ average injection condition	psig

Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

There are currently multiple sources of anthropogenic CO_2 being considered for the Monterey Formation A1-A2 sequestration. These include capture off of the Elk Hills NGCC Power Plant as well as 3rd party existing and proposed industrial sources in the Southern San Joaquin Valley area. The carbon dioxide stream will consist of a minimum of 95% CO_2 by volume. Other key constituents that will be controlled for corrosion mitigation include water content (25#/mmscf) and oxygen level (<50 ppm).

Corrosiveness of the CO_2 stream is very low as long as the entrained water is kept in solution with the CO_2. This is ensured by the 25#/mmscf injectate specification referred to above. Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. In early injection time, it is likely that gas phase CO_2 will exist towards the lower depths of the tubing string. Tubing with metallurgy appropriate for the CO_2 stream specification will be selected in the injection wells to mitigate this potential corrosion impact should free-phase water be present.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills A1-A2 Storage Project

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate two CO_2 geologic sequestration wells at the Elk Hills Oil Field (EHOF) located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO_2 stored in the Monterey Formation at 0.25 - 0.75 million tonnes annually for 15 years with injection starting in 2025. The anthropogenic CO_2 will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. The project will consist of two existing injectors, surface facilities, and monitoring wells. This supporting documentation applies to the two injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

   Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

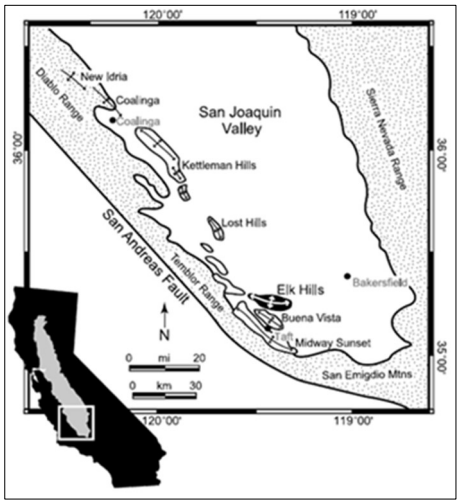
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation A1-A2 sequestration reservoir was discovered in the 1970's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

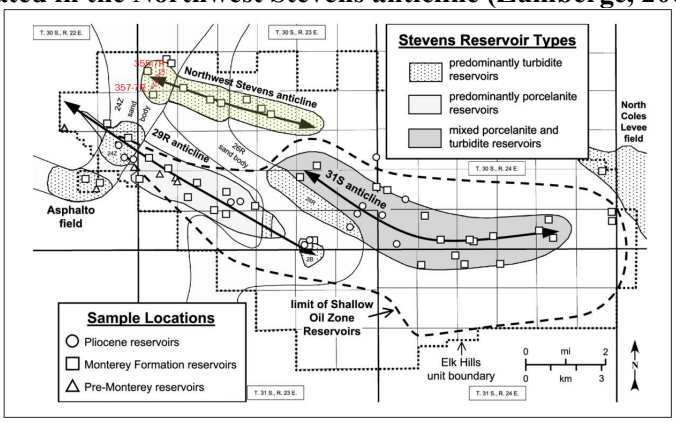
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide. With increasing depth, the structure sub-divides into three distinct anticlines (Figure 2), separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

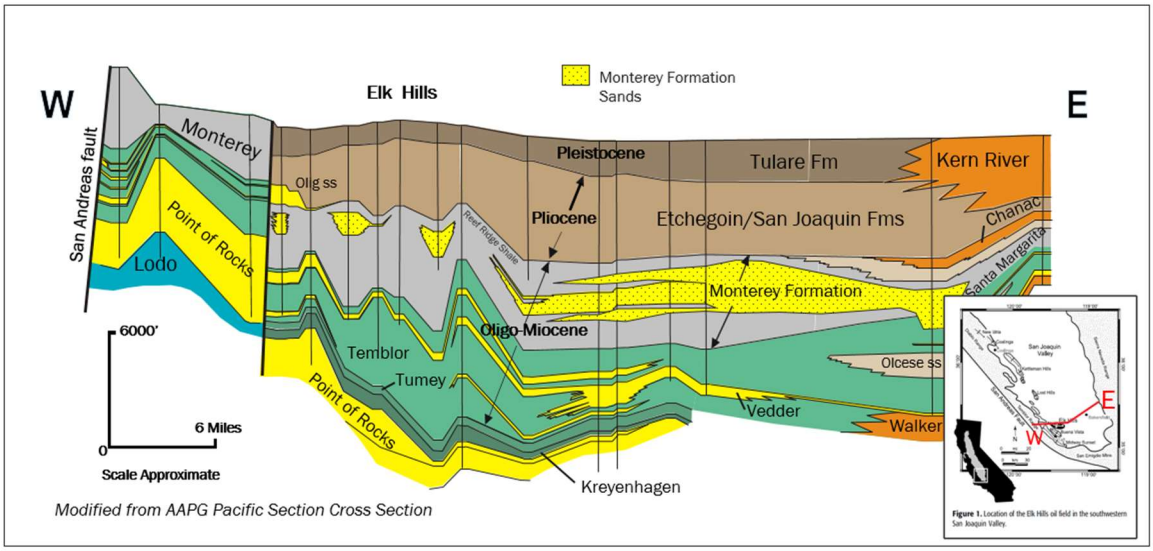
Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation A1-A2 CO2 sequestration reservoir is located in the Northwest Stevens anticline (Zumberge, 2005).



Geological Sequence

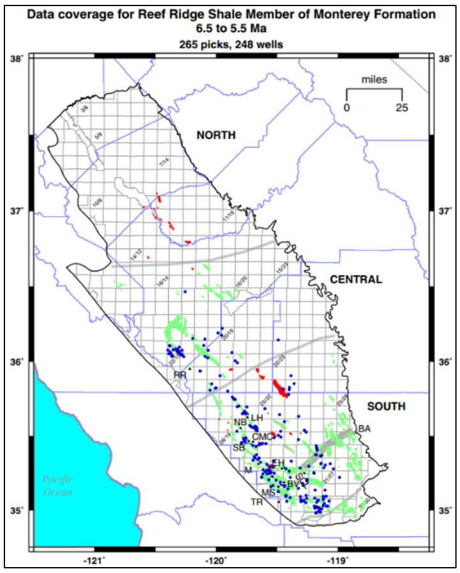
Figure 3 shows the stratigraphy of the EHOF. The two injection wells will inject CO_2 into the Miocene aged Monterey Formation A1-A2 at the Northwest Stevens anticline approximately 8,500 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin (Figure 4) and serves as the primary confining layer for the Monterey Formation A1-A2 reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Figure 4: Reef Ridge Shale data coverage over the San Joaquin Basin (Hosford, 2007).

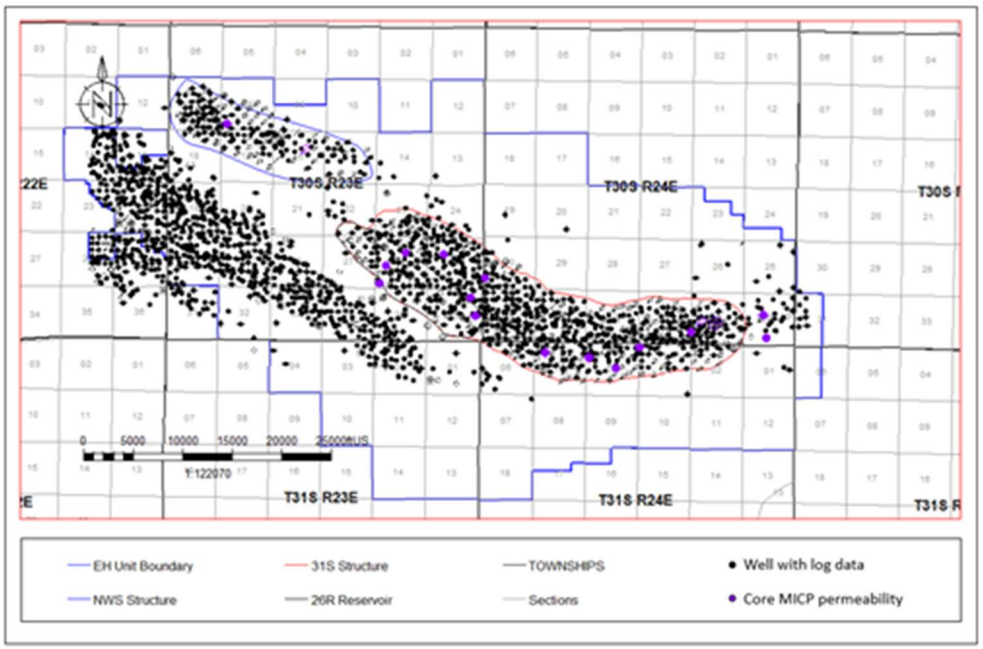


Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 5), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

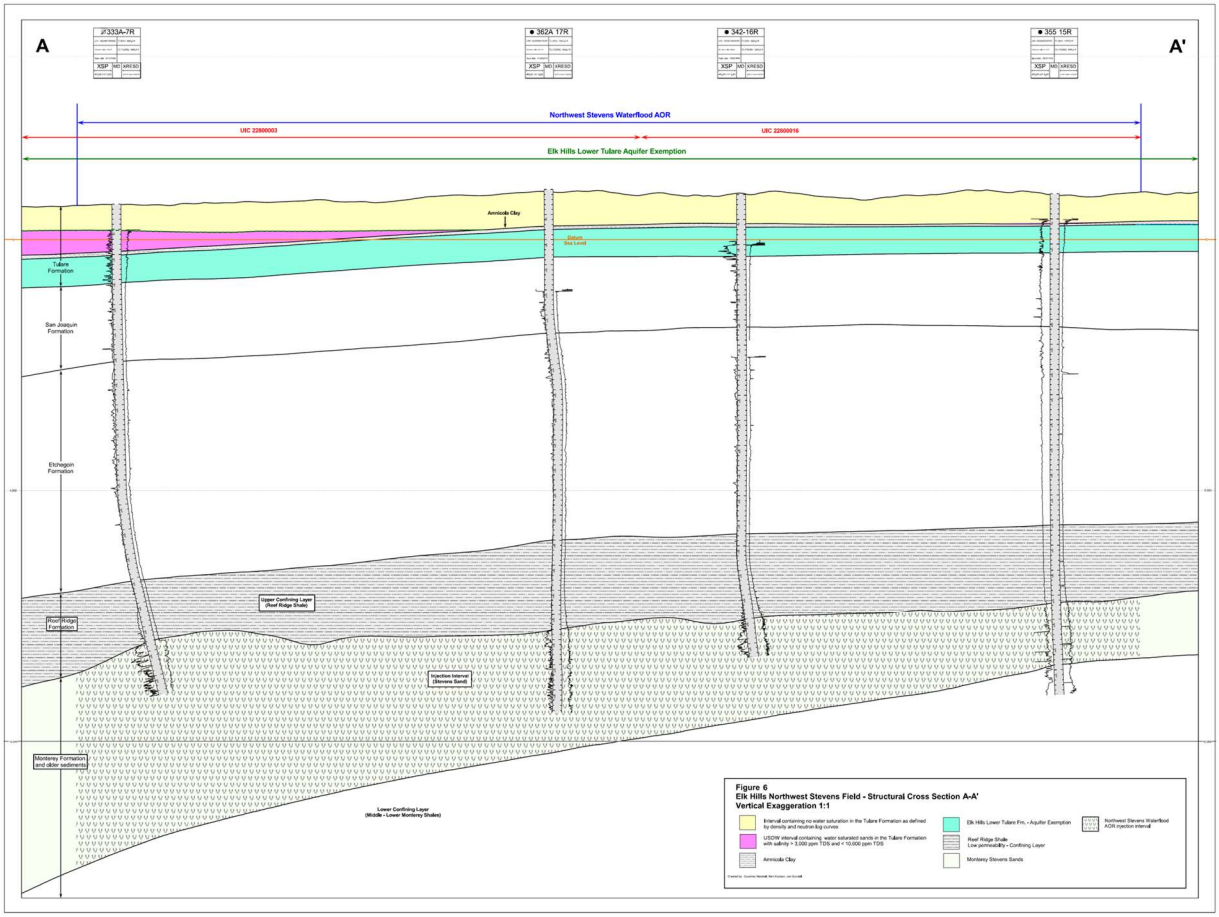
Figure 5: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core from the Monterey Formation are in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 6 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 6: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the Northwest Stevens anticline.



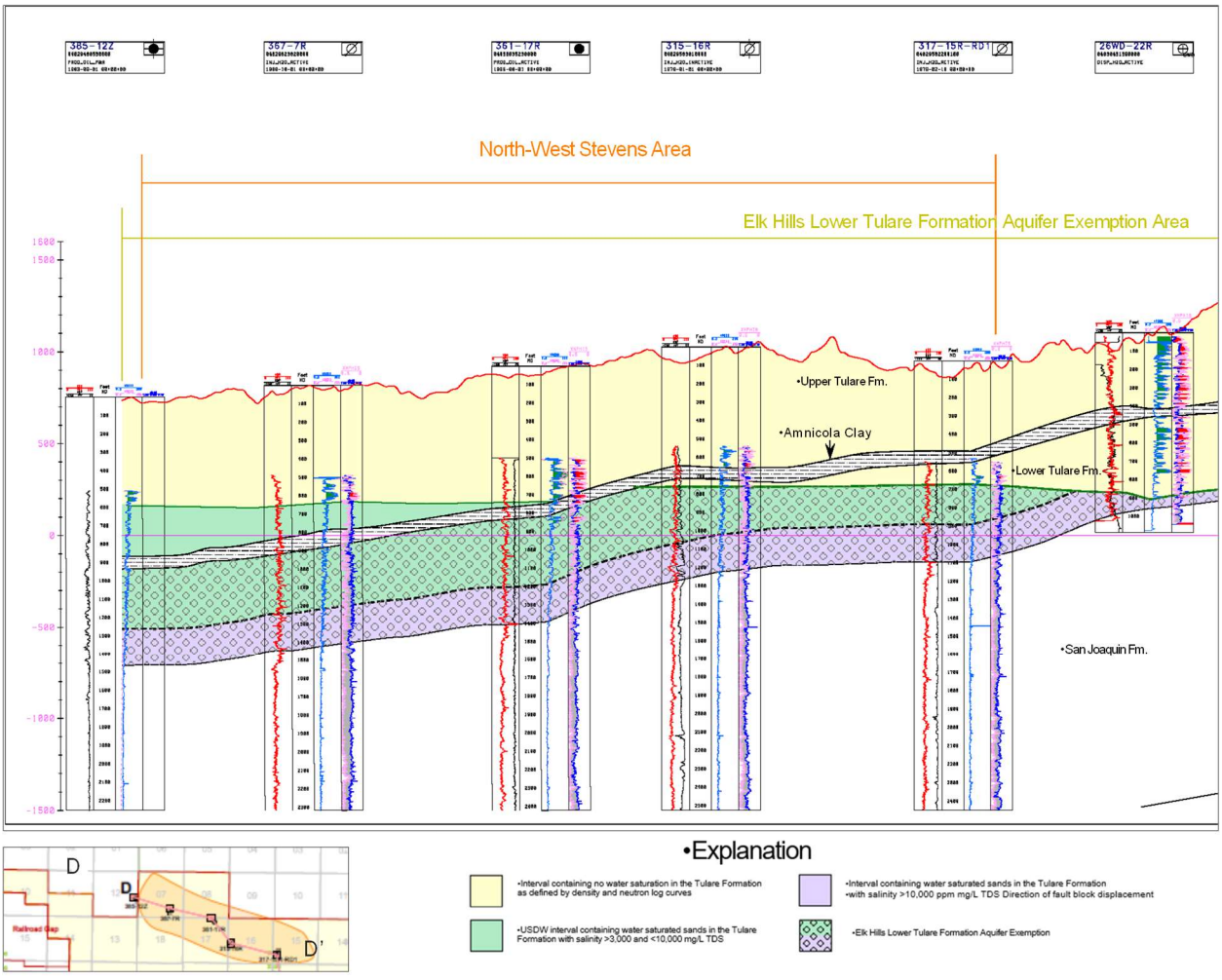
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 7), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare contains 3,000 - 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) water and is the only USDW in the AoR. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 7: The Tulare Formation consists of the Upper Tulare USDW and Lower Tulare and is separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer. The Upper Tulare USDW has formation water 3,000 - 10,000 mg/l TDS.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and

conglomerate of the Tulare Formation interfinger with the San Joaquin beds. The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000' in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 6,929-7,962 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

The Reef Ridge directly overlies the Monterey Formation A1-A2 sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

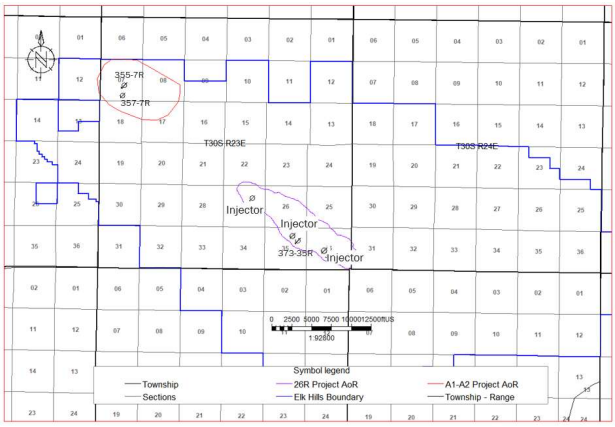
The Monterey Formation A1-A2 sequestration zone is approximately 8,500 feet deep and produces from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 16% and 60 mD, respectively.

The Monterey Formation A1-A2 sands were deposited in two coalescing turbidite channels which were influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. Figure 2 shows the orientation and depositional fairways for these channels in the Northwest Stevens anticline. The sands were largely aggregational with minimal erosive deposition. At the base of the Monterey Formation is the Lower Antelope Shale Member, a stack of thinly bedded siliceous shale with interbedded sands.

The reservoir is continuous across the AoR and sands pinch-out on the channel edges. The Monterey Formation A1-A2 sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

The Monterey Formation will be developed with the Elk Hills A1-A2 and the Elk Hills 26R reservoir projects. The AoR and injectors for each project is shown in Figure 8.

Figure 8: AoR and injection well location map for Elk Hills A1-A2 project. The injection wells, 355-7R and 357-7R are 1,250 feet apart. Also shown is the Elk Hills 26R AOR and injection wells.



Underlying Monterey Formation A3-A11:

Underlying the Monterey A1-A2 Formation is the Monterey Formation A3-A11 reservoir. This stratigraphic package is not in communication with the A1-A2, as indicated by the following:

1. The two packages have been developed separately. The A1-A2 reservoir was previously pressure supported by gas injection (175 billion cubic feet injected) while the A3-A11 reservoir is currently pressure supported by waterflood (449 million barrels of water injected).
2. The Monterey Formation A1-A2 reservoir is at 200-300 PSI and the A3-A11 reservoir is much higher at approximately 1,700 PSI. This pressure differential is maintained due to hydraulic confinement between the two reservoirs. Pressure data obtained using Repeat Formation Testers (RFT) during the drilling of Oil & Gas wells in the project area has shown a clear separation in the pressure and pressure gradients in the A1-A2 reservoir in comparison to the A3-A11 reservoir. RFT data from two wells in the project area drilled in 2014 is shown below in Figure 10.
3. The laterally continuous A2 shale separates the reservoirs (Figure 9). This shale is greater than 20 feet thick across the AoR and prevents communication between the Monterey Formation A1-A2 reservoir and the Monterey Formation A3-A11 reservoir.

The permeability function (Figure 19) is constrained with high clay content samples that enable the function to characterize the A2 shale permeability. Based on the 357-7R well, the A2 shale is 8900'-8920 feet in depth, 20 feet thick and has a permeability of 0.05 millidarcies. The derived permeability is shown in Figure 9.

Figure 9: 357-7R injector showing the Monterey Formation A1-A2 reservoir and the laterally continuous A2 Shale above the Monterey Formation A3-A11 reservoir. The depths shown are for feet subsea true vertical depth and feet measured depth.

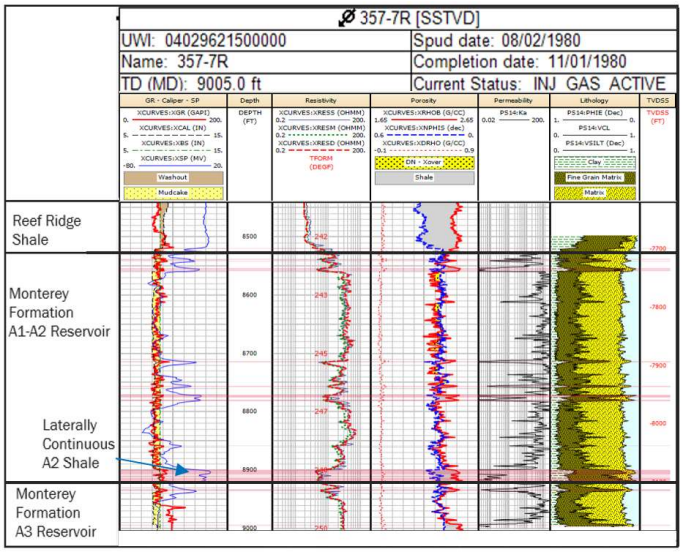
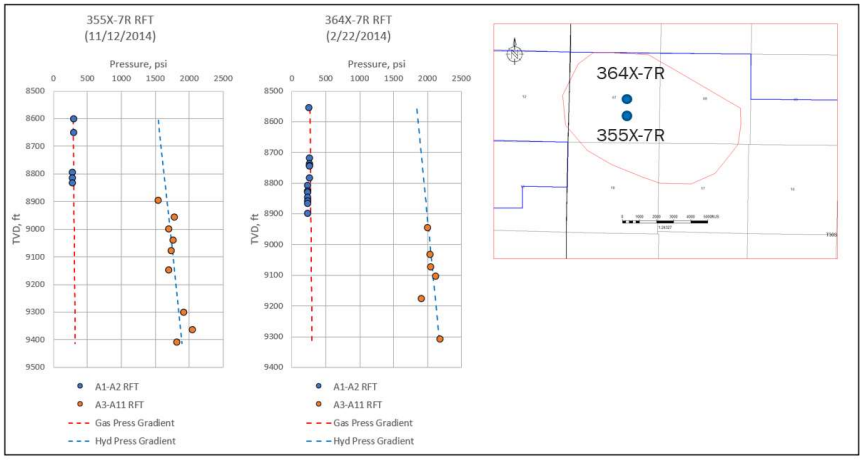


Figure 10: Repeat formation pressure data readings showing hydraulic separation between the A1-A2 and A3-A11 reservoirs. Large pressure difference between the two reservoirs and different fluid gradients as indicated by the red and blue dotted lines



CTV will monitor the Monterey Formation A3-A11 reservoir and wellbores for CO_2 migration. Waterflood producers will be monitored via fluid sampling once per quarter for changes in composition. In addition, Monterey Formation A3-A11 waterflood injectors will have mechanical integrity tests (MIT) and standard annular pressure tests (SAPT) to ensure internal and external

mechanical integrity. This monitoring will be discussed in more detail within the Testing and Monitoring Plan. Additionally, due to its waterflood infrastructure and high reservoir pressure, the A3-A6 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

Summary:

The Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as confinement by the Reef Ridge Shale.

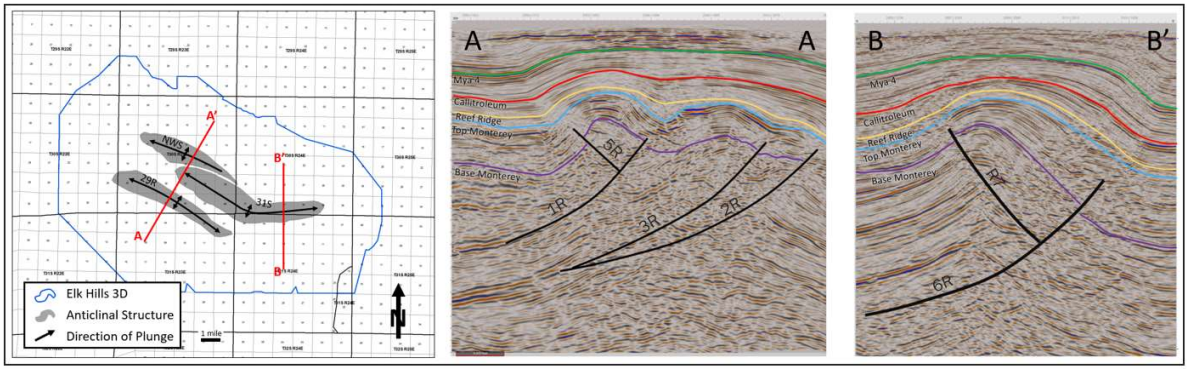
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 11 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the NWS anticlines are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale.

Figure 11: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.



Fluid Confinement

Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO_2 injectate in the Monterey Formation A1-A2 sands:

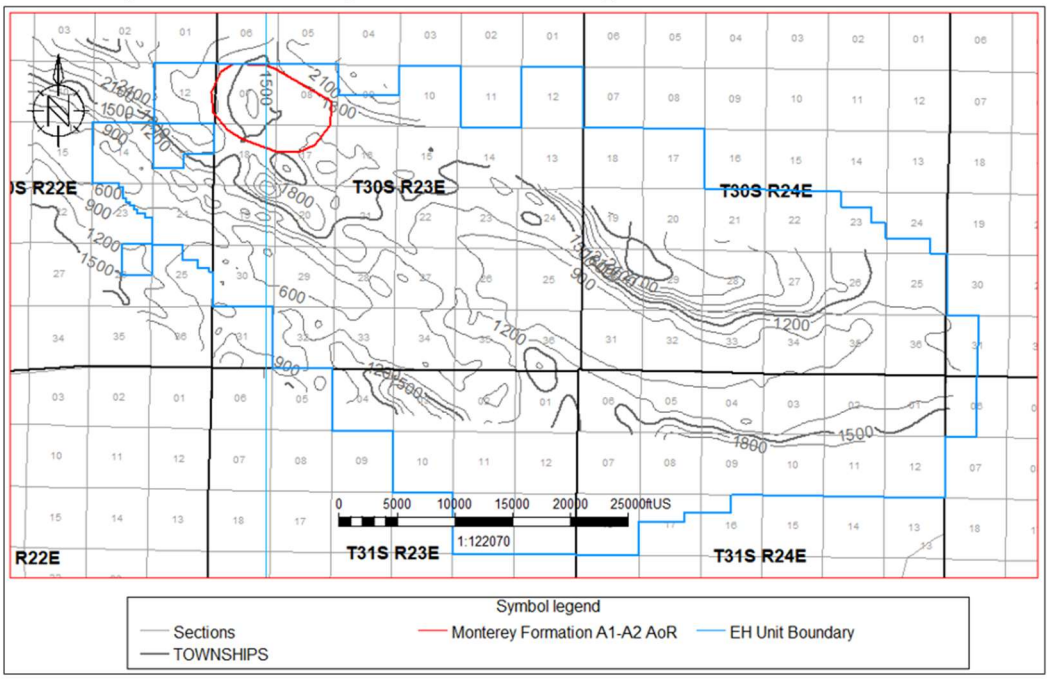
1. There are no faults that extend into the confining Reef Ridge Shale.
2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. A pressure differential exists above and below the Reef Ridge confining interval, confirming lack of communication.

4. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,100 feet (Figure 12) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 12: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



2. Waterflooding and Gas Injection

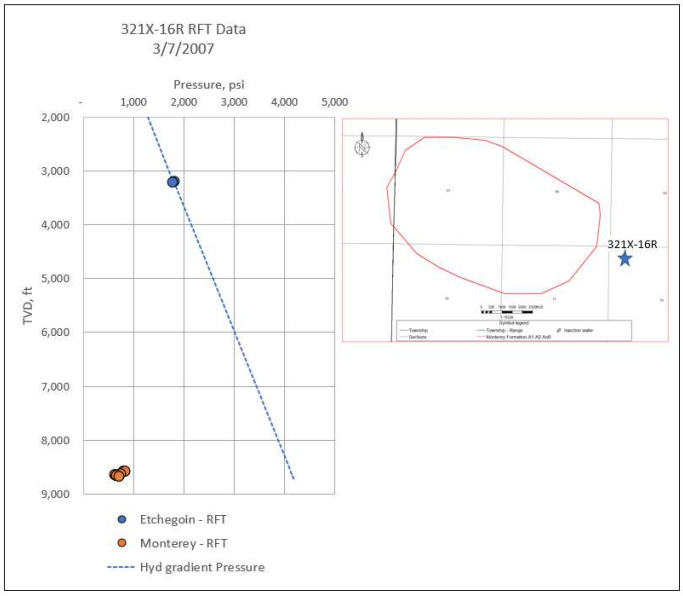
Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control Board. To date, more than five million barrels of water and 175 billion cubic feet of gas have been injected into the Monterey Formation A1-A2 sands. There has been no evidence of water or gas migrating out of the reservoir or through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically and aerially

confined.

3. Pressure Differentials

The Monterey Formation A1-A2 sequestration zone average current pressure is approximately 230 PSI. Overlying the sequestration zone, and separated by the confining Reef Ridge Shale, the Etchegoin Formation aquifer sands are at a much higher pressure of 1,500 PSI (0.43 PSI/foot gradient at 3,600 feet depth). This pressure differential of 1,300 PSI between the overlying Etchegoin Formation and Monterey Formation is maintained because the Reef Ridge is sealing and there are no transmissive features. Figure 13 shows an example of RFT pressure data collected in 2004 during the drilling of an Oil & Gas well near the project area. The RFT data shows that the Etchegoin is hydraulically separated from the deeper Monterey formation and at a much higher pressure.

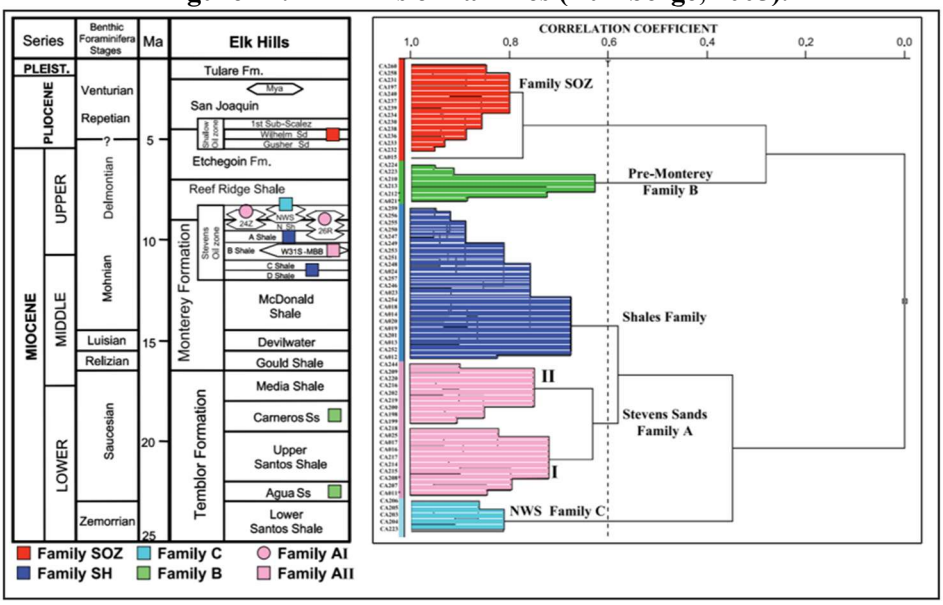
Figure 13: Etchegoin and Monterey RFT data collected during the drilling of Oil & Gas well 321X-16R near the project area showing hydraulic separation between the two formations



4. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 14) sourced from the Miocene Monterey Formation and tied to stratigraphic intervals (sample locations shown on Figure 2). The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests "minimal up-section, [and] cross stratigraphic migration". The authors conclude that the hydrocarbons present in the overlying formations are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

Figure 14: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

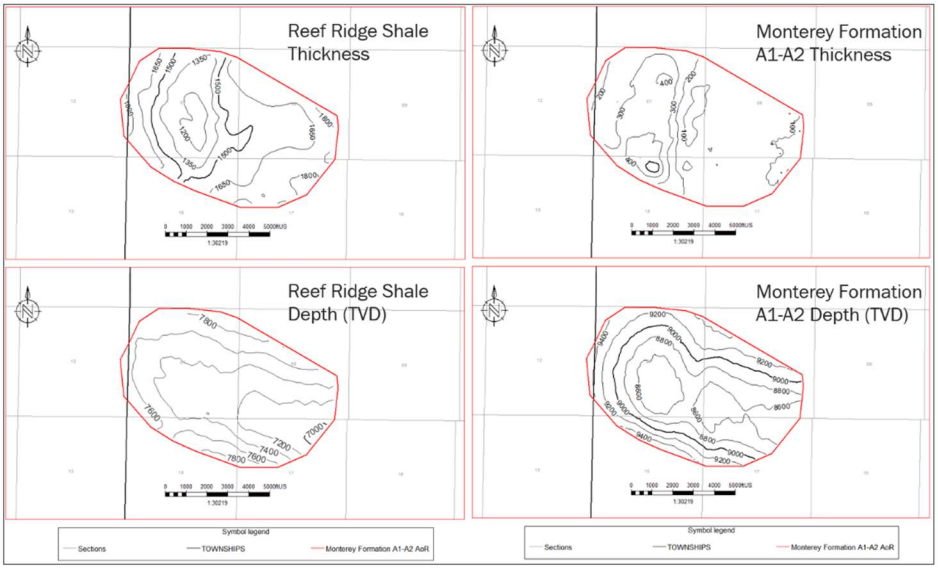
Depths and thickness of the Monterey Formation A1-A2 reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 15) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability due to deposition of the Monterey Formation sands. In the AoR, the Reef Ridge Shale minimum thickness corresponds to a high in Monterey Formation A1-A2 sand thickness.
3. Monterey Formation A1-A2 thickness variability is from pinch-out of the reservoir on the structure.

Table 1: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone Reef Ridge Shale	Thickness (feet)	1,122	1,892	1,555
	Depth (feet TVD)	6,929	7,962	7,441
Reservoir Monterey Formation A1-A2 Sand	Thickness (feet)	27	548	204
	Depth (feet TVD)	8,403	9,598	8,907

Figure 15: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth maps.



Variability in the thickness and depth of the either the Reef Ridge Shale or the Monterey Formation A1-A2 sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

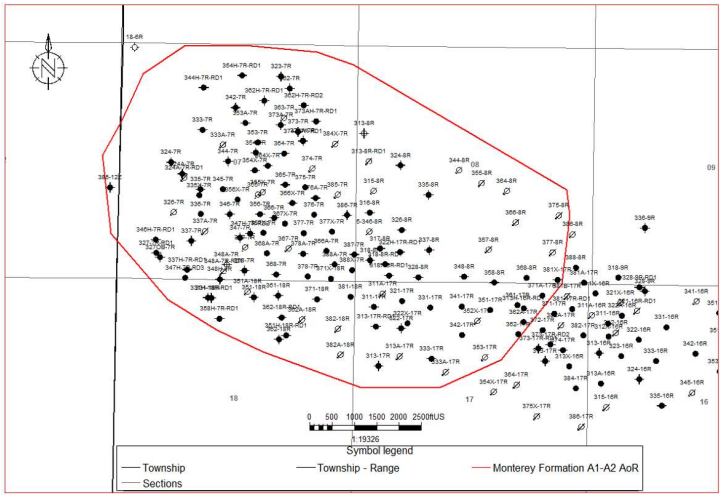
Facies Changes in the Injection or Confining Zone

The Monterey Formation A1-A2 reservoir and Reef Ridge Shale has been defined with extensive data (Figure 16), with a total of 255 well and spacing of 400-800 feet. Each of these wells is used to define stratigraphy, lithology/facies and reservoir properties for the static geological model and the maps shown in Figure 15. This quantity and spacing of data is more than sufficient to generate a data driven static model that define facies changes in for the reservoir and confining zone.

For example, during the drilling of well 355-7R in 1972 spontaneous potential (SP) resistivity (dual induction laterlog), density, neutron porosity and formation dip from 10,509' to 3,393', covering the Etchegoin dissipation zone, Reef Ridge Shale confining layer and the Monterey Formation A1-A2 storage reservoir. In addition 28 sidewall core samples were obtained over the same interval (no detailed analysis of the core samples). The log data supports the characterization of the injection zone and the confining zone at the well site.

Based on Monterey Formation A1-A2 operational experience and plume modeling results, there are no facies changes that will either impact injection operations or confinement.

Figure 16: Well data used to define the Monterey Formation A1-A2 injection reservoir and confining zone. These wells have open-hole log data that is used to establish, clay volume, porosity, permeability, and facies (sand and shale) that are used in the static geological model.



Mineralogy

Monterey Formation A1-A2:

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the AoR. Offset well 367-7R

(Figure 17) provides an example of the mineralogy for the reservoir interval in 357-7R. Clean reservoir sand intervals have an average of 43% quartz, 38% potassium feldspar, albite and oligoclase as well as 7% total clay.

Figure 17: Monterey Formation A1-A2 sand mineralogy from well 367-7R. The map shows the location for 367R and the other wells with XRD in the Elk Hills field.

DEPTH	GDI	SAMP/ WT	QTZ	CHRT	OP-A	OP-CT	ALB	OLIG	AND	KSPAR	CALC	DOLO	PYR	KAOL	CHLOR	ILL/SMEC
8551.9	2.62	8.34	30	13	0	0	17	0	2	21	2	0	1	0	0	14
8552	2.62	9.41	29	13	0	0	14	10	0	15	3	0	0	0	3	14
8554.1	2.62	10.73	45	0	0	0	19	0	2	20	4	0	0	0	0	10
8560.6	2.62	11.37	44	0	0	0	15	11	0	17	5	0	0	2	0	6
8570	2.62	8.32	33	0	0	0	17	8	4	17	3	0	0	0	0	8
8583	2.6	14.88	45	0	0	0	15	11	0	18	4	0	0	0	0	7
8604.3	2.6	18.83	21	21	0	0	15	0	10	14	2	0	0	0	0	17
8634.3	2.52	12.65	44	0	0	0	14	13	1	17	3	0	0	0	0	6
8648.6	2.52	14.16	47	0	0	0	14	3	5	19	3	0	0	0	0	5
8649.2	2.42	15.58	49	0	0	0	18	0	4	14	3	0	0	2	0	6
8649.8	2.42	8.76	50	0	0	0	17	0	4	17	1	2	0	3	0	6
8660.9	2.42	11.24	45	0	0	0	14	9	4	17	2	1	0	2	0	6
8651.4	2.42	8.75	45	0	0	0	14	0	4	19	3	0	0	0	0	10
8656	2.43	23.41	38	0	0	0	14	10	4	14	12	2	0	0	0	6
8702.5	2.41	10.58	40	13	0	0	15	0	5	18	2	0	0	0	0	7

GDI = Grain Density
Sample WT = Weight of Fresh Sample Crushed For Analysis
QTZ = Quartz
CHRT = Chert
OP-A = Opal-A
OP-CT = Opal-CT
ALB = Albite
OLIG = Oligoclase
AND = Andesine
KSPAR = Potassium Feldspar
CALC = Calcite
DOLO = Dolomite
PYR = Pyrite
CHLOR = Chlorite
Ill/SMEC = Illite - Smectite

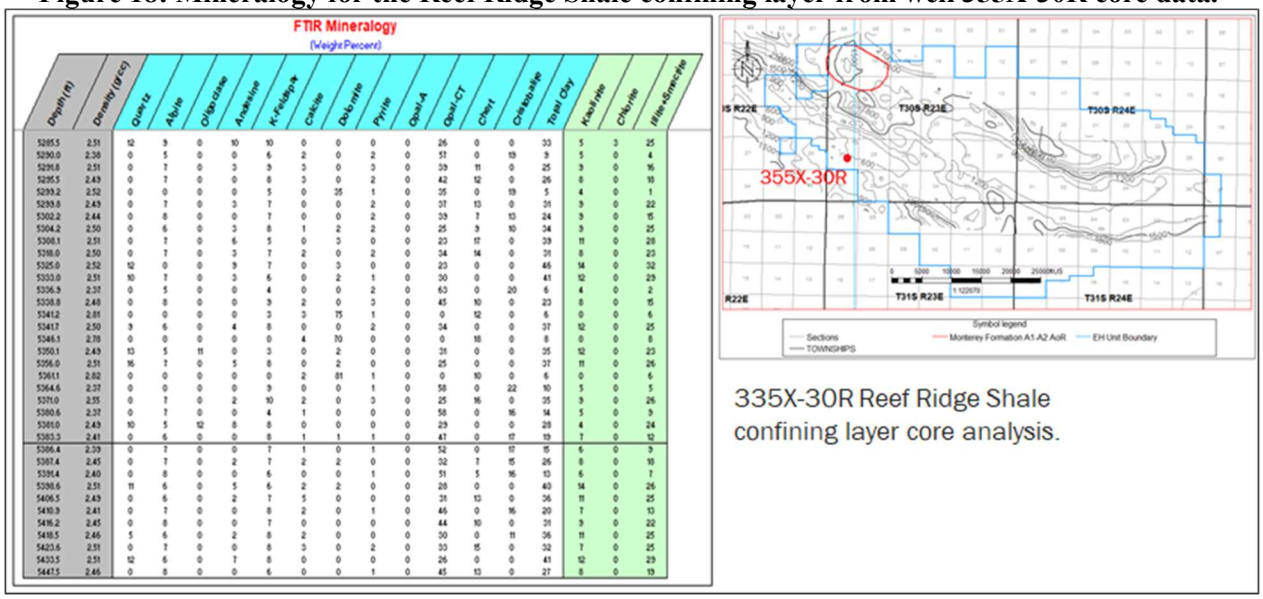


Reef Ridge Shale:

Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 18). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AOR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 18: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.



Porosity and Permeability

Monterey Formation A1-A2:

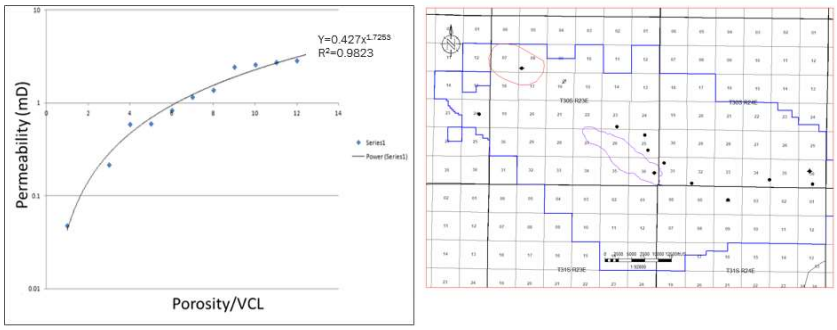
Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.

Volume of clay is determined by neutron-density separation and is calibrated to core data.

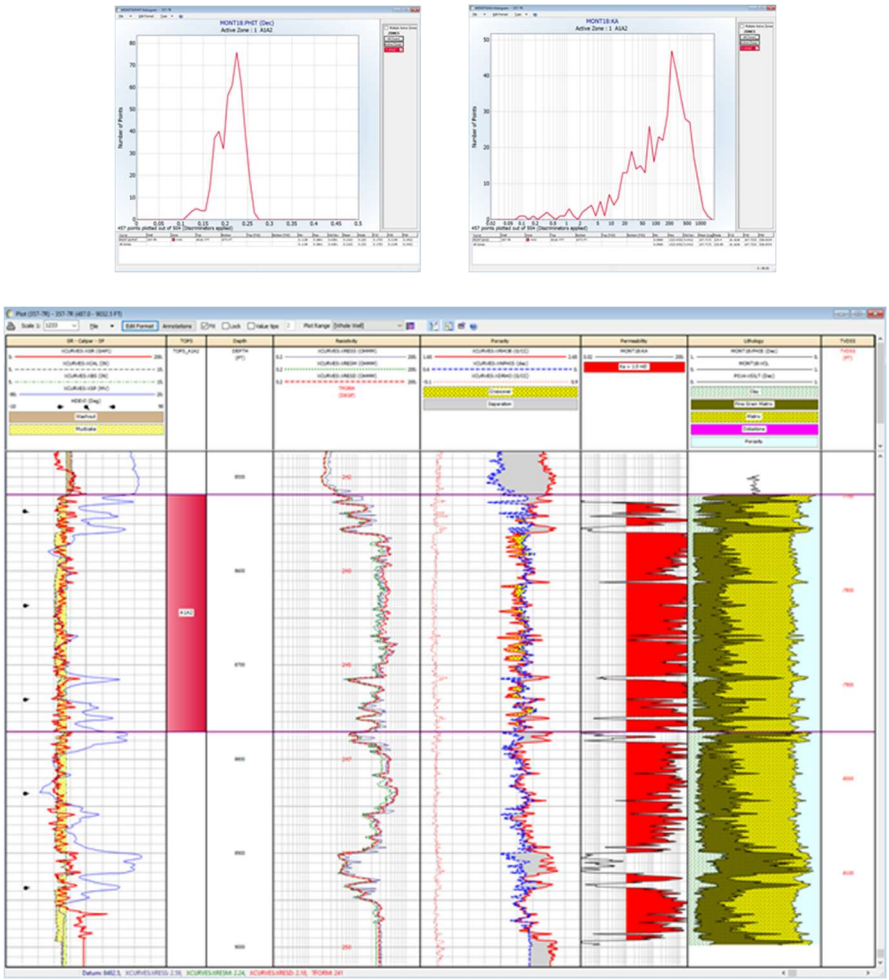
Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells (Figure 19) with 175 data points were used to calibrate log porosity and to develop a permeability transform. This distribution of wells and data points covers Monterey Formation sands in the Elk Hills field and ensures coverage of the porosity-permeability range in the storage reservoir. An example of the transform from core data is illustrated in Figure 19 below.

Figure 19: Permeability function developed based on mercury injection capillary pressure data and calculated from log derived porosity and clay volume. Map shows the locations for wells with Monterey Formation sand core data used in the function.



In the example below for the Monterey Formation A1-A2 sands, the porosity ranges from 11% - 27% with a mean of 21%. The permeability ranges from 0.1 mD - 1300 mD with a log mean of 108 mD (Figure 20).

Figure 20: Porosity and permeability for well 357-7R, showing the distribution and the input and output log curves.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2).

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

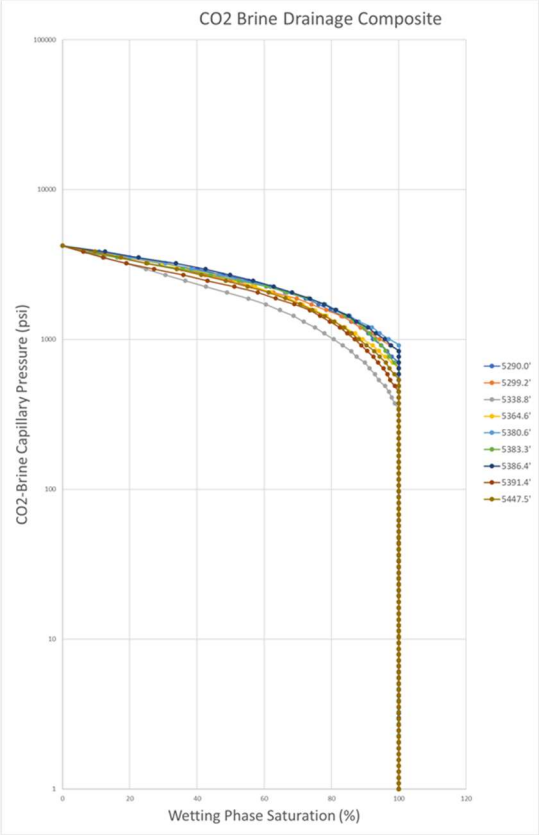
Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006
TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 21). The capillary pressure was determined by applying CO_2-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO_2-brine, respectively.

Figure 21: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR, 18 wells had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 59,214 individual logging data points. The location for the 18 wells is shown on the map in Figure 22.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

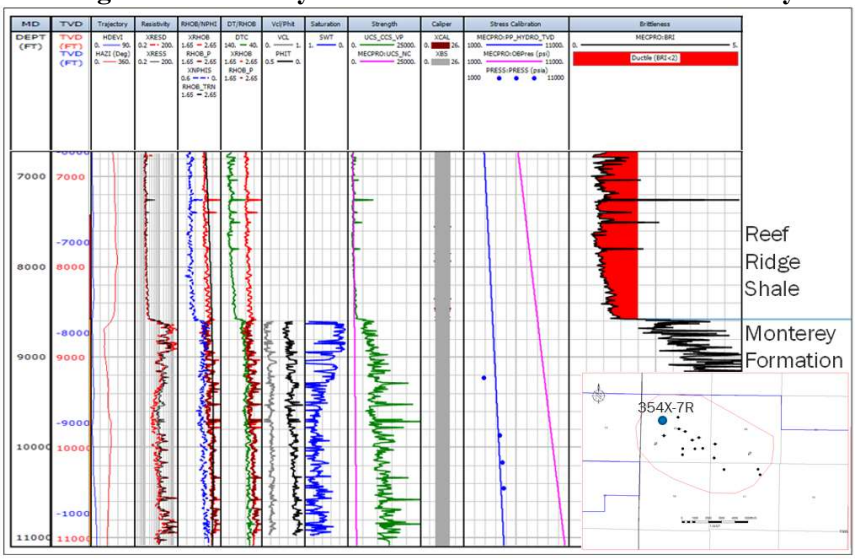
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 354X-7R is shown below (Figure 22). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method. Ductility less than two is shaded red.

Figure 22: Unconfined compressive strength and ductility calculations for well 354X-7R. The Reef Ridge Shale ductility is less than two and will be sufficiently.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to accommodate large amounts of strain without undergoing brittle failure.

The average ductility of the confining zone based on the mean value from 18 wells is 1.24.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,452 psi.

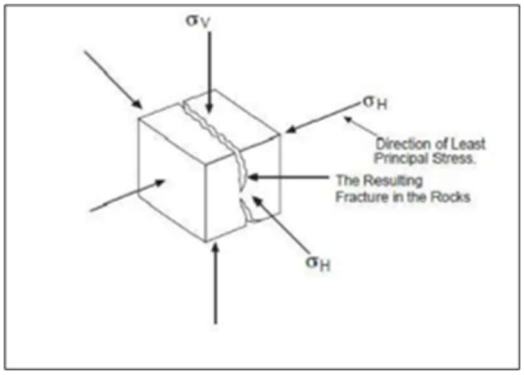
As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the Monterey Formation A1-A2 reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

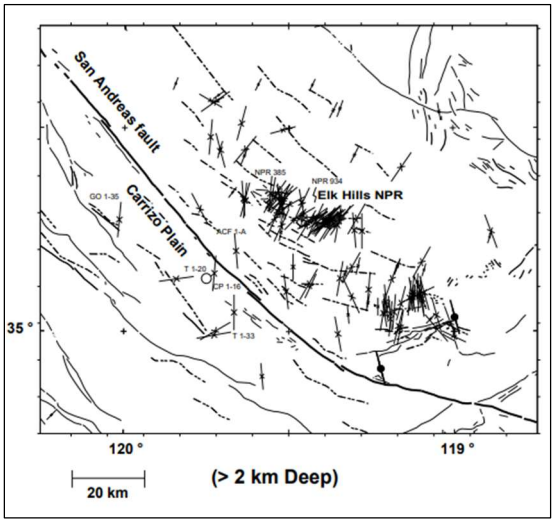
The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. in this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (Figure 23).

Figure 23: Stress diagram showing the three principal stresses and the fracturing that will occur perpendicular to the minimum principal stress.



Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 24 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

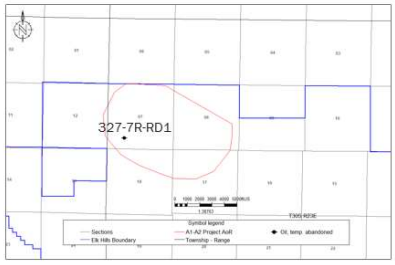
Figure 24: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).



From a fracture test in well 327-7R-RD1, the Monterey Formation A1-A2 has a fracture gradient of 0.82psi/ft, based on the initial shut-in pressure with an overburden gradient of 0.94psi/ft and pore pressure gradient of 0.2psi/ft. Using this gradient, the injectors are planned to be operated such that they will not exceed 90% of the fracture pressure, which equates to a maximum allowable bottomhole gradient of 0.9*0.82 psi/ft = 0.738psi/ft. Applying this gradient to the two injector locations, the maximum bottom injection pressures are shown in table 3.

Table 3: Injectors 355-7R and 357-7R maximum allowable bottom hole injection pressure (psi) for the Monterey Formation A1-A2 injection zone.

Stress	357-7R	355-7R
Reservoir Fracture Gradient with Safety Factore (psi/foot)	0.738	0.738
Montery Formation A1-A2 Injection Zone Top (feet TVD)	8,485	8,462
Fracture Pressure (psi)	6261.9	62,44.9



In the project AoR there is no site specific Reef Ridge Shale fracture pressure or fracture gradient. A Reef Ridge Shale step rate test will be conducted as per the preoperational testing plan. In the interim, CTV is making the assumption that the Reef Ridge Shale will have a similar fracture gradient as the Monterey Formation.

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO_2 injection. A modified Barton-Bandis model can be used to allow CO_2 to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO_2 is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO_2 to leak from the storage reservoir.

Results:

Failure pressures for the four scenarios are given in Table 4. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

Table 4: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	**FAILURE PRESSURE, PSI**
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Description:

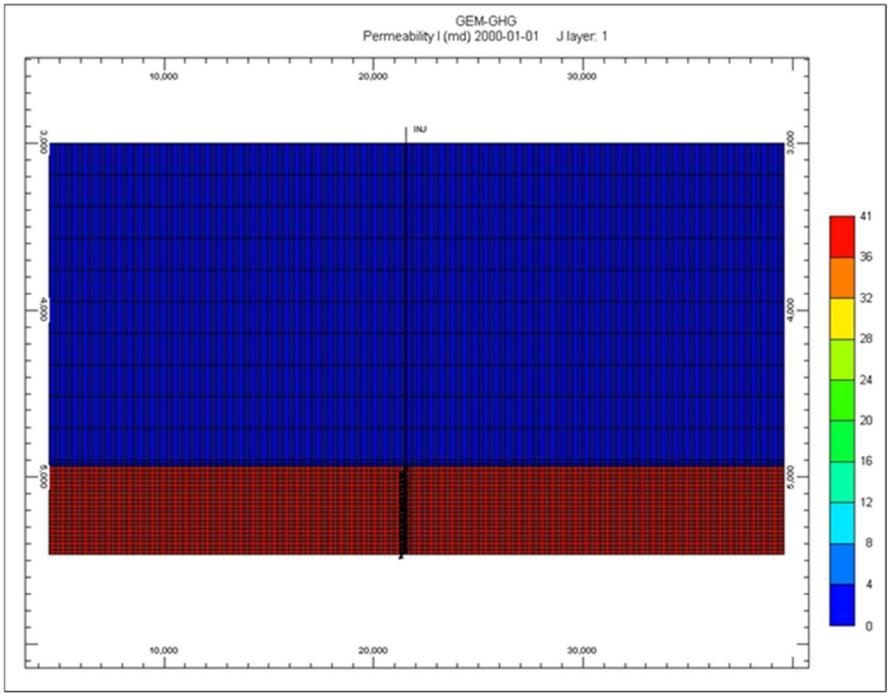
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 25.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO_2 with a maximum injection pressure of 10,000 PSI.

Figure 25: Geomechanics Model.

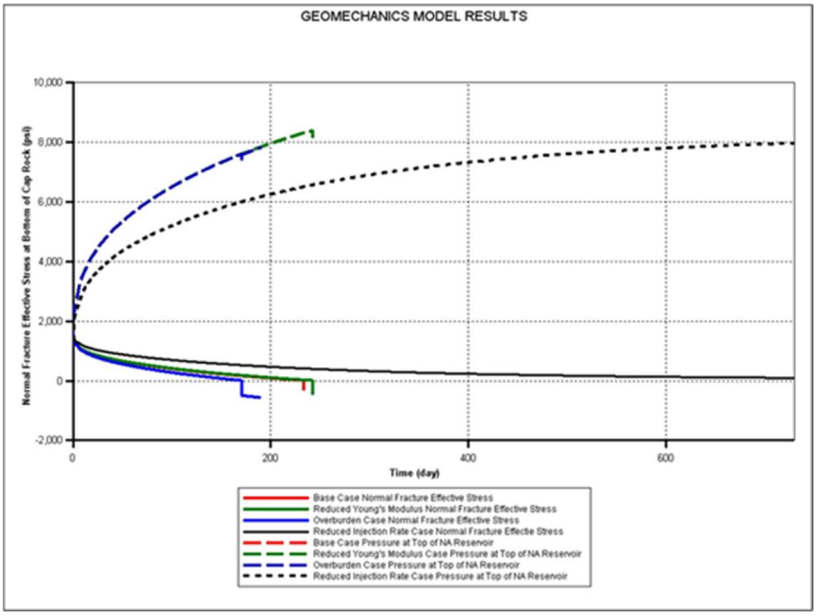


Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 26 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO_2 bleeding into the cap rock despite the very low vertical permeability.

Figure 26: Normal Fracture Stress and Pressure for Geomechanics Cases. Base case follows the reduced Young's Modulus case.



Geomechanical Modeling Parameters

The geomechanical parameters used in the modeling were selected to represent a range of values for thickness, poisons ratio and Youngs Modulus. The following is a short description for parameter variability selection:

> **Thickness:** Reef Ridge thickness scenarios for the geomechanical modeling was 795 feet and 1,935 feet. The mean thickness of the Reef Ridge Shale confining layer overlying the Monterey Formation A1-A2 AoR is 1,555 feet thick (Figure 12) as derived from open-hole log interpretation, which is between the parameters modeled.

Poisson's Ratio: Compressional and shear sonic logs were used to calculate Poisson's Ratio (Yale, 2017).

$$\nu_{dyn} = \nu_{stat} = \frac{V_p^2 - 2V_s^2}{2\left(V_p^2 - V_s^2\right)}$$

The following table shows the range of values determined for Poisons Ratio and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case (1140' of Caprock)	P10	P50	P90
Caprock Reef Ridge	0.23	0.23	0.23	0.24	0.28	0.32
Reservoir A1-A2	0.25			0.19	0.25	0.3

Young's Modulus: Young's Modulus was calculated using compressional and shear sonic and bulk density logs. The dynamic to static correction applied was the Lacy shale method (Lacy, 1997):

$$E_{dyn} = \frac{\rho V_s^2\left(3V_p^2 - 4V_s^2\right)}{\left(V_p^2 - V_s^2\right)}$$

- See equation 8.1 in Fjaer et. al, 2008

$$E_{stat} = 0.0428E_{dyn}^2 + 0.2334E_{dyn}$$

- See equation 2 in Lacy, 1997.

The following table shows the range of values determined for Young's Modulus and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case (Top 1140' of Caprock)	P10 E	P50 E	P90 E
Caprock Reef Ridge	0.9	0.8	0.6	0.66	0.91	1.36
Reservoir A1-A2	0.725			0.79	0.85	0.92

Seismic History [40 CFR 146.82(a)(3)(v)]

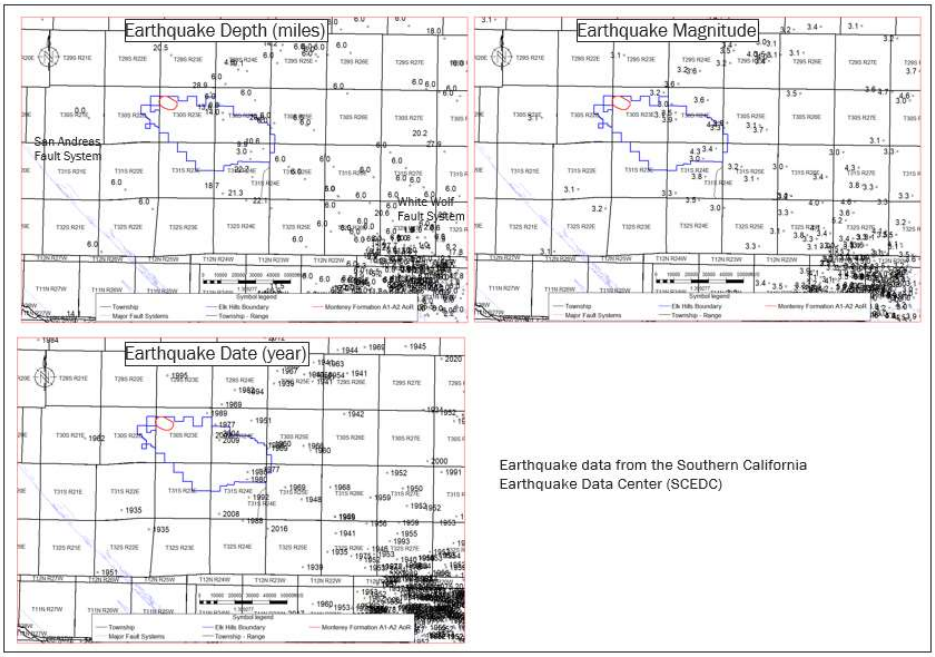
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

There have been no earthquakes in the AoR (Figure 27). In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF. The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, CTV will establish a baseline and assess natural versus induced seismicity.

Figure 27: Earthquakes in the southern San Joaquin Basin with a magnitude greater than 3 since 1932. The White Wolf Fault is active in the southern San Joaquin Basin.



Seismic Risk:

The EHOF has been closely monitored for the effects of seismicity by CRC and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

The following is a summary of CTVs seismic risk:

Has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO2 proposed to be injected.

- Extensive historical operations in the Monterey Formation A1-A2 reservoir is valuable experience to understand operating conditions such as injection volumes and reservoir containment. The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
- VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high Vs30means (Figure 28) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
- There are no faults or fractures identified in the AoR that will impact the confinement of CO2 injectate.

Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;

- The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- Injection and monitoring well pressure monitoring will ensure that pressures are beneath the fracture pressure of the sequestration reservoir and confining zone. Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.

Figure 28: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.

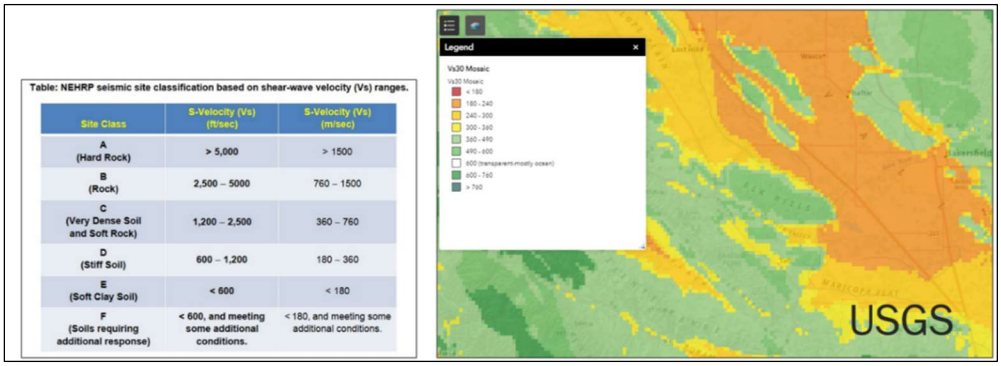


Table: NEHRP seismic site classification based on shear-wave velocity (Vs) ranges.

Site Class	S-Velocity (Vs) (ft/sec)	S-Velocity (Vs) (m/sec)
A (Hard Rock)	> 5,000	> 1500
B (Rock)	2,500 – 5000	760 – 1500
C (Very Dense Soil and Soft Rock)	1,200 – 2,500	360 – 760
D (Stiff Soil)	600 – 1,200	180 – 360
E (Soft Clay Soil)	< 600	< 180
F (Soils requiring additional response)	< 600, and meeting some additional conditions.	< 180, and meeting some additional conditions.

Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV personnel will be notified of events that are considered an early warning sign. Early warning signs will be addressed to ensure that more significant events do not occur.
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations.

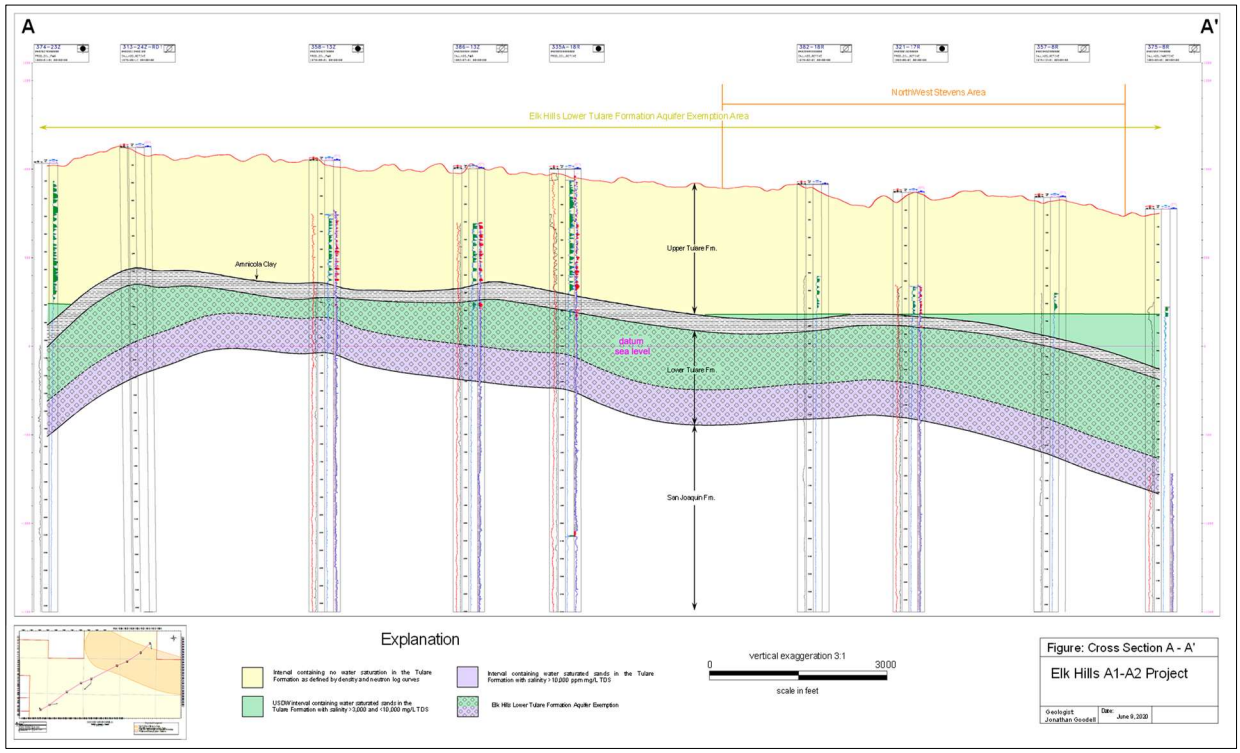
Poses a low risk of inducing a felt seismic event.

- Pressure will be monitored in each injector and sequestration monitoring well to ensure that pressure does not exceed the fracture pressure of the reservoir or confining layer.
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.
- The operational strategy of keeping the reservoir pressure at or beneath the initial pressure of the reservoir has been designed to reduce the risk for seismic events.

Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

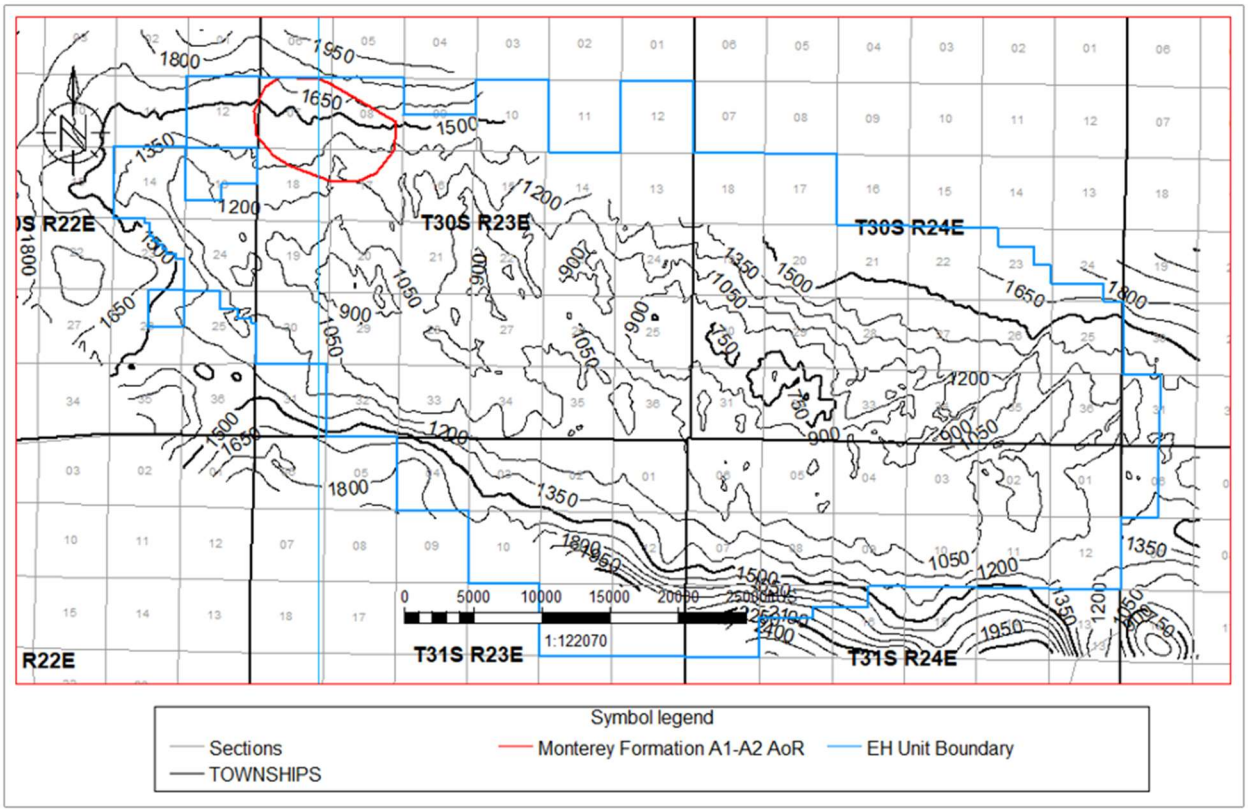
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 29). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 29: Cross-section showing the Tulare Formation USDW. The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands have 3,000 – 10,000 TDS water at the base, on the edges of the Northwest Stevens anticline.



The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 29). The depth is 600 - 2,500 feet and the thickness ranges from 1,200 - 1,500 feet (Figure 30).

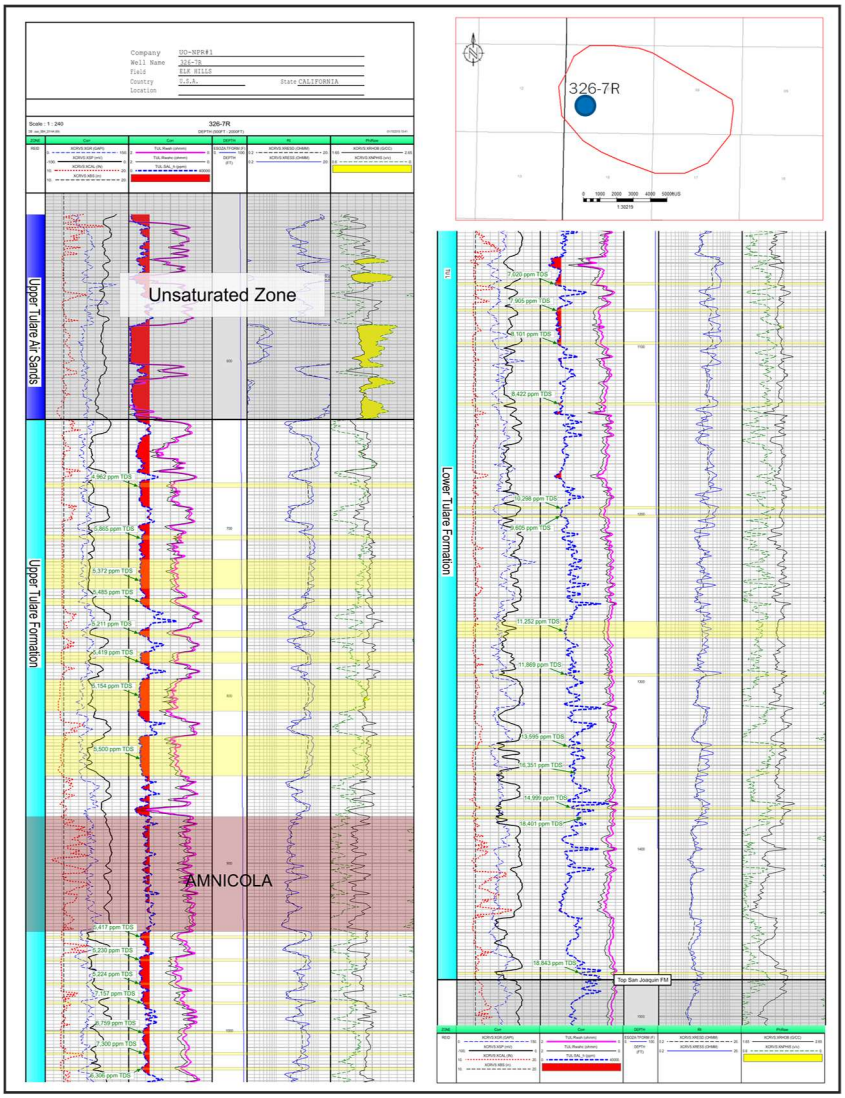
Figure 30: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare USDW. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 31). The characteristic density-neutron crossover (orange-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity.

Figure 31 shows the Upper Tulare USDW overlain by the Upper Tulare air sands. The Upper Tulare is 850 feet in depth and is separated from the underlying Reef Ridge Shale confining layer by 6,450 feet and the Monterey Formation A1-A2 sequestration reservoir by 7,650 feet.

Figure 31: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, Upper Tulare USDW and Lower Tulare exempt aquifer.



Salinity Calculation

Calculation of salinity as shown in Figure 31 is a four step process:

(1) converting measured density to formation porosity

The equation to convert measured density to porosity is:

POR = (Rhom - RHOB) /(Rhom-Rhof)

Parameter definitions for the equation are:

POR is formation porosity

Rhom is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones

RHOB is calibrated bulk density taken from well log measurements (g/cc)

Rhof is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

(2) calculation of apparent water resistivity using the Humble equation,

The Humble equation calculates apparent water resistivity. The equation is:

Rwah = ((POR**m) * XRESD)/a

Parameter definitions for the equation are:

Rwah is apparent water resistivity (ohmm)

POR is formation porosity as derived from the density conversion formula

m is the cementation factor; 2.15 is the standard value

XRESD is deep reading resistivity taken from well log measurements (ohmm)

a is the archie constant; 0.62 is the standard value

(3) correcting apparent water resistivity to a standard temperature

Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

Rwahc = Rwah * ((TEMP)+6.77)/(75+6.77)

Parameter definitions for the equation are:

Rwahc is apparent water resistivity (ohmm), corrected to surface temperature

TEMP is down hole temperature based on temperature gradient (DegF)

(4) converting temperature corrected apparent water resistivity to salinity.

The following formular was used:

SAL_h = 10 ** ((3.562-(Log10(Rwahc-0.0123)))/.955)

Parameter definitions for the equation are:

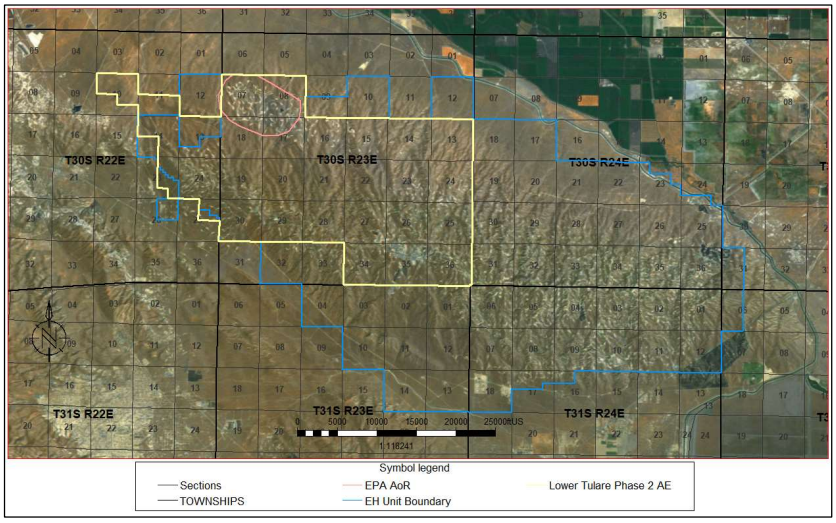
SAL_h is salinity from corrected Rwahc (ppm)

Rwahc is apparent water resistivity, corrected to surface temperature (ohmm),

Water Samples

Tulare Formation water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum containment levels (MCL).

Figure 32: Lower Tulare aquifer exemption boundary.

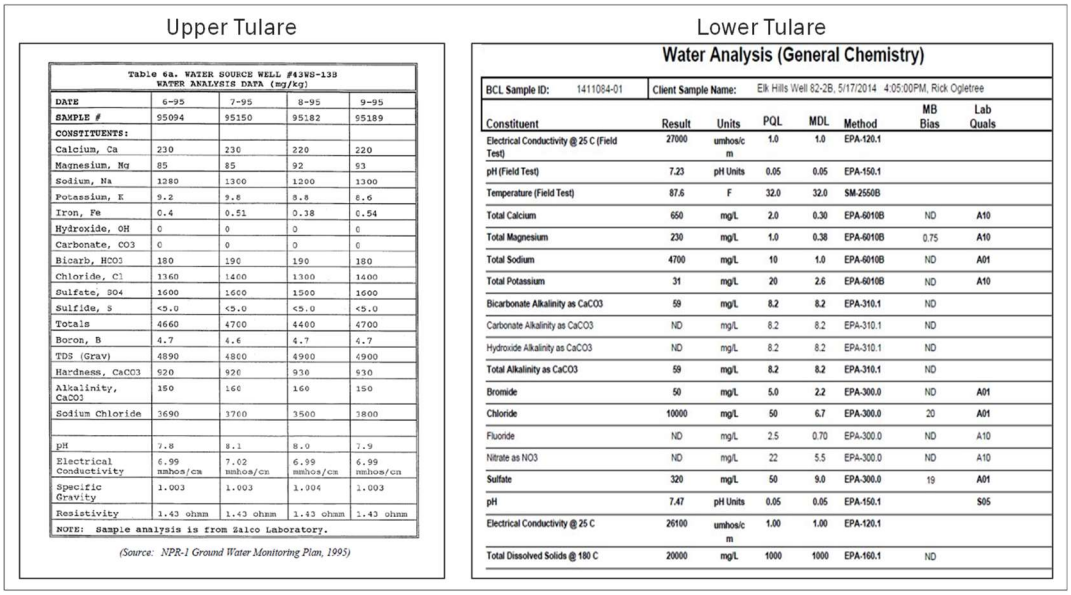


In 2018 the Lower Tulare aquifer (boundary shown on map in Figure 32) was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and
2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

The Upper Tulare USDW has 3,000-10,000 mg/l TDS on the edges of the NWS anticline. Water quality for the Upper Tulare USDW is shown in Figure 33. The water is not used within the AoR or the EHOF.

Figure 33: Upper Tulare USDW and Lower Tulare Formation water analysis.



Upper Tulare

Table 6a. WATER SOURCE WELL #43WS-13S
WATER ANALYSIS DATA (mg/kg)

DATE	6-95	7-95	8-95	9-95
SAMPLE #	95094	95150	95182	95189
CONSTITUENTS:				
Calcium, Ca	230	230	220	220
Magnesium, Mg	85	85	92	93
Sodium, Na	1280	1300	1200	1300
Potassium, K	9.2	9.8	8.8	8.6
Iron, Fe	0.4	0.51	0.38	0.54
Hydroxide, OH	0	0	0	0
Carbonate, CO3	0	0	0	0
Bicarb, HCO3	180	190	190	180
Chloride, Cl	1360	1400	1300	1400
Sulfate, SO4	1600	1600	1500	1600
Sulfide, S	<5.0	<5.0	<5.0	<5.0
Totals	4660	4700	4400	4700
Boron, B	4.7	4.6	4.7	4.7
TDS (Grav)	4890	4800	4900	4900
Hardness, CaCO3	920	920	930	930
Alkalinity, CaCO3	150	160	160	150
Sodium Chloride	3690	3700	3500	3800
pH	7.8	8.1	8.0	7.9
Electrical Conductivity	6.99 mmhos/cm	7.02 mmhos/cm	6.99 mmhos/cm	6.99 mmhos/cm
Specific Gravity	1.003	1.003	1.004	1.003
Resistivity	1.43 ohmm	1.43 ohmm	1.43 ohmm	1.43 ohmm

NOTE: Sample analysis is from Zalco Laboratory.

(Source: NPR-1 Ground Water Monitoring Plan, 1995)

Lower Tulare

Water Analysis (General Chemistry)

BCL Sample ID: 1411084-01 Client Sample Name: Elk Hills Well 82-2B, 5/17/2014 4:05:00PM, Rick Ogletree

Constituent	Result	Units	PQL	MDL	Method	MB Bias	Lab Quals
Electrical Conductivity @ 25 C (Field Test)	27000	umhos/cm	1.0	1.0	EPA-120.1		
pH (Field Test)	7.23	pH Units	0.05	0.05	EPA-150.1		
Temperature (Field Test)	87.6	F	32.0	32.0	SM-2550B		
Total Calcium	650	mg/L	2.0	0.30	EPA-6010B	ND	A10
Total Magnesium	230	mg/L	1.0	0.38	EPA-6010B	0.75	A10
Total Sodium	4700	mg/L	10	1.0	EPA-6010B	ND	A01
Total Potassium	31	mg/L	20	2.6	EPA-6010B	ND	A10
Bicarbonate Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Carbonate Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Hydroxide Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Total Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Bromide	50	mg/L	5.0	2.2	EPA-300.0	ND	A01
Chloride	10000	mg/L	50	6.7	EPA-300.0	20	A01
Fluoride	ND	mg/L	2.5	0.70	EPA-300.0	ND	A10
Nitrate as NO3	ND	mg/L	22	5.5	EPA-300.0	ND	A10
Sulfate	320	mg/L	50	9.0	EPA-300.0	19	A01
pH	7.47	pH Units	0.05	0.05	EPA-150.1		S05
Electrical Conductivity @ 25 C	26100	umhos/cm	1.00	1.00	EPA-120.1		
Total Dissolved Solids @ 180 C	20000	mg/L	1000	1000	EPA-160.1	ND	

Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

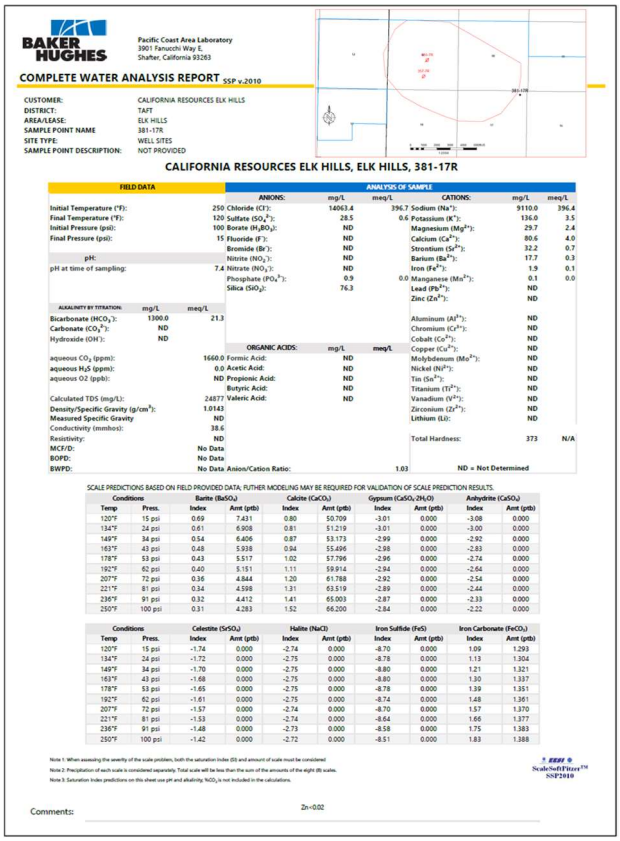
Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry A1-A2 Reservoir:

The Monterey Formation A1-A2 reservoir has a gas cap that overlies a thin oil band and a basal water zone. CRC and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation A1-A2 geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Figure 34 shows the water chemistry from well 381-17R, taken from a sand underlying the Monterey Formation A1-A2 reservoir. Reservoir depletion of the Monterey Formation A1-A2 has reduced the water saturation to residual, preventing representative water sampling.

Figure 34: Monterey Formation A1-A2 reservoir water geochemistry from well 381-17R. Monterey Formation total dissolved solids based on well 381-17R is 24,877, well above USDW standards.



BAKER HUGHES

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Shafter, California 93263

COMPLETE WATER ANALYSIS REPORT SSP v.2010

CUSTOMER:	CALIFORNIA RESOURCES ELK HILLS
DISTRICT:	TAFT
AREA/LEASE:	ELK HILLS
SAMPLE POINT NAME	381-17R
SITE TYPE:	WELL SITES
SAMPLE POINT DESCRIPTION:	NOT PROVIDED

CALIFORNIA RESOURCES ELK HILLS, ELK HILLS, 381-17R

FIELD DATA	
Initial Temperature (°F):	250
Final Temperature (°F):	120
Initial Pressure (psi):	100
Final Pressure (psi):	15
pH:	
pH at time of sampling:	7.4

ALKALINITY BY TITRATION:	mg/L	meq/L
Bicarbonate (HCO_3^-):	1300.0	21.3
Carbonate (CO_3^{2-}):	ND	
Hydroxide (OH^-):	ND	
aqueous CO_2 (ppm):		1660.0
aqueous H_2S (ppm):		0.0
aqueous O2 (ppb):		ND
Calculated TDS (mg/L):		24877
Density/Specific Gravity (g/cm³):		1.0143
Measured Specific Gravity		ND
Conductivity (mmhos):		38.6
Resistivity:		ND
MCF/D:		No Data
BOPD:		No Data
BWPD:		No Data

ANALYSIS OF SAMPLE — ANIONS:	mg/L	meq/L
Chloride (Cl^-):	14063.4	396.7
Sulfate (SO_4^{2-}):	28.5	0.6
Borate ($H_2BO_3^-$):	ND	
Fluoride (F^-):	ND	
Bromide (Br^-):	ND	
Nitrite (NO_2^-):	ND	
Nitrate (NO_3^-):	ND	
Phosphate (PO_4^{3-}):	0.9	0.0
Silica (SiO_2):	76.3	

ORGANIC ACIDS:	mg/L	meq/L
Formic Acid:	ND	
Acetic Acid:	ND	
Propionic Acid:	ND	
Butyric Acid:	ND	
Valeric Acid:	ND	

CATIONS:	mg/L	meq/L
Sodium (Na^+):	9110.0	396.4
Potassium (K^+):	136.0	3.5
Magnesium (Mg^{2+}):	29.7	2.4
Calcium (Ca^{2+}):	80.6	4.0
Strontium (Sr^{2+}):	32.2	0.7
Barium (Ba^{2+}):	17.7	0.3
Iron (Fe^{2+}):	1.9	0.1
Manganese (Mn^{2+}):	0.1	0.0
Lead (Pb^{2+}):	ND	
Zinc (Zn^{2+}):	ND	
Aluminum (Al^{3+}):	ND	
Chromium (Cr^{3+}):	ND	
Cobalt (Co^{2+}):	ND	
Copper (Cu^{2+}):	ND	
Molybdenum (Mo^{2+}):	ND	
Nickel (Ni^{2+}):	ND	
Tin (Sn^{2+}):	ND	
Titanium (Ti^{2+}):	ND	
Vanadium (V^{2+}):	ND	
Zirconium (Zr^{2+}):	ND	
Lithium (Li^-):	ND	
Total Hardness:	373	N/A

Anion/Cation Ratio: 1.03

ND = Not Determined

SCALE PREDICTIONS BASED ON FIELD PROVIDED DATA; FUTHER MODELING MAY BE REQUIRED FOR VALIDATION OF SCALE PREDICTION RESULTS.

Conditions		Barite ($BaSO_4$)		Calcite ($CaCO_3$)		Gypsum ($CaSO_4 \cdot 2H_2O$)		Anhydrite ($CaSO_4$)	
Temp	Press.	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)
120°F	15 psi	0.69	7.431	0.80	50.709	-3.01	0.000	-3.08	0.000
134°F	24 psi	0.61	6.908	0.81	51.219	-3.01	0.000	-3.00	0.000
149°F	34 psi	0.54	6.406	0.87	53.173	-2.99	0.000	-2.92	0.000
163°F	43 psi	0.48	5.938	0.94	55.496	-2.98	0.000	-2.83	0.000
178°F	53 psi	0.43	5.517	1.02	57.796	-2.96	0.000	-2.74	0.000
192°F	62 psi	0.40	5.151	1.11	59.914	-2.94	0.000	-2.64	0.000
207°F	72 psi	0.36	4.844	1.20	61.788	-2.92	0.000	-2.54	0.000
221°F	81 psi	0.34	4.598	1.31	63.519	-2.89	0.000	-2.44	0.000
236°F	91 psi	0.32	4.412	1.41	65.003	-2.87	0.000	-2.33	0.000
250°F	100 psi	0.31	4.283	1.52	66.200	-2.84	0.000	-2.22	0.000

Conditions		Celestite ($SrSO_4$)		Halite (NaCl)		Iron Sulfide (FeS)		Iron Carbonate ($FeCO_3$)	
Temp	Press.	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)
120°F	15 psi	-1.74	0.000	-2.74	0.000	-8.70	0.000	1.09	1.293
134°F	24 psi	-1.72	0.000	-2.75	0.000	-8.78	0.000	1.13	1.304
149°F	34 psi	-1.70	0.000	-2.75	0.000	-8.80	0.000	1.21	1.321
163°F	43 psi	-1.68	0.000	-2.75	0.000	-8.80	0.000	1.30	1.337
178°F	53 psi	-1.65	0.000	-2.75	0.000	-8.78	0.000	1.39	1.351
192°F	62 psi	-1.61	0.000	-2.75	0.000	-8.74	0.000	1.48	1.361
207°F	72 psi	-1.57	0.000	-2.74	0.000	-8.70	0.000	1.57	1.370
221°F	81 psi	-1.53	0.000	-2.74	0.000	-8.64	0.000	1.66	1.377
236°F	91 psi	-1.48	0.000	-2.73	0.000	-8.58	0.000	1.75	1.383
250°F	100 psi	-1.42	0.000	-2.72	0.000	-8.51	0.000	1.83	1.388

Note 1: When assessing the severity of the scale problem, both the saturation Index (SI) and amount of scale must be considered

Note 2: Precipitation of each scale is considered separately. Total scale will be less than the sum of the amounts of the eight (8) scales.

Note 3: Saturation Index predictions on this sheet use pH and alkalinity. HCO_3 is not included in the calculations.

ScaleSoftPitzer™ SSP2010

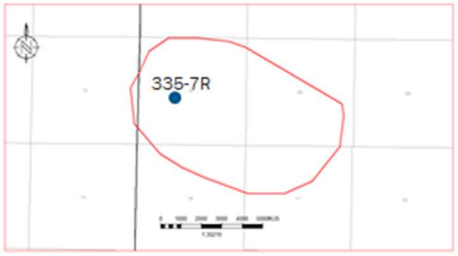
Comments: Zn<0.02

The hydrocarbon composition for the Monterey Formation A1-A2 reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 35 shows the results of the hydrocarbon composition for well 335-7R within the AoR. Oil composition analysis

was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

Figure 35: Monterey Formation A1-A2 hydrocarbon geochemistry from well 335-7R in 1974.

Hydrogen Sulfide	Nil	Nil
Carbon Dioxide	0.60	0.23
Nitrogen	0.04	0.01
Methane	45.77	6.43
Ethane	1.82	0.48
Propane	4.66	1.80
iso-Butane	1.32	0.67
n-Butane	3.74	1.90
iso-Pentane	1.39	0.88
n-Pentane	1.41	0.89
Hexanes	2.86	2.15
Heptanes plus	36.39	84.56
	100.00	100.00



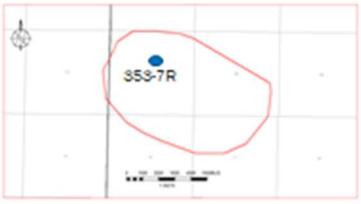
Gas composition for the Monterey Formation A1-A2 is collected to assess the changing concentration of key components. Since 2011, CTV has used two injectors for reservoir pressure support; 357-7R and 355-7R to inject gas containing up to 44% CO_2. Figure 36 shows the produced natural gas analysis for 353-7R in 2021. Note that the composition has 6.5 mole % CO_2.

Figure 36: Natural gas composition analysis for well 353-7R in 2021.

CALIFORNIA RESOUCES CORPORATION
35R LABORATORY SERVICES

NATURAL GAS ANALYSIS

LOG NUMBER :	NT210833
SAMPLER NUMBER :	353-7R
SAMPLE LOCATION :	353-7R
SAMPLE SOURCE :	Well Head
SAMPLE TYPE :	A1-A2
DATE SAMPLED :	06/02/21
TIME SAMPLED:	
PRESSURE (PSIG) :	
TEMPERATURE (F) :	
SAMPLED BY :	CD
REPORTED BY :	AR
REQUESTED BY :	NGL



Gas Chromatographic Analysis

COMPONENTS	NAME (Abreviated)	MOL %	GPMCF	BBL/MMSCF
OXYGEN	- O2	0.040		
NITROGEN	- N2	0.452		
CARBON DIOXIDE	- CO2	6.572		
METHANE	- C1	66.909		
ETHANE	- C2	5.078		
PROPANE	- C3	7.057	1.94	46.28
ISO-BUTANE	- IC4	1.250	0.41	9.74
N-BUTANE	- NC4	4.607	1.45	34.57
ISO-PENTANE	- IC5	1.549	0.57	13.49
N-PENTANE	- NC5	1.735	0.63	14.97
HEXANES PLUS	- C6+	4.750	2.05	48.71
	TOTAL:	100.000	7.05	167.75

C4+ (GPMCF)	5.10
Relative Density (Air = 1) :	0.992
Gross Heating Value (BTU/CU FT):	1520
Compressibility Factor, Z :	0.9934

REMARKS:
1. Data are calculated at 60 F, 14.73 psia, dry, real gas.
2. Reference Methods: ASTM D-1945, ASTM D-3588, GPA-2145, GPA-2261, GPA-2172, GPA-2177.

Monterey Formation A1-A2 Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO_2 injectate:

1. The Monterey Formation A1-A2 reservoir has a low current water volume (~15% saturation in the gas cap and 85% in the thin oil leg) due to production related to oil and gas operations, where four million net barrels of water have been produced. This low volume of water will minimize both the quantity of CO_2 that will dissolve in solution and the quantity of carbonic acid formed in-situ.
2. Residual oil saturation (15%) in the Monterey Formation A1-A2 reservoir will also dissolve only a small amount of CO_2.
3. The Monterey Formation A1-A2 has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO_2 and carbonic acid and any dissolution or changes that occur will be on grain surfaces.
4. Since 2011 6.3 billion cubic feet of gas has been injected in the 357-7R and 355-7R wells, consisting of up to 44% CO_2. Injectivity of the reservoir has not changed.

The oil and water CO_2 trapping mechanisms have been incorporated in the computational modeling and will be discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

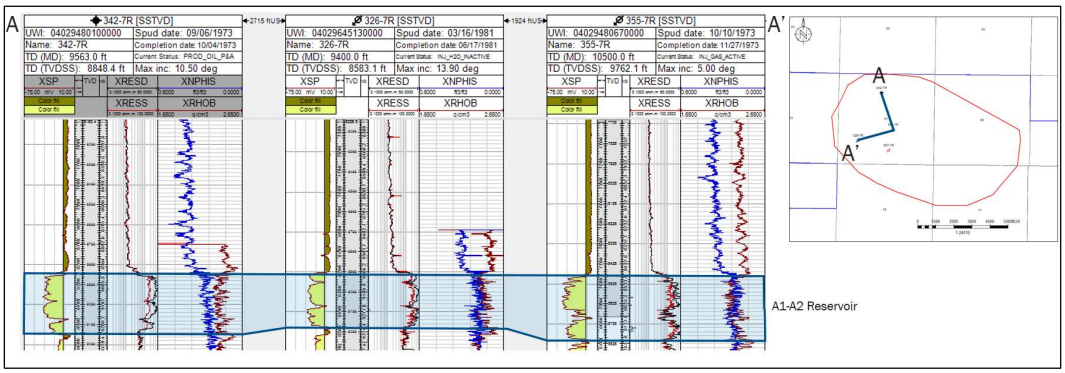
There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO_2 injectate.

Site Suitability [40 CFR 146.83]

The Monterey Formation A1-A2 reservoir in the Northwest Stevens anticline was discovered in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the Monterey Formation A1-A2 reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. Figure 37 shows the continuity of the A1-A2 reservoir and illustrates representative logs data collected during drilling used to develop the static model. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

Figure 37: Cross section showing continuity of the A1-A2 reservoir. Logs shown are representative of those collected during drilled and used to develop the static geological model.



A key component of the A1-A2 reservoir characterization was the development of a geo-cellular model, which is used to assess CO_2 plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement, and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale). Cross-sections in Figures 38 and 39 shows the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers supports predictable plume development.

CO2 Injectate Confinement:

Confinement of CO_2 injected into the storage reservoir is supported by the following:

1. Prior to discovery of the Monterey Formation A1-A2 reservoir, a gas cap with underlying oil was confined for several million years.
2. The Reef Ridge Shale primary confining layer is 1,500 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 175 billion cubic feet of gas and five million barrels of water with no leakage.

3. Cross section A-A' (Figure 38) shows the lateral confinement of the injected CO_2 plume by the anticline structure. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does migrate beyond the edges of the anticline structure or into the Reef Ridge shale.
4. In Cross section B-B' (Figure 39) the up-dip CO_2 plume is confined by shale and the non-deposition of reservoir sands.

Figure 38: Plume modeling results showing lateral confinement of the CO2 plume by the edges of the anticline structure.

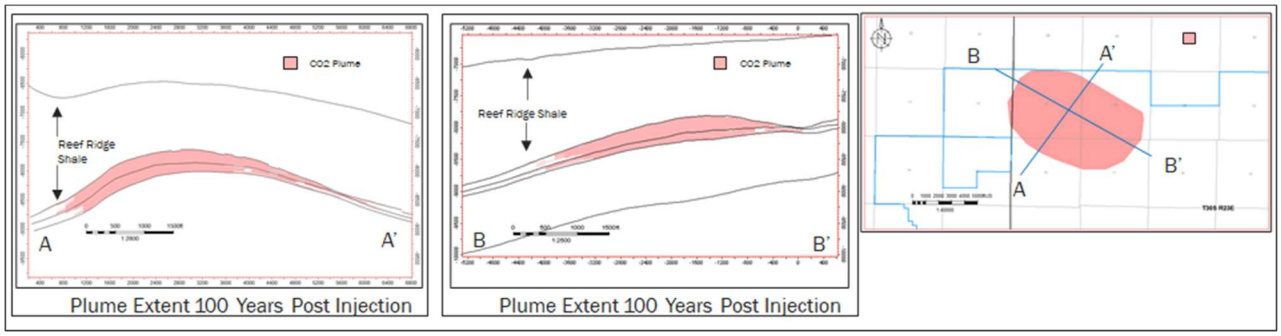
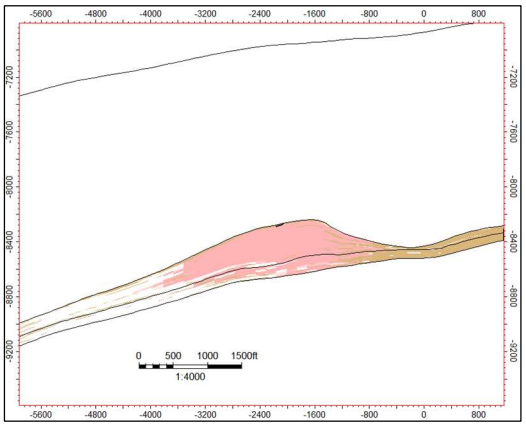


Figure 39: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the A1-A2 sand facies and the increasing shale facies.



Storage capacity for the Monterey Formation A1-A2 storage reservoir based on computational modeling results is approximately 8 -10 million tonnes of CO_2. This is sufficient capacity for the total proposed injectate.

References:

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2. Zumberge, John, Russell, Just and Reid, Stephen, Charging of Elk Hills reservoirs as determined by oil geochemistry, AAPG Bulletin, v. 89, no. 10 (October 2005), pp. 1347–1371.
3. Hosford, Allegra and Magoon, Les, 2007 Age, U.S. Geological Survey Professional Paper 1713, California Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, Chapter 5.
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5. Castilla, Davis and Younker, Leland, 1997, David A. Castillo Leland W. Younker A High Shear Stress Segment along the San Andreas Fault: Inferences Based on Near-Field Stress Direction and Stress Magnitude Observations in the Carrizo Plain Area, Lawrence Livermore National Laboratory.
6. Ingram G. M., Urai J. L., Naylor M. A. (1997) in Hydrocarbon Seals: Importance for Exploration and Production, Sealing processes and top seal assessment, Norwegian Petroleum Society (NPF) Special Publication, eds Moller-Pedersen P., Koestler A. G. **7**, pp 165–175.
7. Lacy, L., 1997, Dynamic Rock Mechanics Testing for Optimized Fracture Designs, SPE 38716, 1997 SPE Annual Technical Conference and Exhibition.
8. Yale, D.P. and Swami, V., 2017, Conversion of dynamic mechanical property calculations to static values for geomechanical modeling , presented at 51st US Rock Mechanics/ Geomechanics Symposium, San Francisco, June 2017. ARMA17-0644.
9. Lacy, L., "Dynamic Rock Mechanics Testing for Optimized Fracture Designs," SPE 38716, 1997 SPE Annual Technical Conference and Exhibition.

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage Project
357-7R & 355-7R

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Table 1. Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE	
	355-7R	357-7R
Maximum Injection Pressure - Surface	2990 psi	2993 psi
Maximum Injection Pressure - Bottomhole	6260 psi	6281 psi
Annulus Pressure	3820 psi	3834 psi
Annulus Pressure/Tubing Differential	1397 psi	1531 psi
Maximum CO_2 Injection Rate	15 mmscfpd	15 mmscfpd

The maximum injection pressure was determined using the 0.82 psi/ft fracture gradient obtained from well 327-7R-RD1 multiplied by 0.9, per 40 CFR 146.88(a).

Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), the permittee will reduce CO_2 injection at a rate of 130 tons per day over a 6-day period to ensure protection of health, safety, and the environment. Procedures that address immediately shutting in the well are in the Emergency and Remedial Response Plan of this permit.

Reporting requirements

Below tables summarize the reporting requirements for 355-7R, 357-7R and the A1-A2 storage project.

Table 2. Class VI Injection Well Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
CO_2 stream characterization	Semi-annually
Injection pressure, injection rate, injection volume, pressure on the annulus, and annulus fluid level	Semi-annually
Corrosion monitoring	Semi-annually
External MITs	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Table 3. Class VI Project Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills A1-A2 Storage Project
357-7R & 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 763-6101/ Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data
- Well completion, production, and injection data from the reservoir's entire depletion history

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the CalCapture A1-A2 project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery

pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.

2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al

2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al

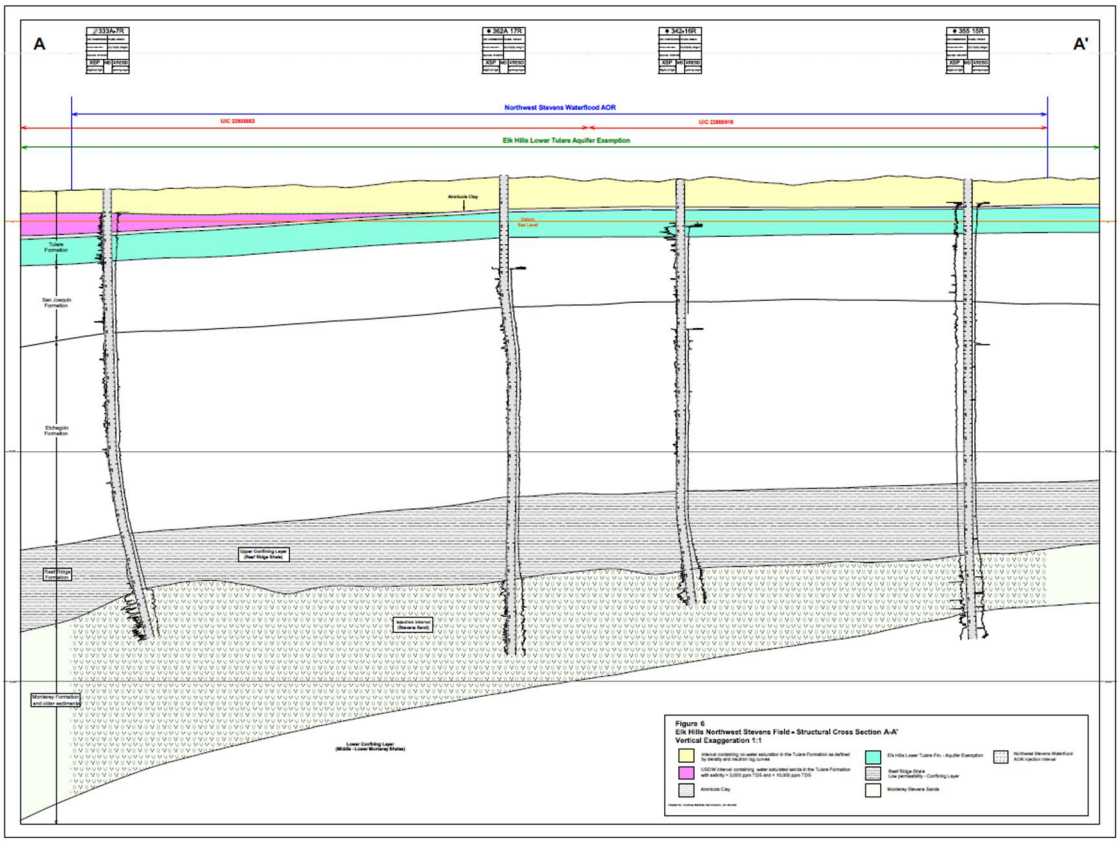
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A'), while the lowermost sands, are present across the entire structure.

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing the Monterey Formation A1-A2 sands pinching-out on the NWS anticline.



The CalCapture Class VI injection wells will target injection in the Monterey Formation A1-A2 sands. The Monterey Formation A1-A2 oil and gas reservoir was discovered in the 1970's and has

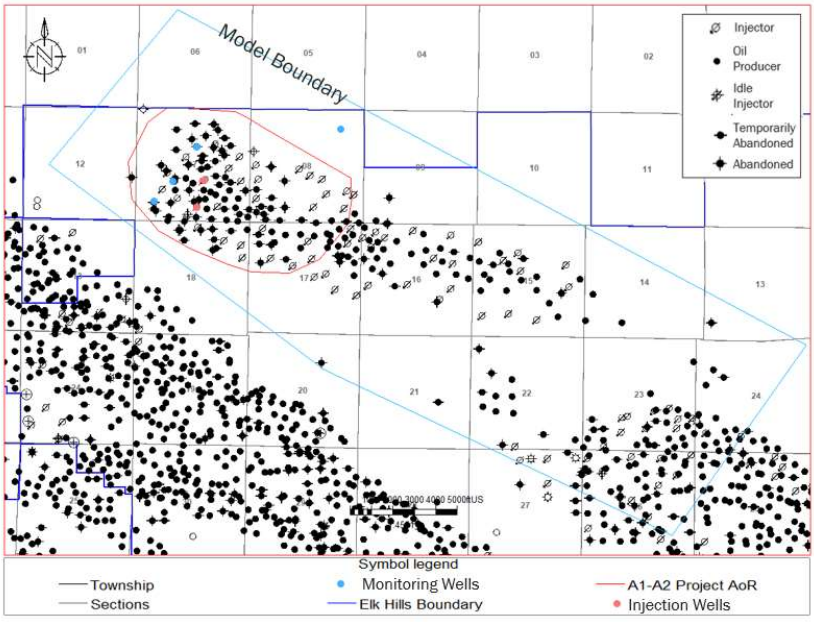
been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Gas and water injection initiated in 1982 supported reservoir pressures and helped maintain oil production. Starting in the year 2000, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation A1-A2 reservoir.

Process	Phase	Volume
Production	Oil	28 million barrels
	Gas	193 billion cubic feet
	Water	9 million barrels
Injection	Water	6 million barrels
	Gas	175 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model used in computational modeling.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2.

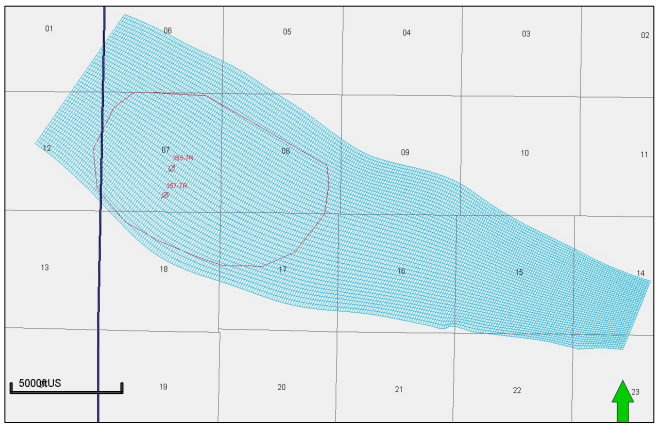
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6,095,241.81	**Coordinate of X max**	6,122,433.26
Coordinate of Y min	2,302,015.15	**Coordinate of Y max**	2,316,903.12
Elevation of bottom of domain	-10,426.35	**Elevation of bottom of domain**	-6,670.36

The geo-cellular grid is uniformly spaced throughout the 6.4 square mile model area (Figure 3) at 150 feet x 150 feet. These grid dimensions allow for adequate resolution of plume development. Finer resolution for the grid will prevent the simulation from running efficiently and a coarser grid will not adequately simulate plume movement.

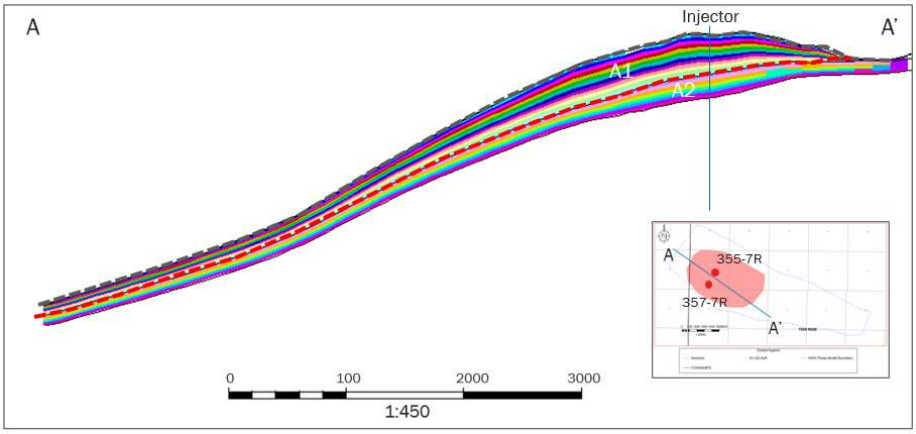
The model is oriented at 55 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were defined to include the entire Northwest Stevens anticline, the plume extent and all Monterey Formation sands.

Figure 3: Plan view of the model boundary and project AoR.



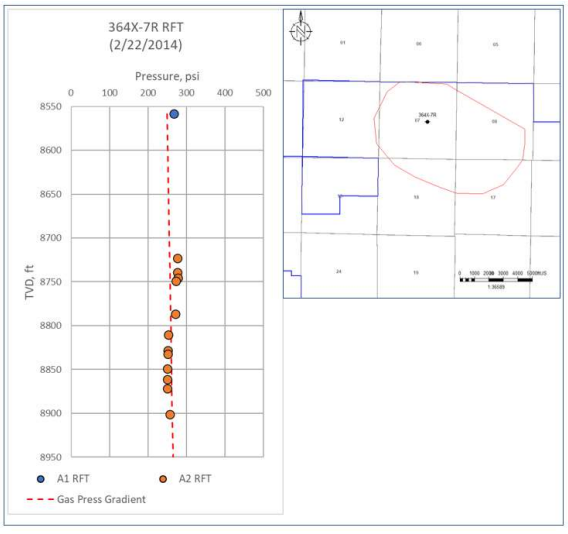
The reservoir has been separated into two zones, A1 and A2 sands, with 8 and 13 proportional layers (Figure 4) respectively, resulting in an average grid cell height of 11.5 feet. The model grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the A1-A2 storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 4: Static model layering of the Monterey Formation A1-A2 reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale.



The A1-A2 sands were modeled separately to ensure stationarity for the property distribution. The reservoirs are in communication as demonstrated by the pressures shown in Figure 5.

Figure 5: A1 and A2 reservoir pressure from well 364X-7R.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 6) that is dependent on porosity and clay volume.

Figure 6: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

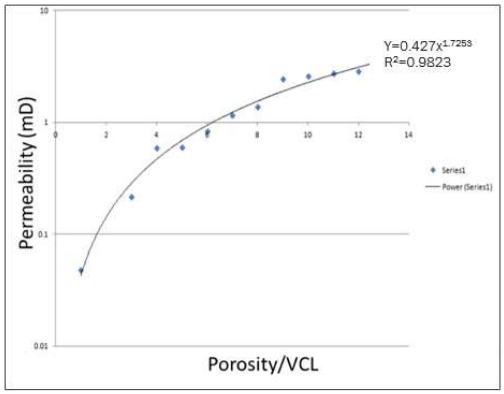


Figure 7: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.

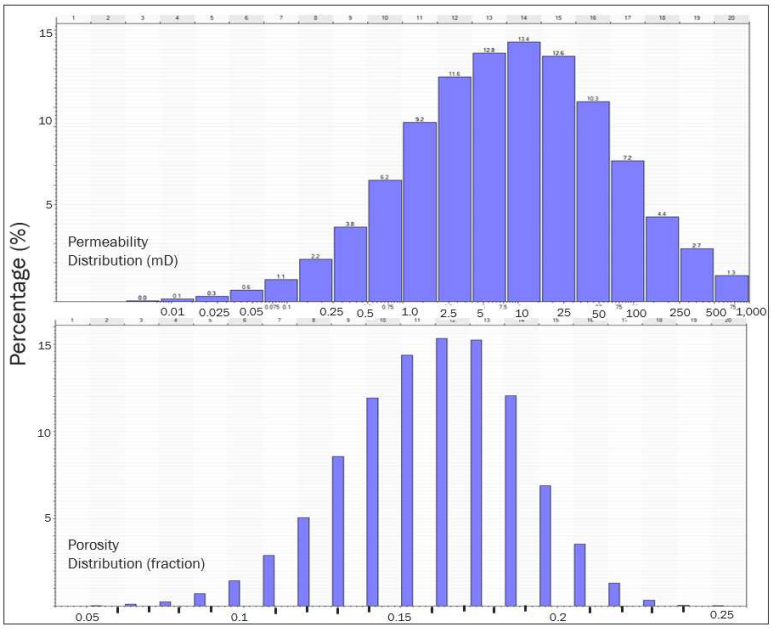
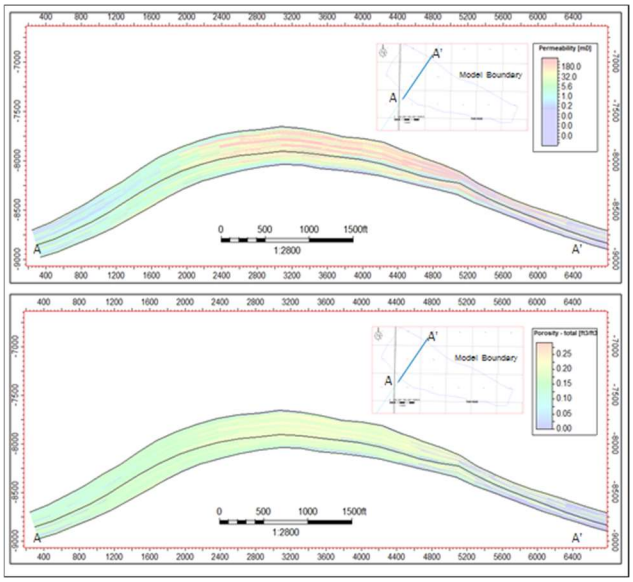


Figure 7 shows porosity and permeability histograms for the Monterey Formation A1-A2 sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 8 shows the permeability and porosity distribution in cross-section A-A'. Reservoir quality is the highest at the top of the anticline, porosity and permeability are lower on the edges.

Figure 8: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



Constitutive Relationships and Other Rock Properties

The Monterey Formation A1-A2 reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

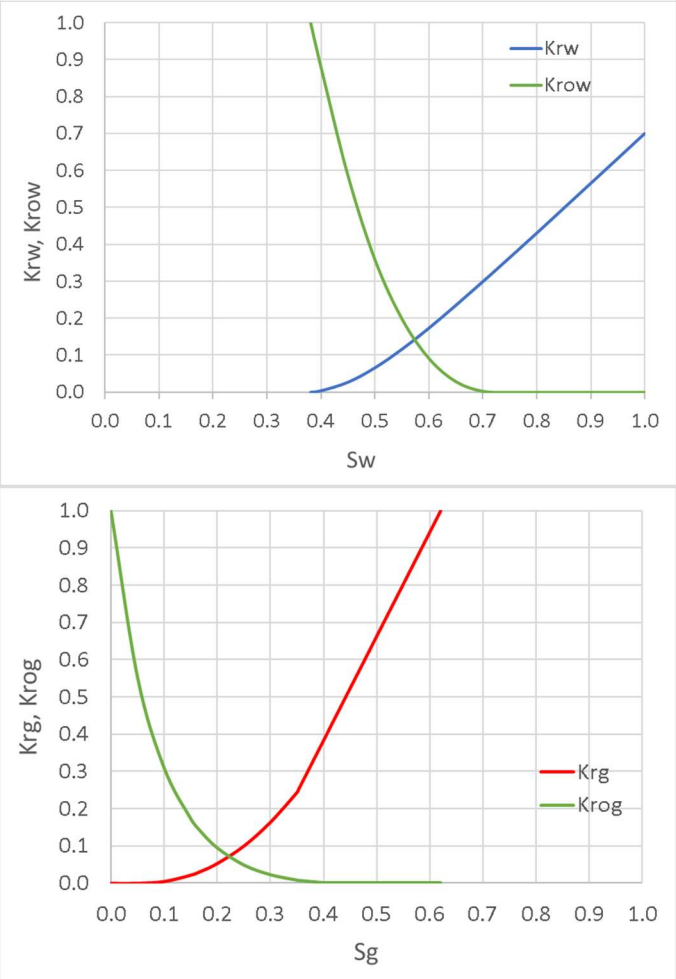
Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil 8,400	Oil - Water 8,550	
Saturation (fraction)	Water: 0.18 Gas: 0.82	Oil: 0.15 Water: 0.85	Water: 1.0

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two

sets of two-phase relative permeability data are needed to determine three-phase relative permeability for the sand facies: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 9 shows the relative permeability curves used in the computational modeling. The saturations at start of CO_2 injection were based on Material Balance calculations that were done for the A1-A2 reservoir. Material Balance is a well accepted method to determine the average saturations and fluid contacts in an oil and gas reservoir over time.

Figure 9: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study (krow = relative permeability oil in an oil-water system, krg = relative permeability to gas in a gas-oil system, krw = relative permeability to water in an oil-water system, and krog = relative permeability to oil in a gas-oil system).



Mineralization

Previous studies into reactive transport modeling and geochemical reaction in CCS have shown that the amount of CO2 trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage, prepared by Working Group III of the Intergovernmental Panel on Climate Change) for

sandstone reservoirs. For the sake of computational efficiency and the minor expected effect on the AoR, reactive transport was not included as a part of the compositional simulation modeling.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation A1-A2 reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

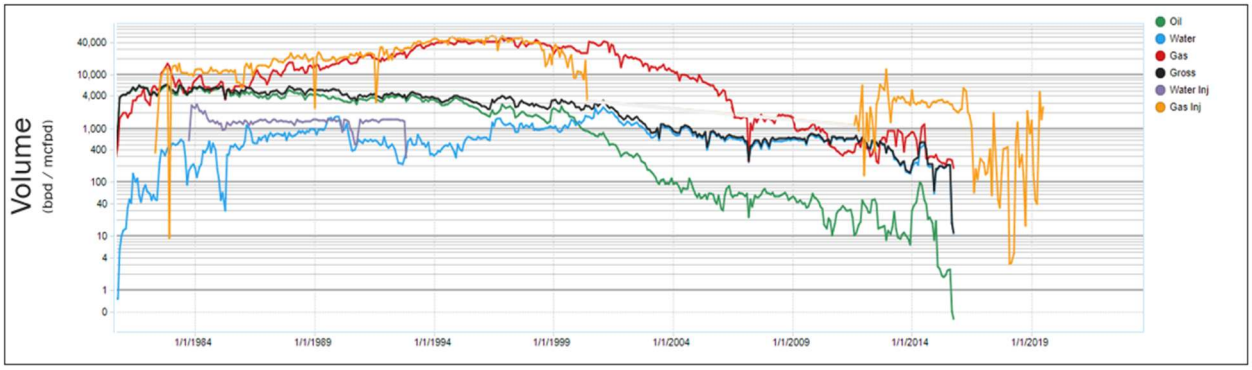
2. Performance data from operating the Monterey Formation A1-A2 oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 10) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 10) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 230 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

Figure 10: Monterey Formation A1-A2 production and injection data.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation A1-A2 reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	240	Fahrenheit	8,300	Fluid Analysis
Formation pressure	200-300	Pounds per square inch	8,300	Pressure Test
Fluid density	61	Pounds per cubic foot	8,300	Water analysis
Salinity	25,000	Parts per million	8,300	Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	Injection Well 1 357-7R	Injection Well 2 355-7R
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft TVD) Z top Z bottom	 8,511 8,793	 8,483 8,608
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15
Injection rate (t/day)*	530-794	530-794

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

The Monterey Formation A1-A2 reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process, California Resources Corporation (CRC) obtained Class II UIC approval from CalGEM.

The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate.

CRC has also conducted tests to determine the fracture gradient for the injection zone. These results are consistent with data collected outside the field. The 0.82 PSI/foot fracture gradient for the Monterey Formation A1-A2 reservoir was obtained from well 327-7R-RD1. CTV will conduct a step rate test for the Reef Ridge Shale as per the pre-operational testing plan.

CTV will ensure that the injection pressure is beneath 90% of the fracture gradient at the top of perforations in the injection wells (Table 6). CTV expects to operate the wells with a planned subsurface wellbore injection pressure of 4,500 PSI.

Table 6. Injection pressure details.

Injection Pressure Details	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Fracture gradient (psi/ft)	0.82	0.82
Maximum allowable bottomhole injection pressure (90% of fracture pressure) (psi)	6,281	6,260
Elevation corresponding to maximum injection pressure (ft TVD)	8,511	8,483
Elevation at the top of the perforated interval (ft TVD)	8,511	8,483
Planned bottom hole injection pressure at top of perforations (psi)	1,140 - 3,909	1,175 - 3,923
Planned bottom hole injection gradient at top of perforations (psi/foot)	0.13 – 0.46	0.14 - 0.46

Computational Modeling Results

Predictions of System Behavior

The following maps (Figure 11) and cross-sections (Figure 12) show the computational modeling results and development of the CO_2 plume at seven time-steps. The boundaries of the AoR have been defined with a 3% CO_2 global mole fraction cutoff. The maximum vertical and lateral extent of the CO_2 plume is within the first year of post-injection, at which time the plume largely stabilized. The reservoir quickly becomes stable because the most significant trapping mechanism is structure.

For all layers in the model and at all time-steps, the plume stays within the 2.1 square mile AoR. Within the first two years of injection, the AoR extent is largely defined. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

Figure 11: Plan view showing the plume development through time for layer 15. Sections 8 and 17 have CO_2 in small quantities due to minor potential connected sand lenses, as the reservoir becomes shale dominated up-dip. It is highly unlikely that CO_2 will migrate to these areas.

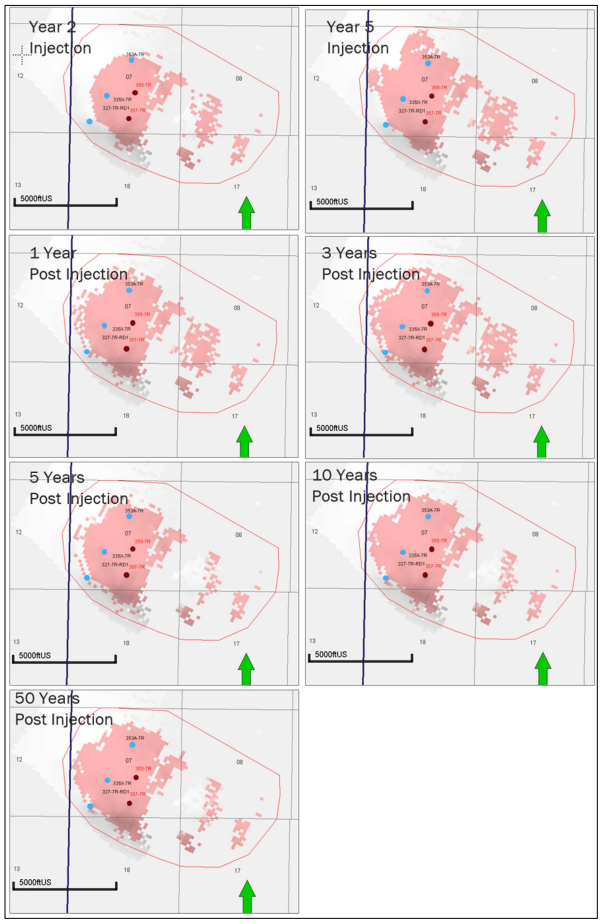
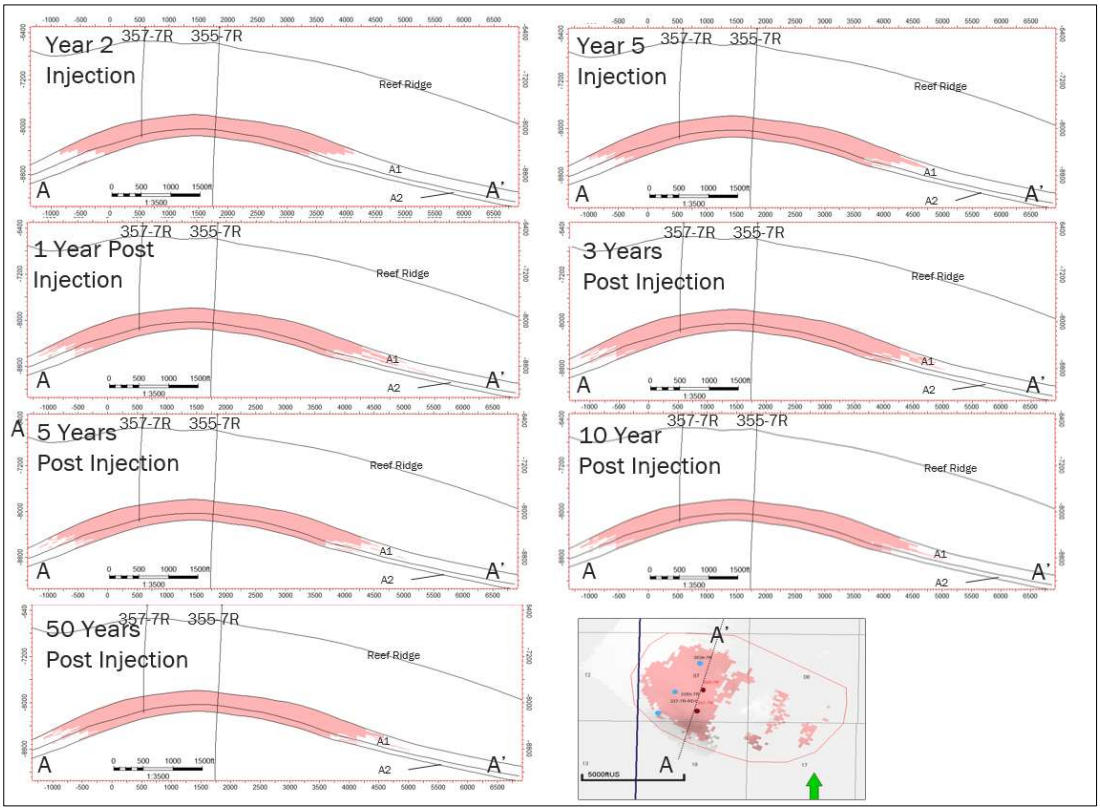


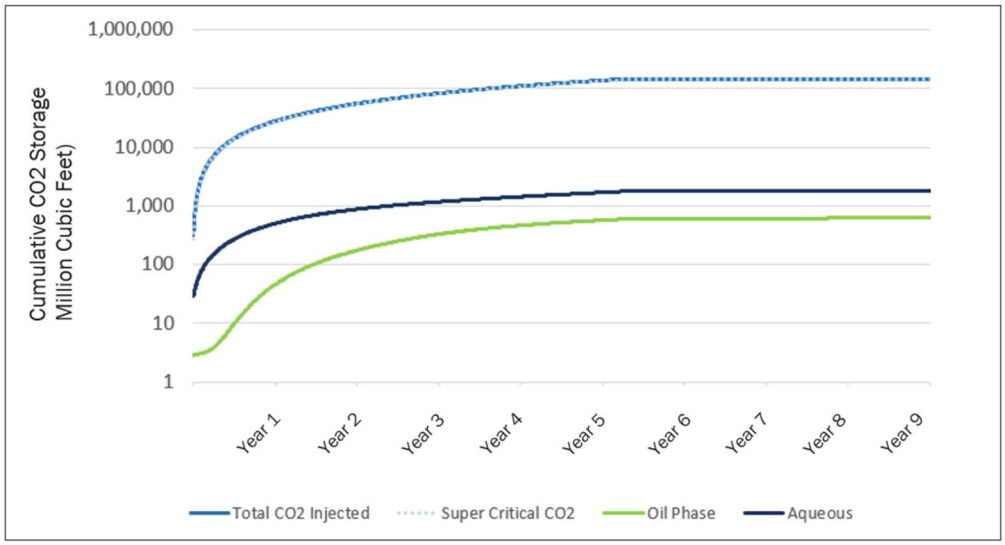
Figure 12: Cross-sections showing the plume development through varying times through the project.



CO_2 injected into the Monterey Formation A1-A2 reservoir will be soluble in both water and oil. Due to the low remaining saturation for oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is only 0.5% and 1.3% of the CO_2 injected respectively. 98% of CO_2 injected is stored as super-critical CO_2. Figure 13 shows the cumulative storage for each of the mechanisms.

After 5 years of injection, there is no additional change in the quantity of CO_2 dissolving in the oil and water.

Figure 13: CO2 storage mechanisms in the reservoir.



Model Calibration and Validation

CRC has injected 175 BCF of gas into the Monterey Formation A1-A2 reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The Base case simulation was run for five years of injection. This base case represents the highest injection rate for the project. In addition, a scenario was also run with 15 years of injection at lower rate. Both scenarios were run for 100 years post injection to verify plume stabilization. There was no difference in AoR extent or storage volume between the scenarios.

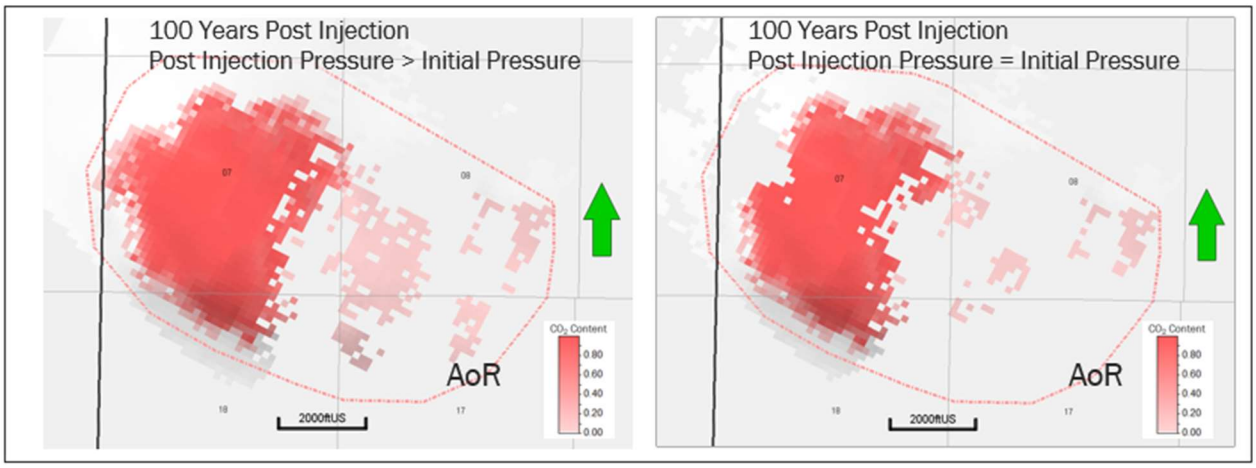
As a computational model sensitivity, CTV also ran a scenario where high injection rate was maintained for nine years, with an increase of the post-injection pressure and total CO_2 injected. At a final reservoir pressure of 5,750 psi, versus base case of 4,000 psi, the reservoir can store 193 BCF of CO_2, an addition of 61 BCF CO_2. Figure 14 shows the difference in plume development at 100 years post injection. Note that the plume stays within the AoR, with increased CO_2 concentrations in cells in northwestern portion of the AoR.

Additionally, the scenarios listed in the Table 7 were run varying major inputs to the simulation to see whether it had any significant impact on the AoR boundary. The results from the different scenarios were reviewed and showed varying final CO2 storage amount but no impact to the AoR boundary.

Table 7: Simulation sensitivity scenarios

Scenario	AoR impact
Base Case: High Injection rate (5yrs of injection)	Base AoR
Low Injection rate scenario (15yrs of injection)	No impact to AoR
Higher final reservoir pressure scenario	No impact to AoR
NTG : 10% reduction from base case	No impact to AoR
Porosity: 10% reduction from base case	No impact to AoR
Porosity: 10% increase from base case	No impact to AoR
Permeability: 10% reduction from base case	No impact to AoR
Permeability: 10% increase from base case	No impact to AoR
Grid XY dimensions: reduced to 75'x75'	No impact to AoR

Figure 14: Plan view of plume development at layer 15 in the computational model.



These scenarios demonstrate that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent for a range of scenarios. This provides confidence that the corrective action well review and potential impact to the Upper Tulare USDW is conservative and has been appropriately evaluated.

AoR Delineation

The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation A1-A2 reservoir until the reservoir pressure reached the discovery pressure of 4,000 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.

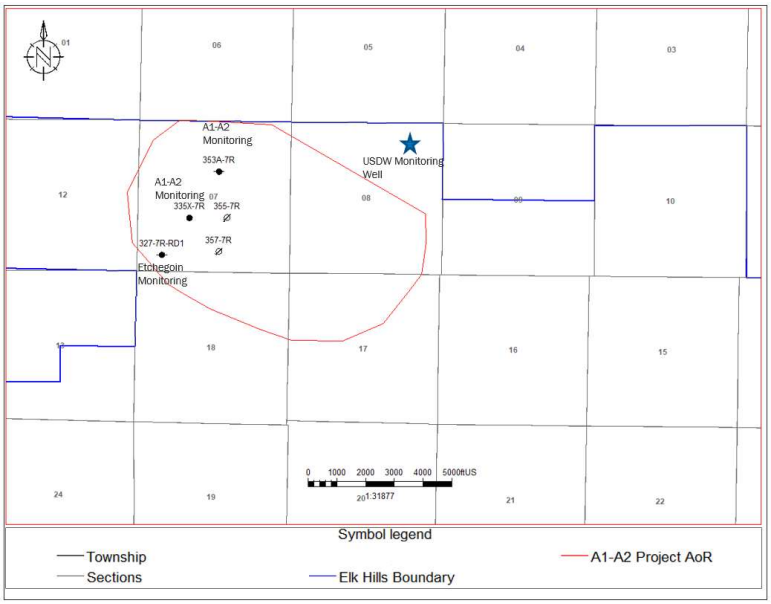
Figure 15 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 15: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

Tabulation of Wells within the AoR

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation A1-A2 reservoir was discovered in 1973 and developed subsequently.

As such, there are excellent records for wells drilled in the field. There have been no "un-documented" historical wells found during the over 40-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications.

Tables 8 and 9 provide counts of the AoR wellbores by status and type, for each wellbore with a unique API-12 identifier. Appendix 1 provides a complete list of all API-12 wellbores within the AoR. As required by 40 CFR 146.84(c)(2), the well table in Appendix 1 describes each well's type, construction, date drilled, location, measured depth, true vertical depth, completion record relative to the A1-A2 injection zone, record of plugging, requirement for corrective action, if necessary. CTV also identifies well work to be completed during the pre-operational testing phase.

Table 8: Wellbores in the AoR by Status

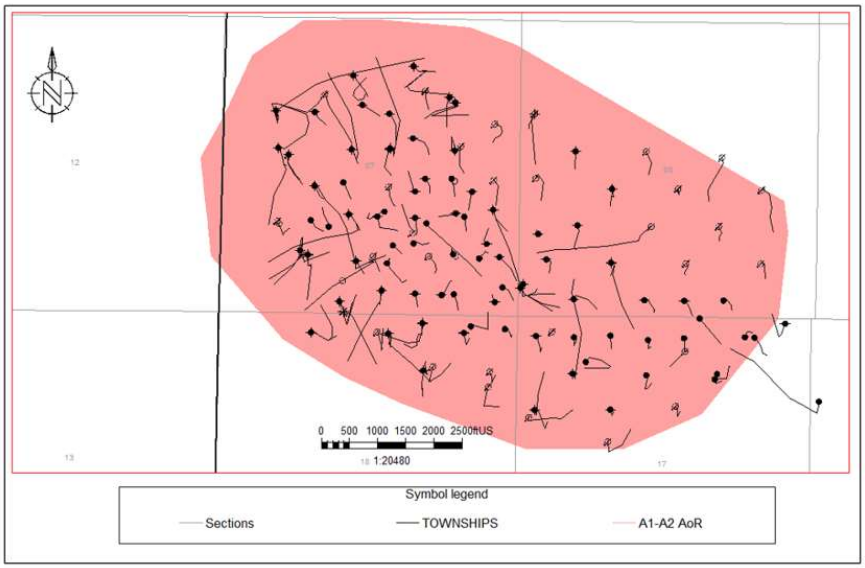
Status	Count
Active	41
Idle	70
Plugged and Abandoned	39
Total	**150**

Table 9: Wellbores in the AoR by Type

Type	Count
Oil & Gas Producing Wells	79
Class II Injection/Disposal Wells	32
Observation Wells	0
Plugged and Abandoned	39
Total	**150**

Wells in the AoR with an active status are development wells completed below the Monterey Formation A1-A2 reservoir and associated with a CalGEM Class II approval within the A3-A11 sand intervals.

Figure 16: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation A1-A2 sequestration reservoir reviewed for corrective action.



Protection of USDW

For the Elk Hills A1-A2 Storage Project, CTV assessed USDW protection by evaluating all wellbores that penetrate the confining Reef Ridge Shale. All wells within the AoR meet the criteria below, ensuring protection of the USDW:

1. Surface or intermediate casing over the USDW
2. If well is abandoned, cement plug across base of USDW
3. Cement in the annulus:
    a. Intermediate casing – cement above the above the surface casing shoe.
    b. Sufficient annular cement within the confining Reef Ridge Shale.

Wells Penetrating the Confining Zone

The depth of the confining zone in each of the wells penetrating the Reef Ridge shale was determined through open-hole well logs utilizing the deviation survey. All wells in the AoR penetrate the Reef Ridge Shale confining zone.

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q1 2021.

Monterey Formation A1-A2 Isolation

Wells that will not be used for the Elk Hills A1-A2 Storage Project that penetrate and are currently perforated in the Monterey Formation A1-A2 will be abandoned prior to injecting CO_2. These wells have not been deemed deficient, and they will not be used for hydrocarbon production from the A3-A11 underlying sands. The abandonment of these wells is considered to be normal operating procedures to manage and minimize liabilities. Wellbores that meet this criteria are included in the 33 wells identified for abandonment in Appendix 1.

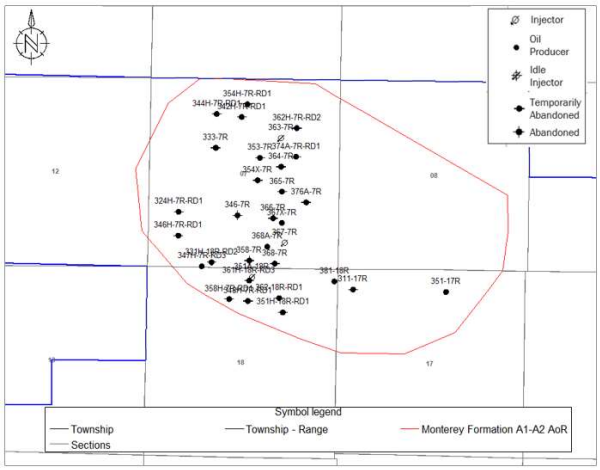
Wells that pass through and are not completed in the A1-A2 sand serve to either inject into or produce from some combination of the A3-A11 sands. All pass through wells not planned for abandonment during pre-operational testing have been determined to be adequately isolated from A1-A2 sands.

Corrective Action Assessment of Wells in AoR

The corrective action assessment included the generation of detailed casing diagrams for each wellbore, review of all perforations, assessment of cement tops for each casing string, and determination of cement plug depths. CTV can demonstrate that the USDW is protected and that with the abandonment of 33 wells (Figure 17), the Monterey Formation A1-A2 reservoir will be isolated. Annular cement and cement plugs within the casing will be placed within the Reef Ridge confining layer so as to re-establish caprock integrity.

Appendix 2 provides the plugging procedure that will be used to abandon these wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. Additionally, the procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Figure 17: Wells to be abandoned prioir to injection.



Plan for Site Access

CTV operates and owns 100% of the surface, mineral and pore space rights for the project where all activities will take place. As such, site access has been guaranteed for the duration of the project and for post-injection monitoring.

Corrective Action Schedule

Corrective action for all wells withing the AoR will be completed before CO_2 is injected in the reservoir. This will ensure that CO_2 is confined to the injection zone for the entire AoR, protecting the overlying USDW and ensuring confinement.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation A1-A2 reservoir that are not related to well integrity.

    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.

    c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

a. The presence of faults near the confining zone that indicates propagation into the confining zone.

b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director within six months of an event to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.

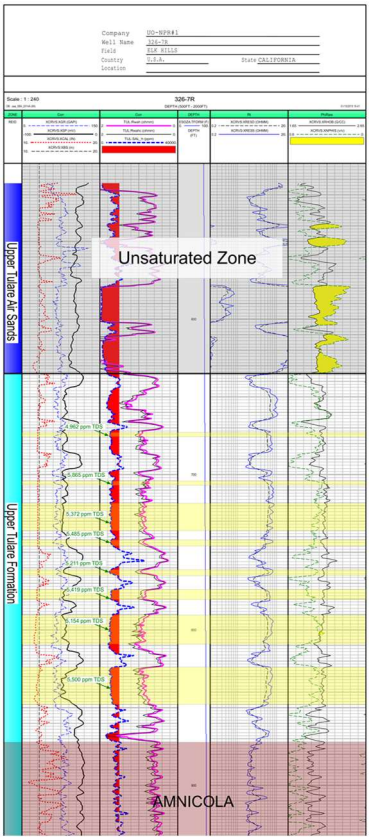
CLASS VI CRITICAL PRESSURE CALCULATION
ELK HILLS A1-A2 PROJECT

Critical Pressure Calculation

Upper Tulare USDW Inputs

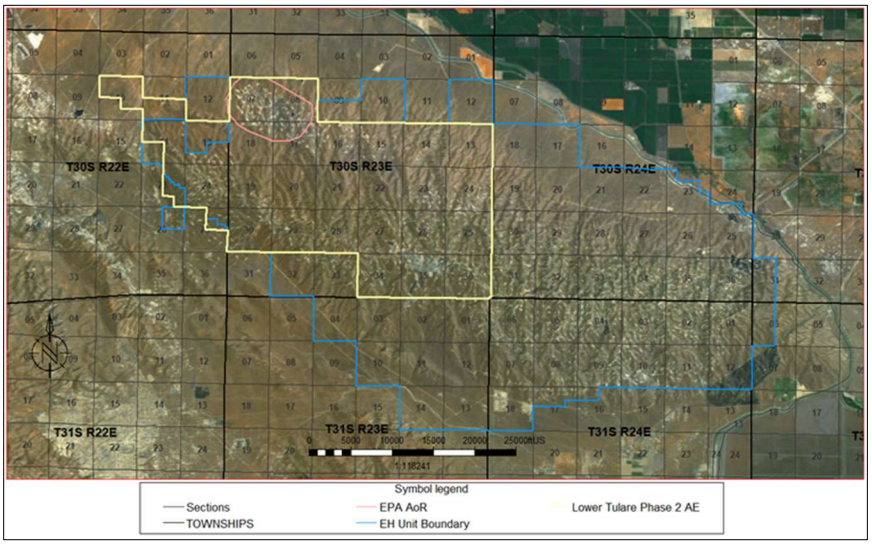
The unconfined Upper Tulare Formation USDW within the area of review (AoR) onlaps onto the anticline structure. As such, there are areas within the project with no USDW. The hydraulic head and depth is based on the 326-7R type well (Figure 1). Water levels with the Upper Tulare USDW are variable and have historically been falling. As such, water presence, depths and thickness for the Upper Tulare USDW are conservative. Calculated salinities are annotated for each sand in the Upper Tulare.

Figure 1: Well 326-7R type well of the Upper Tulare Formation USDW.



The Lower Tulare Formation has been approved as an exempt aquifer, the area approved is shown in Figure 2. North of the AoR the USDW is not defined as the Upper Tulare Formation but the Lower Tulare.

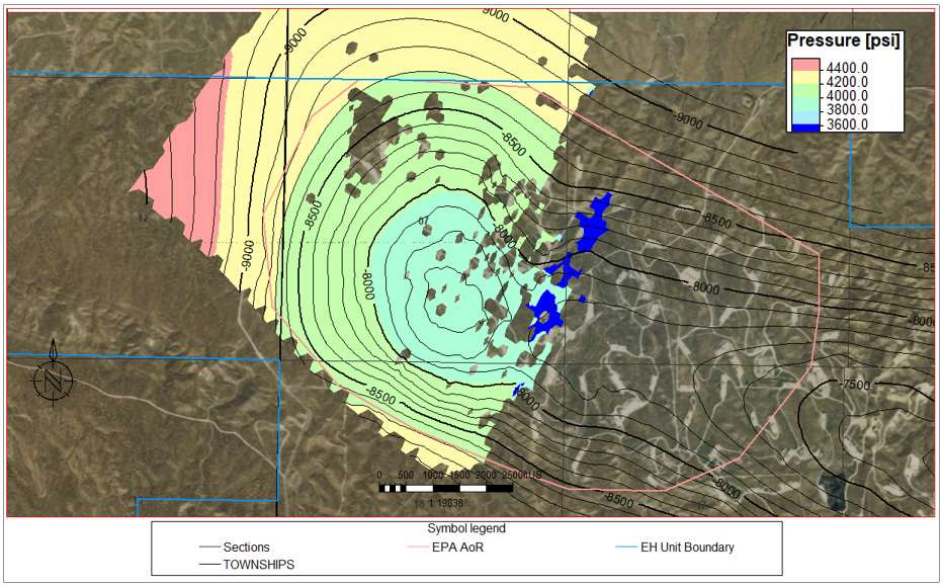
Figure 2: Lower Tulare aquifer exemption area.



Computational Modeling Monterey Formation A1-A2 Pressure

The Monterey Formation A1-A2 reservoir has been depleted by oil and gas production. Currently the pressure of the reservoir is 200-300 PSI. The final CO_2 reservoir pressure will be at or below the initial reservoir conditions (4,000 PSI). The pressure for the reservoir post injection based on computational modeling results is shown in Figure 3.

Figure 3: Monterey Formation A1-A2 structure map showing computational modeling reservoir pressure post-injection (top layer of the model). In the eastern portion of the AoR the reservoir sands grade to shale for the top layer of the model so the reservoir pressure is not determined.



Critical Pressure Calculation

Using the equation below, the critical pressure for the Monterey Formation A1-A2 reservoir is 3,400 PSI (Figure 4).

$$\frac{P_{i,f}}{\rho_i g} + z_i = \frac{P_u}{\rho_u g} + z_u$$

Where,

$P_{i,f}$ – Injection zone Pressure

P_u – Base of USDW zone pressure, 227' hydraulic head (equivalent to 677,692Pa or 98psi)

ρi – injection zone brine density, 1014 kg/m3

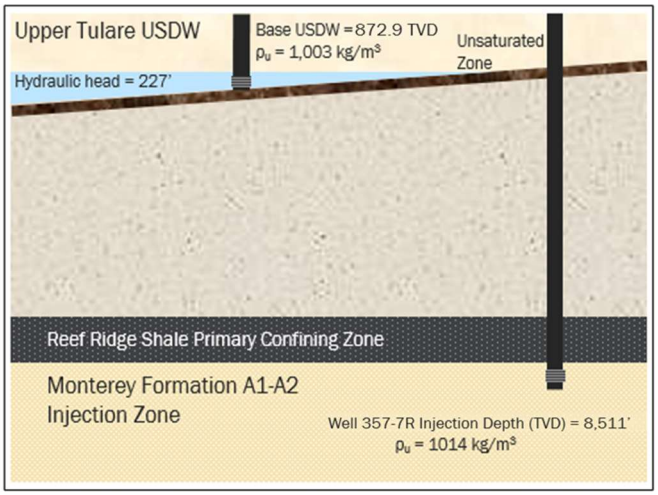
ρ_u – USDW zone water density, 1003 kg/m3

Zi – Injection zone depth 8,511 ft TVD or 2,594m TVD

Zu – Base of USDW zone depth, 872.9 ft TVD or 266m TVD

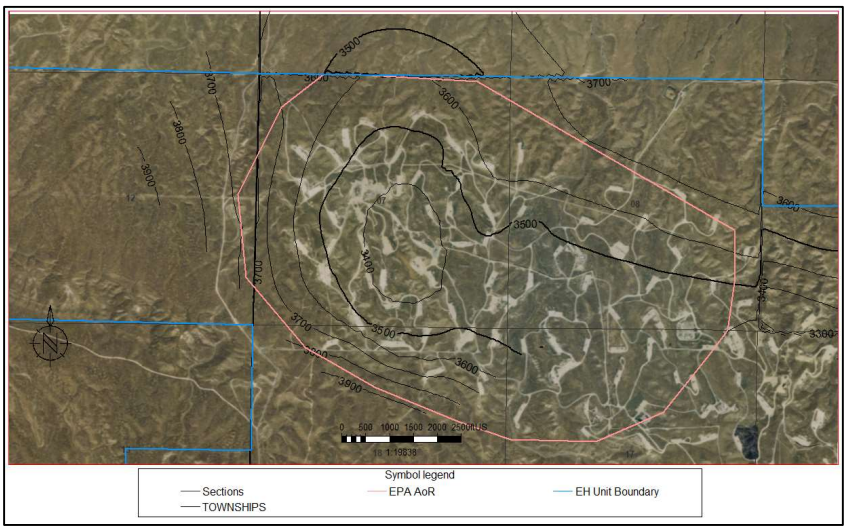
g – acceleration due to gravity, 9.81m/s2

Figure 4: Schematic section of the storage site with inputs to critical pressure calculation. Values for the USDW are based on the 326-7R well. The injection depth is based on the 357-7R injector. Using data from wells 357-7R injector and 326-7R the critical pressure is 3,458 PSI.



Critical pressure calculated for the reservoir is shown in Figure 5 using the Monterey Formation A1-A2 reservoir top and Base USDW and comes out to 3,458psi.

Figure 5: Critical pressure map in PSI using the Base USDW and Monterey Formation A1-A2 surfaces. Note that across the Elk Hills boundary the base of USDW is defined by the Lower Tulare instead of the Upper Tulare, resulting in a change in the contours.



Summary of AoR

The final pressure of the Monterey Formation A1-A2 reservoir will be at or below the initial reservoir pressure to ensure that CO_2 occupies the same pore space that was initially saturated with hydrocarbons and the pressure front is at equilibrium with initial conditions. As such, CTV defines the AoR as the aerial extent of the CO_2 plume.

Elk Hills A1-A2 Project Confidentiality

The following are proprietary to CTV and considered confidential:

1. **AoR and Corrective Action Plan:** Appendix 1_AoR Well Table
2. **AoR and Corrective Action Plan:** Appendix 2_ AoR CA_Abandonment Well Plugging Plans
3. **Testing and Monitoring Plan**: Appendix 1_Monitoring Well Schematics

Requests for these files can be made to Travis Hurst.

Phone: 661-342-2409

Email: Travis.Hurst@crc.com

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Document Version History

Version	Submission Date	File Name	Description of Change
1	8/2/2021	Att B – AoR_CA Final	Original submission as part of Elk Hills A1-A2 Storage project
2	3/31/2022	Att B – AoR_CA Final V2	Updated submission to address EPA evaluation from 1/11/2022. Updated images and the following sections – Model domain, Fracture pressure and fracture gradient, Computational modeling results, Triggers for re-evaluation of AoR
3	11/4/2022	Att B – AoR_CA Final V3	Updated submission to address EPA evaluation from 7/20/2022. Following sections updated – Boundary Conditions, Initial Conditions, Operational Information, Fracture pressure and fracture gradient, Computational modeling results, Triggers for AoR reevaluation

Facility Information

Facility name: Elk Hills A1-A2 Storage Project
357-7R & 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409/ Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data
- Well completion, production, and injection data from the reservoir's entire depletion history

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the CalCapture A1-A2 project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

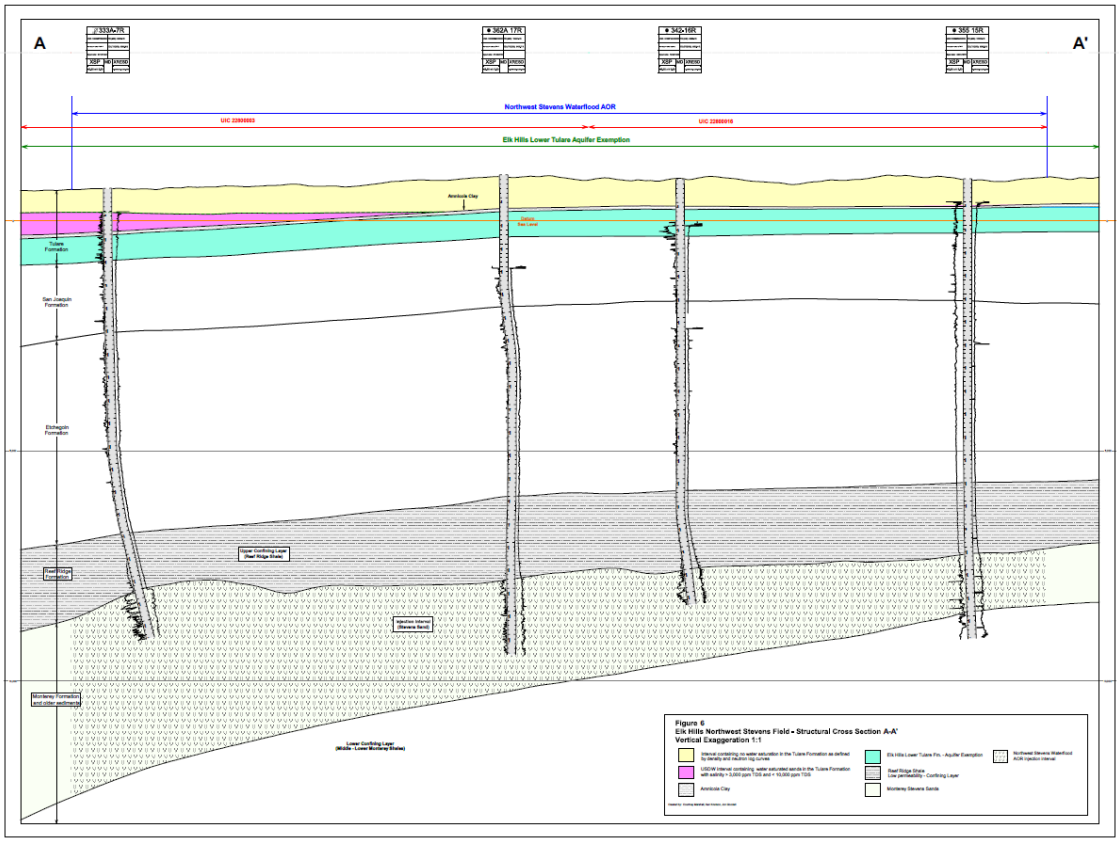
1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A'), while the lowermost sands, are present across the entire structure.

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing the Monterey Formation A1-A2 sands pinching-out on the NWS anticline.



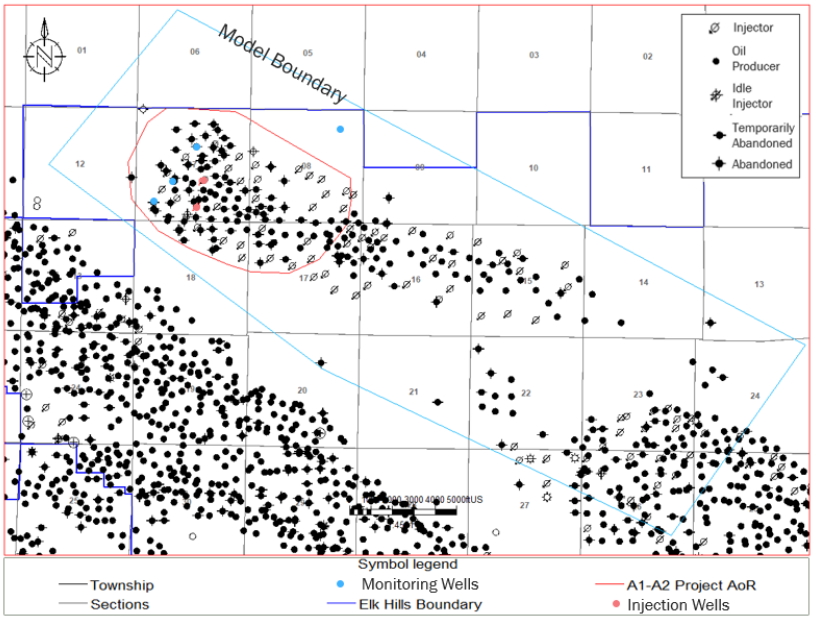
The Class VI injection wells will target injection in the Monterey Formation A1-A2 sands. The Monterey Formation A1-A2 oil and gas reservoir was discovered in the 1970's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Gas and water injection initiated in 1982 supported reservoir pressures and helped maintain oil production. Starting in the year 2000, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation A1-A2 reservoir.

Process	Phase	Volume
Production	Oil	28 million barrels
	Gas	193 billion cubic feet
	Water	9 million barrels
Injection	Water	6 million barrels
	Gas	175 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model used in computational modeling.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2.

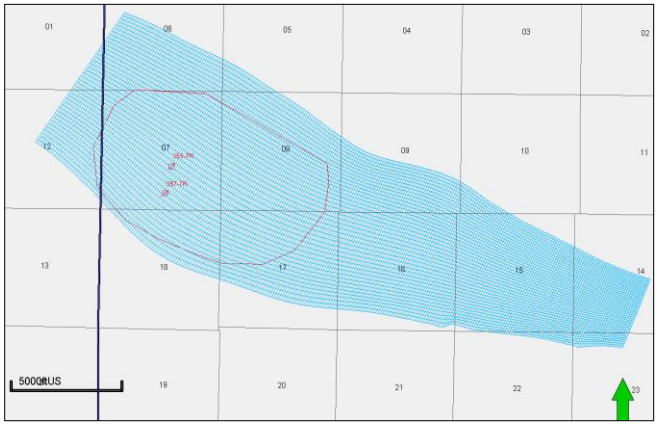
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6,095,241.81	**Coordinate of X max**	6,122,433.26
Coordinate of Y min	2,302,015.15	**Coordinate of Y max**	2,316,903.12
Elevation of bottom of domain	-10,426.35	**Elevation of bottom of domain**	-6,670.36

The geo-cellular grid is uniformly spaced throughout the 6.4 square mile model area (Figure 3) at 150 feet x 150 feet. These grid dimensions allow for adequate resolution of plume development. Finer resolution for the grid will prevent the simulation from running efficiently and a coarser grid will not adequately simulate plume movement.

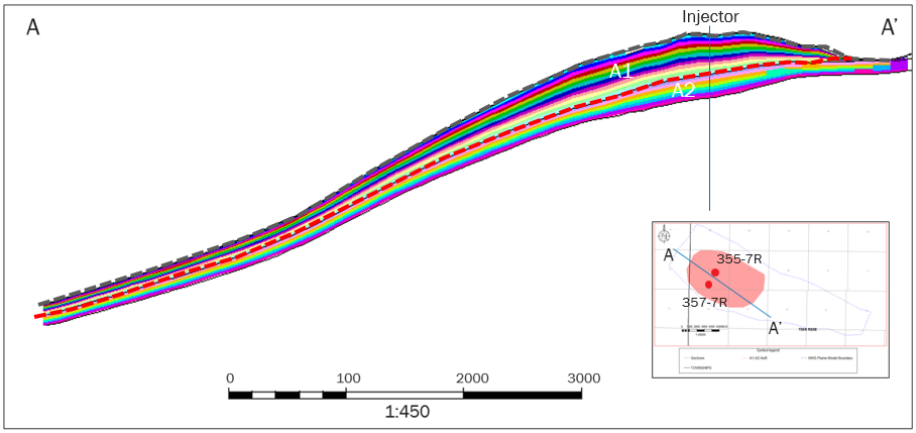
The model is oriented at 55 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were defined to include the entire Northwest Stevens anticline, the plume extent and all Monterey Formation sands.

Figure 3: Plan view of the model boundary and project AoR.



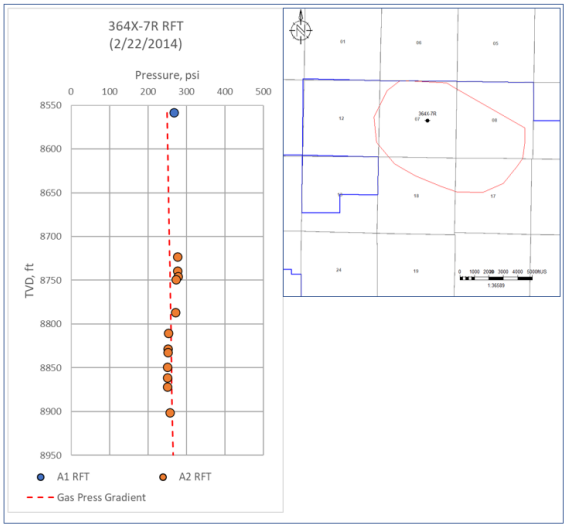
The reservoir has been separated into two zones, A1 and A2 sands, with 8 and 13 proportional layers (Figure 4) respectively, resulting in an average grid cell height of 11.5 feet. The model grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the A1-A2 storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 4: Static model layering of the Monterey Formation A1-A2 reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale.



The A1-A2 sands were modeled separately to ensure stationarity for the property distribution. The reservoirs are in communication as demonstrated by the pressures shown in Figure 5.

Figure 5: A1 and A2 reservoir pressure from well 364X-7R.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 6) that is dependent on porosity and clay volume.

Figure 6: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

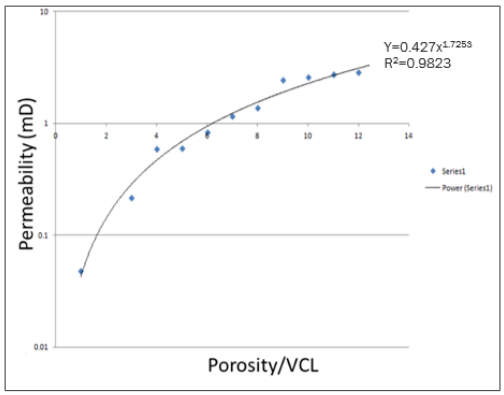


Figure 7: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.

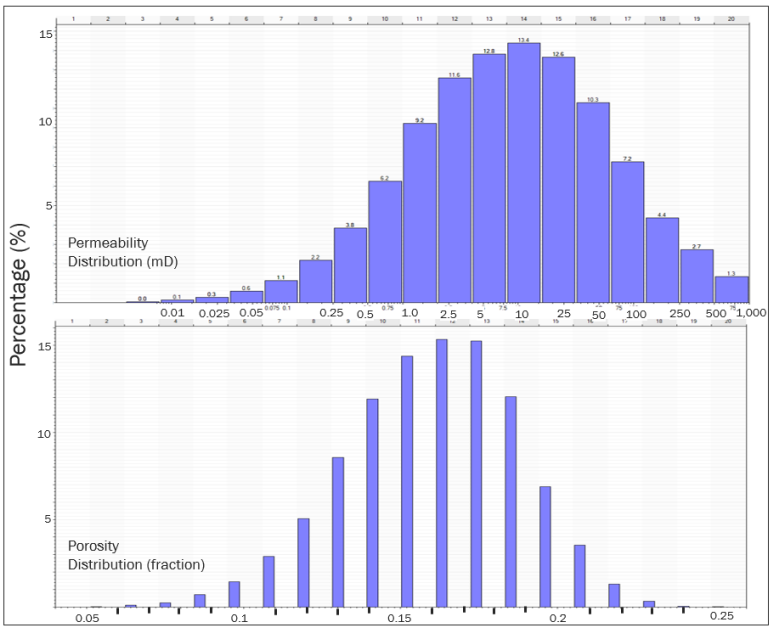
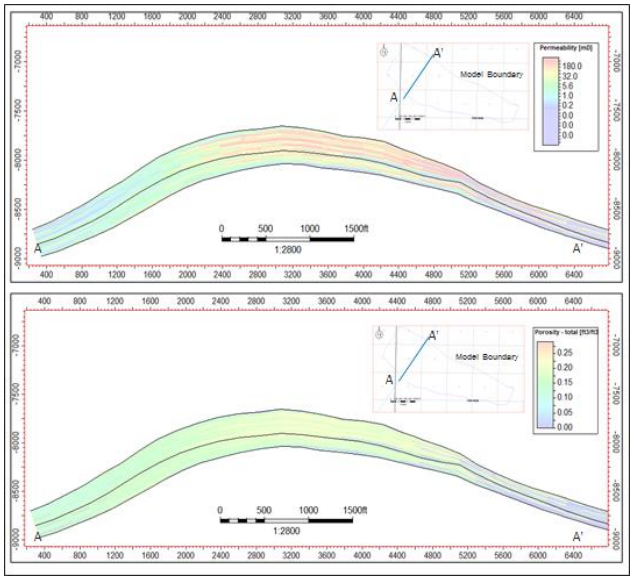


Figure 7 shows porosity and permeability histograms for the Monterey Formation A1-A2 sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 8 shows the permeability and porosity distribution in cross-section A-A'. Reservoir quality is the highest at the top of the anticline, porosity and permeability are lower on the edges.

Figure 8: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



Constitutive Relationships and Other Rock Properties

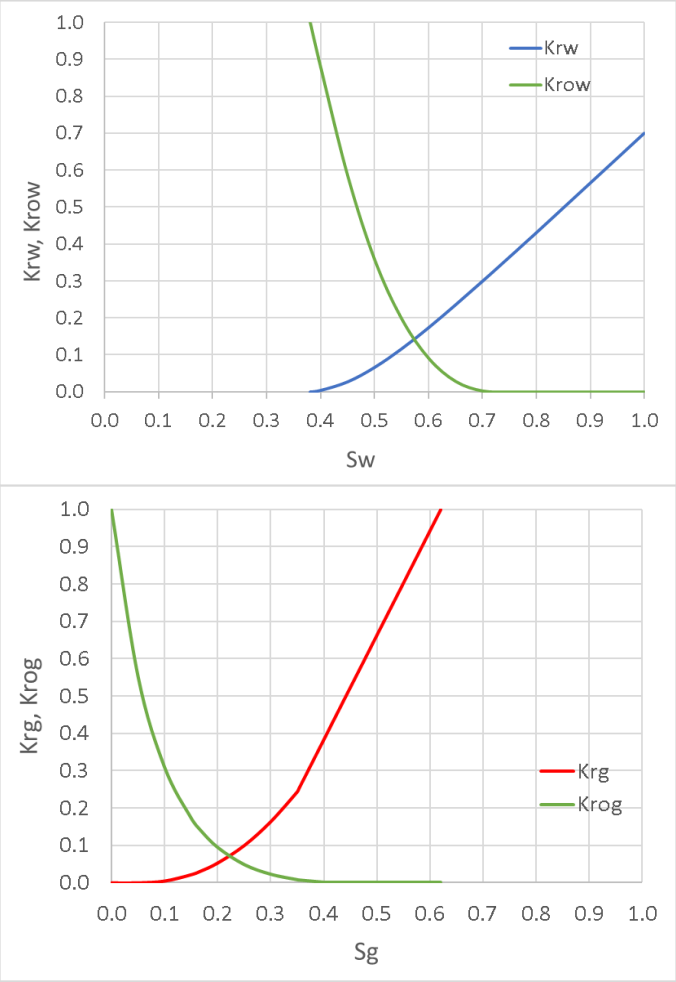
The Monterey Formation A1-A2 reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil 8,400	Oil - Water 8,550	
Saturation (fraction)	Water: 0.18 Gas: 0.82	Oil: 0.15 Water: 0.85	Water: 1.0

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability for the sand facies: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 9 shows the relative permeability curves used in the computational modeling. The saturations at start of CO_2 injection were based on Material Balance calculations that were done for the A1-A2 reservoir. Material Balance is a well accepted method to determine the average saturations and fluid contacts in an oil and gas reservoir over time.

Figure 9: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study (krow = relative permeability oil in an oil-water system, krg = relative permeability to gas in a gas-oil system, krw = relative permeability to water in an oil-water system, and krog = relative permeability to oil in a gas-oil system).



Mineralization

Previous studies into reactive transport modeling and geochemical reaction in CCS have shown that the amount of CO_2 trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage, prepared by Working Group III of the Intergovernmental Panel on Climate Change) for sandstone reservoirs. For the sake of computational efficiency and the minor expected effect on the AoR, reactive transport was not included as a part of the compositional simulation modeling.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation A1-A2 reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

2. Performance data from operating the Monterey Formation A1-A2 oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 10) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 10) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir gas cap is at 230 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

3. Formation pressure measurements taken, after the blow down of the A1-A2 reservoir, during the drilling of wells in the area show large pressure difference between the A1-A2 reservoir and the underlying A3-A11 reservoir, and the overlying Etchegoin formation. This supports the conclusion that the A1-A2 reservoir is hydraulically separate. Figure 11 shows the pressure data from wells in the area and their location with respect to the AoR.

Figure 10: Monterey Formation A1-A2 production and injection data.

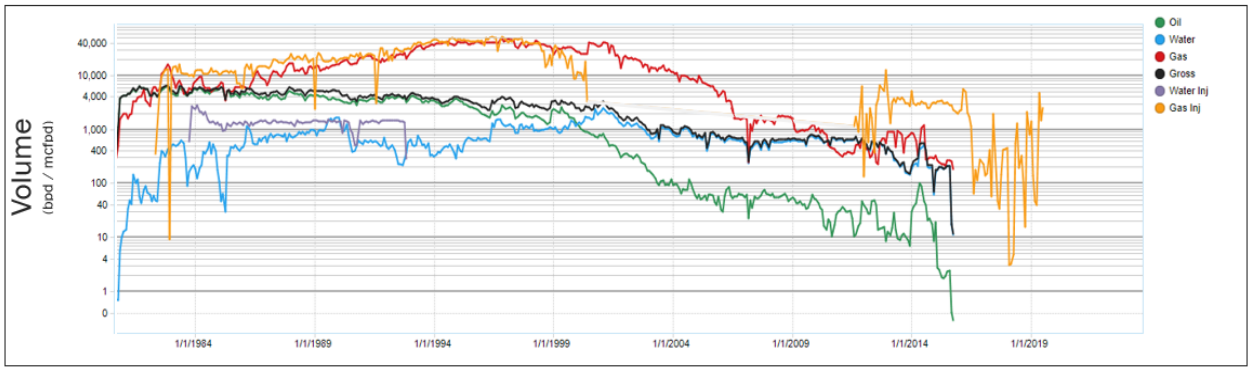
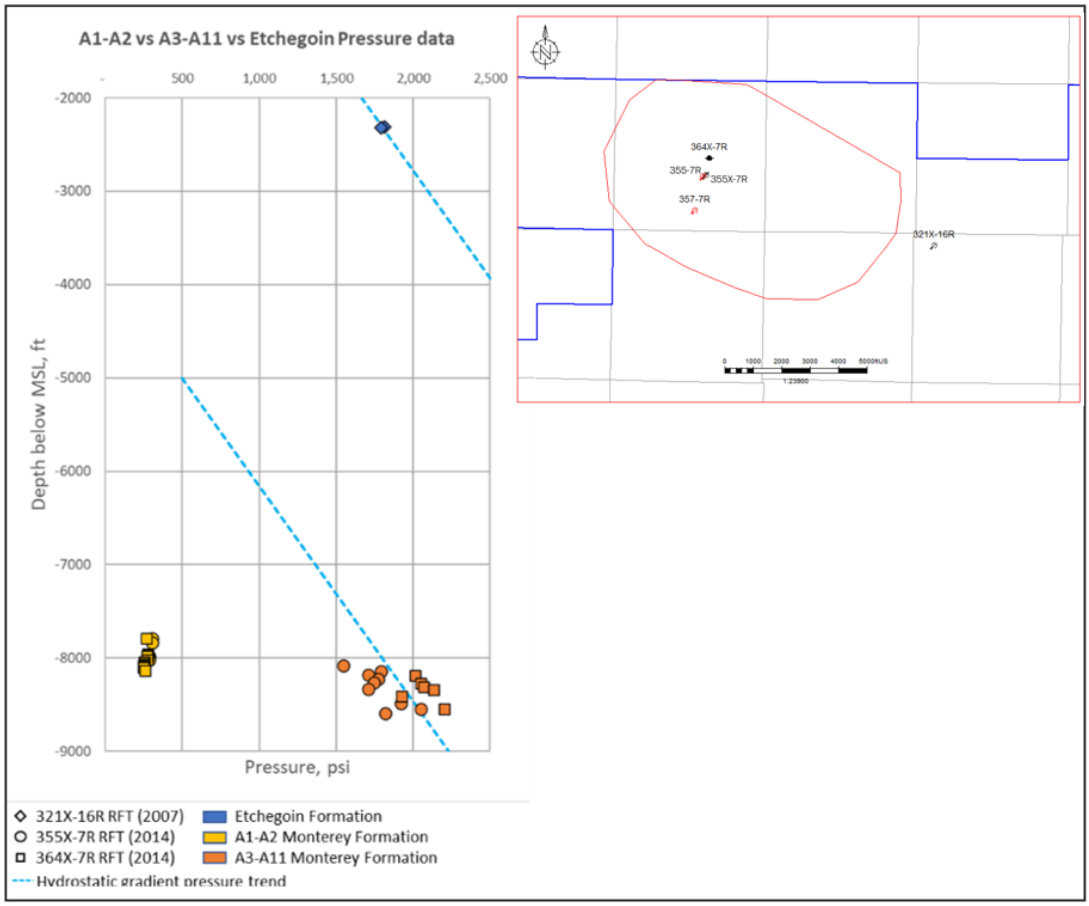


Figure 11: Formation pressure data in the area gathered in 2007 and 2014, after the blowdown of the A1-A2 reservoir, showing large pressure differentials between the A1-A2 and the underlying (A3-A11) and overlying (Ethcegoin) reservoirs, which supports the conclusion of the A1-A2 reservoir being pressure isolated



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation A1-A2 reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	240	Fahrenheit	8,300	Fluid Analysis
Formation pressure	200-300	Pounds per square inch	8,300	Pressure Test
Fluid density	61	Pounds per cubic foot	8,300	Water analysis
Salinity	25,000	Parts per million	8,300	Water analysis

Elevation of 8,300ft below MSL (Mean Sea Level) was used as a datum to initialize the model as it was a legacy datum depth used in historical data collection and study of the reservoir (corresponding to mid-point of the original Oil leg in the reservoir). This depth is in the current Gas Cap of the reservoir which is where the injectors are located and due to the high gas saturation where there is almost no Pressure variation with depth prior to injection. On initialization, the simulation model calculates the pressure, temperature, and fluid properties at every grid cell in the model. The injectors 357-7R and 355-7R are located and perforated in the Gas Cap of the A1-A2 reservoir, and as such the conditions at 8,300ft (below MSL) should be representative of the pressure and temperature at the injectors.

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft TVD/ ft MSL / ft MD) Top Bottom	 8,511 / 7719 / 8520 8,793 / 8001 / 8802	 8,483 / 7769 / 8488 8,658 / 7944 / 8663
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15
Injection rate (t/day)*	530-794	530-794

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

The Monterey Formation A1-A2 reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process, California Resources Corporation (CRC) obtained Class II UIC approval from CalGEM.

The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate.

Tests have been conducted in the history of the reservoir to determine the fracture gradient for the injection zone. These results are consistent with data collected outside the field. A 0.82 PSI/foot fracture gradient for the Monterey Formation A1-A2 reservoir was obtained from well 327-7R-RD1. CTV will conduct a step rate test for the Reef Ridge Shale as per the pre-operational testing plan.

CTV will ensure that the injection pressure is beneath 90% of the fracture pressure at the top perforation in the injection wells (shown in Table 6) calculated using a 0.82psi/ft fracture gradient, which is 6,281psi and 6,260psi for 357-7R and 355-7R respectively. Further details on injector operating parameters are provided in the "355-7R Operating Procedures" and "357-7R Operating Procedures" attachments.

Table 6. Injection pressure details.

Injection Pressure Details	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Fracture gradient (psi/ft)	0.82	0.82
Maximum bottomhole injection pressure (90% of fracture pressure) (psi)	6,281	6,260
Elevation corresponding to maximum injection pressure (ft TVD)	8,511	8,483
Elevation at the top of the perforated interval (ft TVD)	8,511	8,483
Average bottom hole injection pressure at top of perforations (psi)	2302	2423
Average bottom hole injection gradient at top of perforations (psi/foot)	0.27	0.28

Computational Modeling Results

Predictions of System Behavior

The Base case simulation was for 15 years of injection with a total of 145 BSCF (7.7 MMT) of CO2 injected, taking the pore volume average reservoir pressure back up to discovery pressure of 4000psi. The Simulation was run for a total period of 115 years (15 years of injection and 100 years of post-injection).

Currently a 100% CO2 injectate stream was assumed for the simulation studies. Table 7 summarizes the expected properties of the injectate at reservoir conditions at the low pressure start of the project and at the higher pressure end of the project.

Table 7: Injectate property at average reservoir conditions at start and end of project

Injectate Property	At start of injection	At end of injection
Viscosity, cp	0.020	0.046
Density, lb/ft3	3.12	34.39
Salinity, ppm	NA	NA
Compressibility factor, Z	0.933	0.674
Fluid Compressibility, psi^{-1}	0.0022	0.0002

The following maps (Figure 12) and cross-sections (Figure 13) show the computational modeling results and development of the CO_2 plume at seven time-steps. The boundaries of the AoR have been defined with a 3% CO_2 global mole fraction cutoff. The maximum vertical and lateral extent of the CO_2 plume is within the first year of post-injection, at which time the plume largely stabilized. The reservoir quickly becomes stable because the most significant trapping mechanism is structure.

For all layers in the model and at all time-steps, the plume stays within the 2.1 square mile AoR. Within the first two years of injection, the AoR extent is largely defined. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The majority of the CO2 is predicted to remain in Section 7 as shown in Figure 12. The simulation predicts minor amounts of CO2 in the shale dominated updip portion of the reservoir in Sections 8 and 17 (Central and Eastern portion of the AoR boundary) due to minor potential connected sand lenses modeled in the geomodel. This is a conservative interpretation and resulting AoR. In reality, it is likely that CO2 may not migrate to these areas due to those sand lenses not being sufficiently connected.

Figure 112: Plan view showing the plume development through time for layer 15. Red dots ae the injectors, Blue dots are monitoring wells. Sections 8 and 17 have CO_2 in small quantities due to minor potential connected sand lenses, as the reservoir becomes shale dominated up-dip. It is highly unlikely that CO_2 will migrate to these areas.

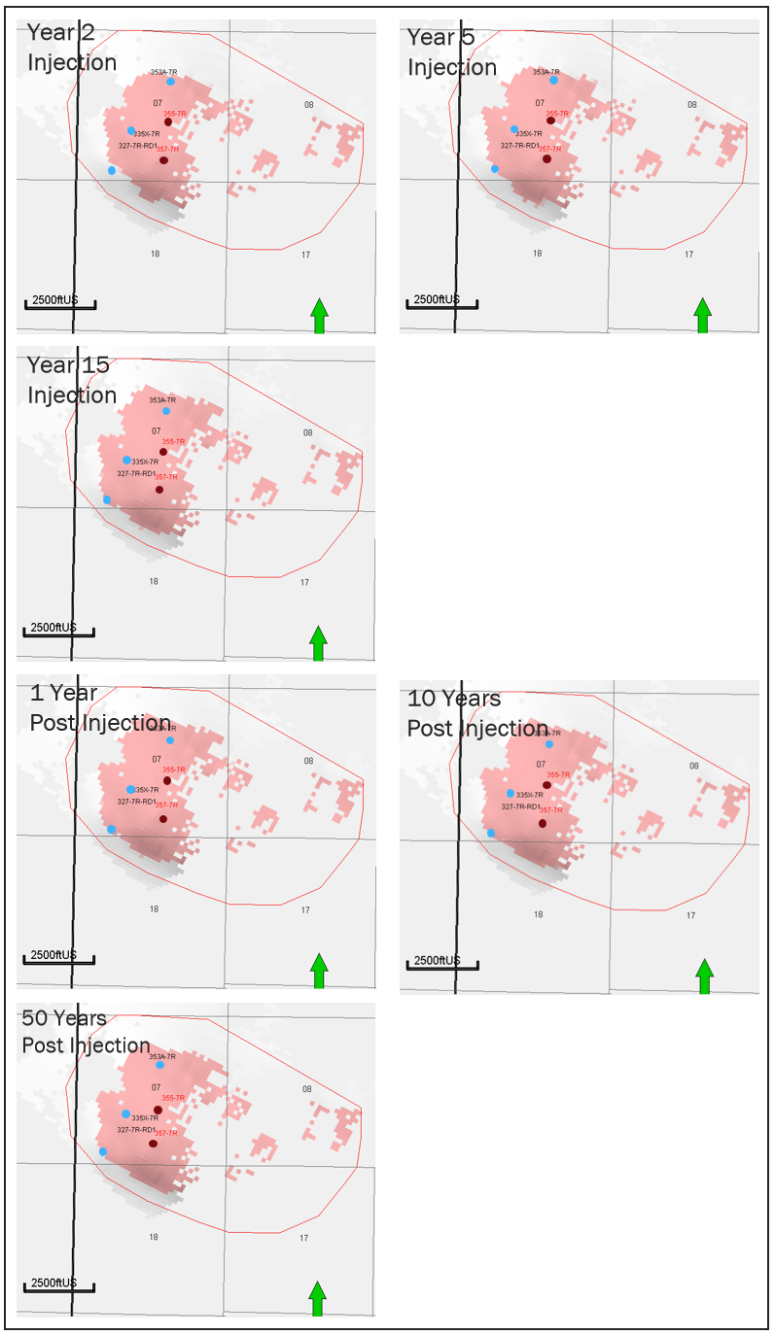
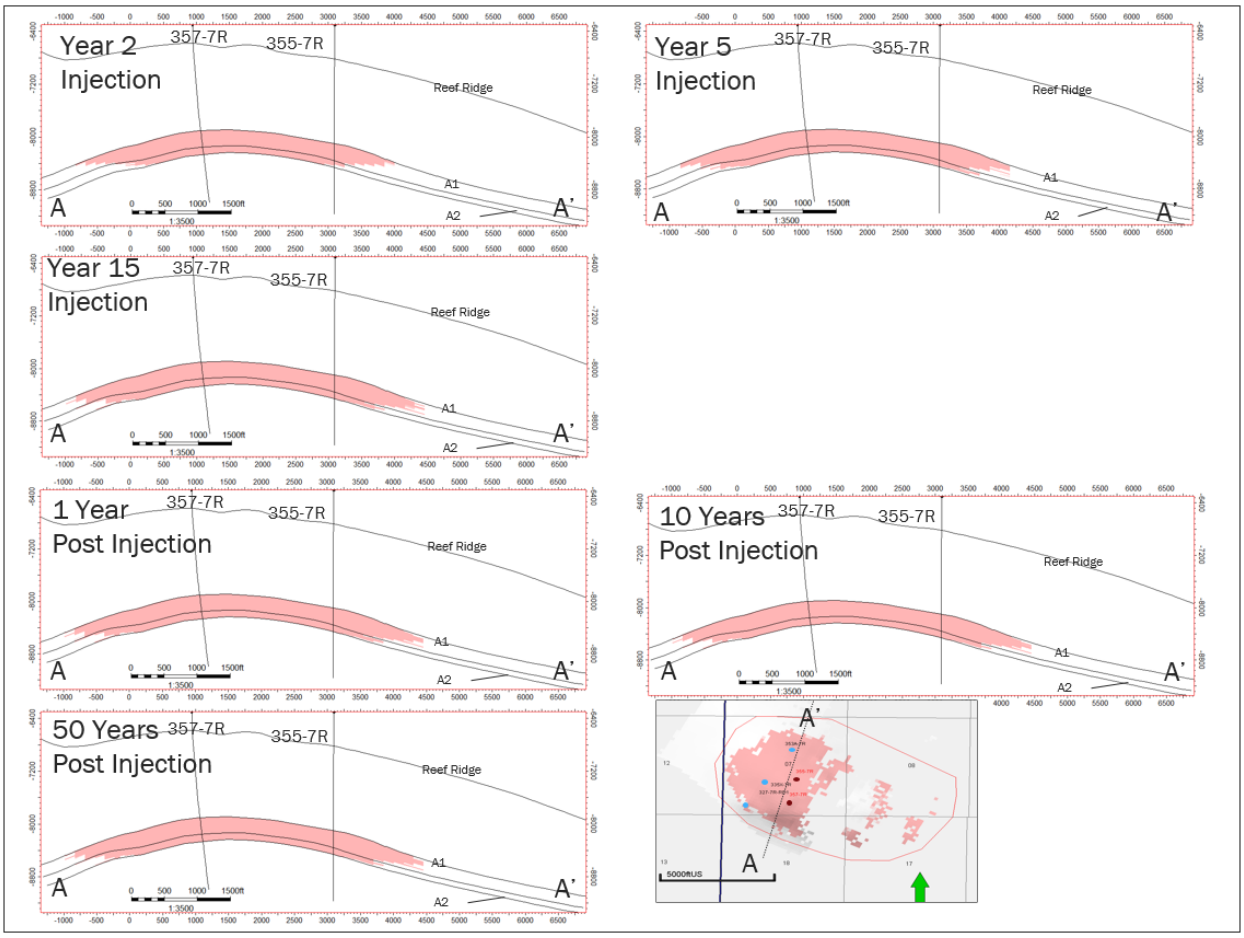


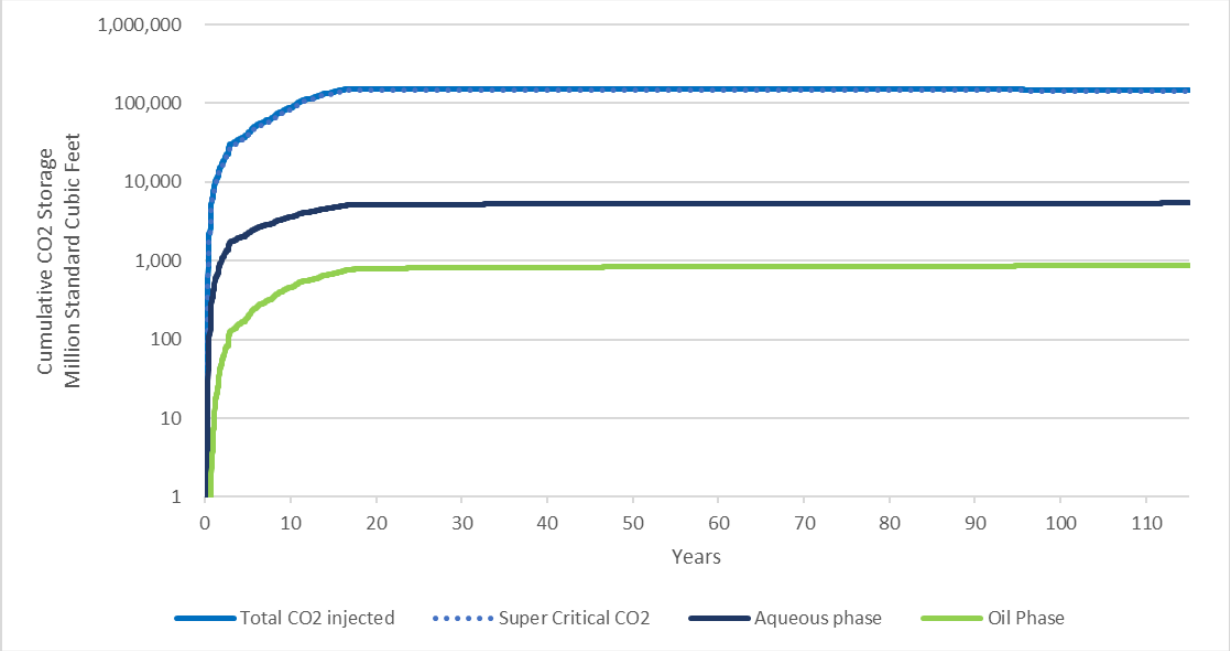
Figure 13: Cross-sections showing the plume development through varying times through the project.



CO_2 injected into the Monterey Formation A1-A2 reservoir will be soluble in both water and oil. Due to the low remaining saturation for oil and water in the depleted reservoir, majority of the CO2 is stored as Supercritical phase and there is little change in storage mechanism after the end of injection. 100 years after the end of injection 96% of the CO2 is still in the Supercritical phase, with only 3.5% in dissolved in the Aqueous phase and 0.5% in the Oil Phase.

Figure 14 shows the Cumulative storage for each of the mechanisms over the 15 year injection period and 100 years after the end of injection.

Figure 14: CO2 storage mechanisms in the reservoir. Note that since majority of the CO2 is in the Supercritical phase, the Total CO2 injected (blue line) and Super Critical CO2 (dotted blue line) are almost identical on the graph.



Model Calibration and Validation

CRC has injected 175 BCF of gas into the Monterey Formation A1-A2 reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The Base case simulation was run for 15 years of injection. This represents the anticipated project duration and rate. In addition, a scenario was also run with 5 years of injection at a much higher injection rate. Both scenarios were run for 100 years post injection to verify plume stabilization. There was no difference in AoR extent or storage volume between the scenarios.

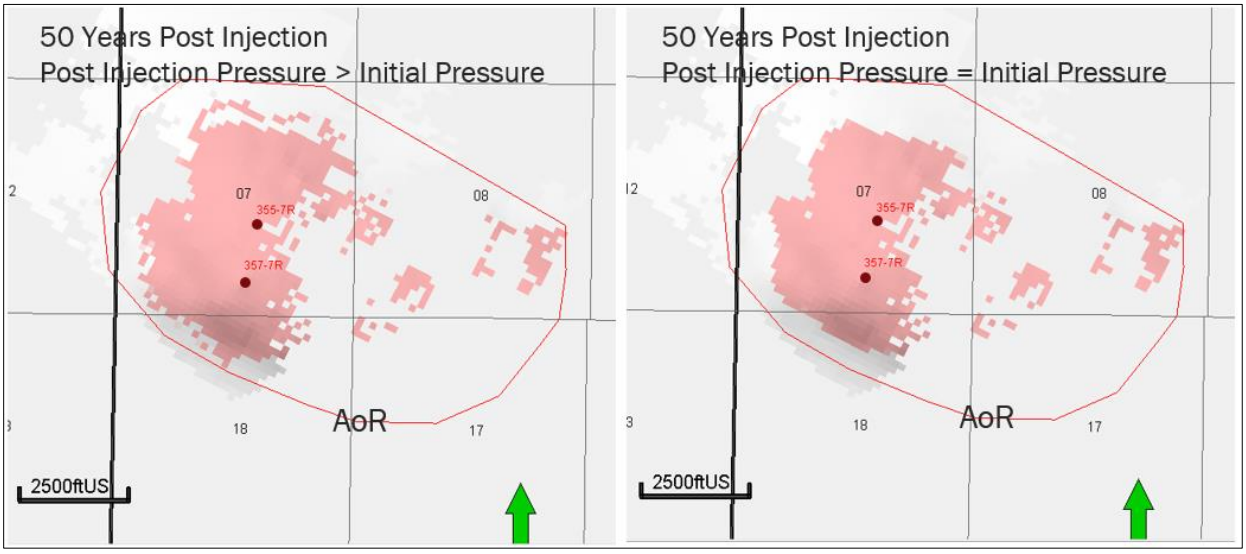
As a computational model sensitivity, CTV also ran a scenario where high injection rate was maintained for nine years, with an increase of the post-injection pressure and total CO_2 injected. At a final reservoir pressure of 5,750 psi, versus base case of 4,000 psi final reservoir pressure, the reservoir can store 193 BCF of CO_2. Figure 15 shows the difference in plume development at 100 years post injection. Note that the plume stays within the AoR, with increased CO_2 concentrations in cells in northwestern portion of the AoR.

Additionally, the scenarios listed in the Table 8 were run varying major inputs to the simulation to see whether it had any significant impact on the AoR boundary. The results from the different scenarios were reviewed and showed varying final CO2 storage amount but no impact to the AoR boundary.

Table 8: Simulation sensitivity scenarios

Scenario	AoR impact
Base Case: (15yrs of injection)	Base AoR
High Injection rate scenario (5yrs of injection)	No impact to AoR
Higher final reservoir pressure scenario	No impact to AoR
NTG : 10% reduction from base case	No impact to AoR
Porosity: 10% reduction from base case	No impact to AoR
Porosity: 10% increase from base case	No impact to AoR
Permeability: 10% reduction from base case	No impact to AoR
Permeability: 10% increase from base case	No impact to AoR
Grid XY dimensions: reduced to 75'x75'	No impact to AoR

Figure 15: Plan view of plume development at layer 15 in the computational model.



These scenarios demonstrate that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent for a range of scenarios. This provides confidence that the corrective action well review and potential impact to the Upper Tulare USDW is conservative and has been appropriately evaluated.

AoR Delineation

The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation A1-A2 reservoir until the reservoir pressure reached the discovery pressure of 4,000 PSI. Benefits of this

operational strategy are that there is no increased pressure front beyond the original reservoir limits.

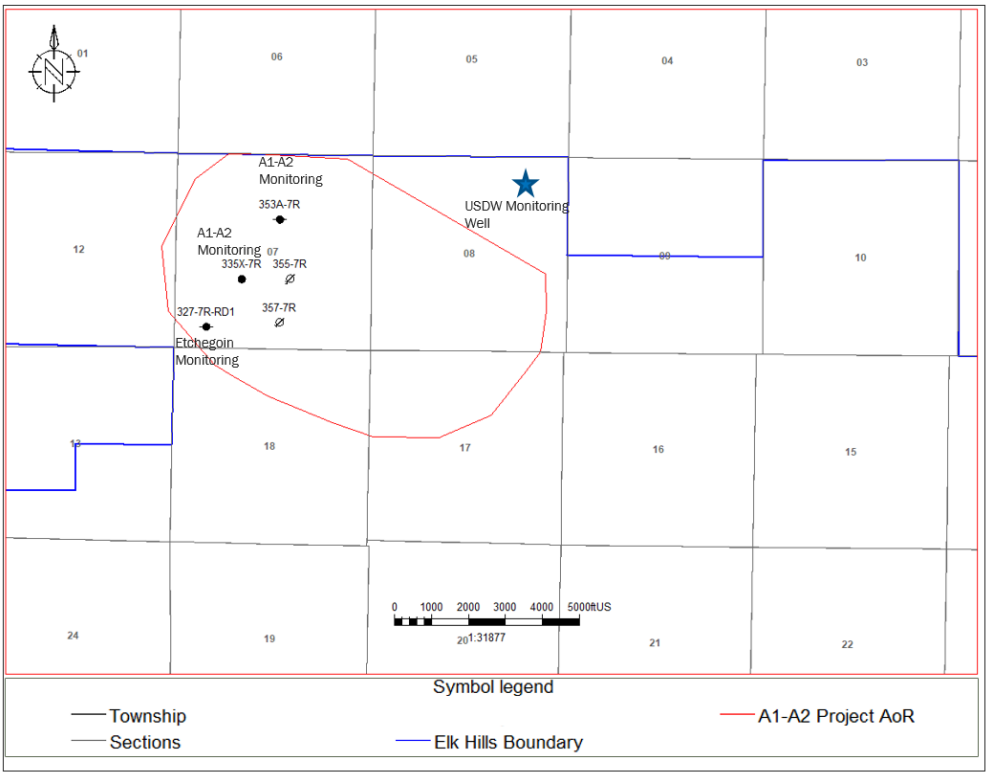
Figure 16 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 16: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

Tabulation of Wells within the AoR

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation A1-A2 reservoir was discovered in 1973 and developed subsequently. As such, there are excellent records for wells drilled in the field. There have been no "un-

documented" historical wells found during the over 40-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications.

Tables 9 and 10 provide counts of the AoR wellbores by status and type, for each wellbore with a unique API-12 identifier. Appendix 1 provides a complete list of all API-12 wellbores within the AoR. As required by 40 CFR 146.84(c)(2), the well table in Appendix 1 describes each well's type, construction, date drilled, location, measured depth, true vertical depth, completion record relative to the A1-A2 injection zone, record of plugging, requirement for corrective action, if necessary. CTV also identifies well work to be completed during the pre-operational testing phase.

Table 9: Wellbores in the AoR by Status

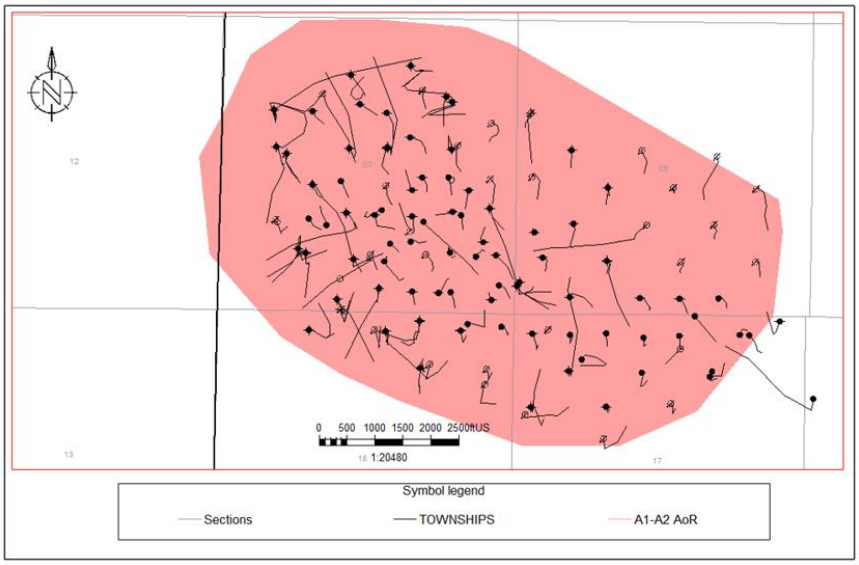
Status	Count
Active	41
Idle	70
Plugged and Abandoned	39
Total	**150**

Table 10: Wellbores in the AoR by Type

Type	Count
Oil & Gas Producing Wells	79
Class II Injection/Disposal Wells	32
Observation Wells	0
Plugged and Abandoned	39
Total	**150**

Wells in the AoR with an active status are development wells completed below the Monterey Formation A1-A2 reservoir and associated with a CalGEM Class II approval within the A3-A11 sand intervals.

Figure 17: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation A1-A2 sequestration reservoir reviewed for corrective action.



Protection of USDW

For the Elk Hills A1-A2 Storage Project, CTV assessed USDW protection by evaluating all wellbores that penetrate the confining Reef Ridge Shale. All wells within the AoR meet the criteria below, ensuring protection of the USDW:

1. Surface or intermediate casing over the USDW
2. If well is abandoned, cement plug across base of USDW
3. Cement in the annulus:
    a. Intermediate casing – cement above the above the surface casing shoe.
    b. Sufficient annular cement within the confining Reef Ridge Shale.

Wells Penetrating the Confining Zone

The depth of the confining zone in each of the wells penetrating the Reef Ridge shale was determined through open-hole well logs utilizing the deviation survey. All wells in the AoR penetrate the Reef Ridge Shale confining zone.

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q1 2021.

Monterey Formation A1-A2 Isolation

Wells that will not be used for the Elk Hills A1-A2 Storage Project that penetrate and are currently perforated in the Monterey Formation A1-A2 will be abandoned prior to injecting CO_2. These wells have not been deemed deficient, and they will not be used for hydrocarbon production from the A3-A11 underlying sands. The abandonment of these wells is considered to be normal operating procedures to manage and minimize liabilities. Wellbores that meet this criteria are included in the 33 wells identified for abandonment in Appendix 1.

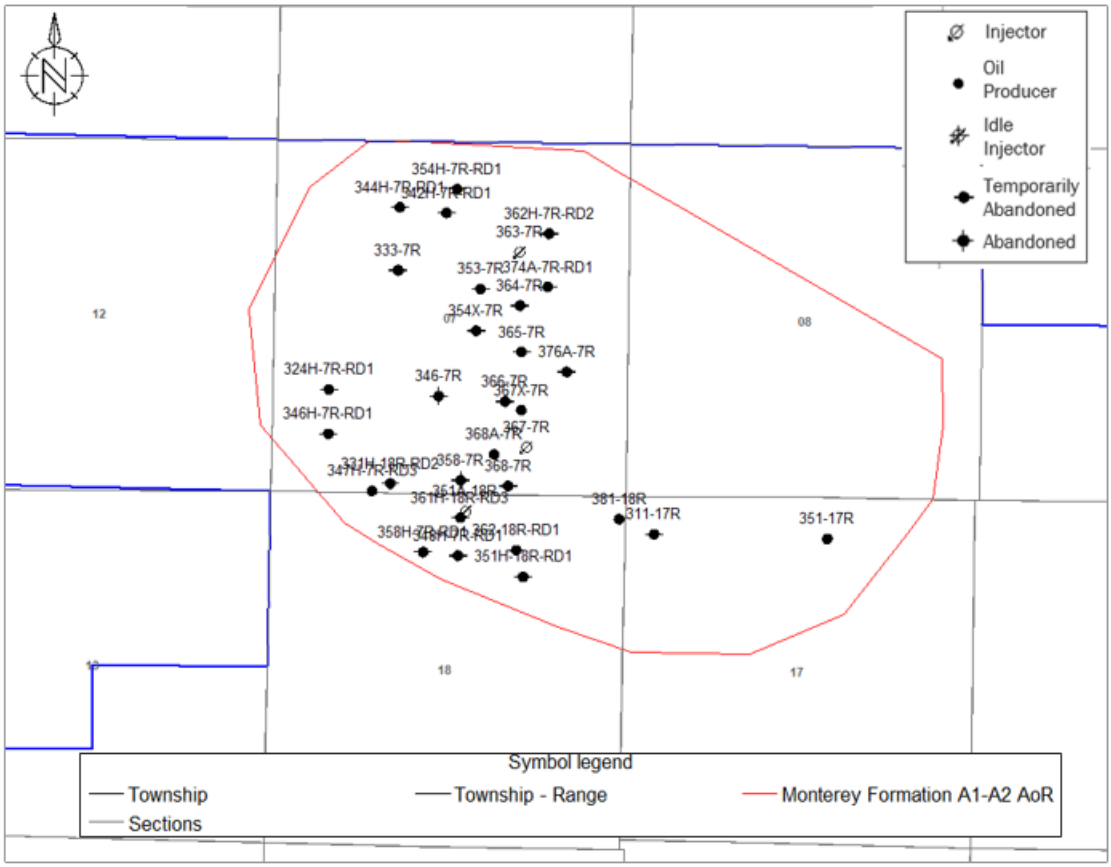
Wells that pass through and are not completed in the A1-A2 sand serve to either inject into or produce from some combination of the A3-A11 sands. All pass through wells not planned for abandonment during pre-operational testing have been determined to be adequately isolated from A1-A2 sands.

Corrective Action Assessment of Wells in AoR

The corrective action assessment included the generation of detailed casing diagrams for each wellbore, review of all perforations, assessment of cement tops for each casing string, and determination of cement plug depths. CTV can demonstrate that the USDW is protected and that with the abandonment of 33 wells (Figure 18), the Monterey Formation A1-A2 reservoir will be isolated. Annular cement and cement plugs within the casing will be placed within the Reef Ridge confining layer so as to re-establish caprock integrity.

Appendix 2 provides the plugging procedure that will be used to abandon these wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. Additionally, the procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Figure 18: Wells to be abandoned prior to injection.



Plan for Site Access

CTV operates and owns 100% of the surface, mineral, and pore space rights for the project where all activities will take place. As such, site access has been guaranteed for the duration of the project and for post-injection monitoring.

Corrective Action Schedule

Corrective action for all wells withing the AoR will be completed before CO_2 is injected in the reservoir. This will ensure that CO_2 is confined to the injection zone for the entire AoR, protecting the overlying USDW and ensuring confinement.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation A1-A2 reservoir that are not related to well integrity.

    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a variance >±10% from the Base Case Simulation.

    c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

    a. The presence of faults near the confining zone that indicates propagation into the confining zone.

    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event

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CLASS VI LOGGING AND TESTING

INJECTION WELL 355-7R
40 CFR 146.82(c)(4),(7) and 146.87(a)(1)-(3)

ELK HILLS A1-A2 PROJECT

Injection Well 355-7R Logging and Testing

The 355-7R injection well is being repurposed for the Elk Hills A1-A2 project. The 355-7R well has been approved by California Geologic Energy Management (CalGEM) for Class II pressure maintenance using gas as injectate.

Deviation Checks During Drilling

Deviation checks for 355-7R were acquired during drilling every 100 feet from 3,500 feet measured depth (MD) to bottom hole at 10,500 feet MD (Figure 1).

Figure 1: Deviation checks during drilling for the 357-7R well.

Δ$_N$ Y [ftUS]	Δ$_E$ V [ftUS]	Z [ft]	MD [ft]	Inclination [deg]	Azimuth GN [deg]	Azimuth TN [deg]	Δ$_N$ DR [ftUS]	Δ$_E$ DV [ftUS]	Δ$_N$ DX TN [ftUS]	Δ$_E$ DY TN [ftUS]	TVD (Well datum) [ft]	Δt TWT [ms]	DLS [deg/100ft]
6101133.09	2310474.86	728.86	0.00	0.00	180.00	179.12	0.00	0.00	0.00	0.00	0.00		0.00
6101130.09	2310412.92	-2771.29	3500.00	2.00	180.00	179.12	0.00	-61.06	0.94	-61.07	3499.29		0.00
6101130.00	2310409.43	-2871.23	3600.00	2.00	169.00	179.12	0.00	-64.57	0.99	-64.56	3599.23		0.00
6101103.18	2310401.55	-2971.17	3700.00	2.00	174.00	173.12	0.16	-68.06	1.23	-68.04	3699.17		0.21
6101102.55	2310401.48	-3071.11	3800.00	2.00	174.00	173.12	0.55	-71.52	1.65	-71.50	3799.11		0.00
6101103.85	2310399.30	-3171.05	3900.00	2.00	176.00	175.12	0.86	-75.00	2.00	-74.98	3899.05		0.07
6101103.87	2310399.52	-3270.98	4000.00	2.00	180.00	179.12	0.97	-78.49	2.18	-78.46	3999.98		0.14
6101103.70	2310399.03	-3370.92	4100.00	2.00	189.00	188.12	0.76	-81.98	1.86	-81.94	4098.92		0.21
6101103.11	2310398.80	-3470.86	4200.00	2.00	187.00	186.12	0.21	-85.40	1.53	-85.35	4198.86		0.07
6101102.94	2310398.12	-3570.80	4300.00	2.00	182.00	181.12	-0.06	-88.86	1.31	-88.87	4298.80		0.27

Δ$_N$ Y [ftUS]	Δ$_E$ V [ftUS]	Z [ft]	MD [ft]	Inclination [deg]	Azimuth GN [deg]	Azimuth TN [deg]	Δ$_N$ DR [ftUS]	Δ$_E$ DV [ftUS]	Δ$_N$ DX TN [ftUS]	Δ$_E$ DY TN [ftUS]	TVD (Well datum) [ft]	Δt TWT [ms]	DLS [deg/100ft]
6101181.90	2310158.91	-8897.80	9633.33	3.52	132.40	131.52	78.90	-317.09	83.76	-315.85	9625.80		1.14
6101181.43	2310155.58	-8931.07	9666.67	3.68	129.45	128.57	80.43	-318.42	85.32	-317.16	9659.07		1.14
6101185.19	2310154.20	-8963.33	9700.00	4.00	127.00	126.12	82.16	-319.80	87.09	-318.51	9692.33		1.14
6101187.91	2310152.03	-8614.21	9750.00	3.95	130.00	129.13	84.91	-321.87	89.85	-320.61	9742.21		0.42
6101190.57	2310149.73	-9064.09	9800.00	4.00	135.00	132.12	87.52	-324.27	92.49	-323.30	9792.09		0.42
6101193.14	2310147.46	-9113.97	9850.00	3.95	129.50	128.63	90.14	-326.57	95.15	-325.16	9841.97		0.49
6101195.49	2310145.20	-9163.85	9900.00	4.00	129.00	125.12	92.89	-329.70	97.94	-327.25	9891.85		0.49
6101198.74	2310143.28	-9213.72	9950.00	4.00	124.30	123.42	95.74	-330.72	100.85	-329.21	9941.72		0.21
6101201.64	2310141.29	-9263.60	10000.00	4.00	123.00	122.12	98.64	-332.65	103.74	-331.11	9991.60		0.21
6101204.57	2310139.46	-9313.48	10050.00	4.00	122.50	121.62	101.57	-334.54	106.70	-332.95	10041.48		0.07
6101207.52	2310137.60	-9363.36	10100.00	4.00	122.00	121.12	104.52	-336.40	109.68	-334.76	10091.36		0.07
6101209.57	2310136.30	-9396.60	10133.33	4.33	122.77	121.89	106.57	-337.70	111.74	-336.03	10124.60		1.01
6101211.76	2310134.87	-9429.84	10166.67	4.67	123.62	122.75	108.76	-339.12	113.96	-337.43	10157.84		1.01
6101214.89	2310133.21	-9463.09	10200.00	5.00	124.00	123.12	111.89	-340.89	116.91	-338.95	10191.09		1.01
6101217.78	2310131.01	-9512.86	10250.00	4.95	120.00	119.13	114.78	-342.99	120.04	-341.20	10240.86		0.70
6101221.62	2310128.97	-9562.67	10300.00	5.00	116.00	115.12	118.62	-345.03	123.91	-343.18	10290.67		0.70
6101224.13	2310127.70	-9595.89	10333.33	4.66	117.71	116.83	121.13	-346.30	126.41	-344.41	10323.89		1.10
6101226.42	2310126.45	-9629.12	10366.67	4.33	119.65	118.81	123.42	-347.55	128.74	-345.62	10357.12		1.10
6101228.50	2310125.21	-9662.36	10400.00	4.00	122.00	121.12	125.50	-348.79	130.84	-346.83	10390.36		1.10
6101234.41	2310121.51	-9762.12	10500.00	4.00	122.00	121.12	131.41	-352.89	136.81	-350.44	10490.12		0.00

357-7R Open Hole Log Analysis: Before Installation of Long String

Open-hole wireline log data was acquired in 355-7R with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity, neutron porosity and bulk density (Figure 2).

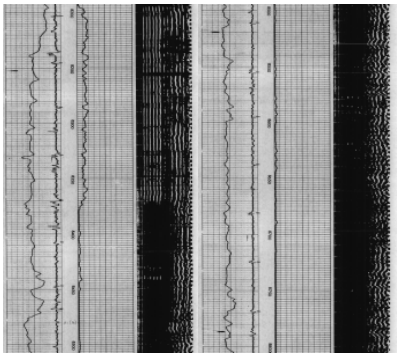
Figure 2: Open-hole well logs for 355-7R before installation of long string.



357-7R Cased Hole: After Installation of Long String

The cement bond log seismogram and percent bond show isolation. Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 3).

Figure 3: Cement bond log example for 355-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,470 feet.



ATTACHMENT C: TESTING AND MONITORING PLAN
40 CFR 146.90

Elk Hills A1-A2 Storage Project

Facility Information

Facility Name: Elk Hills A1-A2 Storage
357-7R & 355-7R

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment C- TM Final V3	3	11/4/22	Updated to include responses to EPA comments dated 07/20/22
Attachment C- TM V4	4	05/14/23	Updated to include responses to EPA comments dated 03/08/2023.

This Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills A1-A2 Storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting Procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the start of injection and every three months thereafter.

CTV is evaluating several sources of CO_2 as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and

2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)

Parameter	Analytical Method(s)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane, Ethane, Ethylene	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry

Sampling Methods

CO_2 stream sampling will occur at the discharge of the last compressor upstream of the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a state certified full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the injected CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the "Injection & Monitoring Well Schematics_v2" document.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface Downhole 355-7R: 8,387' (MD) 357-7R: 8,420' (MD)	10 seconds	30 seconds
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface Downhole 355-7R: 8,387' (MD) 357-7R: 8,420' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure of 90% of the injection zone's fracture pressure. Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

Calculation of Injection Volumes

The volume of CO_2 injected into the Monterey Formation A1-A2 will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation A1-A2 will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive brine with corrosion inhibitor. The casing-tubing annulus for injection wells 355-7R and 357-7R will be maintained on average with 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1000 psi and cannot be explained by operational conditions.

Corrosion Monitoring [40 CFR 146.90(c)]

CTV will monitor well materials during the operation period for loss of mass, change in thickness, cracking, pitting, or other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors.

Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For wells 357-7R and 355-7R, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 Carbon Steel (355-7R)
	N-80 Carbon Steel (357-7R)
	P-110 Carbon Steel (353A-7R, 335X-7R)
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. 327-7R-RD1 (Figure 1) is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 3,782' - 3,934' MD in 327-7R-RD1. In addition, the A1-A2 in zone monitoring wells (353A-7R and 335X-7R) will provide additional coverage for the Etchegoin Formation with continuous DTS temperature monitoring. In the event that temperature anomalies are observed at these locations, CTV will review with the EPA and potentially add additional Etchegoin monitoring to the project area.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure, decrease in temperature and change in composition of the Etchegoin. Compositional changes will be detectable with fluid sampling and geochemical monitoring within the 327-7R-RD1. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The location of the USDW monitoring well is structurally down-dip of the AoR to ensure that there is adequate water for sampling. The Upper Tulare is mostly unsaturated in the AoR and the water column height increases to the north, off the structure. The Upper Tulare Formation USDW will be monitored between 940' – 960' MD in the USDW monitoring well.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation A1-A2 CO_2 injection.

2. Tulare Formation pressure or composition changes due to Monterey Formation A1-A2 CO_2 injection.

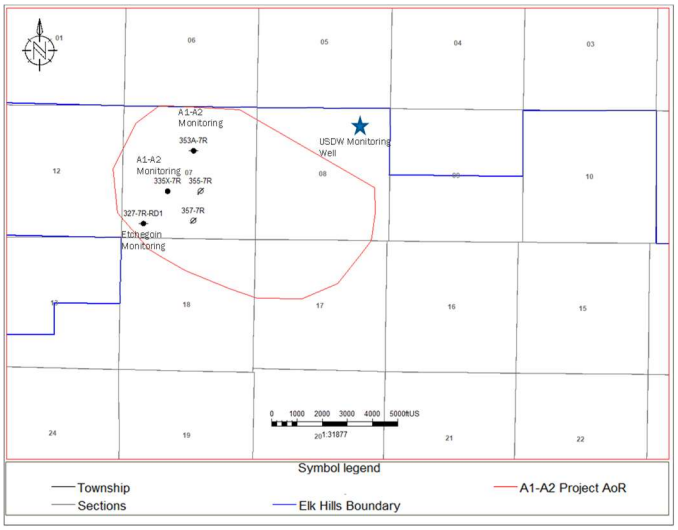
Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well locations with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD	Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD 961' MD 854' MD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD	Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' MD 3850' - 3990' MD	Continuous

Figure 1: Above confining zone monitoring wells, USDW monitoring well and 327-7R-RD1.



Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si, Sb)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Dissolved Methane	SM 6211 B or 6211 C
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage Project site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following.

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a SAPT will be performed. The injection

and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b).

Standard Annular Pressure Testing (SAPT)

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished, throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.

2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.

4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.

5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least one-minute intervals.

6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure, ie. 900 psi, the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director.

Table 6. Internal MIT requirements

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)
Standard Annular Pressure Test (SAPT)	355-7R[1]	Casing/tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	2990	3090
	357-7R[1]					2993	3093
	327-7R-RD1[2]				Any time packer is replaced or reset	--	1000
	335X-7R[3]					--	1000
	353A-7R					--	1000
Annular Pressure	355-7R[1] 357-7R[1] 327-7R-RD1[2] 335X-7R[3] 353A-7R[3]	Wellhead	Continuous	Continuous	Not Applicable	--	--
Fluid Sampling	345-7R[4] 388X-7R[4] 341-17R[4]	Wellhead	Baseline	Quarterly	Annual	--	--

[1] CO2 injection well
[2] Above Zone monitoring well
[3] Injection Zone monitoring well
[4] Monterey Formation A3-A11 monitoring well

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3% of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in realtime based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

Internal MIT for Monterey Formation A3-A11 Monitoring Wells

The active wells that will be used for monitoring the underlying A3-A11 reservoir will be monitored for internal mechanical integrity through fluid sampling. The wells are not configured with tubing and packer such than an annulus is not available to monitor or test using SAPT procedures. The current application of these wells precludes configuring these wells with this equipment. Fluid sampling, as described in the Carbon Dioxide Plume and Pressure Front Monitoring section below, will evaluate the presence or absence of CO_2 as a proxy for internal mechanical integrity. The presence of CO2 in the fluid sample will require EPA notification and diagnosis of the source of CO2 in the wellbore, either through the A3-A11 underlying reservoir or through wellbore mechanical integrity failure. In this event, CTV will provide a diagnostic plan and request approval from the EPA Director.

External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While DTS may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Since temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for

other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. To ensure mechanical integrity of the monitoring wells CTV will complete a SAPT, CBL and install DTS for continues temperature. DTS will enable CTV to develop a temperature log for any specified time to demonstrate mechanical integrity.

Table 7. External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will utilize the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.

2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.

3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.

4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

d. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

e. The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in realtime, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.

4. Start injection and record the temperature profile for 6 hours.

5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-

depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will likely be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warmback can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in realtime. If dense phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data is superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

DTS will not be installed on the Monterey Formation A3-A11 wells.

Description of Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging may be carried out while injection is occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Run a noise survey from top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.

3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

a. The base of the lowermost bleed-off zone above the injection interval and

b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging may be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray (GR) log and Casing Collar Locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up hole or downhole as necessary at no more than 50 foot intervals and take stationary readings to determine the area of fluid migration.

Pressure Fall-Off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests on each injector during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut in. The injection pressure will be high enough to produce a pressure decrease upon shut in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.

2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottomhole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10 second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.

5. Interference testing may be conducted at the conclusion of the falloff test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut in well.

6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry standard methodologies. Anomalies that are identified from the interpretation will be investigated.

7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Falloff Testing Requirements document.

Carbon Dioxide Plume and Pressure Front Tracking

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted A1-A2 zone. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Figure 2: Monterey Formation A1-A2 sequestration reservoir monitoring wells, 335X-7R and 353A-7R.

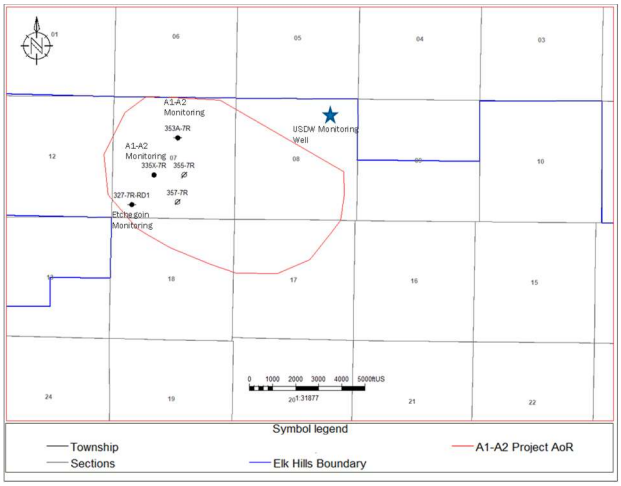


Table 8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Table 8. Plume monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm A1-A2	Fluid Sampling	335X-7R	8737' - 9030' MD	Once	Quarterly
		Pressure		8667' MD	Baseline	Continuous
		Temperature		8667' MD	Baseline	Continuous
	Monterey Fm A1-A2	Fluid Sampling	353A-7R	8773' - 9130' MD	Once	Quarterly
		Pressure		8703' MD	Baseline	Continuous
		Temperature		8703' MD	Baseline	Continuous
	Monterey Fm A3-A11 (below injection zone)	Fluid Sampling	345-7R	8904' - 9402' MD	Once	Quarterly
		Fluid Sampling	388X-7R	8800' - 9290' MD	Once	Quarterly
		Fluid Sampling	341-17R	8844' - 9307' MD	Once	Quarterly
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	335X-7R	8737' - 9030' MD	Baseline	Every 2 years from start of injection
			353A-7R	8773' - 9130' MD		

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone and the Monterey Formation A3-A11.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B

Parameters	Analytical Methods
pH (field)	EPA 150.1
Specific Conductance	APHA 2510
Temperature (field)	Thermocouple
Dissolved Methane	SM 6211 B or 6211 C
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 8.

The DTS from the two monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 96% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

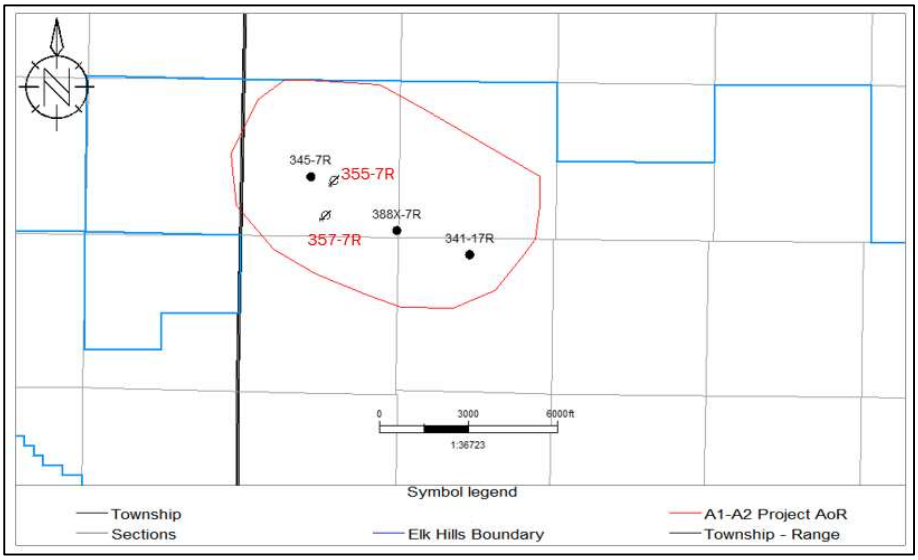
CTV does not plan to conduct VSP monitoring for the depleted A1-A2 oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Monitoring the Underlying Monterey A3-A11 Reservoir

The Monterey Formation A3-A11 reservoir will be monitored for the presence of CO_2 above baseline in the production stream as an indication of CO_2 migration below the A1-A2 injection zone. Waterflood producers shown in Figure 3 will be monitored during injection operations by sampling the produced fluid at surface once per quarter for changes in composition as per Table 9. Prior to the conclusion of A1-A2 injection and initiation of the post injection site care period, these producers and the A3+ waterflood operations will be abandoned as part of standard asset retirement as per CalGEM regulations.

Due to its waterflood infrastructure and high reservoir pressure, the A3-A11 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

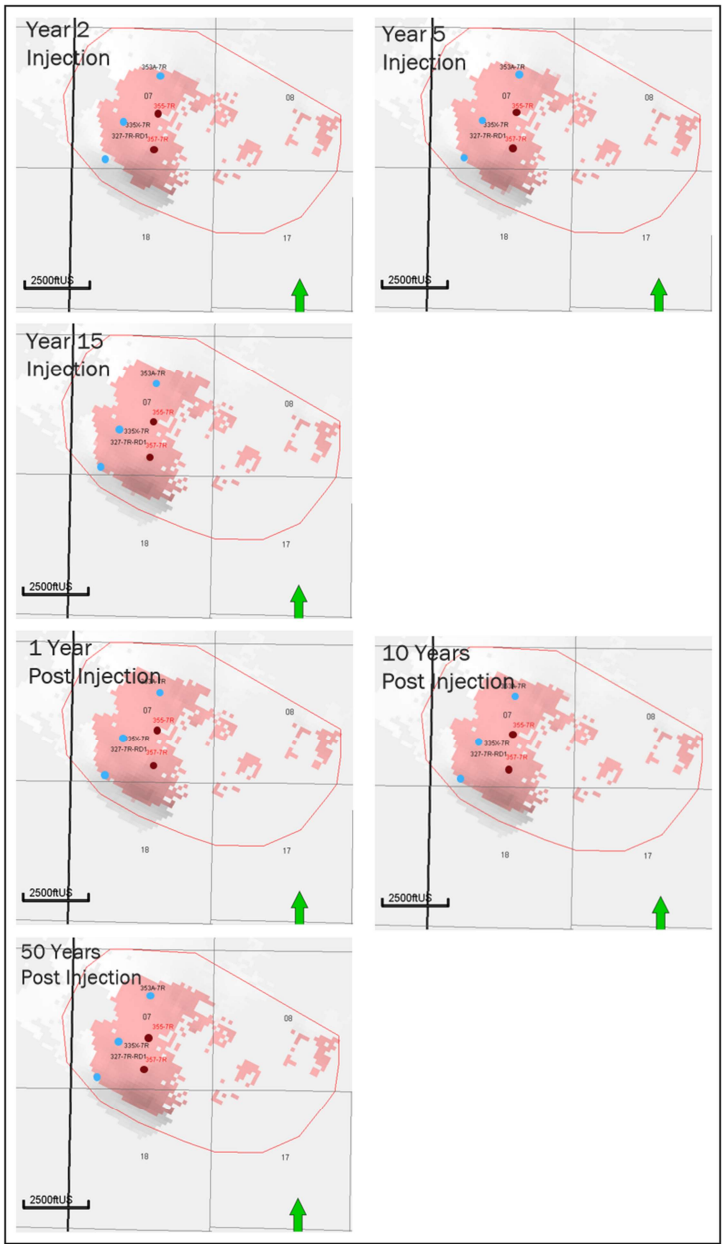
Figure 3: A3-A11 wells for fluid sampling to assess basal confinement of the CO_2 injectate.



Pressure Front Monitoring Location and Frequency

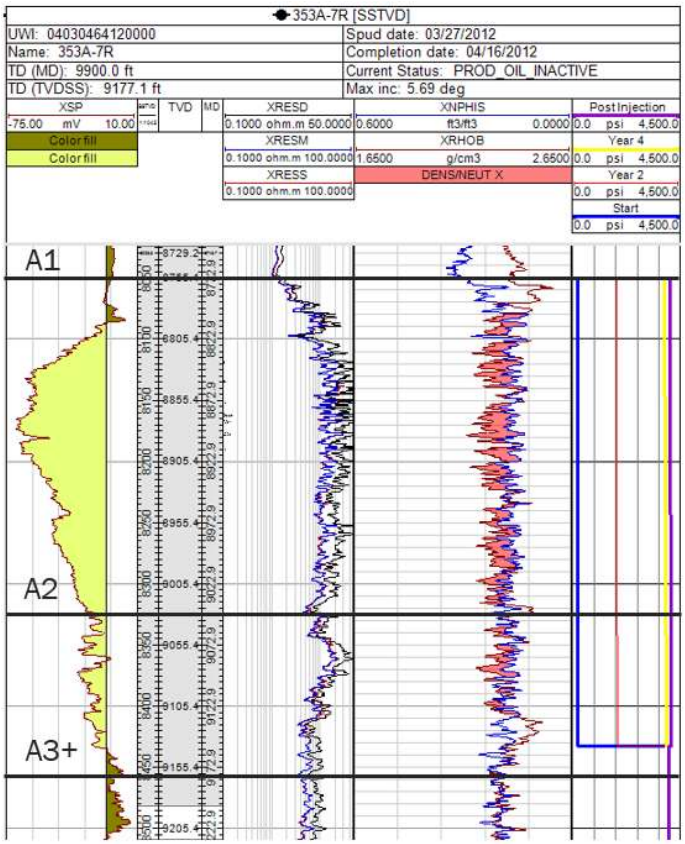
The aerial extent of plume development in the Monterey Formation A1-A2 reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 4.

Figure 4. Monitoring well location with maps showing plume development through time from computational modeling.



Monitoring well 353A-7R pressure development based on the computational model is shown in Figure 5 in the right-hand track. The reservoir pressure stabilizes after five years. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Figure 5: Monitoring well 353A-7R showing the pressure increase through time from the computational modeling results.



Pressure Front Monitoring Details

Direct pressure and temperature monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 353A-7R and 335X-7R. The depleted Monterey Formation A1-A2 oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 6 shows the pressure in the reservoir post injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

Figure 6: Monterey Formation A1-A2 pressure 100 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

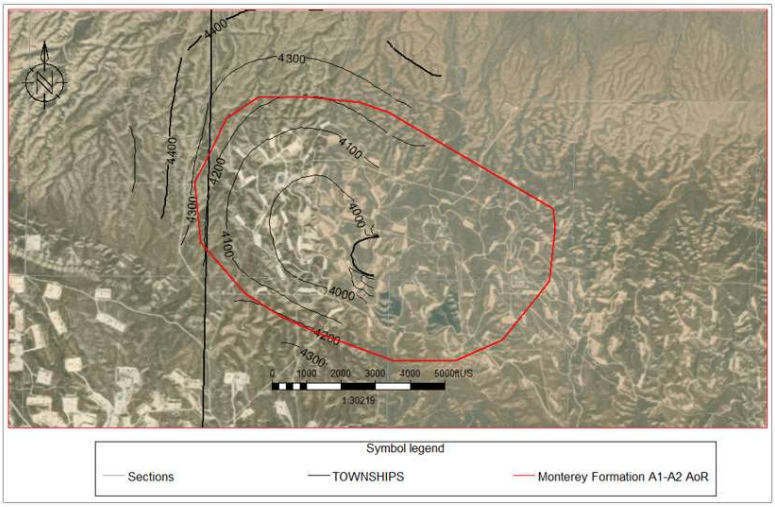


Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Table 10. Pressure-front monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm A1-A2	Pressure	335X-7R	8737' - 9030' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
	Monterey Fm A1-A2	Pressure	353A-7R	8773' - 9130' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)]	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. This network will be implemented to monitor seismic activity near the project

site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 7)
- Borehole sensors will be deployed deeper than 1,500' to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events >M_w 0.0

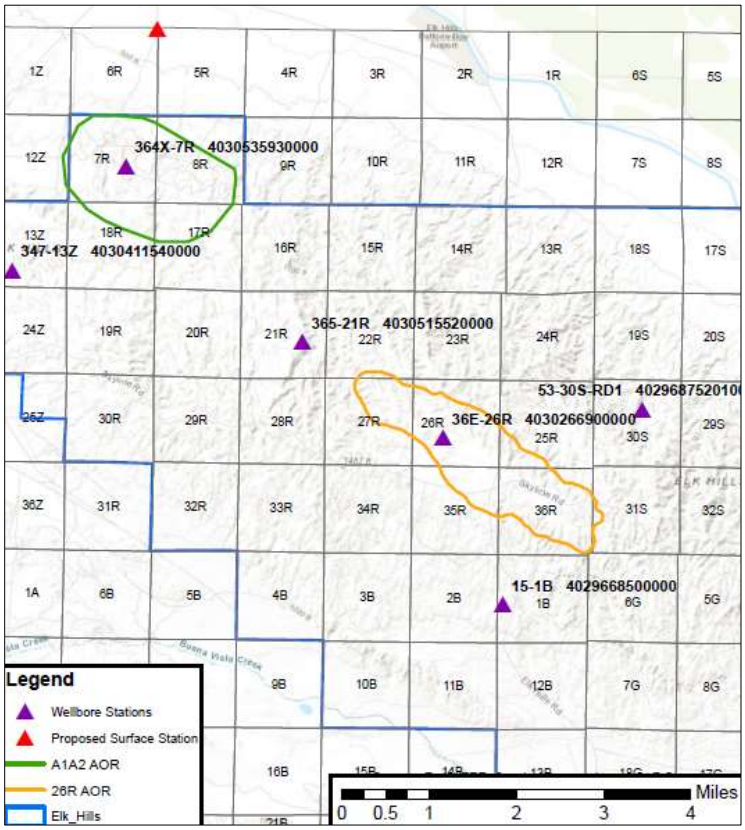


Figure 7: Elk Hills seismic monitoring network.

Baseline Analysis:

The monitoring network will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection

to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data transmitted near real-time via cellular modem or other wireless means and archived in a database

- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

ATTACHMENT C: TESTING AND MONITORING PLAN
40 CFR 146.90

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R & 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 642-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills A1-A2 Storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality assurance procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the start of injection and every three months thereafter.

CTV is evaluating several sources of CO_2 as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling location and frequency

CO_2 injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the date of authorization of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and

2. Facility or injector downtime is greater than thirty days.

Analytical parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	**Analytical Method(s)**
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry

Sampling methods

CO_2 stream sampling will occur in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory to be used/chain of custody and analysis procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a state certified full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date.
2. Sample description.
3. Sample type.
4. Relinquished by and received by signature.
5. Sampler name.
6. Location information.

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring location and frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	10 seconds	30 seconds
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface and Downhole	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Monitoring Details

Injection Rate and Pressure Monitoring

Injection pressure (gauge), temperature and flow rate (flow meter) will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole

injection pressure of 90% of the injection zone's fracture pressure. Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

Calculation of Injection Volumes

The volume of CO_2 injected into the Monterey Formation A1-A2 will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation A1-A2 will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the down-hole packer and tubing. Pressure will be read at the surface via a pressure gauge. The annulus will be filled with a non-corrosive fluid. Any deviations in the annular pressure may indicate a well integrity issue that will be investigated.

Casing-tubing Pressure

CTV will monitor the casing-tubing pressure continuously (every 10 seconds) via a pressure gauge. The surface pressure of the casing-tubing annulus will be between 100 psi and 299 psi per injection well operating procedure documents.

Injection Rate

The injection rate will be monitored with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent.

Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring location and frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). CTV will continually update the corrosion monitoring plan as data is acquired.

Sample description

Samples of the materials used in the construction of the pipeline, and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials (Table 3) will be weighed, measured, and photographed prior to installation. For wells 357-7R and 355-7R, long string casing material (N80) will be included in the corrosion coupon monitoring. General construction materials for pipeline, tubing and wellhead as shown in Table 3. Updated materials will be provided a prior to injection as part of pre-operational testing.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	357-7R Carbon Steel (N80)
	355-7R Carbon Steel (N80)
Tubing	Chrome Alloy
Wellhead	Chrome Alloy

Monitoring details

The corrosion coupons will be located in the pipeline that feeds CO_2 injectate to the injectors. Quarterly the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with ASTM G1-03.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year.

Above Confining Zone Monitoring

CTV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). Monitoring above the confining zone will include the following:

1. Tulare Formation - The Upper Tulare Formation USDW will be monitored between 940-960’ MD in the USDW monitoring well.

2. Etchegoin Formation – between the confining layer and USDW from 3,782 - 3,934 feet MD in 327-7R-RD1.

Monitoring location and frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the

monitoring well locations with respect to the AoR. The wells are located within the Elk Hills Oil Field, CTV owns the surface and mineral rights.

Etchegoin Formation

The Etchegoin Formation zone between the confining zone and Upper Tulare USDW will dissipate any CO_2 injectate that migrates upward through the confining zone. The Etchegoin will be monitored continuously for pressure and temperature changes and quarterly via fluid sampling within a continuous sand. Leakage from the Monterey Formation to the Etchegoin Formation will increase the reservoir pressure and decrease the temperature of the Etchegoin. This is the first porous interval above the sequestration reservoir.

The Etchegoin zone is continuous across the AoR. As such, 327-7R-RD1 (Figure 1) will adequately monitor for pressure and temperature changes.

Prior to injection, baseline water analysis will be acquired for the Etchegoin Formation monitoring zone.

Tulare Formation

Monitoring in the Upper Tulare will include pressure, temperature and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The location of the monitoring well is structurally down-dip of the AoR to ensure that there is adequate water for sampling. The Upper Tulare is mostly unsaturated in the AoR and the water column height increases to the north, off the structure.

Prior to injection, an updated baseline analysis will be completed for the USDW monitoring well. Future results will be compared against these baseline results for significant changes or anomalies. In particular, pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

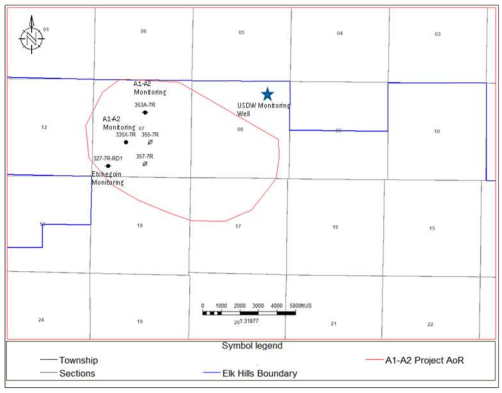
1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation A1-A2 CO_2 injection.

2. Tulare Formation pressure or composition changes due to Monterey Formation A1-A2 CO_2 injection.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency	Depth
Tulare Formation	Fluid Sampling	USDW Monitoring Well	Quarterly	940 - 960 MD 940 - 960 TVD
	Pressure/Temperature	USDW Monitoring Well	Continuously	
Etchegoin Formation	Pressure/Temperature	327-7R-RD1	Continuously	3,782 – 3934 MD 3,780 – 3,932 TVD
	Fluid Sampling	327-7R-RD1	Quarterly	

Figure 1: Above confining zone monitoring wells, USDW monitoring well and 327-7R-RD1.



Analytical parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C

Parameters	Analytical Methods
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple

Sampling methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory to be used/chain of custody procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Mechanical Integrity Testing

CTV will conduct at least one test periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90. MITs on the injectors and Monterey Formation monitoring wells will be performed annually, within 30 days of the commencement of the injection date, by one of two methods in Table 6. If CTV elects to conduct an alternate MIT, notification that includes the test and a description will be sent to the EPA for approval.

Testing location and frequency

Table 6. MITs.

Test Description	Location
Temperature (DTS)	Along wellbore via DTS
Temperature Log	Along wellbore via wireline well log

Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will measure the injector and monitoring wells annular temperature along the tubing. This will be used to assess the mechanical integrity of the well.

The following is procedures to utilize DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well. Stop injection and record the temperature for sufficient time to allow cooling.

3. Start injection and record the temperature profile for 6 hours.

4. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Temperature Logging Testing details

CTV will follow the following procedures for MIT temperature logging:

1. Stabilize injection for 24 hours prior to running the temperature log. If possible, the wireline speed will be limited to 20 feet per minute or less. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).

2. Run a temperature survey from 200 feet above the Reef Ridge Shale base to the deepest point reachable in the well, while injecting at a rate that allows for safe operations.

3. Shut-in well and run multiple temperature surveys with 4 hours between runs.

4. Assess the acquired time lapse temperature profiles. As the well cools, the temperature profile is compared to the baseline. External integrity issues present themselves anomalies when compared to the baseline.

5. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the top most section of the log, additional logging runs over a higher interval will be required to find the top of migration.

Pressure Fall-Off Testing

CTV will perform pressure fall-off tests during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f).

Testing location and frequency

The main benefit of pressure fall-off testing is to assess injectivity, reservoir flow boundary distances and reservoir pressures. The fall-off test will be done on the two injectors every five years.

Testing details

The following procedure will be followed:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. The pressure falloff analysis will use several months of preceding injection data.

3. The test well should be shut-in at the wellhead in order to minimize wellbore storage and after-flow.

4. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously every ten seconds. If there are offset injectors, rates will be held constant and recorded during the test.

5. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

6. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.

7. A report containing the pressure falloff data and interpretation of the reservoir pressure will be submitted to the EPA within 90 days of the test.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy. CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for additional procedures such as planning and evaluation.

Carbon Dioxide Plume and Pressure Front Tracking

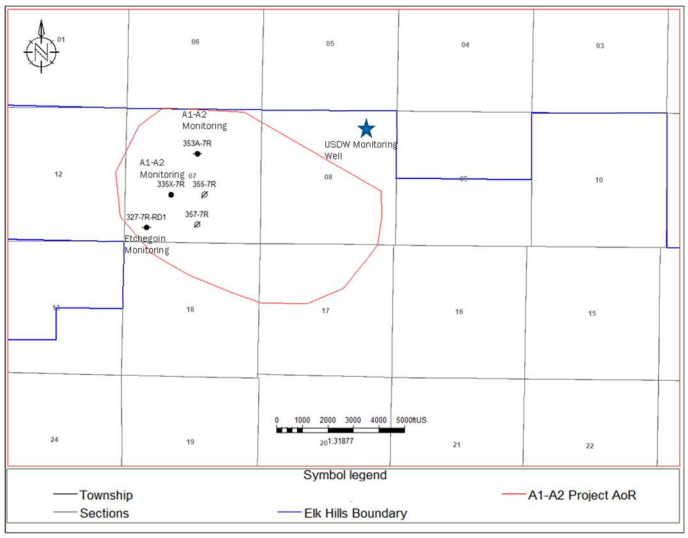
CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume monitoring location and frequency

Table 7 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 8. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted A1-A2 zone. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Figure 2: Monterey Formation A1-A2 sequestration reservoir monitoring wells, 335X-7R and 353A-7R.



Plume monitoring details

Fluid sampling (quarterly), pressure and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 8.

The DTS from the two monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 98% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

Underlying Monterey A3-A11 Reservoir Monitoring

Monterey Formation A3-A11 reservoir and wellbores will be monitored for CO_2 migration. Waterflood producers shown in Figure 3 will be monitored during injection operations via fluid sampling once per quarter for changes in composition as per Table 8. Due to its waterflood infrastructure and high reservoir pressure, the A3-A11 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

Figure 3: A3-A11 wells for fluid sampling to assess basal confinement of the CO2 injectate.

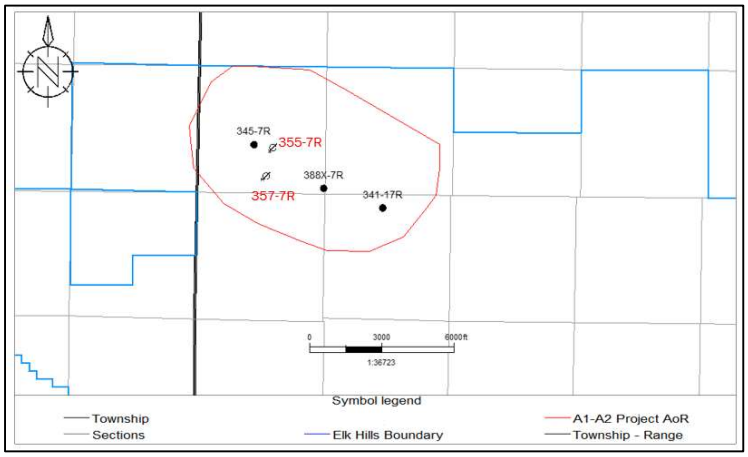


Table 7. Plume monitoring activities.

DIRECT PLUME MONITORING				**Depths**
Monterey Formation A1-A2	Fluid Sampling	353A-7R and 335X-7R	Quarterly	353A-7R: 8,773–9,130 MD 335X-7R: 8,737-9,030 MD
Monterey Formation A1-A2	Pressure and temperature	353A-7R and 335X-7R	Continuously	
Monterey Formation A3-A11	Fluid Sampling	345-7R, 388X-7R and 341-17R	Quarterly	345-7R: 8,904.5-9,402 MD 388X-7R: 8,800-9,290 MD 341-17R: 8,844-9,307 MD
INDIRECT PLUME MONITORING				
Monterey Formation A1-A2	Pulse Neutron Logging	353A-7R and 335X-7R	Every two years from start of injection.	

Table 8. Summary of analytical and field parameters for fluid sampling in the injection zone and the Monterey Formation A3-A11.

Parameters	**Analytical Methods**
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, ZN, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple

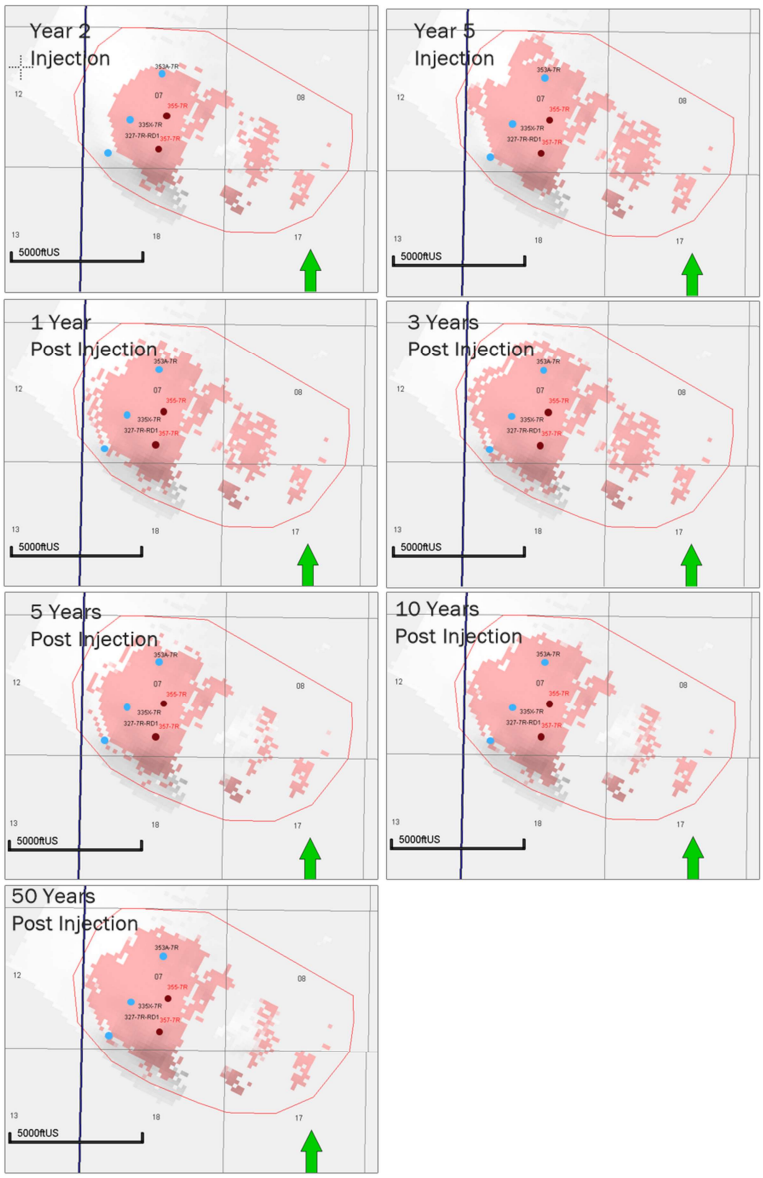
Pressure-front monitoring location and frequency

Table 9 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ.

Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

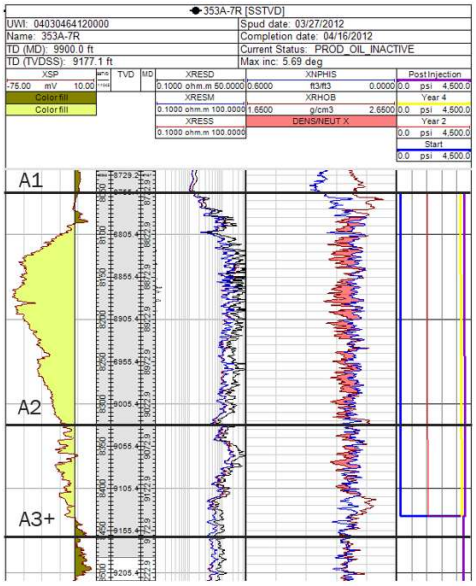
The aerial extent of plume development in the Monterey Formation A1-A2 reservoir will reach the AoR boundaries early in the injection phase. Because the reservoir is pressure depleted, injected CO_2 will quickly fill the available pore space. Monitoring well locations with respect to plume development through time are shown in Figure 4.

Figure 4. Monitoring well location with maps showing plume development through time from computational modeling.



Monitoring well 353A-7R pressure development based on computational is modeled in Figure 5. Note that the reservoir pressure after five years is stable. This is due to the high amount of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases.

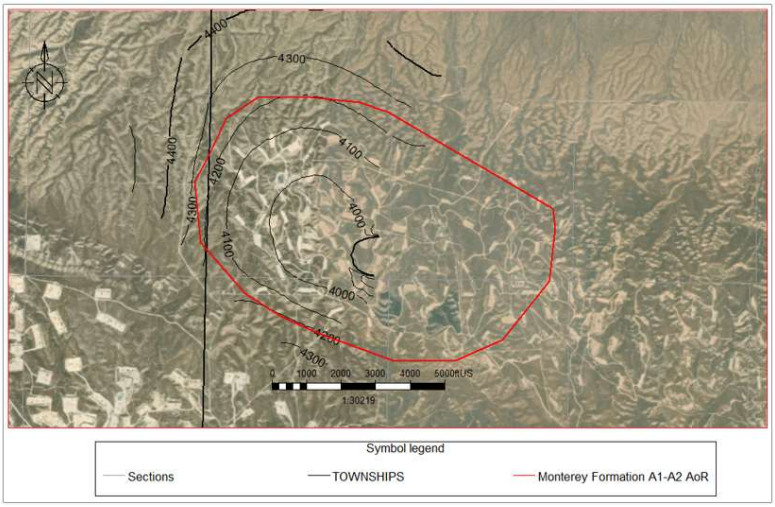
Figure 5: Monitoring well 353A-7R showing the pressure increase through time from the computational modeling results.



Pressure-front monitoring details

Direct pressure monitoring of the plume will be achieved through installation of pressure gauges in monitoring wells 353A-7R and 335X-7R. The depleted Monterey Formation A1-A2 oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 6 shows the pressure in the reservoir post injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

Figure 6: Monterey Formation A1-A2 pressure 100 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.



The modeled pressure increases at monitoring well 353A-7R are shown in Figure 5. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 9. Pressure-front monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FRONT MONITORING			
Monterey Formation A1-A2	Pressure and temperature monitoring	353A-7R and 335X-7R	Continuous
INDIRECT PRESSURE-FRONT MONITORING			
All formations	Seismicity	AoR	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with surface and shallow borehole seismometers in the AoR. The seismometers will be able to detect events with a magnitude 0 to 0.5 and will be installed one year prior to injection to provide baseline seismicity. In addition, CTV will monitor the Southern California Earthquake Data Center (SCEDC) network for seismic events. Historical seismicity within the area will be accounted for in the baseline assessment.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

ATTACHMENT C: TESTING AND MONITORING PLAN
40 CFR 146.90

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R

Facility contact: Kenneth Haney / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 763-6101/ Kenneth.Haney@CTV.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills A1-A2 Storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality assurance procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the date of authorization of injection and every three months thereafter.

CTV is evaluating several sources of CO_2 as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling location and frequency

CO_2 injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the date of authorization of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and

2. Facility or injector downtime is greater than thirty days.

Analytical parameters

CTV will analyze the CO_2 for the constituents identified in Table 1 using the methods listed.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen	ASTM D1945
Nitrogen	ASTM D1945
Carbon Monoxide	ASTM D1945
Total hydrocarbons	ASTM D1945
Methane	ASTM D1945
Hydrogen Sulfide	ASTM D1945/D6228
CO_2 purity	ASTM D1945
Total Sulfur	ASTM 3246

Sampling methods

CO_2 stream sampling will occur in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory to be used/chain of custody and analysis procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date.
2. Sample description.
3. Sample type.
4. Relinquished by and received by signature.
5. Sampler name.
6. Location information.

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring location and frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table.

All monitoring will be continuous with a 30 second sampling and recording frequency for both active and shut-in periods.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	30 seconds	30 seconds
Injection rate	Flowmeter	Surface	30 seconds	30 seconds
Injection volume	Calculated	Surface	30 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	30 seconds	30 seconds
CO_2 stream temperature	Temperature gauge	Surface and Downhole	30 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Monitoring details

Injection Rate and Pressure Monitoring

Injection pressure (gauge), temperature (gauge) and flow rate (flow meter) will be continuously and monitored by the Elk Hills Central Command Facility (CCF). Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable injection pressure of 90% of the injection zone's fracture pressure.

Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

Calculation of Injection Volumes

The volume of CO_2 injected into the Monterey Formation A1-A2 will be calculated from the injection flow rate and CO_2 density. Density will be determined from the Massachusetts Institute of Technology's CO_2 Thermophysical Calculator.

https://sequestration.mit.edu/tools/index.html

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the down-hole packer and tubing. Pressure will be read at the surface via a pressure gauge. The annulus will be filled with a non-corrosive fluid. Any deviations in the annular pressure may indicate a well integrity issue that will be investigated.

Casing-tubing Pressure

CTV will monitor the casing-tubing pressure continuously (every 30 seconds) via a pressure gauge. The surface pressure of the casing-tubing annulus will be between 0 and 800 PSI.

Injection Rate

The injection rate will be monitored with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent.

Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring location and frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7).

CTV will continually update the corrosion monitoring plan as data is acquired.

Sample description

Samples of the materials used in the construction of the pipeline, and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials (Table 3) will be weighed, measured, and photographed prior to installation.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	CS A106B
Casing	N80 Steel
Tubing	13 CR-95
Wellhead	Stainless steel

Monitoring details

The corrosion coupons will be located in the pipeline that feeds CO_2 injectate to the injectors. Every six months the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram.

A corrosion rate of greater than 0.3 mils/year will initiate consultation with the regulatory agencies. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year.

Above Confining Zone Monitoring

CTV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

Monitoring above the confining zone will include the following:

1. Tulare Formation - Tulare Formation that includes the Upper Tulare Formation USDW and Lower Tulare Formation will be monitored from 1,017 – 1,950 feet TVD (- 399 to -1332 feet TVDSS).

2. Etchegoin Formation – between the confining layer and USDW at 3,828 feet TVD (-3,091 feet TVDSS).

Monitoring location and frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well locations with respect to the AoR. The wells are located within the Elk Hills Oil Field, CTV owns the surface and mineral rights.

Etchegoin Formation

The Etchegoin Formation zone between the confining zone and Upper Tulare USDW will dissipate any CO_2 injectate that migrates upward through the confining zone. The Etchegoin will be monitored continuously for pressure and temperature changes within a continuous sand at –3,091 feet SSTVD. Leakage from the Monterey Formation to the Etchegoin Formation will increase the reservoir pressure and decrease the temperature of the Etchegoin.

The 346-7R-RD1 Etchegoin monitor well is located between the two CO_2 injection wells (Figure 1). The Etchegoin zone is continuous across the AoR. As such, 346-7R-RD1 will adequately monitor for pressure and temperature changes.

Prior to injection, baseline water analysis will be acquired for the Etchegoin Formation monitoring zone.

Tulare Formation

Monitoring in the Upper Tulare will include pressure and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration).

Along with the Upper Tulare aquifer, CTV will monitor the Lower Tulare in well 61WS-8R due to the following:

1. Within the AoR, the liquid column in the Upper Tulare is very thin. It is dependent on regional aquifer recharge and due to drought, the water level is falling. The down-dip 61WS-8R monitoring well location will have a thicker section of Upper Tulare USDW water to be sampled.

2. The Lower Tulare is not considered an exempt aquifer outside the project area. The monitoring well will validate that the Lower Tulare is not impacted by CO_2.

CTV has obtained a baseline analysis for the 61WS-8R well. Prior to injection, an updated baseline analysis will be completed. Future results will be compared against these baseline results for significant changes or anomalies. In particular, pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

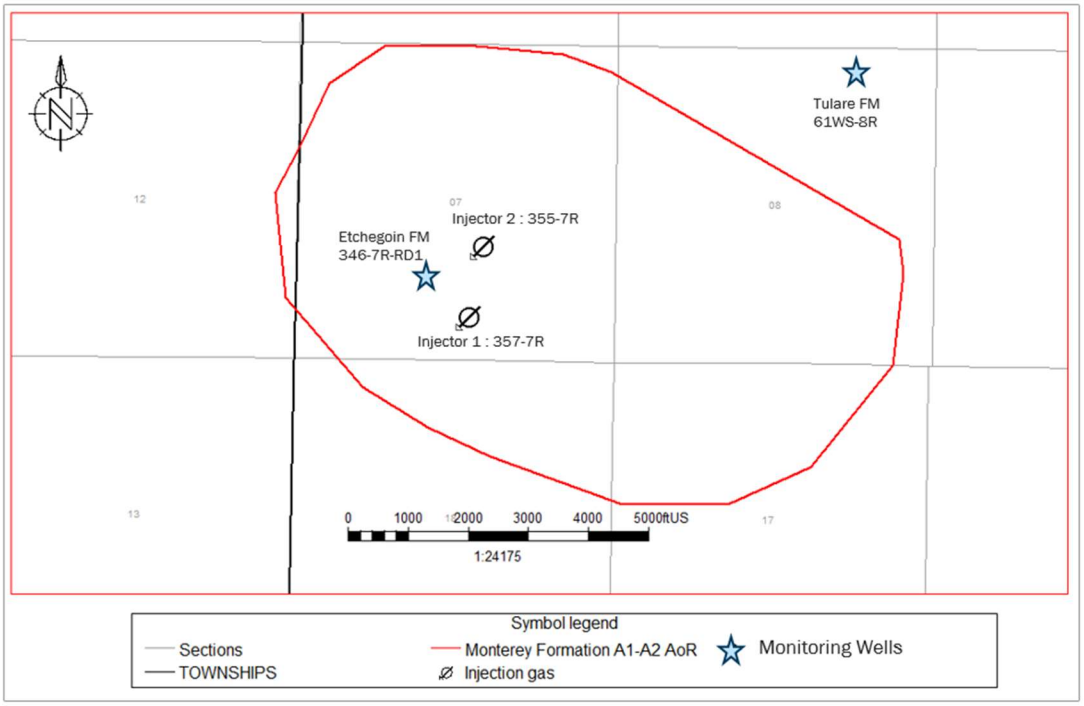
1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation A1-A2 CO_2 injection.

2. Tulare Formation pressure or composition changes due to Monterey Formation A1-A2 CO_2 injection.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
Tulare Formation	Fluid Sampling	61WS-8R	Annually
	Pressure/Temperature	61WS-8R	Continuously
Etchegoin Formation	Pressure/Temperature	346-7R-RD1	Continuously

Figure 1: Above confining zone monitoring wells.



Analytical parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for ground water samples.

Parameters	**Analytical Methods**
Tulare Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	SM 4500-CO2-C
Total Dissolved Solids	SM 2540 C
Alkalinity	SM 2320 B
pH (field)	EPA 150.1 / SM4500-H+B
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple
Dissolved Methane	RSK-175/Gas Chromatography

Sampling methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory to be used/chain of custody procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

External Mechanical Integrity Testing

CTV will conduct at least one test periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90. MITs will be performed annually, within 30 days of the injection authorization date.

CTV will run a temperature log via wireline to ensure mechanical integrity of the tubing and downhole packer. If CTV elects to conduct an alternate MIT, notification that includes the test and a description will be sent to the EPA for approval.

Testing location and frequency

Table 6. MITs.

Test Description	Location
Temperature Log	Along wellbore via wireline well log
Radioactive Tracer	Along wellbore via iodine

Testing details

CTV will follow the following procedures for MIT temperature logging:

1. Stabilize injection for 24 hours prior to running the temperature log. If possible, the wireline speed will be limited to 20 feet per minute or less.

2. Run a temperature survey from 200 feet above the Reef Ridge Shale base to the deepest point reachable in the well, while injecting at a rate that allows for safe operations.

3. Shut-in well and run multiple temperature surveys with 1-2 hours between runs.

4. Assess the acquired time lapse temperature profiles. As the well cools, the temperature profile is compared to the baseline. External integrity issues present themselves anomalies when compared to the baseline.

Pressure Fall-Off Testing

CTV will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

Testing location and frequency

The main benefit of pressure fall-off testing is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation A1-A2 reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

Testing details

If CTV completes a pressure fall-off test, the following procedure will be followed:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Carbon Dioxide Plume and Pressure Front Tracking

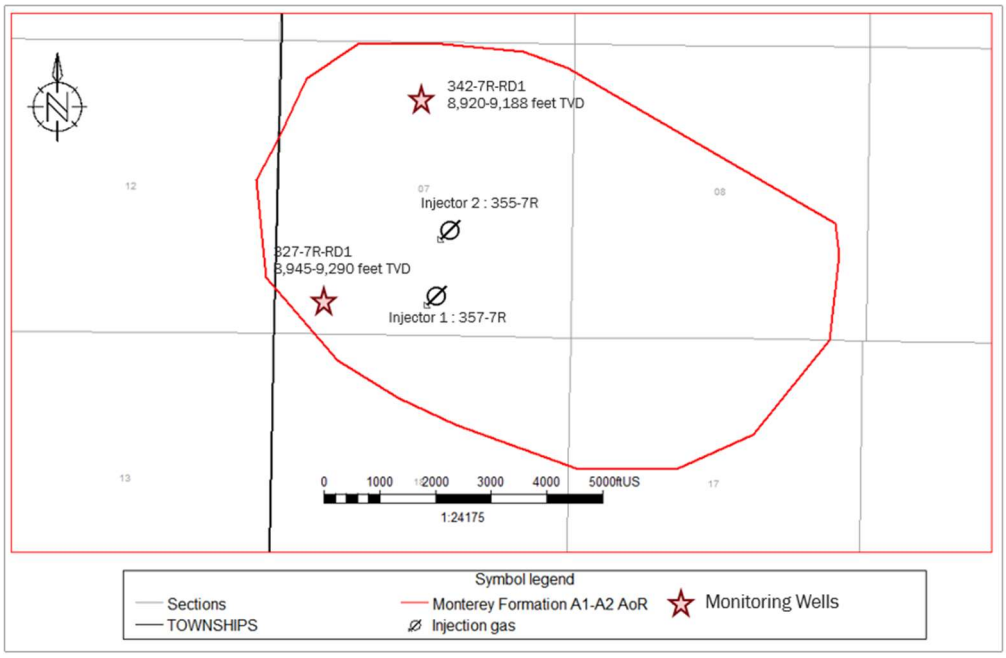
CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume monitoring location and frequency

Table 7 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 8. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND AQUISTION of the QASP.

Figure 2 shows the location and depth of the wells that will monitor the CO_2 plume directly in the targeted A1-A2 zone. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary.

Figure 2: Monterey Formation A1-A2 sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.



Plume monitoring details

Fluid sampling and pressure monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 8.

As discussed in the AoR and Corrective Action Plan, 98% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

Underlying Monterey A3-A11 Reservoir Monitoring

CTV will monitor the Monterey Formation A3-A11 reservoir and wellbores for CO_2 migration. Waterflood producers will be monitored via fluid sampling once per quarter for changes in composition. In addition, Monterey Formation A3-A11 waterflood injectors will have MITs and SAPTs to ensure internal and external mechanical integrity. This monitoring will be discussed in more detail within the Testing and Monitoring Plan. Additionally, due to its waterflood infrastructure and high reservoir pressure, the A3-A6 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

Table 7. Plume monitoring activities.

DIRECT PLUME MONITORING			
Monterey Formation A1-A2	Fluid Sampling	327-7R-RD1 and 342-7R-RD1	Annual
Monterey Formation A3+	Fluid Sampling	EOR producers	Quarterly
INDIRECT PLUME MONITORING			
Monterey Formation A1-A2	Pulse Neutron Logging	327-7R-RD1 and 342-7R-RD1	Every two years from start of injection.

Table 8. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	**Analytical Methods**
Tulare Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO2	SM 4500-CO2-C
Total Dissolved Solids	SM 2540 C
Alkalinity	SM 2320 B
pH (field)	EPA 150.1 / SM4500-H+B
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple
Dissolved Methane	RSK-175/Gas Chromatography

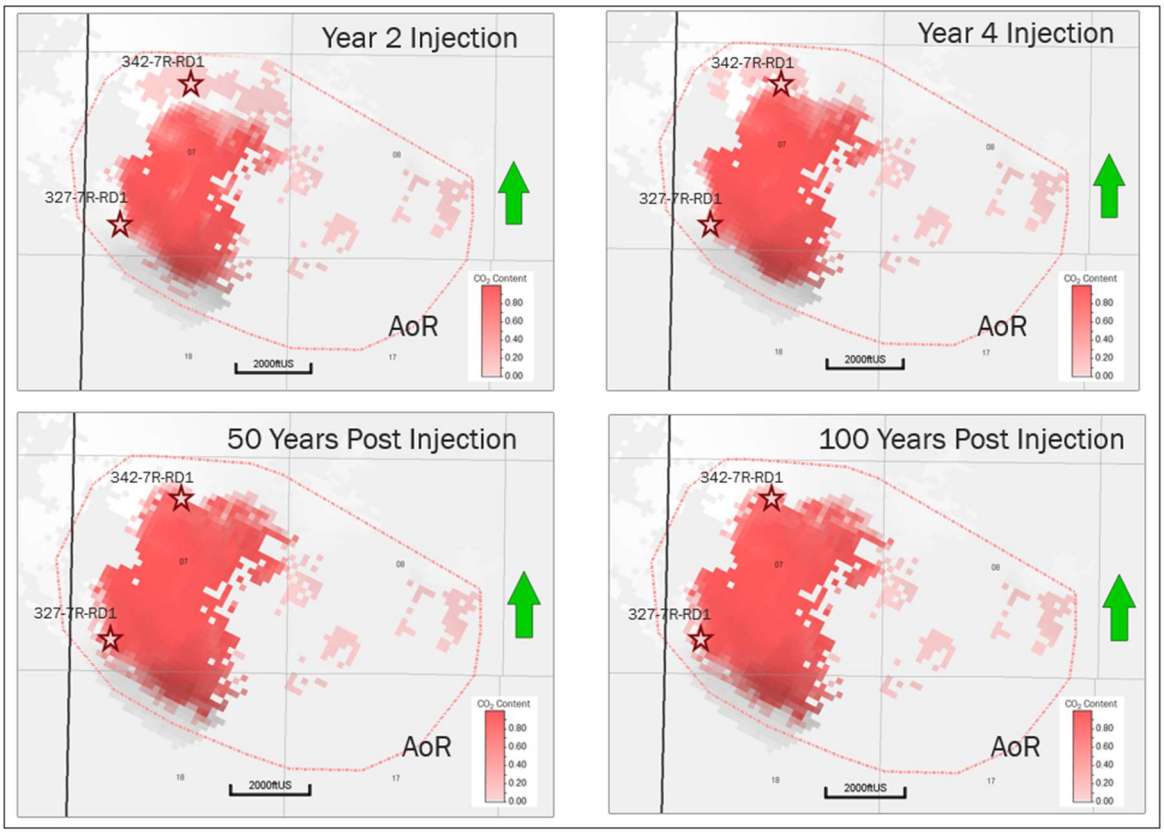
Pressure-front monitoring location and frequency

Table 9 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ.

Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND AQUISTION of the QASP.

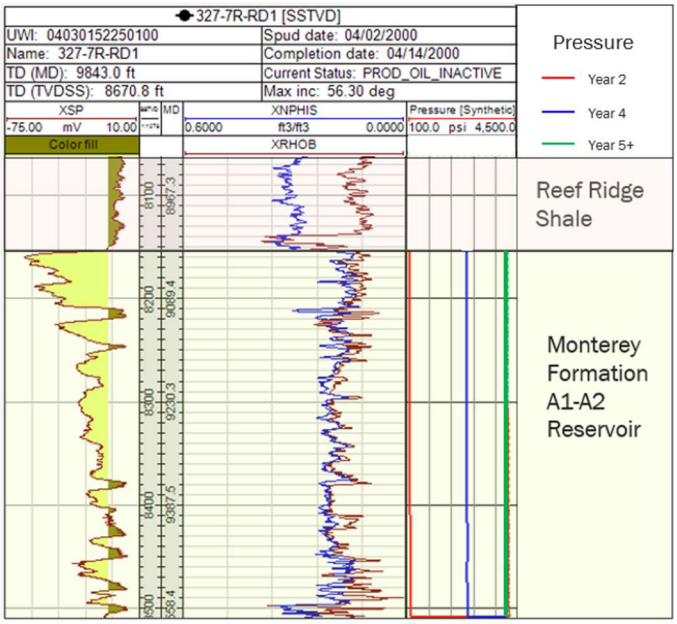
The aerial extent of plume development in the Monterey Formation A1-A2 reservoir will reach the AoR boundaries early in the injection phase. Because the reservoir is pressure depleted, injected CO_2 will quickly fill the available pore space. Monitoring well locations with respect to plume development through time are shown in Figure 3.

Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.



Monitoring well 327-7R-RD1 pressure development based on computational is modeled in Figure 4. Note that the reservoir pressure after five years is stable. This is due to the high amount of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases.

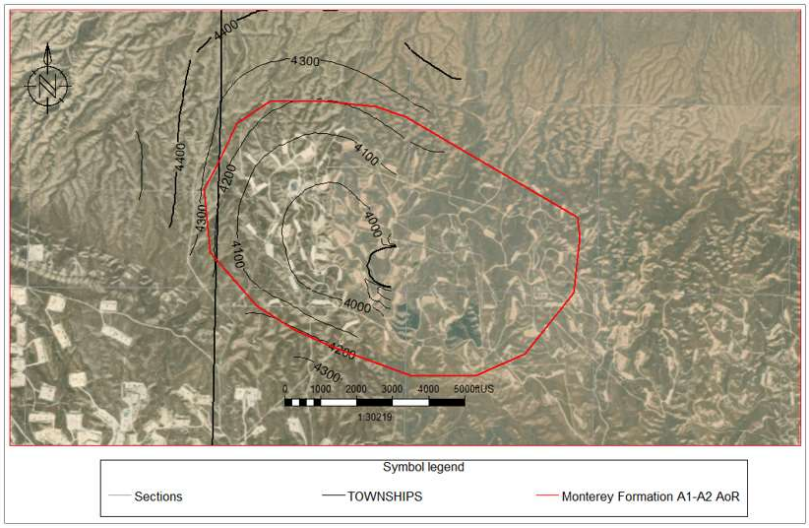
Figure 4: Monitoring well 327-7R-RD1 showing the pressure increase through time from the computational modeling results.



Pressure-front monitoring details

Direct pressure monitoring of the plume will be achieved through installation of pressure gauges in monitoring wells 327-7R-RD1 and 342-7R-RD1. The depleted Monterey Formation A1-A2 oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

Figure 5: Monterey Formation A1-A2 pressure 100 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.



The modeled pressure increases at monitoring well 327-7R-RD1 are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 9. Pressure-front monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FRONT MONITORING			
Monterey Formation A1-A2	Pressure and temperature monitoring	327-7R-RD1 and 342-7R-RD1	Continuous
INDIRECT PRESSURE-FRONT MONITORING			
All formations	Seismicity	AoR	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with surface and shallow borehole seismometers in the AoR. The seismometers will be tied in with the regional network to increase resolution and assess natural versus induced seismicity. The seismometers will be able to detect events with a magnitude 0 to 0.5 and will be installed pre-injection to provide baseline seismicity. In addition, CTV will monitor the Southern California Earthquake Data Center (SCEDC) network for seismic events.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

ATTACHMENT C: TESTING AND MONITORING PLAN
40 CFR 146.90

Elk Hills A1-A2 Storage Project

Facility Information

Facility Name: Elk Hills A1-A2 Storage
357-7R & 355-7R

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Att C- TM Final V3	3	11/4/22	Updated to include responses to EPA comments dated 07/20/22

This Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills A1-A2 Storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting Procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the start of injection and every three months thereafter.

CTV is evaluating several sources of CO_2 as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and

2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)

Parameter	Analytical Method(s)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry

Sampling Methods

CO_2 stream sampling will occur at the discharge of the last compressor upstream of the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a state certified full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the injected CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the "Injection & Monitoring Well Schematics_v2" document.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface Downhole 355-7R: 8,387' (MD) 357-7R: 8,420' (MD)	10 seconds	30 seconds
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface Downhole 355-7R: 8,387' (MD) 357-7R: 8,420' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure of 90% of the injection zone's fracture pressure. Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

Calculation of Injection Volumes

The volume of CO_2 injected into the Monterey Formation A1-A2 will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation A1-A2 will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive brine with corrosion inhibitor. The casing-tubing annulus for injection wells 355-7R and 357-7R will be maintained on average with 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1000 psi and cannot be explained by operational conditions.

Corrosion Monitoring [40 CFR 146.90(c)]

CTV will monitor well materials during the operation period for loss of mass, change in thickness, cracking, pitting, or other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors.

Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For wells 357-7R and 355-7R, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 Carbon Steel (355-7R)
	N-80 Carbon Steel (357-7R)
	P-110 Carbon Steel (353A-7R, 335X-7R)
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. 327-7R-RD1 (Figure 1) is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 3,782' - 3,934' MD in 327-7R-RD1.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure and decrease in temperature of the Etchegoin. Additionally, potential leakage will create compositional changes detectable with fluid sampling and geochemical monitoring. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The location of the USDW monitoring well is structurally down-dip of the AoR to ensure that there is adequate water for sampling. The Upper Tulare is mostly unsaturated in the AoR and the water column height increases to the north, off the structure. The Upper Tulare Formation USDW will be monitored between 940' – 960' MD in the USDW monitoring well.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation A1-A2 CO_2 injection.

2. Tulare Formation pressure or composition changes due to Monterey Formation A1-A2 CO_2 injection.

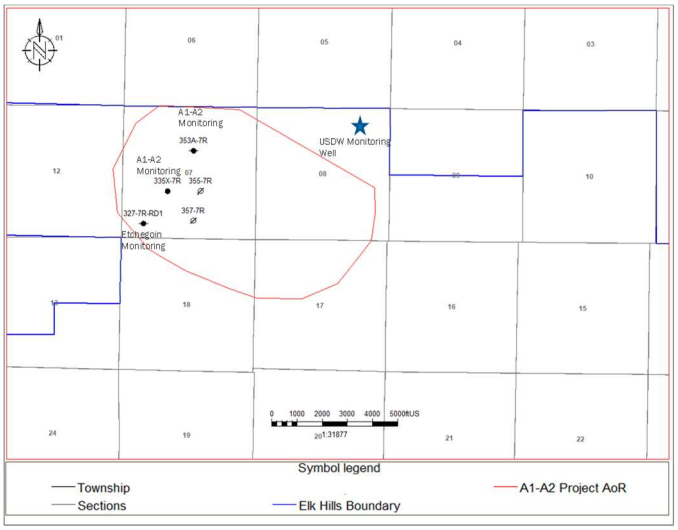
Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well locations with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD	Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD 961' MD 854' MD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD	Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' MD 3850' - 3990' MD	Continuous

Figure 1: Above confining zone monitoring wells, USDW monitoring well and 327-7R-RD1.



Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Ti)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si, Sb)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Sampling Methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage Project site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following.

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a SAPT will be performed. The injection and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b).

Standard Annular Pressure Testing (SAPT)

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished, throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.

2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.

4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.

5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least one-minute intervals.

6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure, ie. 900 psi, the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director.

Table 6. Internal MIT requirements

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)
Standard Annular Pressure Test (SAPT)	355-7R[1]	Casing/tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	2990	3090
	357-7R[1]					2993	3093
	327-7R-RD1[2]				Any time packer is replaced or reset	--	1000
	335X-7R[3]					--	1000
	353A-7R					--	1000
Annular Pressure	355-7R[1] 357-7R[1] 327-7R-RD1[2] 335X-7R[3] 353A-7R[3]	Wellhead	Continuous	Continuous	Not Applicable	--	--
Fluid Sampling	345-7R[4] 388X-7R[4] 341-17R[4]	Wellhead	Baseline	Quarterly	Annual	--	--

[1] CO2 injection well
[2] Above Zone monitoring well
[3] Injection Zone monitoring well
[4] Monterey Formation A3-A11 monitoring well

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3% of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in realtime based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

Internal MIT for Monterey Formation A3-A11 Monitoring Wells

The active wells that will be used for monitoring the underlying A3-A11 reservoir will be monitored for internal mechanical integrity through fluid sampling. The wells are not configured with tubing and packer such than an annulus is not available to monitor or test using SAPT procedures. The current application of these wells precludes configuring these wells with this equipment. Fluid sampling, as described in the Carbon Dioxide Plume and Pressure Front Monitoring section below, will evaluate the presence or absence of CO_2 as a proxy for internal mechanical integrity. The presence of CO2 in the fluid sample will require EPA notification and diagnosis of the source of CO2 in the wellbore, either through the A3-A11 underlying reservoir or through wellbore mechanical integrity failure. In this event, CTV will provide a diagnostic plan and request approval from the EPA Director.

External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While DTS may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Since temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for

other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. Instead, another approved method under 40 CFR 146.89(c) may be utilized, or DTS may be proposed for EPA Director approval for monitoring well MIT.

Table 7. External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will utilize the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.

2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.

3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.

4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

    b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

d. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

e. The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in realtime, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.

4. Start injection and record the temperature profile for 6 hours.

5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS

will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will likely be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warmback can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in realtime. If dense phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data is superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

DTS will not be installed on the Monterey Formation A3-A11 wells.

Description of Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging may be carried out while injection is occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Run a noise survey from top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.

3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

   a. The base of the lowermost bleed-off zone above the injection interval and

b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging may be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray (GR) log and Casing Collar Locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a “no vertical flow behind the casing” section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up hole or downhole as necessary at no more than 50 foot intervals and take stationary readings to determine the area of fluid migration.

Pressure Fall-Off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests on each injector during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut in. The injection pressure will be high enough to produce a pressure decrease upon shut in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.

2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottomhole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10 second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.

5. Interference testing may be conducted at the conclusion of the falloff test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut in well.

6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry standard methodologies. Anomalies that are identified from the interpretation will be investigated.

7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Falloff Testing Requirements document.

Carbon Dioxide Plume and Pressure Front Tracking

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted A1-A2 zone. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Figure 2: Monterey Formation A1-A2 sequestration reservoir monitoring wells, 335X-7R and 353A-7R.

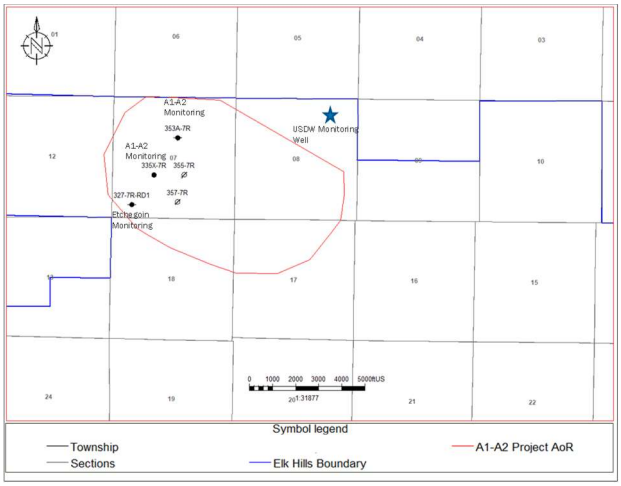


Table 8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Table 8. Plume monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm A1-A2	Fluid Sampling	335X-7R	8737' - 9030' MD	Once	Quarterly
		Pressure		8667' MD	Baseline	Continuous
		Temperature		8667' MD	Baseline	Continuous
	Monterey Fm A1-A2	Fluid Sampling	353A-7R	8773' - 9130' MD	Once	Quarterly
		Pressure		8703' MD	Baseline	Continuous
		Temperature		8703' MD	Baseline	Continuous
	Monterey Fm A3-A11 (below injection zone)	Fluid Sampling	345-7R	8904' - 9402' MD	Once	Quarterly
		Fluid Sampling	388X-7R	8800' - 9290' MD	Once	Quarterly
		Fluid Sampling	341-17R	8844' - 9307' MD	Once	Quarterly
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	335X-7R	8737' - 9030' MD	Baseline	Every 2 years from start of injection
			353A-7R	8773' - 9130' MD		

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone and the Monterey Formation A3-A11.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Ti)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1

Parameters	Analytical Methods
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Plume Monitoring Details

Fluid sampling, pressure monitoring, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 8.

The DTS from the two monitoring wells will provide continuous temperature from packer to surface.

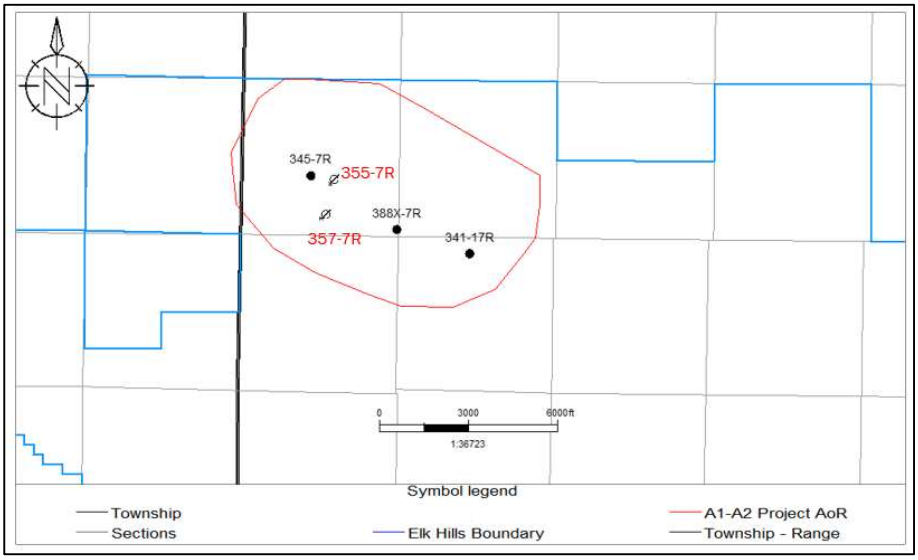
As discussed in the AoR and Corrective Action Plan, 96% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

Monitoring the Underlying Monterey A3-A11 Reservoir

The Monterey Formation A3-A11 reservoir will be monitored for the presence of CO_2 above baseline in the production stream as an indication of CO_2 migration below the A1-A2 injection zone. Waterflood producers shown in Figure 3 will be monitored during injection operations by sampling the produced fluid at surface once per quarter for changes in composition as per Table 9. Due to its waterflood infrastructure and high reservoir pressure, the A3-A11 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

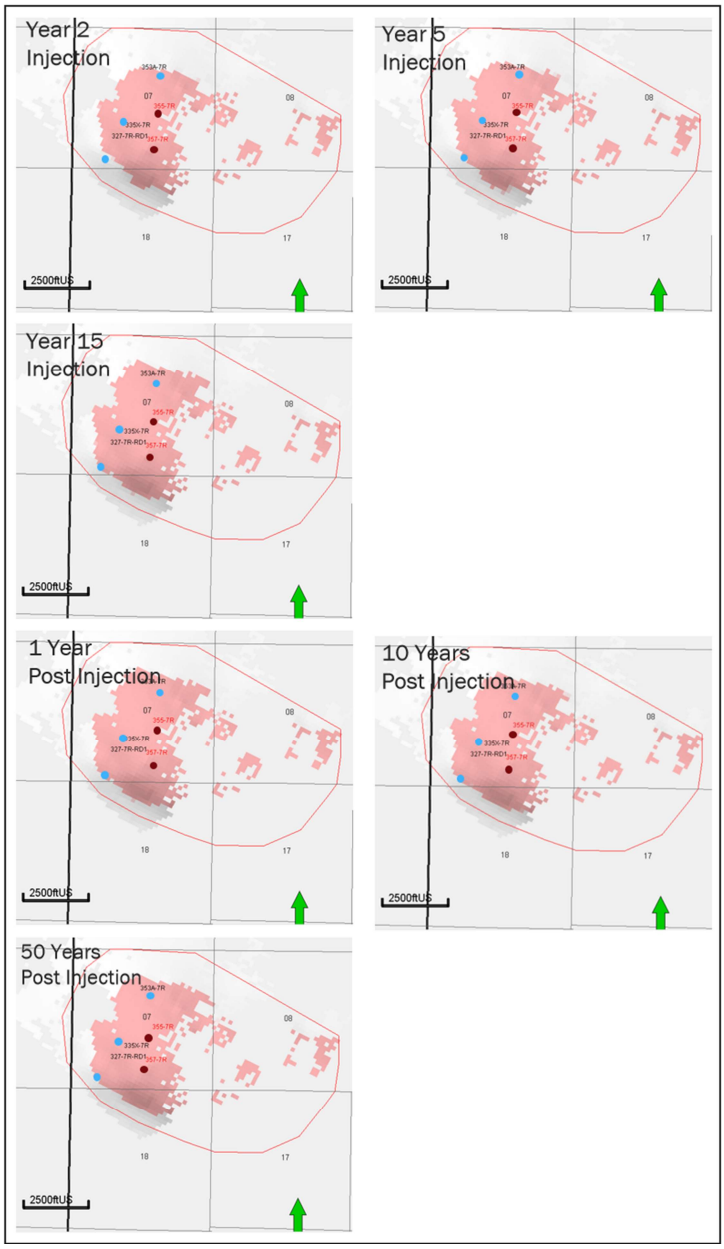
Figure 3: A3-A11 wells for fluid sampling to assess basal confinement of the CO_2 injectate.



Pressure Front Monitoring Location and Frequency

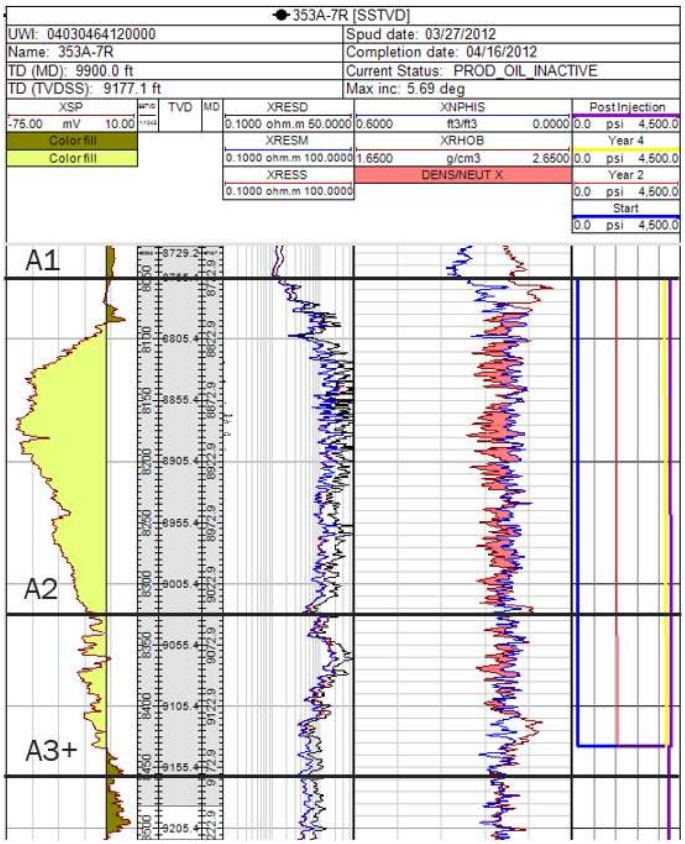
The aerial extent of plume development in the Monterey Formation A1-A2 reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 4.

Figure 4. Monitoring well location with maps showing plume development through time from computational modeling.



Monitoring well 353A-7R pressure development based on the computational model is shown in Figure 5 in the right-hand track. The reservoir pressure stabilizes after five years. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Figure 5: Monitoring well 353A-7R showing the pressure increase through time from the computational modeling results.



Pressure Front Monitoring Details

Direct pressure and temperature monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 353A-7R and 335X-7R. The depleted Monterey Formation A1-A2 oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 6 shows the pressure in the reservoir post injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

Figure 6: Monterey Formation A1-A2 pressure 100 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

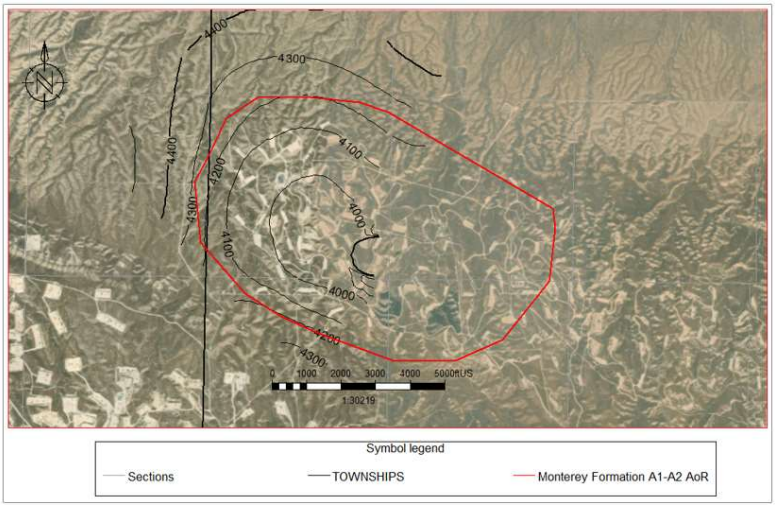


Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Table 10. Pressure-front monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm A1-A2	Pressure	335X-7R	8737' - 9030' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
	Monterey Fm A1-A2	Pressure	353A-7R	8773' - 9130' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)]	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. This network will be implemented to monitor seismic activity near the project

site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones
- Borehole sensors will be deployed deeper than 1,500' to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events $>M_w$ 0.0

Baseline Analysis:

The monitoring network will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data transmitted near real-time via cellular modem or other wireless means and archived in a database
- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network.
The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

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ATTACHMMENT D2: INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage
355-7R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Carbon TerraVault 1 LLC (CTV) will conduct injection well plugging and abandonment according to the procedures below.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a).

A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 1 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Class G cement blend will be utilized that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The wells will have this cement placed inside casing from total depth (TD) of the well to surface. The cement will be set in plug segments per CTV's standard procedures.

Table 1: Plugging details.

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.184	6.184, 6.276, 6.366	6.184, 6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,692	8,371	1,384	25
Sacks of cement to be used (each plug)	58	1322	258	4
Slurry volume to be pumped (ft^3)	67	1520	297	5
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,371	1,384	25	0
Bottom of plug (ft)	8,692	8,371	1,384	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

Narrative Description of Plugging Procedures

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following procedures are planned for plugging:

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Well equipment is removed from the casing and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

3. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up-hole while cementing operations continue. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up-hole while operations are paused to wait on cement. Once the cement has "set", the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval. This process is repeated until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

ATTACHMMENT D: INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R

Facility contact: Kenneth Haney / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 763-6101/ Kenneth.Haney@CTV.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Carbon TerraVault 1 LLC (CTV) will conduct injection well plugging and abandonment according to the procedures below.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a).

A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 1 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Class G cement blend will be utilized that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The wells will have this cement placed inside casing from total depth (TD) of the well to surface. The cement will be set in plug segments per CTV's standard procedures.

Table 1: Plugging details.

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.184	6.366	6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,785	2,970	1,448	25
Sacks of cement to be used (each plug)	65	25	25	5
Slurry volume to be pumped (ft^3)	75	28	28	6
Slurry weight (lb./gal)	15.6	15.6	15.6	15.6
Calculated top of plug (ft)	8,427	2,845	1,323	0
Bottom of plug (ft)	8,785	2,970	1,448	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

Narrative Description of Plugging Procedures

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following procedures are planned for plugging:

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Well equipment is removed from the casing and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

3. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up-hole while cementing operations continue. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up-hole while operations are paused to wait on cement. Once the cement has "set", the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval. This process is repeated until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L DTS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
357-7R & 355-7R

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault I LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize within one year after injection ceases. Injection limits will be based on the fracture pressure of the Monterey Formation A1-A2 and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application, and the AoR and Corrective Action Plan.

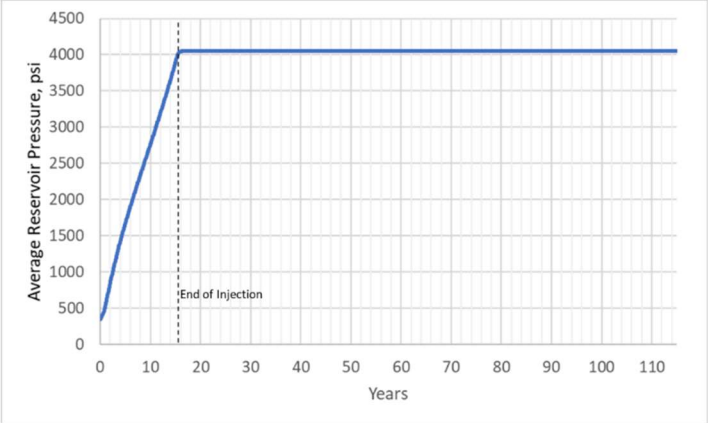
Discussion

The Monterey Formation A1-A2 reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation A1-A2 storage reservoir exists prior to the commencement of CO_2 injection. Through

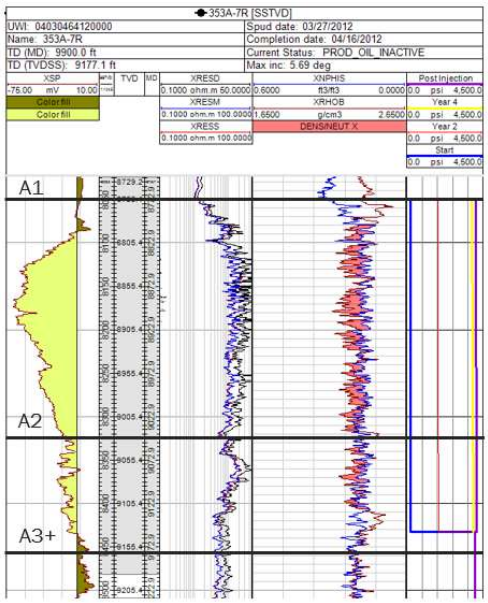
time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Due to high permeability, continuity of the reservoir and low injection pressure differential of the reservoir, pressure stabilization occurs within one year of injection cessation with the rate of change of pressure dropping below 10psi/year (0.027psi/day). Figure 1 shows the A1-A2 reservoir pressure increase during injection and pressure stabilization after injection from computational modeling.

Figure 1: Average Reservoir Pressure trend over the 15 year injection period and 100 years post injection.



Pressure at monitoring well 353A-7R will not decline post-injection (Figure 2). The low water saturation within the Monterey Formation A1-A2 storage reservoir results in greater than 98% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

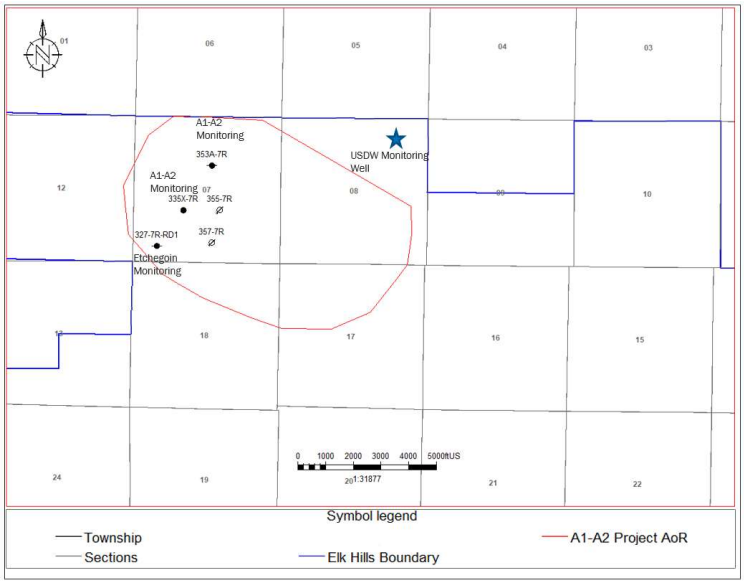
Figure 2: Pressure at the 353A-7R monitoring well at start of injection, year two, four and post injection.



Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 3: Map of the predicted extent of the CO2 plume at site closure. The pressure of the A1-A2 reservoir will be at or beneath the initial pressure at the time of discovery.



Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include pressure monitoring and fluid composition monitoring in the storage reservoir and reservoirs above the injection zone. Post-injection monitoring, as described in the following sections, will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days of the anniversary date of final injection, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

The Testing and Monitoring Plan describes the monitoring strategies within the injection zone, above the injection zone, and within the USDW-containing reservoir. In addition to monitoring the zones above the injection zone for stabilized pressure and absence of CO_2, the injection zone will be monitored for pressure stabilization as the best method to confirm confinement within the storage reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

The Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Surface, mineral, and pore space rights for the Monterey Formation A1-A2 reservoir are owned entirely by CTV where all activities will take place. As such, site access is guaranteed for the duration of the project and for post-injection monitoring.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ.

The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD/VD	Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD/VD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD/VD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD/VD 961' MD/VD 854' MD/VD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD 3780' - 3932' VD	Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' MD/VD 3850' - 3990' MD/VD	Continuous

Table 2. Summary of analytical and field parameters for water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method
Dissolved Methane	SM 6211 B or 6211 C

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	USDW Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	USDW Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the associated increase in pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the Monterey Formation A1-A2 (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

Table 4. Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency	Depth (ft)
DIRECT PLUME MONITORING				
Monterey Formation A1-A2	Fluid Sampling	353A-7R and 335X-7R	Quarterly	353A-7R: 8703' MD 335X-7R: 8667' MD
INDIRECT PLUME MONITORING				
Monterey Formation A1-A2	Pulse Neutron Logging	353A-7R and 335X-7R	Every five years	353A-7R – 8,773'– 9,130' MD 335X-7R – 8,737'-9,030' MD

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si, Sb)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance	APHA 2510
Temperature (field)	Thermocouple

Parameters	Analytical Methods
Water Density (field)	Oscillating body method
Dissolved Methane	SM 6211 B or 6211 C

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the two Monterey Formation A1-A2 monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in plan view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency	Depth (ft)
DIRECT PRESSURE-FRONT MONITORING				
Monterey Formation A1-A2	Pressure and temperature	353A-7R and 335X-7R	Continuous	353A-7R: 8703' MD 335X-7R: 8667' MD
INDIRECT PRESSURE-FRONT MONITORING				
All strata	Seismicity	AoR	Continuous	

Figure 4: Map showing AoR and well locations for post-injection monitoring.

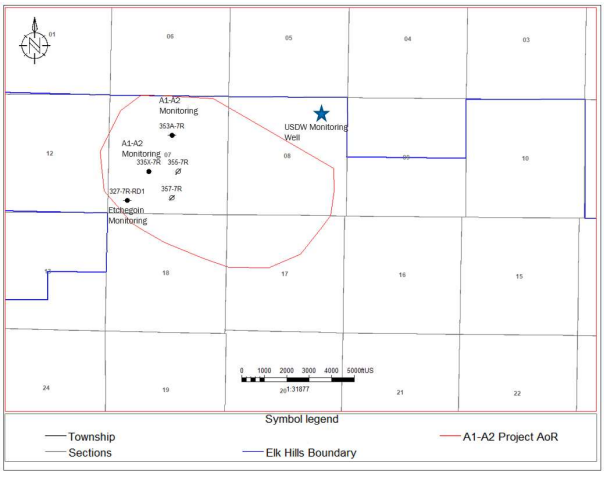
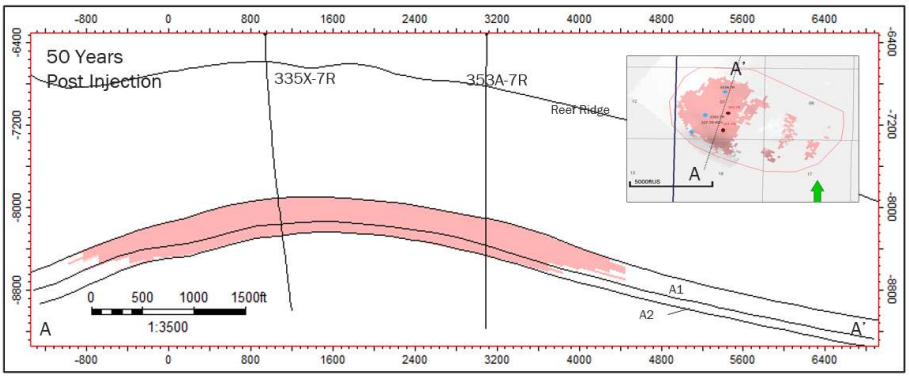


Figure 5: Cross-section showing plume CO2 injectate plume 50 years post injection and well locations for post-injection monitoring.



Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director as per 40 CFR 143.93(b)(2) or (3).

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,

2. Dates of all monitoring events,

3. Changes to the monitoring program over time,

4. An explanation of all monitoring information that has existed at the site,

5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and

6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO_2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO_2 leakage over the project timeframe,

2. the accuracy of the model to predict and represent the storage reservoir, and

3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO_2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW.

Site Closure Plan

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA.

A site closure report will be prepared and submitted within 90 days following site closure supported by the following:

1. Verification of injector and monitoring well plugging,
2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2),
3. Composition and volume of the injected CO_2, and
4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO_2 sequestration, the period of injection and the volume of CO_2 injected,
2. The formation that the fluid was injected, and
3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage Project
357-7R & 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize one year after injection ceases. Injection limits will be based on the fracture pressure of the Monterey Formation A1-A2 and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application, and the AoR and Corrective Action Plan.

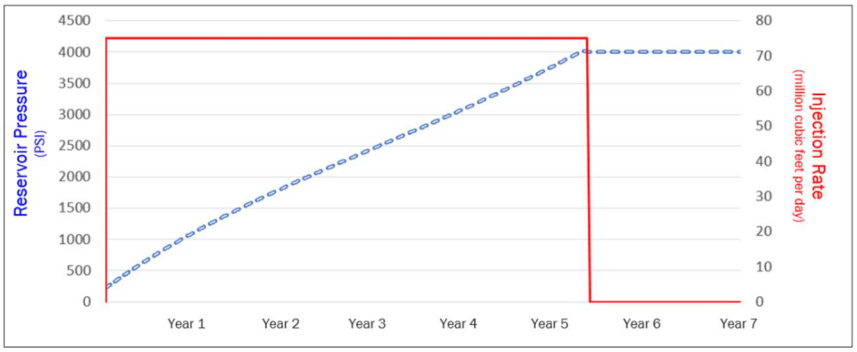
Discussion

The Monterey Formation A1-A2 reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation A1-A2 storage reservoir exists prior to the commencement of CO_2 injection. Through

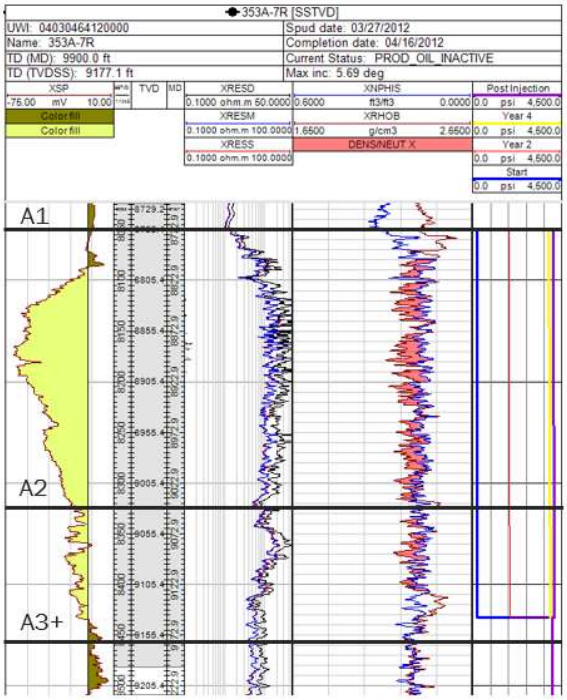
time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Due to high permeability, continuity of the reservoir and low injection pressure differential of the reservoir, pressure stabilization occurs within one year of injection cessation. Figure 1 shows the pressure of the A1-A2 reservoir through time from computational modeling.

Figure 1: Reservoir pressure and injection rate for the initial seven years of the project. Reservoir pressure stabilizes within the first-year post-injection.



Pressure at monitoring well 324-7R-RD1 will not decline post-injection (Figure 2). The low water saturation within the Monterey Formation A1-A2 storage reservoir results in greater than 98% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

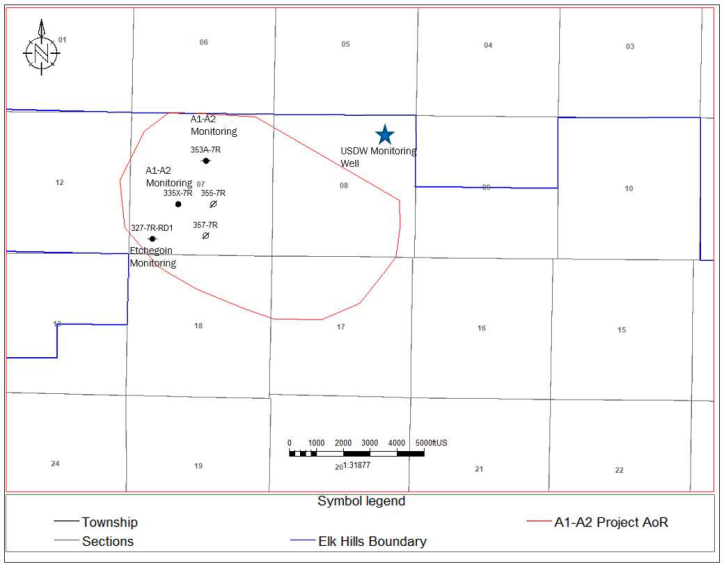
Figure 2: Pressure at the 327-7R-RD1 monitoring well. Pressure at the end of year five is stable through the end of the computational modeling period (100 years post-injection).



Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 3: Map of the predicted extent of the CO2 plume at site closure. The pressure of the A1-A2 reservoir will be at or beneath the initial pressure at the time of discovery.



Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include a combination of groundwater pressure, fluid composition and storage zone pressure as described in the following sections and will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Post-injection monitoring will include a combination of groundwater monitoring, and storage zone pressure monitoring. Pressure monitoring of the Monterey Formation A1-A2 storage reservoir will monitor for pressure stabilization. This is the best method to confirm confinement of the reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

Throughout most of the AoR there is a very small column of USDW. As such, the down gradient Tulare Formation USDW groundwater monitoring well will continuously assess reservoir

pressure. Groundwater samples will be analyzed annually for indicators of CO_2 movement into the USDW.

Surface, mineral and pore space rights for the Monterey Formation A1-A2 reservoir are owned 100% where all activities will take place. As such, site access is guaranteed for the duration of the project and for post-injection monitoring.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ.

The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency	Depth (feet)
Tulare Formation	Fluid sampling	USDW Monitoring Well	AoR	Annually	950 – 967 MD 950 – 967 TVD
	Pressure and Temperature	USDW Monitoring Well	AoR	Continuously	
Etchegoin Formation	Fluid sampling	327-7R-RD1	AoR	Annually	3,782 – 3,934 MD 3,780 – 3,932 TVD
	Pressure and Temperature Monitoring	327-7R-RD1	AoR	Continuously	

Table 2. Summary of analytical and field parameters for water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, ZN, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)

Parameters	Analytical Methods
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	USDW Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	USDW Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation A1-A2 (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

Table 4. Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PLUME MONITORING			
Monterey Formation A1-A2	Fluid Sampling	353A-7R and 335X-7R	Annually
INDIRECT PLUME MONITORING			
Monterey Formation A1-A2	Pulse neutron logging	353A-7R and 335X-7R	Every five years

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, ZN, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the two Monterey Formation A1-A2 monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in plan view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FRONT MONITORING			
Monterey Formation A1-A2	Pressure and temperature	353A-7R and 335X-7R	Continuous
INDIRECT PRESSURE-FRONT MONITORING			
All strata	Seismicity	AoR	Continuous

Figure 4: Map showing AoR and well locations for post-injection monitoring.

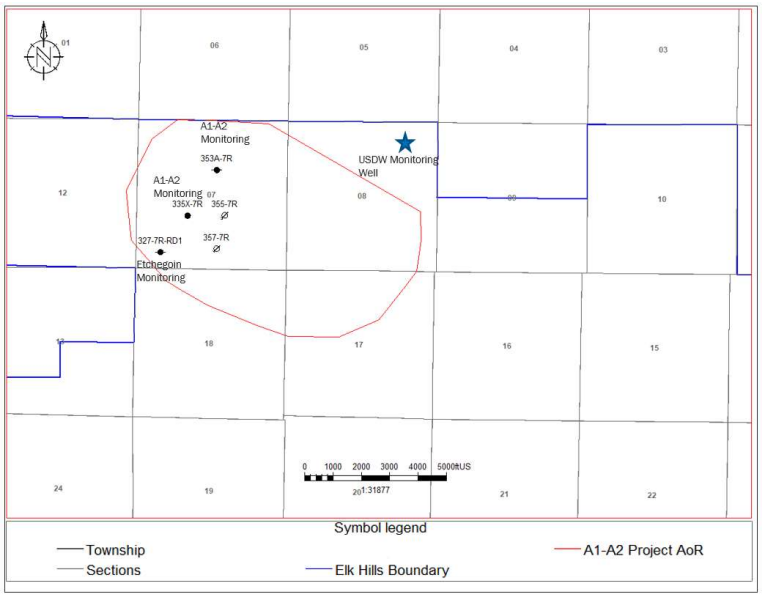
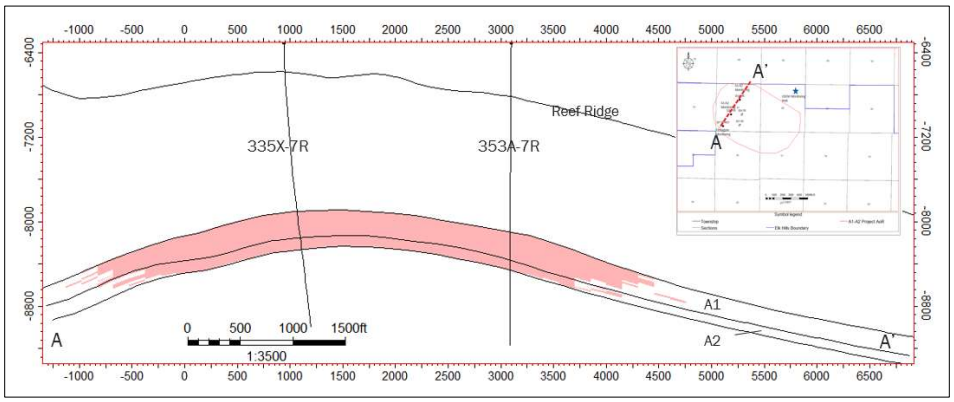


Figure 5: Cross-section showing plume CO2 injectate plume 50 years post injection and well locations for post-injection monitoring.



Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director as per 40 CFR 143.93(b)(2) or (3).

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,
2. Dates of all monitoring events,
3. Changes to the monitoring program over time,
4. An explanation of all monitoring information that has existed at the site,
5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and
6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO_2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO_2 leakage over the project timeframe,
2. the accuracy of the model to predict and represent the storage reservoir, and
3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO_2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW.

Site Closure Plan

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site and submit a site closure plan to the EPA.

A site closure report will be prepared and submitted within 90 days following site closure supported by the following:

1. Verification of injector and monitoring well plugging,

2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2),

3. Composition and volume of the injected CO_2, and

4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO_2 sequestration, the period of injection and the volume of CO_2 injected,

2. The formation that the fluid was injected, and

3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R

Facility contact: Kenneth Haney / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 763-6101/ Kenneth.Haney@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize one year after injection ceases. Final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

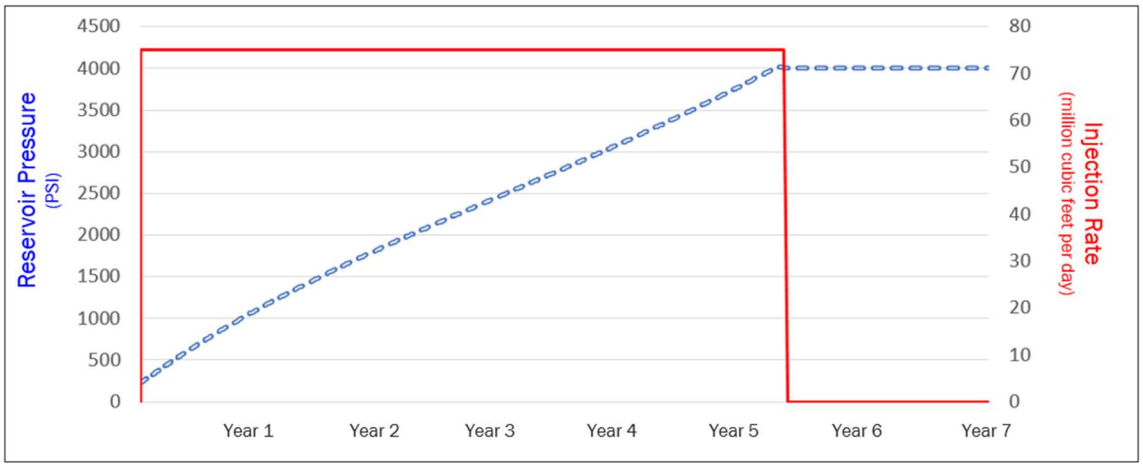
Discussion

The Monterey Formation A1-A2 reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation A1-A2 storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when

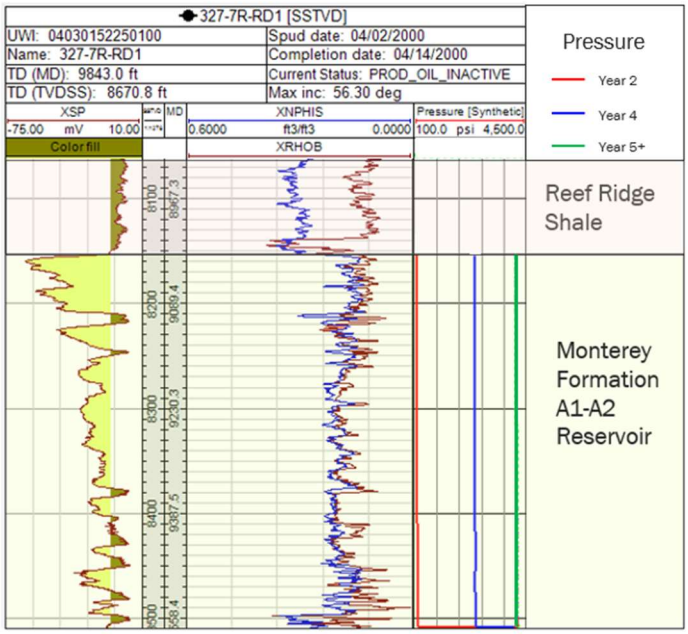
the reservoir pressure will be at the initial conditions of the reservoir. Due to high permeability, continuity of the reservoir and low injection pressure differential of the reservoir, pressure stabilization occurs within one year of injection cessation. Figure 1 shows the pressure of the A1-A2 reservoir through time from computational modeling.

Figure 1: Reservoir pressure and injection rate for the initial seven years of the project. Reservoir pressure stabilizes within the first-year post-injection.



Pressure at monitoring well 327-7R-RD1 will not decline post-injection (Figure 2). The low water saturation within the Monterey Formation A1-A2 storage reservoir results in greater than 98% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

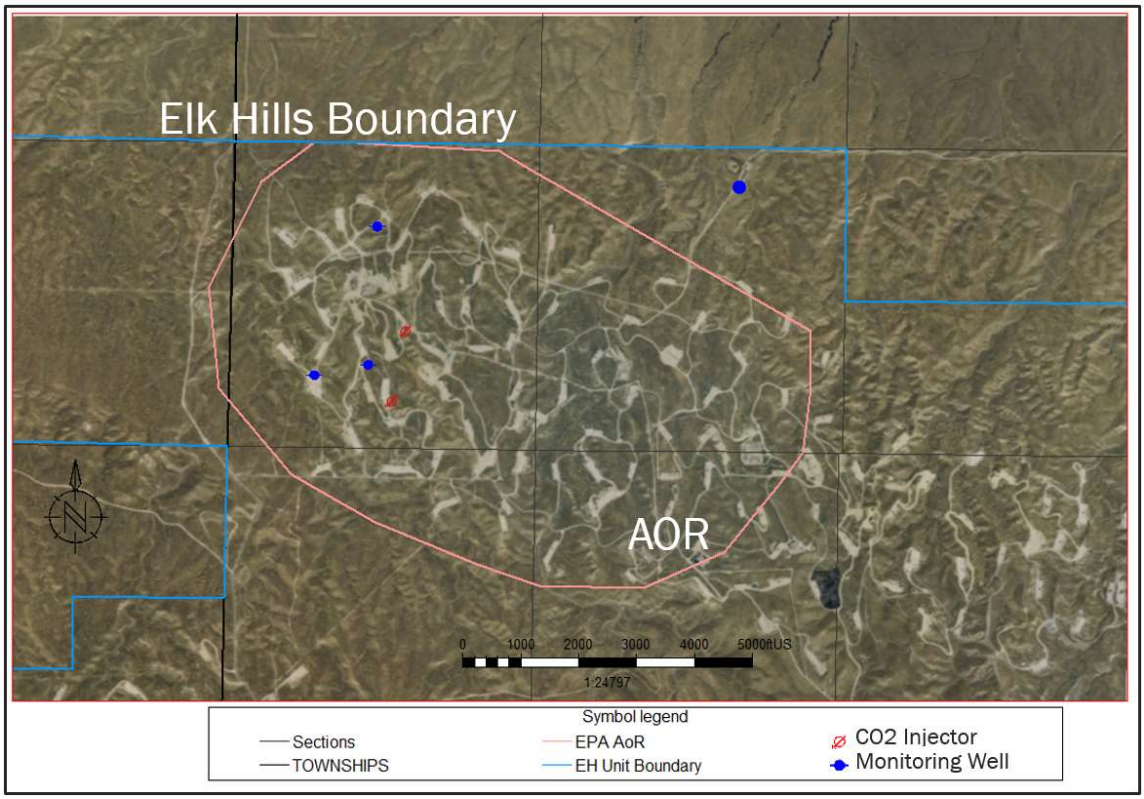
Figure 2: Pressure at the 327-7R-RD1 monitoring well. Pressure at the end of year five is stable through the end of the computational modeling period (100 years post-injection).



Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 3: Map of the predicted extent of the CO2 plume at site closure. The pressure of the A1-A2 reservoir will be at or beneath the initial pressure at the time of discovery.



Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include a combination of groundwater pressure, fluid composition and storage zone pressure as described in the following sections and will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Post-injection monitoring will include a combination of groundwater monitoring, and storage zone pressure monitoring.

> Pressure monitoring of the Monterey Formation A1-A2 storage reservoir will monitor for pressure stabilization. This is the best method to confirm confinement of the reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.
>
> Throughout most of the AoR there is a very small column of USDW. As such, the down gradient Tulare Formation USDW groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed every five years for indicators of CO_2 movement into the USDW.

Surface, mineral and pore space rights for the Monterey Formation A1-A2 reservoir are owned 100% where all activities will take place. As such, site access is guaranteed for the duration of the project and for post-injection monitoring.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ.

The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Tulare Formation	Fluid sampling	61WS-8R	AoR	Annual
	Pressure Monitoring	61WS-8R	AoR	Continuously

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Tulare Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1)	ICP-OEC EPA 200.7/6010B
Cations (Ca, FE, K, Mg, Na and Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300
Dissolved CO2	SM 4500-CO2-C
Alkalinity	SM 2510 B
pH	EPA 150.1 / SM4500-H+B
Total Dissolved Solids (TDS)	SM 4500 C
Specific Conductance (field)	SM 2510 B
Dissolved Methane	RSK – 175 / Gas Chromatography
Temperature (field)	Thermocouple
Pressure	Pressure Gauge

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	61WS-8R	5 hours	5 hours
Post injection	Pressure Gauge	61WS-8R	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be

analyzed as part of fluid sampling in the Monterey Formation A1-A2 (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

Table 4. Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PLUME MONITORING			
Monterey Formation A1-A2	Fluid Sampling	327-7R-RD1 and 342-7R-RD1	Annual
INDIRECT PLUME MONITORING			
Monterey Formation A1-A2	Pulse neutron logging	327-7R-RD1 and 342-7R-RD1	Every five years

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Monterey Formation A1-A2	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1)	ICP-OEC EPA 200.7/6010B
Cations (Ca, FE, K, Mg, Na and Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300
Dissolved CO2	SM 4500-CO2-C
Alkalinity	SM 2510 B
pH	EPA 150.1 / SM4500-H+B
Total Dissolved Solids (TDS)	SM 4500 C
Specific Conductance (field)	SM 2510 B
Dissolved Methane	RSK – 175 / Gas Chromatography
Temperature (field)	Thermocouple
Pressure	Pressure Gauge

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the two Monterey Formation A1-A2 monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in plan view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FRONT MONITORING			
Monterey Formation A1-A2	Pressure	327-7R-RD1 and 342-7R-RD1	Continuous
INDIRECT PRESSURE-FRONT MONITORING			
All strata	Seismicity	AoR	Continuous

Figure 4: Map showing AoR and well locations for post-injection plume monitoring.

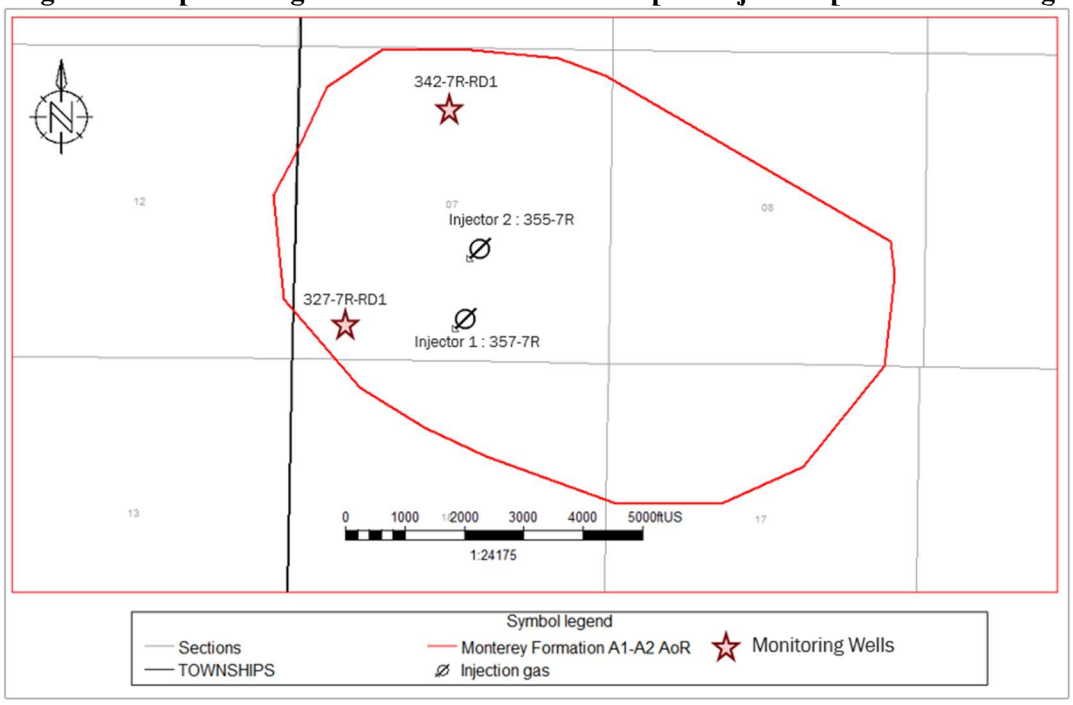
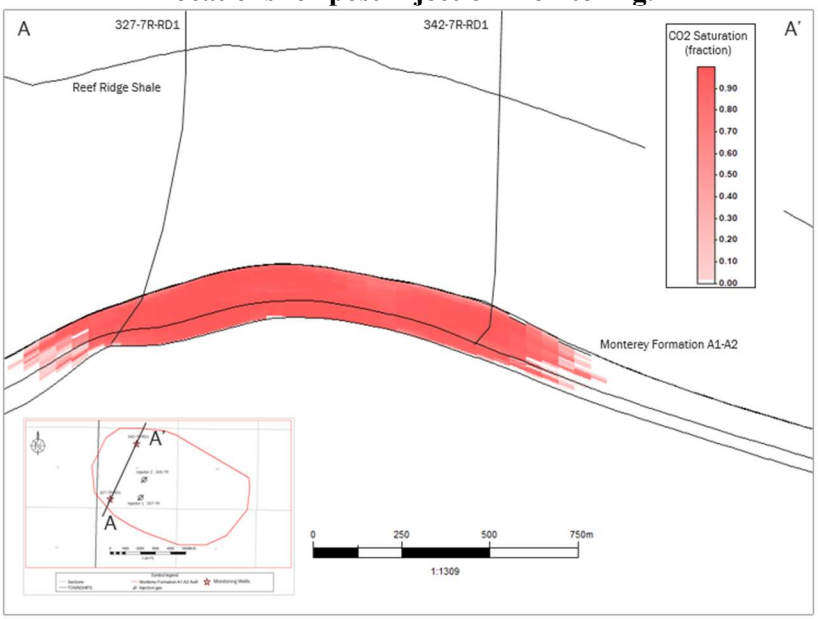


Figure 5: Cross-section showing plume CO2 injectate plume 100 years post injection and well locations for post-injection monitoring.



Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
357-7R & 355-7R

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize within one year after injection ceases. Injection limits will be based on the fracture pressure of the Monterey Formation A1-A2 and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application, and the AoR and Corrective Action Plan.

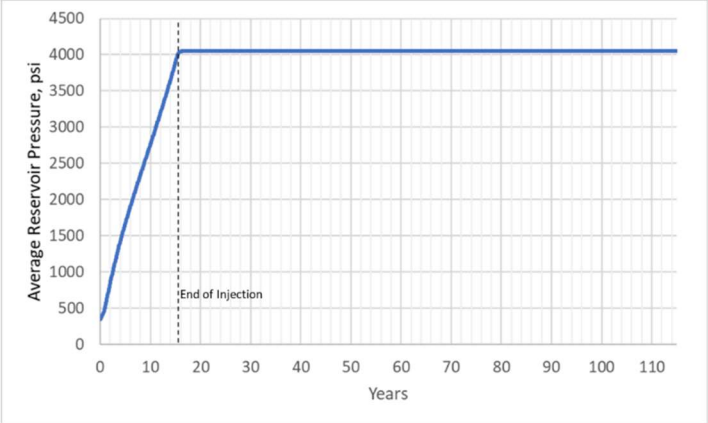
Discussion

The Monterey Formation A1-A2 reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation A1-A2 storage reservoir exists prior to the commencement of CO_2 injection. Through

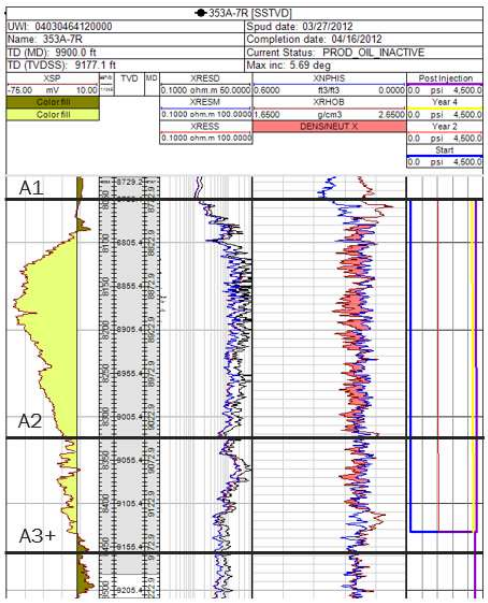
time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Due to high permeability, continuity of the reservoir and low injection pressure differential of the reservoir, pressure stabilization occurs within one year of injection cessation with the rate of change of pressure dropping below 10psi/year (0.027psi/day). Figure 1 shows the A1-A2 reservoir pressure increase during injection and pressure stabilization after injection from computational modeling.

Figure 1: Average Reservoir Pressure trend over the 15 year injection period and 100 years post injection.



Pressure at monitoring well 353A-7R will not decline post-injection (Figure 2). The low water saturation within the Monterey Formation A1-A2 storage reservoir results in greater than 98% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

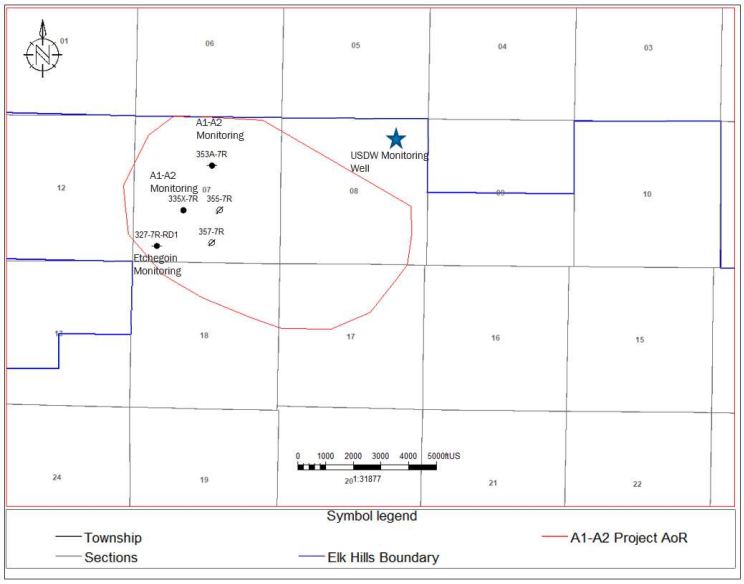
Figure 2: Pressure at the 353A-7R monitoring well at start of injection, year two, four and post injection.



Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 3: Map of the predicted extent of the CO2 plume at site closure. The pressure of the A1-A2 reservoir will be at or beneath the initial pressure at the time of discovery.



Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include pressure monitoring and fluid composition monitoring in the storage reservoir and reservoirs above the injection zone. Post-injection monitoring, as described in the following sections, will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days of the anniversary date of final injection, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

The Testing and Monitoring Plan describes the monitoring strategies within the injection zone, above the injection zone, and within the USDW-containing reservoir. In addition to monitoring the zones above the injection zone for stabilized pressure and absence of CO_2, the injection zone will be monitored for pressure stabilization as the best method to confirm confinement within the storage reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

The Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Surface, mineral, and pore space rights for the Monterey Formation A1-A2 reservoir are owned entirely by CTV where all activities will take place. As such, site access is guaranteed for the duration of the project and for post-injection monitoring.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ.

The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD/VD	Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD/VD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD/VD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD/VD 961' MD/VD 854' MD/VD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD 3780' - 3932' VD	Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' MD/VD 3850' - 3990' MD/VD	Continuous

Table 2. Summary of analytical and field parameters for water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Ti)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	USDW Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	USDW Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the associated increase in pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the Monterey Formation A1-A2 (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

Table 4. Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency	Depth (ft)
DIRECT PLUME MONITORING				
Monterey Formation A1-A2	Fluid Sampling	353A-7R and 335X-7R	Quarterly	353A-7R: 8703' MD 335X-7R: 8667' MD
INDIRECT PLUME MONITORING				
Monterey Formation A1-A2	Pulse Neutron Logging	353A-7R and 335X-7R	Every five years	353A-7R – 8,773'– 9,130' MD 335X-7R – 8,737'-9,030' MD

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Ti)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si, Sb)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the two Monterey Formation A1-A2 monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro seismic events.

Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in plan view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency	Depth (ft)
DIRECT PRESSURE-FRONT MONITORING				
Monterey Formation A1-A2	Pressure and temperature	353A-7R and 335X-7R	Continuous	353A-7R: 8703' MD 335X-7R: 8667' MD
INDIRECT PRESSURE-FRONT MONITORING				
All strata	Seismicity	AoR	Continuous	

Figure 4: Map showing AoR and well locations for post-injection monitoring.

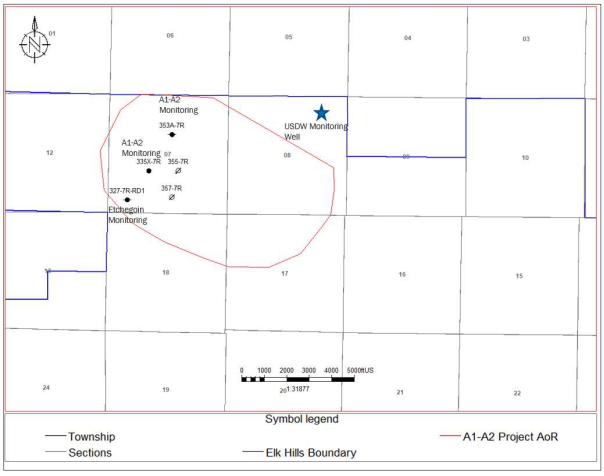
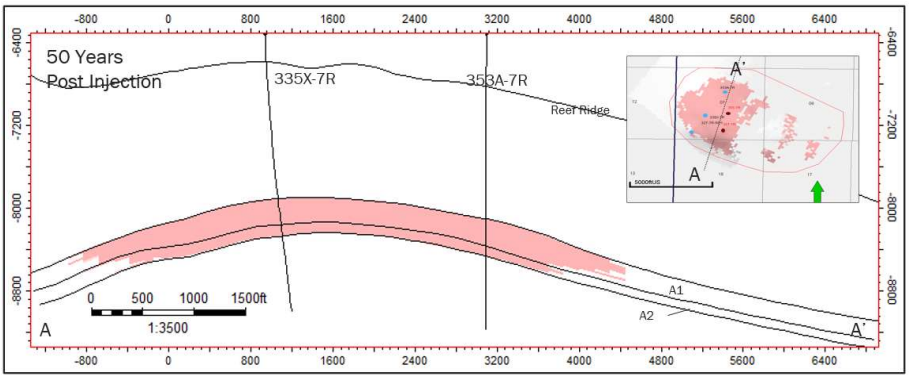


Figure 5: Cross-section showing plume CO2 injectate plume 50 years post injection and well locations for post-injection monitoring.



Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director as per 40 CFR 143.93(b)(2) or (3).

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,
2. Dates of all monitoring events,
3. Changes to the monitoring program over time,
4. An explanation of all monitoring information that has existed at the site,
5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and
6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO_2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO_2 leakage over the project timeframe,
2. the accuracy of the model to predict and represent the storage reservoir, and
3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO_2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW.

Site Closure Plan

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA.

A site closure report will be prepared and submitted within 90 days following site closure supported by the following:

1. Verification of injector and monitoring well plugging,

2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2),

3. Composition and volume of the injected CO_2, and

4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO_2 sequestration, the period of injection and the volume of CO_2 injected,

2. The formation that the fluid was injected, and

3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R

Facility contact: Kenneth Haney / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 763-6101/ Kenneth.Haney@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault 1 LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the Elk Hills A1-A2 Storage facility that may be affected as a result of an emergency event at the project site include:

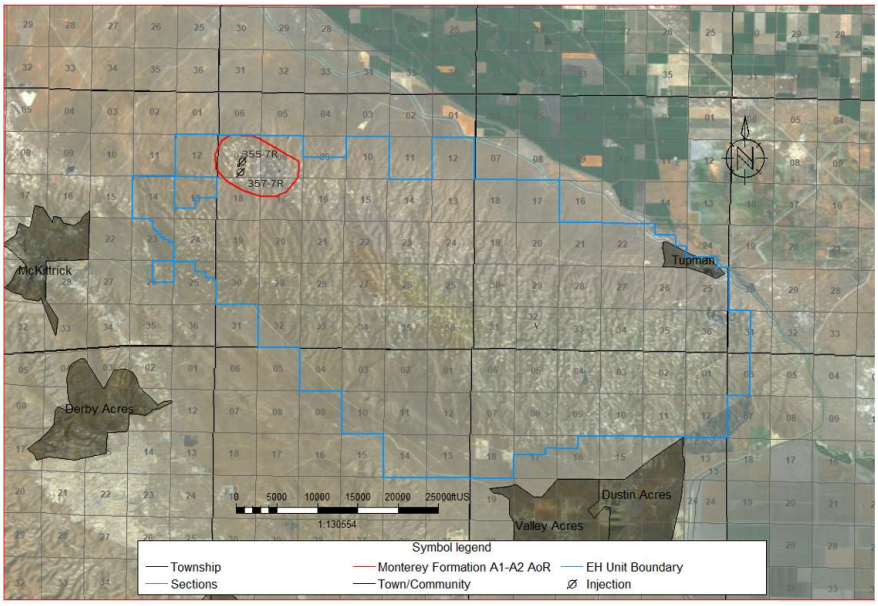
1. Elk Hills oil and gas production resources not associated with the Elk Hills A1-A2 Storage project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the Elk Hills A1-A2 Storage project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest town/community from the project is McKittrick, 3.1 miles from the AoR. The population was 115 at the 2010 U.S. Census.

Infrastructure in the vicinity of the Elk Hills A1-A2 Storage facility that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CTV that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.1 miles from the community of McKittrick.



Potential Risk Scenarios

The following events related to the Elk Hills A1-A2 facility that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike);

- Potential Brine or CO2 Leakage to a USDW;
- CO_2 leakage to USDW or land surface; or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/monitoring

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Preform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Preform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.

    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
    - Verify whether contamination has occurred via handheld CO_2 monitors.
    - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.
- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
    - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing

2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue refer to the Mechanical Integrity Failure scenario.
    - If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

Severity: Serious to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If there is contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
    - Communicate with CTV personnel and local authorities to initiate evacuation procedures.
    - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.
    - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within the AoR, inclusive of a two mile buffer.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills A1-A2 site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Major

Timing of event: Injection or post injection phases.

An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase.

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and issue corrective actions. 6. Document the event in semiannual reports to the EPA

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate rate reduction plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected, endangerment and CO2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and issue corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination is detected, endangerment and CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Review seismic and operational data. 11. Report findings to the UIC Program Director and issue corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, California Geological Survey, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	Phone Number
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EOA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
California Geological Survey	(916) 322-1080
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For

responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilites, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintainence, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintainence of personal monitors, portable multi-gas monitors and stationary montiors throughout the facility.

Carbon Dioxide Haxards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exersise and drills simulating potential emergency situations.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R

Facility contact: Kenneth Haney / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 763-6101/ Kenneth.Haney@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault 1 LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the Elk Hills A1-A2 Storage facility that may be affected as a result of an emergency event at the project site include:

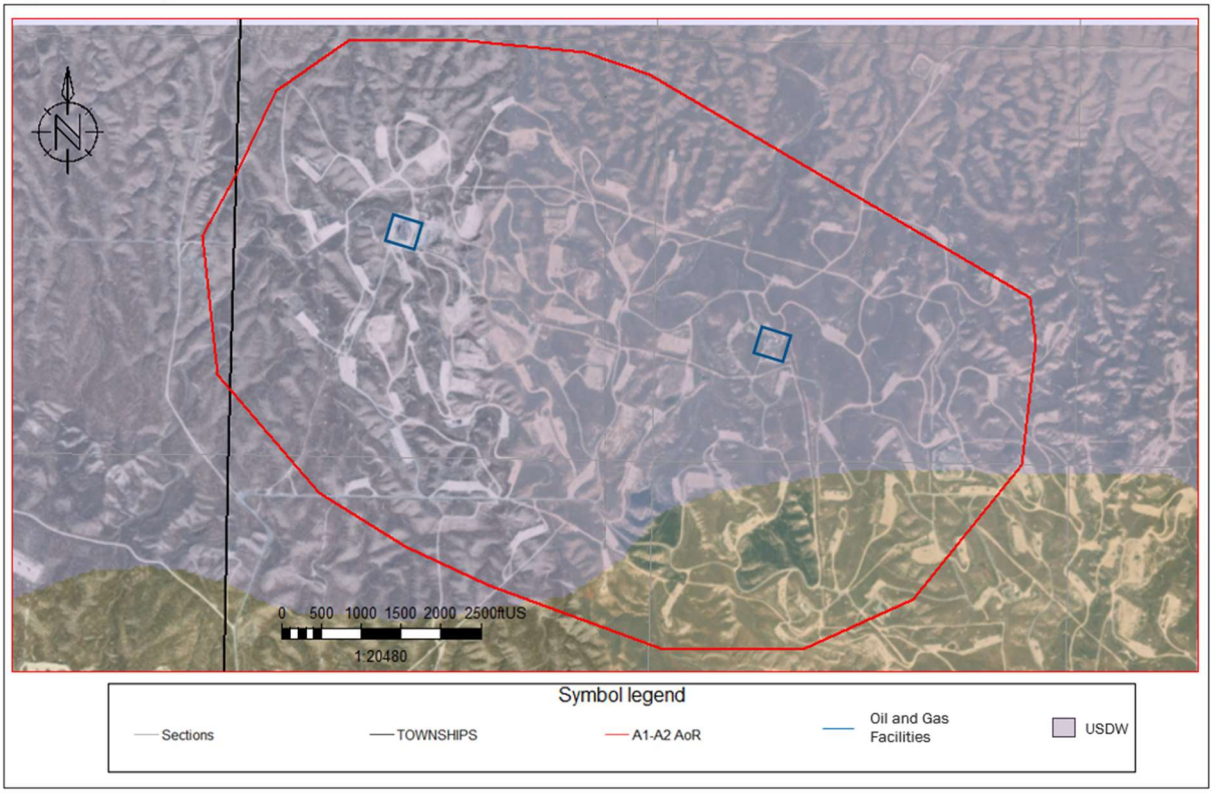
1. Elk Hills oil and gas production resources not associated with the Elk Hills A1-A2 Storage project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the Elk Hills A1-A2 Storage project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.

Infrastructure in the vicinity of the Elk Hills A1-A2 Storage facility that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CTV that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure.



Potential Risk Scenarios

The following events related to the Elk Hills A1-A2 facility that could potentially result in an emergency response:

- Injection or monitoring (verification) well integrity failure;
- Injection well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike);

- Fluid (e.g. brine) leakage to a USDW;
- CO_2 leakage to USDW or land surface; or
- Induced seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW.

Severity: Low

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in USDW monitoring well.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.

- Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
- Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

Severity: Low

Timing of event: Injection

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
  - Initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
  - Shut-in injection well and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within the AoR, inclusive of a ¼ mile buffer.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills A1-A2 site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Low

Timing of event: Injection

An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase.

Avoidance measures: N/A

Detection methods: The seismic monitoring wells

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.0 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Review seismic and operational data. 4. Report findings to the UIC Program Director and issue corrective actions.
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate rate reduction plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 9. Review seismic and operational data. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and issue corrective actions.

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4] Seismic event >M3.5	1. Initiate shutdown plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 9. Review seismic and operational data. 10. Report findings to the UIC Program Director and issue corrective actions.

Response personnel: Emergency response personnel, California Geological Survey, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director

Bill Blair (562-743-8336)

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	Phone Number
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (CalGEM)	661-322-4031
EPA National Response Center (24 hours)	800-424-8802
California Geological Survey	(916) 322-1080
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within three months following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilites, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintainence, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintainence of personal monitors, portable multi-gas monitors and stationary montiors throughout thefacility.

Carbon Dioxide Haxards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercies and drills simulating potential emergency situations.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: CTV I: Elk Hills A1-A2
357-7R and 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the Elk Hills A1-A2 Storage facility that may be affected as a result of an emergency event at the project site include:

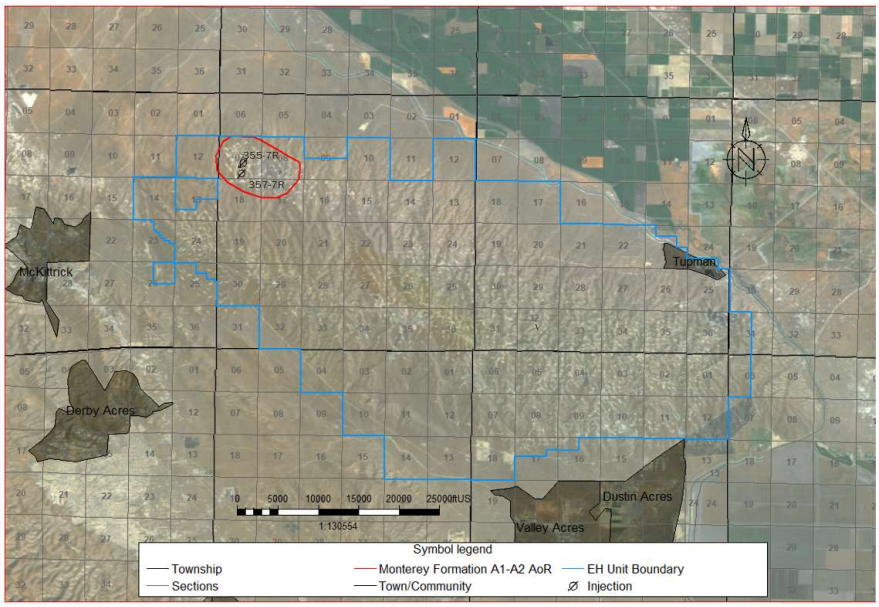
1. Elk Hills oil and gas production resources not associated with the Elk Hills A1-A2 Storage project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the Elk Hills A1-A2 Storage project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest town/community from the project is McKittrick, 3.1 miles from the AoR. The population was 115 at the 2010 U.S. Census.

Infrastructure in the vicinity of the Elk Hills A1-A2 Storage facility that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CTV that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.1 miles from the community of McKittrick.



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Potential Risk Scenarios

The following events related to the Elk Hills A1-A2 facility that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- Potential Brine or CO2 Leakage to a USDW;
- A natural disaster (e.g., earthquake, tornado, lightning strike); or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.

Emergency Condition	Definition
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/Post-Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.

- Initiate shutdown plan.
- Shut-in injection well and vent CO_2 from surface facilities.
- Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Preform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
  - Initiate shutdown plan.
  - Shut-in injection well and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
  - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
  - Perform a well log/MIT to detect CO2 movement outside of the casing.
  - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well or Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
    - Verify whether contamination has occurred via handheld CO_2 monitors.
    - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.
- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.

- If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
- Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
- Contact security to restrict access to the Elk Hills A1-A2 Storage site.
- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW. Indicators include elevated pH levels in the Tulre Formation and pressure increases in the Etchegoin Formation.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits are 0.001 PSI for the pressure gauge and 0.2 for pH.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).

- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue refer to the Mechanical Integrity Failure scenario.
    - If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

Severity: Serious to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If there is contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
    - Communicate with CTV personnel and local authorities to initiate evacuation procedures.
    - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.
    - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills A1-A2 site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Major

Timing of event: Injection / post injection

An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase.

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and issue corrective actions. 6. Document the event in semiannual reports to the EPA

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual rate reduction plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected, endangerment and CO2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and issue corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination is detected, endangerment and CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Review seismic and operational data. 11. Report findings to the UIC Program Director and issue corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, California Geological Survey, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	Phone Number
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
California Geological Survey	(916) 322-1080
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For

responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

Carbon Dioxide Hazards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercise and drills simulating potential emergency situations.

MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Above Zone Monitoring Well, 327-7R-RD1

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
327-7R-RD1 Above Zone Monitoring Well

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_327-7R-RD1	1	11/4/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.
Attachment G – CP Details_327-7R-RD1	2	05/14/2023	In response to EPA questions 03/2023

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring of both the injection interval and one above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, recompletion, logging, testing, operating, and plugging plans for above zone monitoring well 327-7R-RD1.

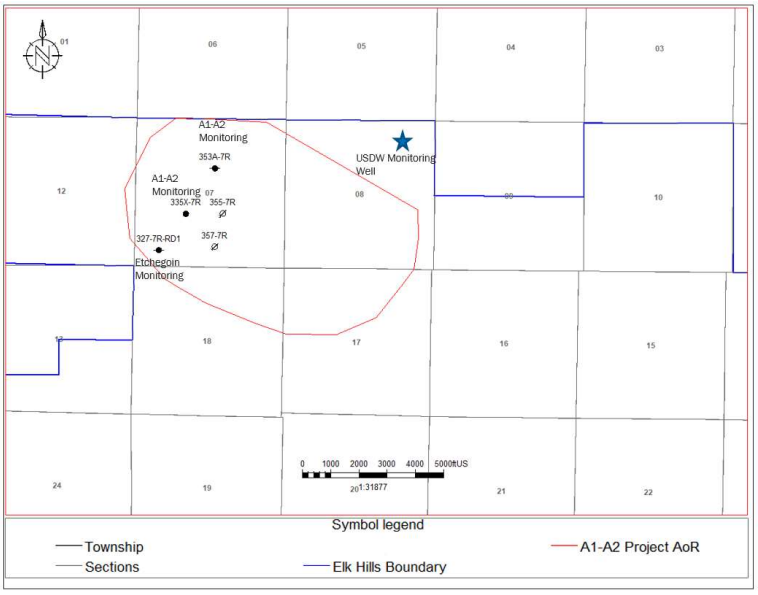


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 327-7R-RD1 is an existing oil and gas production well that was drilled in 2000 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of USDW

327-7R-RD1 was drilled in 2000, at which time there were no drilling and completion issues. The base of USDW is located at 849' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 9-5/8" production casing, multiple casing strings protects shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing was cemented with cement returns to surface. The 9-5/8" casing string was cemented with a theoretical volume to surface, but cement returns were not observed. The 5-1/2" liner was cemented successfully and will be isolated with cement plugs internally and above as part of the recompletion to monitor the reservoir above the confining layer.
3. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
4. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.
5. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 327-7R-RD1 monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Current well materials are compatible with the Etchegoin formation fluids and are suitable for the monitoring purposes intended.

1. Tubing – standard N-80 grade carbon steel tubing is appropriate and is consistent with accepted industry practices and field experience.
2. Wellhead – standard grade carbon steel material
3. Packer – standard carbon steel and elastomer material consistent with accepted industry practices.
4. Casing – the standard grade N-80 and P-110 casing is appropriate and is consistent with accepted industry practices and field experience

5. Cement – Class G and Class C portland cement used in constructing the well is appropriate for monitoring in the reservoir above the confining layer.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Etchegoin Formation temperature is approximately 170 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 327-7R-RD1 Monitoring Well

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20' - 60'	20	19.124	94	-	-	2.62	-	--
Surface	20' - 2337'	13.375	12.515	61	K-55	Short	2.62	3090	1540
Long-String	20' - 6382' 6382' - 8245'	9.625	8.755 8.681	43.5 47	N-80 P-110	Long	2.62	6330 9440	3810 5300
Liner	8059’ – 9842’	5.5	4.892	17	N-80	Long	2.62	7740	6390

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

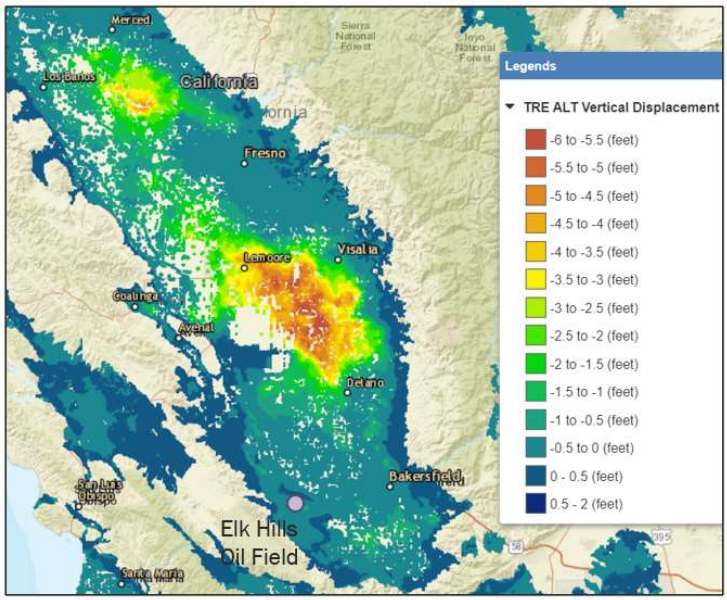


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Portland cements have been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing was cemented using Class C portland cement with 60 bbls returns to surface. The 9-5/8" production casing was cemented using Class G portland cement with circulation throughout the job and no cement returns. No cement evaluation log was acquired at the time of installation. Cement evaluation logging will be performed to ensure annular isolation and well integrity during conversion activities for Etchegoin reservoir monitoring.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c).

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	3762'	2.875	2.441	6.5	N-80	Short	10,570	11,170

Table 3 provides specifications of a hydraulic packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 9-5/8" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Hydraulic, low carbon alloy steel	3732'	30.3	40-47	8.452	2.416

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
50,000	10,000	10,000	8.835	8.681

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 9-5/8" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The

wellhead tree will include redundant valves. Safety valves or other automatic shut-off devices are not required for monitoring wells in general.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided below. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
327-7R-RD1	Cement Bond Log	Along the 9-5/8" casing to surface
	Casing Inspection Log	Along the 9-5/8" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 9-5/8" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~1007’ feet measured depth (MD) to bottom hole at 9843’ feet MD (Table 5).

Table 5: Deviation checks during drilling for the 327-7R-RD1 well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		8767	22.9	202.7	8714.7
1007	2	357	1006.8		8799	23.8	205.1	8744.1
1505	2	0.88	1504.5		8831	24.6	207.9	8773.2
2307	1.75	358	2306.1		8862	25.6	211.4	8801.3
2838	1.75	13	2836.8		8894	27.5	215	8829.9
3331	2.25	5	3329.5		8926	28.9	218.5	8858.1
3841	2.75	12	3839		8957	30.3	223	8885.1
4328	3	15	4325.4		8987	32.1	225.5	8910.8
4876	3.75	22	4872.5		9019	34.2	227.3	8937.6
5627	3	26	5622.2		9050	36.5	228.7	8962.8
6114	1	49	6108.8		9082	38.8	231.1	8988.2
6619	1.5	150	6613.8		9114	41.4	232.2	9012.7
7125	2	178	7119.5		9145	43.9	233.9	9035.5
7567	2	163	7561.3		9177	46.5	235	9058
7807	2.4	164.7	7801.1		9208	47.8	236.8	9079.1
7870	6.1	179.8	7863.9		9239	48.7	236.8	9099.7
7933	11.5	183.3	7926.1		9303	50.5	236.7	9141.2
7995	16.4	187.2	7986.3		9365	51.7	236.1	9180.1
8058	18	188.2	8046.5		9426	55.3	237.8	9216.4
8121	18.6	186.8	8106.3		9489	55	237.8	9252.4
8185	18.9	185.8	8166.9		9521	53	238.5	9271.2
8245	19.19	183.79	8223.6		9551	51.2	238.5	9289.7
8401	18.5	178	8371.3		9614	51.2	239.2	9329.1
8433	18.8	179.5	8401.6		9646	52.9	241.3	9348.8
8496	19.2	178.4	8461.2		9677	54	242	9367.3
8559	19.5	186.8	8520.6		9741	53.7	242	9405
8622	20.7	190.4	8579.8		9800	54	242	9439.8
8684	21.1	196.3	8637.7		9843	54	242	9465.1
8748	22.4	199.5	8697.1					

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of the long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and resistivity.

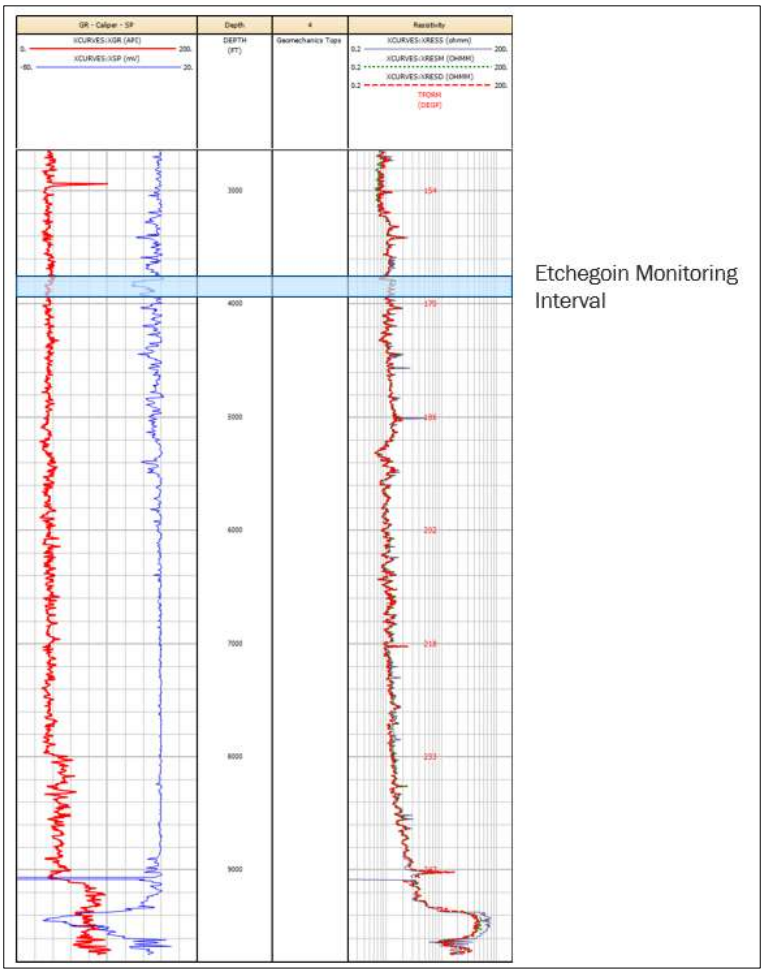


Figure 3: Open-hole well logs for 327-7R-RD1

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was not logged across the entire confining layer. Cement was observed at the top of the liner interval, but no cement bond log was run on the 9-5/8" casing. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 9-5/8" casing string during pre-operational testing.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and

procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials, and methodology for monitoring well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 20' MD due to the depth reference to the kelly bushing 20' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	8.681	8.755	8.755	8.755
Depth to bottom of tubing or drill pipe (ft)	8059	3934	1484	45
Sacks of cement to be used (each plug)	224	412	268	10
Slurry volume to be pumped (bbl)	45.88	84.38	54.89	2.05
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	7433	2802	749	20
Bottom of plug (ft)	8059	3934	1484	45
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Zone Monitoring Well, 335X-7R

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
335X-7R Injection Zone Monitoring Well

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_335X-7R	1	11/4/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.
Attachment G – CP Details_335X-7R	2	05/14/2023	In response to EPA questions 03/2023

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring of both the injection interval and one above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, recompletion, logging, testing, operating, and plugging plans for injection zone monitoring well 335X-7R.

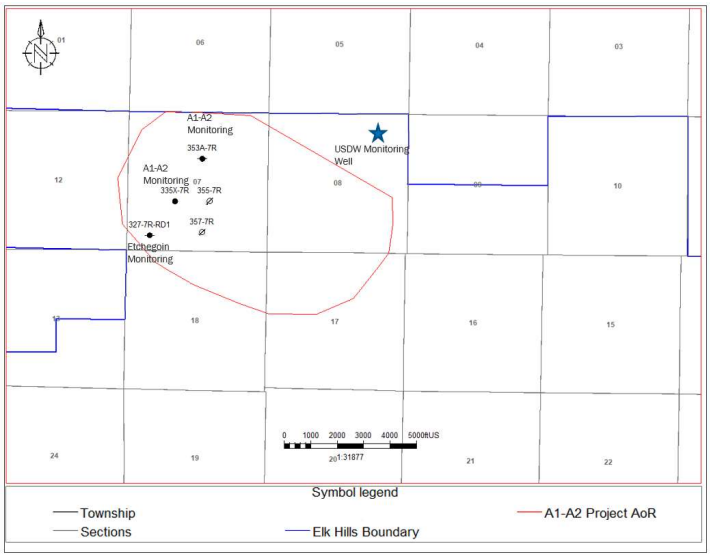


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 335X-7R is an existing oil and gas production well that was drilled in 2014 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of USDW

335X-7R was drilled in 2014, at which time there were no drilling and completion issues. The base of USDW is located at 854' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 7" production casing, multiple casing strings protect shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. Both surface casing and long string casing were cemented with returns to surface.
3. Cement bond logging was performed from the plugback depth of 7" casing around 9700' to surface. The resulting CBL indicates presence of cement in the production casing annulus well above the base of Reef Ridge Shale confining layer.
4. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
5. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
6. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.
7. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 335X-7R monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the mixture of CO_2 injectate and formation fluids to prevent corrosion in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.

4. Casing – the standard grade P-110 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
5. Cement – portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Monterey Formation temperature in A1-A2 is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 335X-7R Monitoring Well

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	25' - 65'	20	19.124	94	-	-	2.62	-	-
Surface	25' - 1993'	9.625	8.921	36	J-55	Long	2.62	3520	2020
Long-String	25' – 9790’	7	6.276	26	P-110	Long	2.62	9950	6230

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

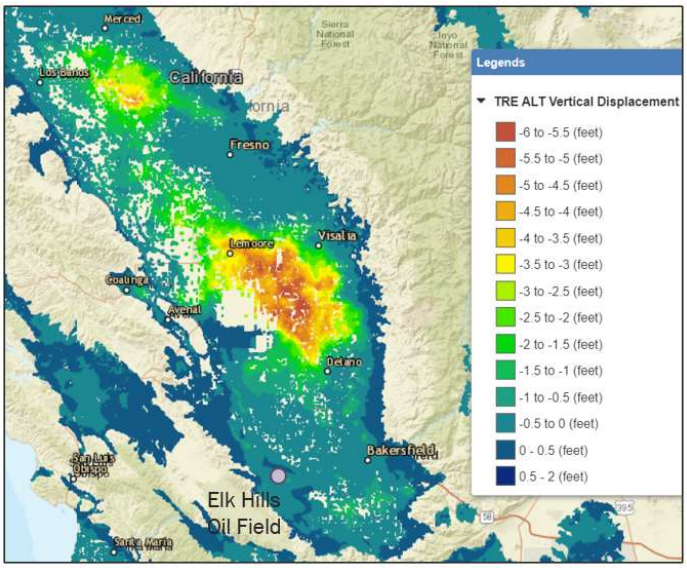


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class C and Class G portland cements have been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 9-5/8" surface casing string was cemented using Class C portland cement with 56 cubic feet of cement returns to surface. The 7" casing string was cemented in place using Class G portland cement with 67 cubic feet of cement returns to surface. Subsequently, a CBL was run from ~9700' to surface and indicates the presence of annular cement that provides isolation between the Monterey and Reef Ridge formations.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	8707’	2.875	2.441	6.5	L-80 CRA	Premium	10,570	11,170

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7” casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8677’	30.3	23 - 32	6	2.37

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	8000	8000	6.466	6.184

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7” casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant master valves and wing valves, and the valves will remain closed during normal injection operations. Safety valves or other automatic shut-off devices are not required for monitoring wells in general. The project does not anticipate risk factors that

warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided below. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
335X-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 7" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~184’ feet measured depth (MD) to bottom hole at 9839’ feet MD (Table 4).

Table 5: Deviation checks during drilling for the 335X-7R well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		6477	0.69	10.39	6475.9
184	0.1	54.1	184		6571	0.61	14.81	6569.9
274	0.4	82.8	274		6665	0.71	9.28	6663.9
553	1.3	45.2	553		6757	0.77	9.58	6755.9
843	1.1	42.7	842.9		6851	0.59	14.07	6849.9
1125	1	34.7	1124.9		6945	0.26	34.35	6943.9
1406	0.7	27.9	1405.8		7040	1.49	342.91	7038.9
1688	0.4	21.1	1687.8		7135	1.43	345.41	7133.8
1973	0.2	52.6	1972.8		7229	1.05	338.33	7227.8
2039	0.17	358.51	2038.8		7324	2.76	335.99	7322.7
2229	1.14	234.95	2228.8		7419	4.4	332.4	7417.6
2418	0.98	235.93	2417.8		7513	5.88	334.34	7511.2
2607	1.03	230.44	2606.7		7608	7.81	331.62	7605.5
2796	1	228.22	2795.7		7703	7.44	329.46	7699.7
2985	1.18	232.7	2984.7		7797	8.77	326.74	7792.7
3173	1.51	238.93	3172.6		7892	8.88	325.45	7886.6
3361	0.84	223.73	3360.6		7987	8.83	325.83	7980.5
3548	1.02	236.33	3547.6		8082	8.47	327.22	8074.4
3736	0.53	156.12	3735.5		8176	8.35	326.11	8167.4
3925	0.72	140.11	3924.5		8270	7.64	330.17	8260.5
4115	0.89	166.88	4114.5		8365	8.03	333.54	8354.6
4305	1.01	156.26	4304.5		8461	8.01	338.06	8449.6
4494	0.61	120.49	4493.5		8556	9.3	345.07	8543.5
4684	0.71	59.67	4683.5		8650	8.92	348.15	8636.4
4873	1.52	59.64	4872.4		8744	8.11	345.93	8729.3
5157	0.91	75.06	5156.4		8838	8.39	347.32	8822.4
5347	1.21	94.84	5346.3		8933	8.87	346.52	8916.3
5536	0.43	70.54	5535.3		9027	8.68	348.32	9009.2
5625	0.29	22.28	5624.3		9122	8.7	351.34	9103.1
5719	2.62	268.23	5718.3		9209	8.75	353.67	9189.1
5814	2.67	274.19	5813.2		9301	7.41	354.44	9280.2
5909	3.01	268.24	5908.1		9396	8.08	347.8	9374.3
6004	1.84	282.07	6003		9498	8.04	350.12	9475.3
6098	1.17	17.42	6096.9		9592	7.58	352.94	9568.4
6193	1.02	3.84	6191.9		9675	7.47	355.22	9650.7
6288	0.86	358.61	6286.9		9768	7.47	358.34	9742.9
6382	0.83	15.11	6380.9		9839	7.47	358.34	9813.3

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of 7" long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), and neutron porosity and bulk density in track 3.

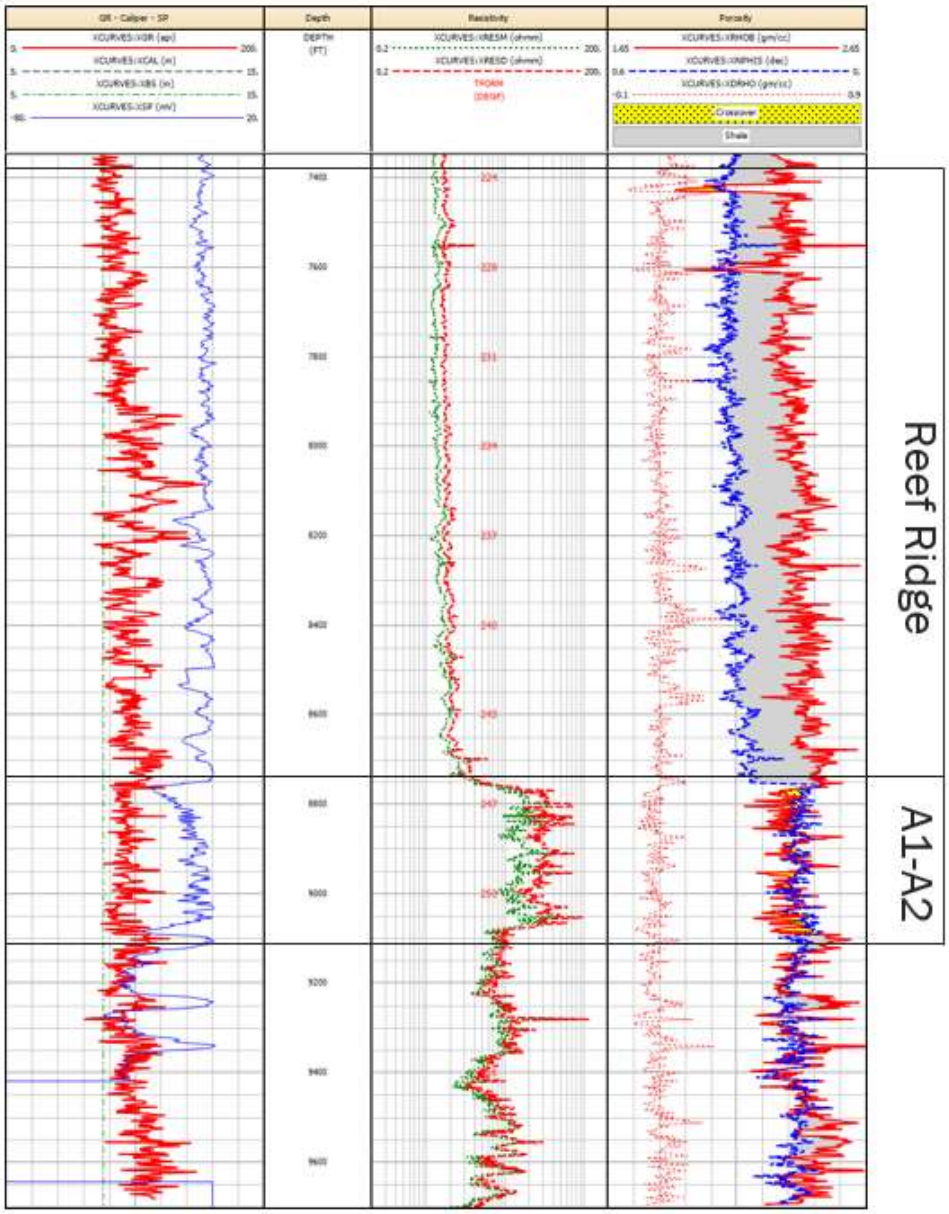


Figure 3: Open-hole well logs for 335X-7R before installation of long string for Reef Ridge Shale and Monterey Formations.

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was logged across the entire 7" casing interval. Figure 4 shows good cement throughout the injection zone, with evidence of continuous cement throughout the confining layer and to surface. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing.

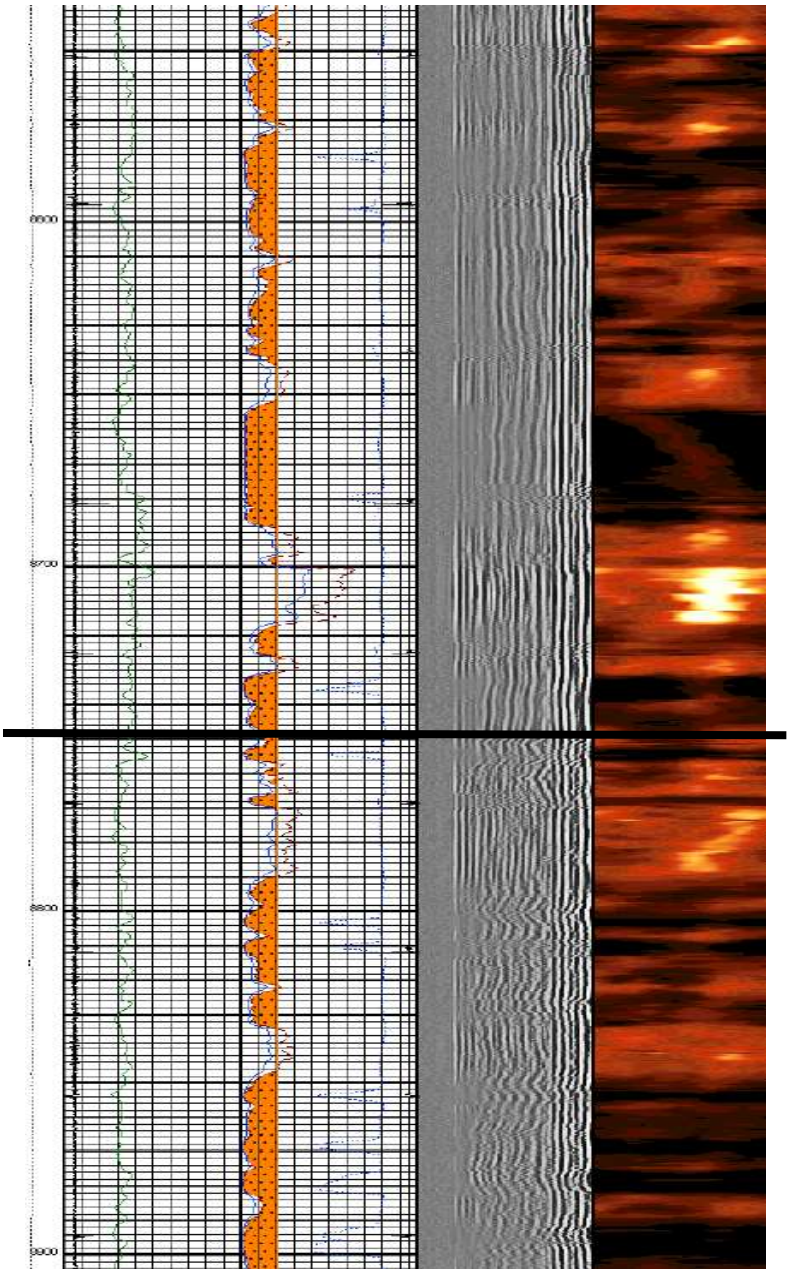


Figure 4: Cement bond log example for 335X-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,736 feet.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials, and methodology for monitoring well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 25' MD due to the depth reference to the kelly bushing 25' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	9060	3003	1503	50
Sacks of cement to be used (each plug)	80	24	141	5
Slurry volume to be pumped (bbl)	16.38	3.89	28.88	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8634	2878	754	25
Bottom of plug (ft)	9060	3003	1503	50
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may

place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

- If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Zone Monitoring Well, 353A-7R

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
353A-7R Injection Zone Monitoring Well

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment H1 – CP Details_353A-7R	1	08/30/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.
Attachment H1 – CP Details_353A-7R	2	05/14/2023	In response to EPA questions 03/2023

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring the injection interval and one existing well for above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, logging, testing, and plugging plans for injection zone monitoring well 353A-7R.

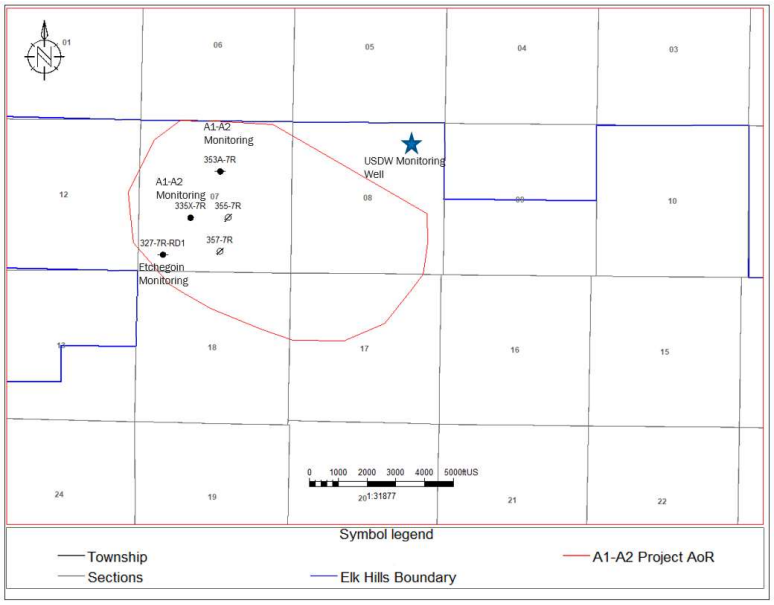


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 353A-7R is an existing oil and gas production well that was drilled in 2012 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of USDW

353A-7R was drilled in 2012, at which time there were no drilling and completion issues. The base of USDW is located at 961' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 7" production casing, multiple casing strings protect shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing was cemented with cement returns to surface. The 7" casing string was cemented with a theoretical volume to surface, but cement returns were not observed.
3. Cement bond logging was performed from the plugback depth of 7" casing at 9800' to 8000'. The resulting CBL indicates presence of cement in the production casing annulus well above the base of Reef Ridge Shale confining layer.
4. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
5. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
6. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.
7. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 353A-7R monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the CO_2 injectate to prevent loss of mechanical integrity in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.

3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.
4. Casing – the standard grade P-110 casing, which is currently installed, will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
5. Cement – portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Monterey Formation temperature in A1-A2 is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 353A-7R Monitoring Well

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	25' - 65'	20	19.124	94	-	-	2.62	-	--
Surface	25' - 2014'	9.625	8.921	36	J-55	Long	2.62	3520	2020
Long-String	25' - 8335' 8335' - 9900'	7	6.276 6.184	26 29	N-80 P-110	Long	2.62	7240 11220	5410 8510

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

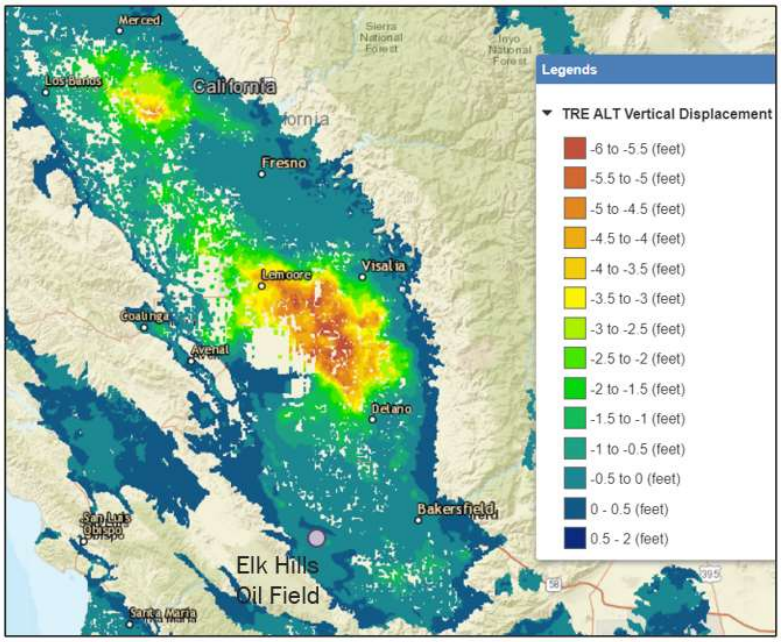


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class C portland cement has been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 9-5/8" surface casing string was cemented using Class C portland cement with 26 barrels of cement returns to surface. The 7" casing string was cemented in place with Class G portland cement. Subsequently, a CBL was run from 8000' – 9790' and indicates the presence of annular cement that provides isolation between the Monterey and Reef Ridge formations.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	8743'	2.875	2.441	6.5	L-80 CRA	Premium	10,570	11,170

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8713'	30.3	23 - 32	5.687	2.688

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	7500	7500	6.366	6.049

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant master valves and wing valves, and the valves will remain closed during normal injection operations. Safety valves or other automatic shut-off devices are not required for monitoring wells, in general. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
353A-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 7" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~158’ feet measured depth (MD) to bottom hole at 9900’ feet MD. Results of the survey are displayed in Table 5.

Table 5: Deviation checks during drilling for the 353A-7R well

MD	INC	AZI	TVD		MD	INC	AZI	TVD
158	0.23	139.02	158		5438	4.38	145.64	5428.8
257	0.28	191.78	257		5533	4.19	135.25	5523.6
349	0.2	132.87	349		5627	5.18	128.17	5617.3
439	0.18	149.89	439		5722	5.22	121.9	5711.9
529	0.33	119.37	529		5816	5.17	121.72	5805.5
620	0.15	67.22	620		5911	5.2	122.14	5900.1
712	0.27	147.78	712		6005	5.23	119.72	5993.7
804	0.25	128.58	804		6100	5.16	111.79	6088.3
896	0.33	130.54	896		6195	5.17	127.82	6182.9
988	0.47	127.11	988		6290	5.24	130.98	6277.6
1081	0.44	131.05	1081		6385	5.24	125.2	6372.2
1172	0.51	150.94	1172		6480	5.23	123.41	6466.8
1267	0.54	124.55	1267		6574	4.95	130.68	6560.4
1361	0.55	132.51	1361		6669	5.1	133.16	6655
1456	0.42	272.54	1456		6763	5.1	133.16	6748.7
1550	0.65	282.83	1550		6858	5.1	127.43	6843.3
1645	0.65	281.41	1645		6952	5.01	120.6	6936.9
1740	0.73	286.98	1740		7047	4.91	125.73	7031.6
1834	0.81	300.37	1833.9		7142	5.16	124.15	7126.2
1929	0.93	299.76	1928.9		7237	5.11	116.1	7220.8
2224	0.07	235.76	2223.9		7331	5.01	119.99	7314.4
2601	0.03	259.66	2600.9		7426	5.03	110.8	7409.1
2791	0.07	351.9	2790.9		7520	3.92	127.22	7502.8
2885	2.17	332.57	2884.9		7615	2.82	140.27	7597.6
2979	2.16	36.71	2978.8		7710	1.32	131.08	7692.6
3074	2.16	83.09	3073.8		7804	0.21	198.69	7786.6
3168	2.2	81.01	3167.7		7899	0.03	285.35	7881.6
3263	3.55	121.66	3262.6		7994	0.03	139.29	7976.6
3357	5	138.3	3356.3		8088	0.03	189.39	8070.6
3452	4.96	136.68	3451		8183	0.07	158.58	8165.6
3546	5	134.9	3544.6		8277	0.1	153.47	8259.6
3641	5.05	143.9	3639.3		8371	0.25	175.69	8353.6
3736	5.64	132.08	3733.9		8466	0.48	173.13	8448.6
3830	5.53	124.58	3827.4		8560	1.16	185.37	8542.5
3925	5.56	131.73	3922		8655	0	360	8637.5
4020	5.64	132.63	4016.5		8749	0.1	163.14	8731.5
4114	5.63	127.87	4110.1		8844	0.03	54.11	8826.5
4209	5.63	118.95	4204.6		8938	0	360	8920.5
4304	5.59	109.14	4299.2		9033	0.03	155.83	9015.5
4398	5.61	111.21	4392.7		9127	0.03	34.73	9109.5
4493	5.59	123.25	4487.3		9222	0.1	313.41	9204.5
4587	5.69	114.14	4580.8		9316	0.03	276.2	9298.5
4682	5.58	116.03	4675.3		9411	0.03	117.75	9393.5
4776	4.97	115.61	4768.9		9505	0.07	186.78	9487.5
4871	5.02	117.61	4863.6		9599	0.07	171.05	9581.5
4965	5.12	111.36	4957.2		9694	0.06	255.48	9676.5
5060	4.3	108.86	5051.9		9788	0	360	9770.5
5154	4.34	118.26	5145.6		9867	0.07	53.37	9849.5
5249	4.26	132.47	5240.4		9900	0.07	53.37	9882.5
5343	4.17	147.2	5334.1					

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of 7" long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), and neutron porosity and bulk density in track 3.

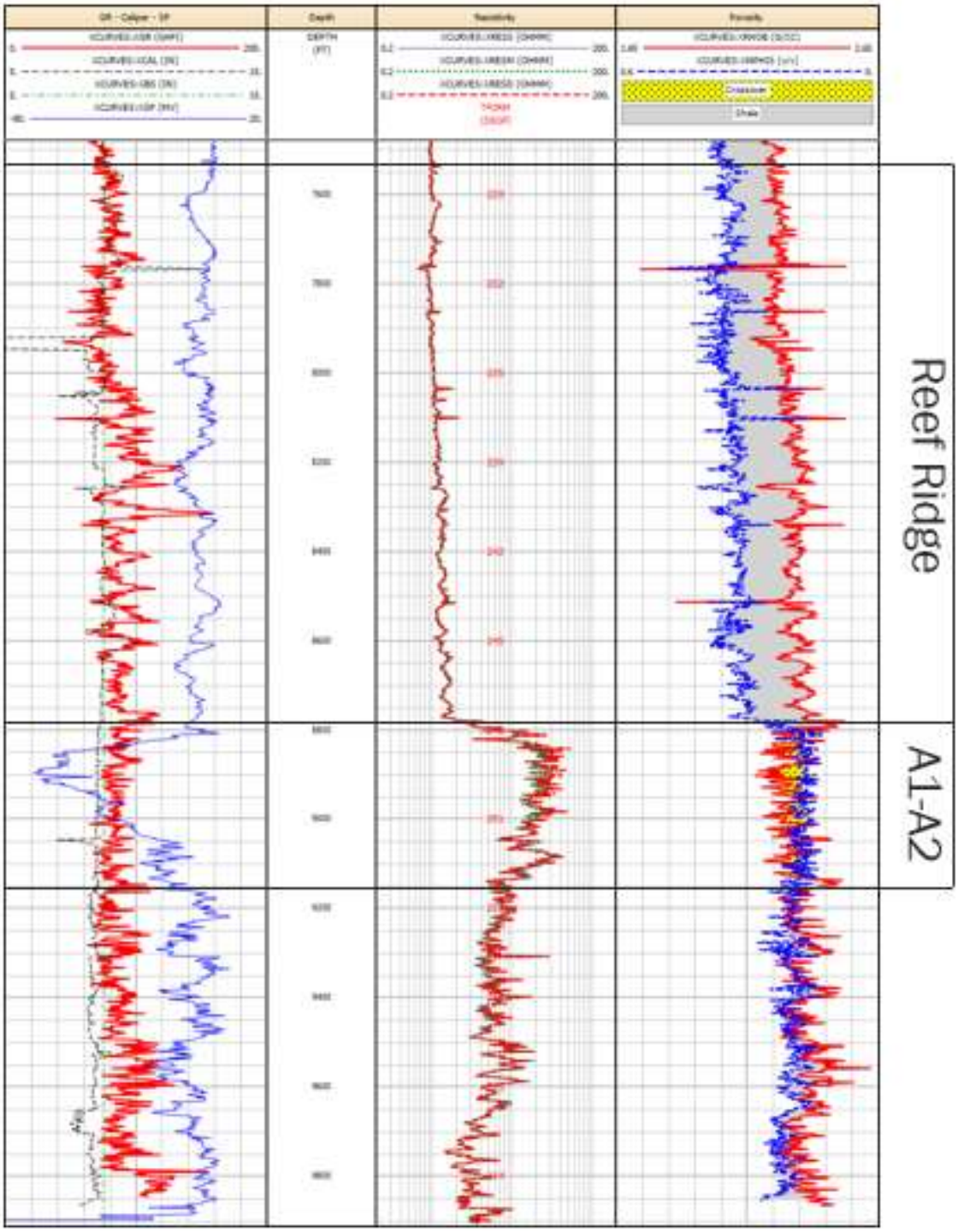


Figure 3: Open-hole well logs for 353A-7R before installation of long string for Reef Ridge Shale and Monterey Formations.

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was not logged across the entire 7" casing interval. The top of cement was not observed deeper than 8000', the top of the cement bond logging interval. As specified in the Pre-Operational Testing plan document, CTV will perform additional cement evaluation logging across the 7" casing string during pre-operational testing.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubular integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection and post-injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials, and methodology for monitoring well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 25' MD due to the depth reference to the kelly bushing 25' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.184	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	9140	3243	1645	50
Sacks of cement to be used (each plug)	85	24	147	5
Slurry volume to be pumped (bbl)	17.41	4.91	30.11	1.02

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8673	3118	861	25
Bottom of plug (ft)	9140	3243	1645	50
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

ATTACHMENT G2: CONSTRUCTION DETAILS

Elk Hills A1-A2 Storage Project

Facility Information

Facility name:	Elk Hills A1-A2 Storage 355-7R
Facility contact:	Travis Hurst / Geological Advisor 28590 Highway 119
	Tupman, CA 93276 (661) 342-2409 / Travis.Hurst@crc.com
Well location:	Elk Hills Oil Field, Kern County, CA 35°19'40.9189"N / 119°32'41.9057"W

Introduction

Injection well 355-7R is an existing well approved for gas injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 2.8 billion cubic feet of gas. As part of the UIC approval, California Resources Corporation (CRC) has conducted mechanical integrity tests and standard annular pressure tests to ensure internal and external mechanical integrity.

The testing activities at the 355-7R injection wellsite are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

Injection Well Construction Details

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,398	4.500	3.920	13.5	L-80	Long	9,020	8,540

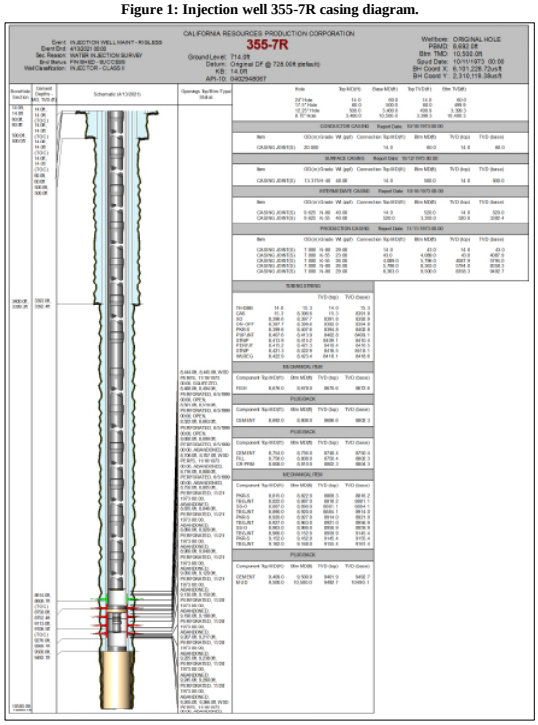
Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

Tubing specifications in the table above is for the current well configuration. CTV plans to configure the well with corrosion resistant tubing.

Figure 1: Injection well 355-7R casing diagram.



Pre-Injection Testing Plan – Injection Well

The following tests and logs have been acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

Deviation Checks

Deviation measurements were conducted approximately every 100 feet during construction of the well.

Tests and Logs

The following logs were acquired during the drilling and prior to the completion of the 355-7R well:

- Dual Induction Laterolog
- Spontaneous Potential Logs
- Caliper Logs
- Compensated Neutron Log
- Formation Density Log
- Four-Arm Dipmeter Log
- Mud Logs
- Micro Seismogram Log (Cement Evaluation)

The following cased-hole logs were acquired after the drilling and completion of the 355-7R well:

- Mechanical Integrity Tests (Temperature Log and SAPT)
- Production Logs

Demonstration of mechanical integrity

Below is a summary of the tests to be performed prior to injection:

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Radioactive Tracer	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Annulus Pressure Test Procedures for Injection Well 355-7R:

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals;

Pressure Fall-Off Test Procedures:

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation A1-A2 reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

Testing details

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

ATTACHMENT G: CONSTRUCTION DETAILS
WELL 357-7R

Elk Hills A1-A2 Storage Project

Facility Information

Facility name:	Elk Hills A1-A2 Storage 357-7R
Facility contact:	Kenneth Haney / CCS Project Manager 28590 Highway 119 Tupman, CA 93276 (661) 763-6101/ Kenneth.Haney@crc.com
Well location:	Elk Hills Oil Field, Kern County, CA 35.32802963 / -119.5449982

Introduction

The testing activities at the 357-7R described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

Injection well 357-7R is an existing well approved for gas injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 3.5 billion cubic feet of gas. As part of the UIC approval, California Resources Corporation (CRC) has conducted annual MITs and SAPT tests every five years to ensure internal and external mechanical integrity.

Injection Well Construction Details

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

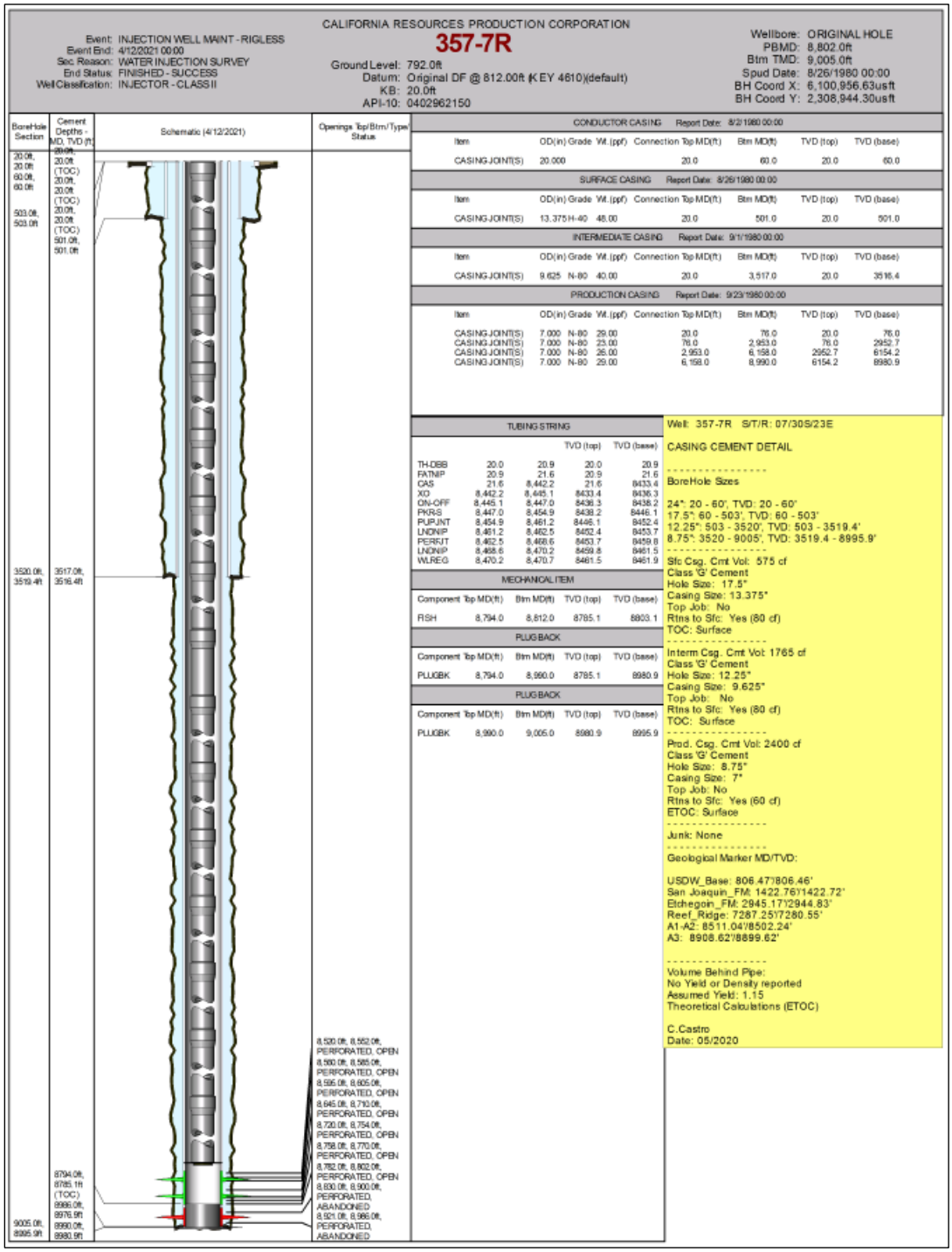
Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,447	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

Injection Well Construction Diagrams

Figure 1: Injection well 357-7R casing diagram.



Pre-Injection Testing Plan – Injection Well

The following tests and logs have been acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

Deviation Checks

Deviation measurements were conducted approximately every 10 feet during construction of the well.

Tests and Logs

The following logs were acquired during the drilling and prior to the completion of the 357-7R well:

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs
- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log
- Mud Log

The following cased-hole logs were acquired after the drilling and completion of the 357-7R well:

- Cement Bond Log
- Mechanical Integrity Tests (Temperature Log and SAPT)

Demonstration of mechanical integrity

Below is a summary of the tests to be performed prior to injection:

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Radioactive Tracer	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Pre-Injection Testing Plan – Deep Monitoring Wells 327-7R-RD1 and 342-7R-RD1

Deep monitoring wells proposed for the Elk Hills A1-A2 Storage project have already been drilled and completed.

Deviation Checks

Deviation measurements for 342-7R-RD1 and 327-7R-RD1 were recorded approximately every 35 and 156 feet respectively, during construction of the well.

Tests and Logs

The following logs were acquired during the drilling and prior to the completion of the 342-7R-RD1 and 327-7R-RD1 wells:

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs
- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log

Demonstration of mechanical integrity

CTV will run mechanical integrity logs and tests prior to injection operations.

Annulus Pressure Test Procedures for Injection Well 357-7R:

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

Annulus Pressure Test Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1:

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source(annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

Pressure Fall-Off Test Procedures:

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation A1-A2 reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

Testing details

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

WELL CONSTRUCTION, OPERATING, AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Well 355-7R

Version History

File Name	Version	Date	Description of Change
COP_355-7R_v1	1	05/16/22	Combines documents, incorporates corrections and EPA feedback dated 04/25/22

Introduction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. The wells are in Section 7R within the unit boundary of the Elk Hills Oil Field. 357-7R and 355-7R surface elevations are 792' and 714' above mean sea level, respectively. These injectors are currently approved by CalGEM for Class II injection of up to 50 million cubic feet per day gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. The wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention

355-7R was drilled in 1973, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement.

4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval, from base of 7" casing to ~5200 feet.
5. Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted
6. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Materials

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
3. Packer – corrosion resistant alloy material or coating and hardened rubber
4. Casing and Cement - N-80 and K-55 casing with Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 with good cement bond between formation and casing into the Reef Ridge Shale

Standards

Well materials follow the following standards:

1. API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. Subsidence has not been observed historically in the areas around the injection wells because of

hydrocarbon production, and shallow compression is not anticipated as a concern for casing or cement integrity.

Casing specifications are presented in Table 1. These specifications show that the well was engineered to standards that allow for the safe operation at the conditions outlined in Table 4 in operating parameters. Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues related to the structural strength.

Table 1: Casing Specifications for the 355-7R injector

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 46	20.000	19.5	52	--	--	2.62	--	--
Surface	14 - 500	13.375	12.715	48	H-40	Short	2.62	1,730	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	2.62	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	2.62	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The cement returns were to surface for the 13-3/8" casing. The 9-5/8" casing string was cemented in place with circulation and top job to achieve cement to surface. The 7" casing string was cemented in place with Class G portland cement. Subsequently, a CBL was run from 5200' – 9400' and indicates annular isolation throughout and above the Monterey and Reef Ridge formations.

Protection of USDW

The USDW and all strata overlying the injection zone will be protected by the following:

1. Surface casing is set and cemented to surface within the USDW interval, providing multiple protective barriers to ensure protection of the USDW above the casing point.

2. The intermediate casing string is set across the base of the USDW, and annular cement isolates the USDW from the injection string by providing multiple protective barriers to ensure protection of USDW.
3. The cement bond log on the 7" casing string indicates several thousand feet of annular cement within and above the injection and confining zones, providing adequate isolation of the USDW from CO_2 injectate.
4. SAPT tests that pressure the well annulus to 500 PSI for 30 minutes have been acquired through time. All SAPT's demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPT will be acquired before the start of injection and every five years thereafter.
5. If mechanical integrity issues are indicated through monitoring during injection, CTV will perform diagnostics and remediate as necessary.

Tubing and Packer

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. A suitable corrosion-resistant alloy will be installed once the CO_2 stream impurities and impurity concentrations have been determined. The grade identified in Table 2 is anticipated to be acceptable.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,423	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8,397	30.3	26-32	5.875	4.000

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with realtime injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

The following data have been acquired during the initial well construction or during subsequent operations. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be addressed in the Pre-Operational Testing plan document.

Deviation Checks During Drilling

Deviation checks for 355-7R were acquired during drilling every 100 feet from 3,500 feet measured depth (MD) to bottom hole at 10,500 feet MD (Figure 1).

Figure 1: Deviation checks during drilling for the 357-7R well.

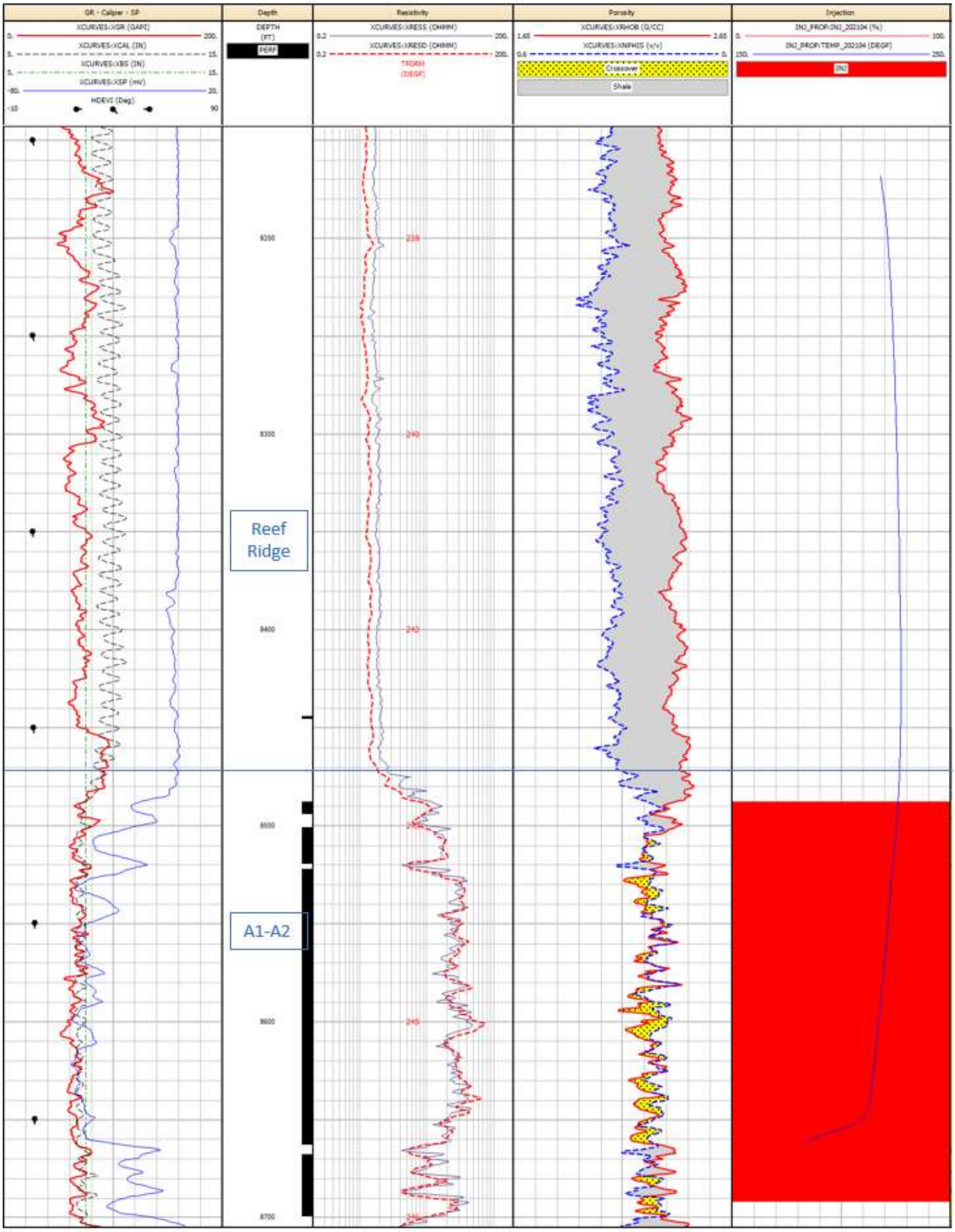
X ftUS	Y ftUS	Z ft	MD ft	Inclination deg	Azimuth GN deg	Azimuth TN deg	DX ftUS	DY ftUS	DX TN ftUS	DY TN ftUS	TVD (Well datum) ft	TWT ms	DLS deg/100ft
6101103.00	2310474.00	728.00	0.00	0.00	180.00	179.12	0.00	0.00	0.00	0.00	0.00		0.00
6101103.00	2310412.92	-2771.29	3500.00	2.00	180.00	179.12	0.00	-61.08	0.94	-61.07	3499.29		0.06
6101103.00	2310409.43	-2871.23	3600.00	2.00	180.00	179.12	0.00	-64.57	0.99	-64.56	3599.23		0.00
6101103.18	2310405.95	-2971.17	3700.00	2.00	174.00	173.12	0.18	-68.05	1.23	-68.04	3699.17		0.21
6101103.55	2310402.48	-3071.11	3800.00	2.00	174.00	173.12	0.55	-71.52	1.65	-71.50	3799.11		0.00
6101103.85	2310399.00	-3171.05	3900.00	2.00	176.00	175.12	0.85	-75.00	2.00	-74.98	3899.05		0.07
6101103.97	2310395.52	-3270.98	4000.00	2.00	180.00	179.12	0.97	-78.48	2.18	-78.46	3998.98		0.14
6101103.70	2310392.05	-3370.92	4100.00	2.00	189.00	188.12	0.70	-81.95	1.96	-81.93	4098.92		0.31
6101103.21	2310388.60	-3470.86	4200.00	2.00	187.00	186.12	0.21	-85.40	1.53	-85.39	4198.86		0.07
6101102.94	2310385.12	-3570.80	4300.00	2.00	182.00	181.12	-0.06	-88.88	1.31	-88.87	4298.80		0.17

X ftUS	Y ftUS	Z ft	MD ft	Inclination deg	Azimuth GN deg	Azimuth TN deg	DX ftUS	DY ftUS	DX TN ftUS	DY TN ftUS	TVD (Well datum) ft	TWT ms	DLS deg/100ft
6101181.90	2310156.91	-8897.80	9633.33	3.32	132.40	131.52	78.90	-317.09	83.76	-315.85	9625.80		1.14
6101183.43	2310155.58	-8931.07	9666.67	3.66	129.45	128.57	80.43	-318.42	85.32	-317.16	9659.07		1.14
6101185.18	2310154.20	-8964.33	9700.00	4.00	127.00	126.12	82.18	-319.80	87.09	-318.51	9692.33		1.14
6101187.91	2310152.03	-9014.21	9750.00	3.99	130.00	129.12	84.91	-321.97	89.85	-320.63	9742.21		0.42
6101190.52	2310149.73	-9064.09	9800.00	4.00	133.00	132.12	87.52	-324.27	92.49	-322.90	9792.09		0.42
6101193.14	2310147.43	-9113.97	9850.00	3.99	129.50	128.62	90.14	-326.57	95.15	-325.16	9841.97		0.49
6101195.89	2310145.30	-9163.85	9900.00	4.00	126.00	125.12	92.89	-328.70	97.93	-327.25	9891.85		0.49
6101198.74	2310143.28	-9213.72	9950.00	4.00	124.50	123.62	95.74	-330.72	100.81	-329.21	9941.72		0.21
6101201.64	2310141.35	-9263.60	10000.00	4.00	123.00	122.12	98.64	-332.65	103.74	-331.11	9991.60		0.21
6101204.57	2310139.46	-9313.48	10050.00	4.00	122.50	121.62	101.57	-334.54	106.70	-332.95	10041.48		0.07
6101207.52	2310137.60	-9363.36	10100.00	4.00	122.00	121.12	104.52	-336.40	109.68	-334.76	10091.36		0.07
6101209.57	2310136.30	-9396.60	10133.33	4.33	122.77	121.89	106.57	-337.70	111.74	-336.03	10124.60		1.01
6101211.76	2310134.87	-9429.84	10166.67	4.67	123.43	122.55	108.76	-339.13	113.96	-337.43	10157.84		1.01
6101214.09	2310133.31	-9463.05	10200.00	5.00	124.00	123.12	111.09	-340.69	116.31	-338.95	10191.05		1.01
6101217.78	2310131.01	-9512.86	10250.00	4.99	120.00	119.12	114.78	-342.99	120.04	-341.20	10240.86		0.70
6101221.62	2310128.97	-9562.67	10300.00	5.00	116.00	115.12	118.62	-345.03	123.91	-343.18	10290.67		0.70
6101224.13	2310127.70	-9595.89	10333.33	4.66	117.71	116.83	121.13	-346.30	126.43	-344.41	10323.89		1.10
6101226.42	2310126.45	-9629.12	10366.67	4.33	119.69	118.81	123.42	-347.55	128.74	-345.62	10357.12		1.10
6101228.50	2310125.21	-9662.36	10400.00	4.00	122.00	121.12	125.50	-348.79	130.84	-346.83	10390.36		1.10
6101234.41	2310121.51	-9762.12	10500.00	4.00	122.00	121.12	131.41	-352.49	136.81	-350.44	10490.12		0.00

Open Hole Log Analysis

Open-hole wireline log data was acquired in 355-7R prior to installation of 7” casing long string. Figure 2 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3 (third from left).

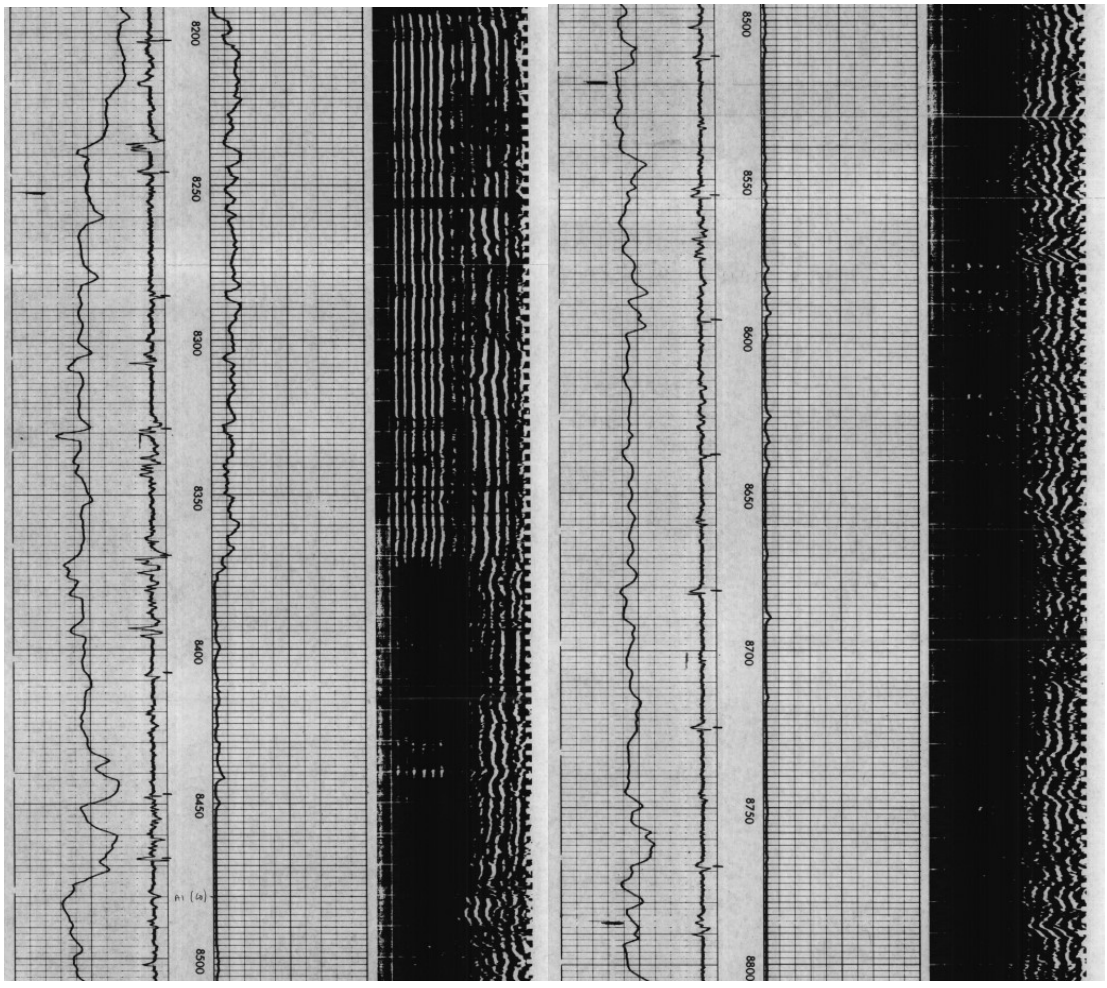
Figure 2: Open-hole well logs for 355-7R before installation of long string.



Cement Evaluation

The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing. The cement bond log seismogram and percent bond show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 3). Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7" casing interval. The top of cement was not identified below 5200', the top of the cement bond logging interval, and it is therefore shallower than 5200'.

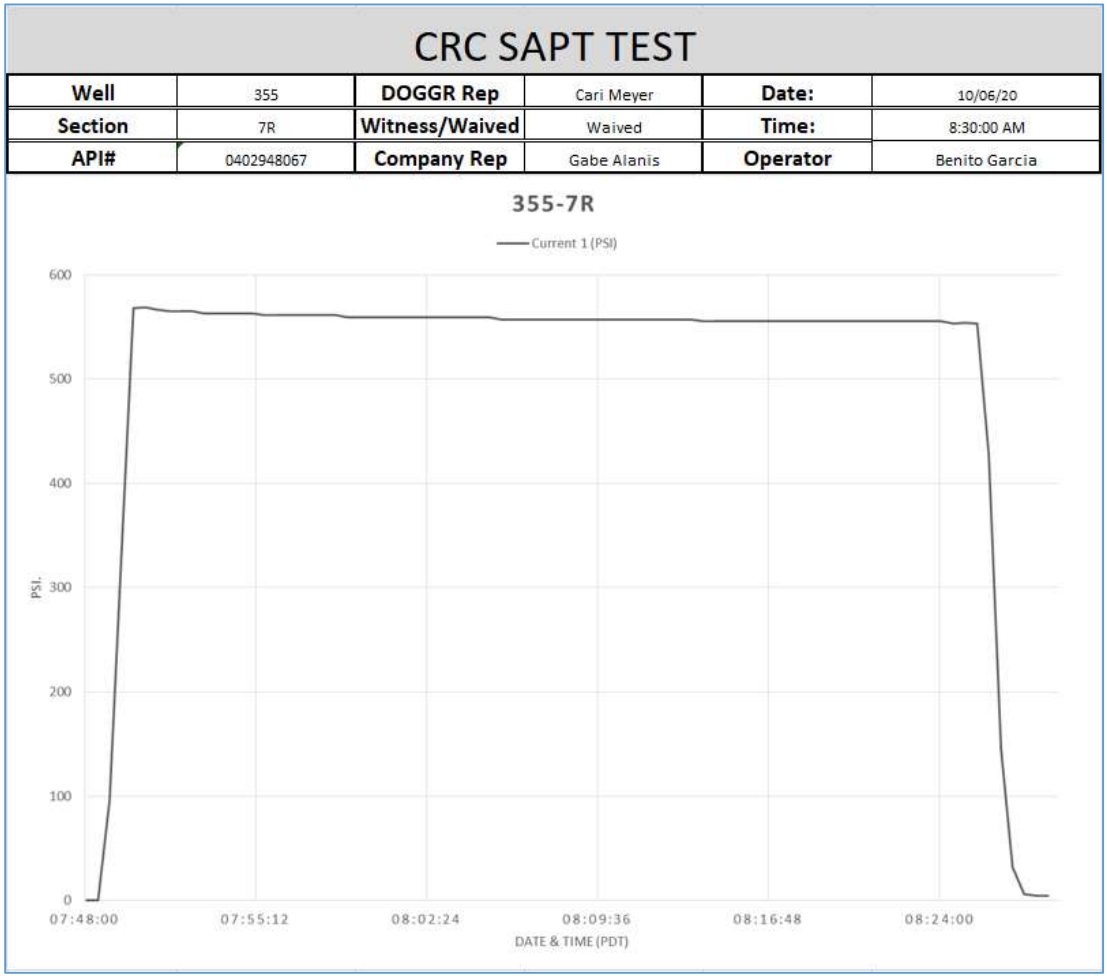
Figure 3: Cement bond log example for 355-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,470 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated October 6th, 2020, shows that the annulus can hold pressure more than 500 psi without gain or loss for 20 to 30 minutes indicating mechanical integrity of the tubing, casing and packer with the tubing and packer equipment currently in the well. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this will be addressed in the Pre-Operational Testing plan document.

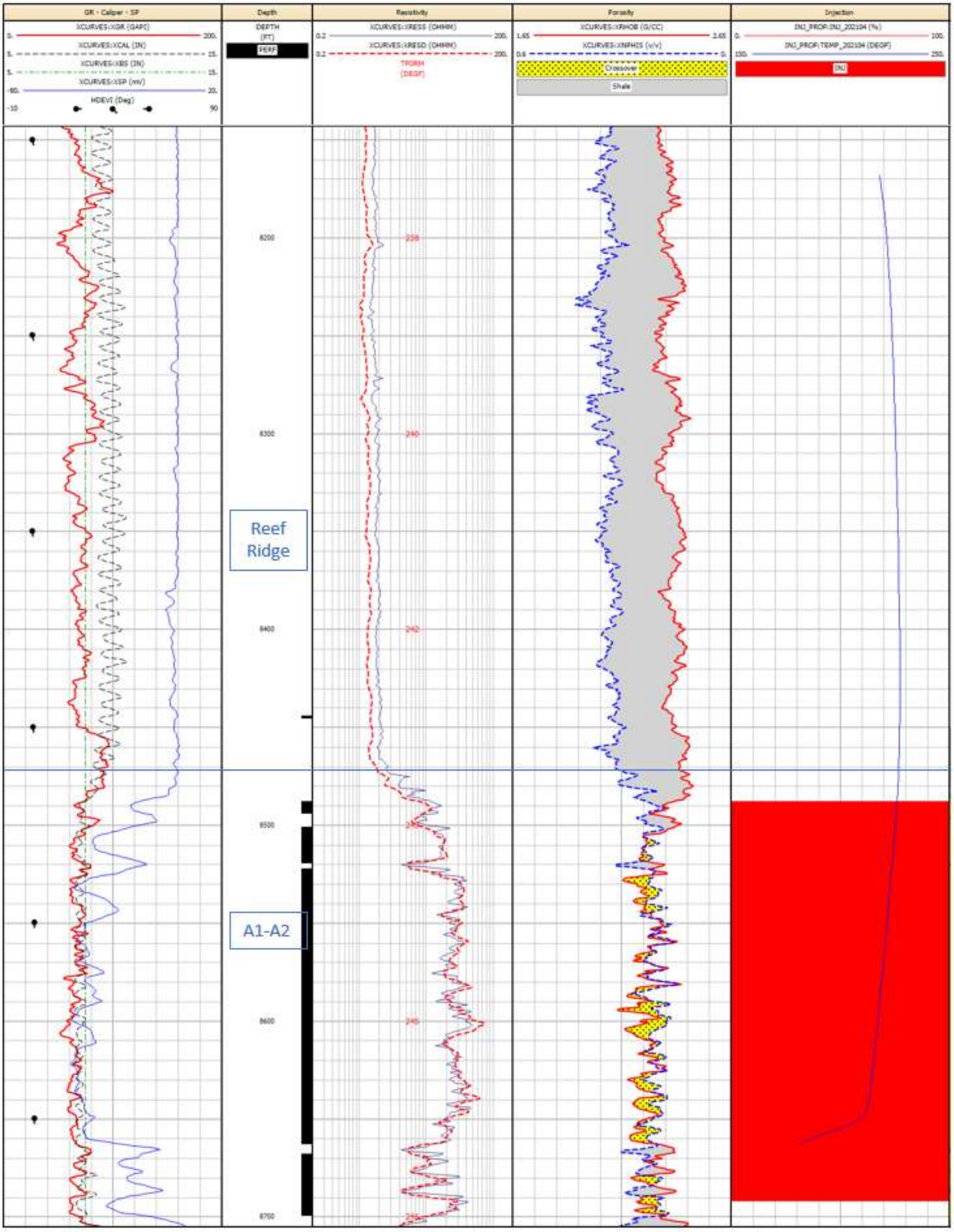
Figure 4: SAPT for 355-7R showing mechanical integrity of the tubing, casing, and packer.



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 5 was acquired on April 13th, 2021. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation at 8488' or at the packer at 8403'. The track on the right represents injection in percent of total rate with red shading showing 100% injection into A1-A2 perforations. The temperature curve shows that injection is confined below the packer as temperature trends toward geothermal gradient above the packer.

Figure 5: Radioactive tracer and temperature survey for well 355-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



Well Operation

Refer to 355-7R Operating Procedures appendix submitted to EPA on 3/31/2022. The final version of this document will include 355-7R Operational Procedures in this section.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 5 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be consistent with the properties of Class G portland cement used in well construction, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 5, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 14' MD due to the depth reference to the kelly bushing 14' above ground level during drilling.

Table 5: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.184	6.276	6.366	6.184
Depth to bottom of tubing or drill pipe (ft)	8,692	3,061	1,509	39
Sacks of cement to be used (each plug)	59	24	148	5
Slurry volume to be pumped (ft^3)	67	27	170	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,371	2,936	740	14
Bottom of plug (ft)	8,692	3,061	1,509	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

WELL CONSTRUCTION, OPERATING, AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Well 357-7R

Version History

File Name	Version	Date	Description of Change
COP_357-7R_v1	1	05/16/22	Combines documents, incorporates corrections and EPA feedback dated 04/25/22

Introduction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. The wells are in Section 7R within the unit boundary of the Elk Hills Oil Field. 357-7R and 355-7R surface elevations are 792' and 714' above mean sea level, respectively. These injectors are currently approved by CalGEM for Class II injection of up to 50 million cubic feet per day gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. The wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention

357-7R was drilled in 1980, during which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement.

4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results.
5. Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions.
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

Materials

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
3. Packer – corrosion resistant alloy material or coating and hardened rubber
4. Casing and Cement - N-80 casing with Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 with good cement bond between formation and casing into the Reef Ridge Shale

Standards

Well materials follow the following standards:

1. API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. Subsidence has not been observed historically in the areas around the injection wells because of

hydrocarbon production, and shallow compression is not anticipated as a concern for casing or cement integrity.

Casing specifications are presented in Table 1. These specifications show that the well was engineered to standards that allow for the safe operation at the conditions outlined in Table 4 in operating parameters. Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues related to the structural strength.

Table 1: Casing Specifications for the 357-7R injector

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20' – 60'	20.000	19.124	94	--	--	2.62	--	--
Surface	20' – 501'	13.375	12.715	48	H-40	Short	2.62	1,730	770
Intermediate	20' – 3,517'	9.625	8.835	40	N-80	Long	2.62	5,750	3,090
Long-string	20' – 76' 76' – 2,953' 2,953' – 6,158' 6,158' – 8,990'	7.000	6.184 6.366 6.276 6.184	29 23 26 29	N-80	Long	2.62	8,160 6,340 7,240 8,160	7,020 3,830 5,410 7,020

Cement

Portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8", 9-5/8", and 7" casing strings were cemented with returns to surface. Subsequently, a CBL was run from 6250 – 8970' and indicates annular isolation within the Monterey and Reef Ridge formations.

Protection of USDW

The USDW and all strata overlying the injection zone will be protected by the following:

1. Surface casing is set and cemented to surface within the USDW interval, providing multiple protective barriers to ensure protection of the USDW above the casing point.
2. The intermediate casing string is set across the base of the USDW, and annular cement isolates the USDW from the injection string by providing multiple protective barriers to ensure protection of USDW.
3. The cement bond log on the 7" casing string indicates annular cement within and above the injection and confining zones, providing adequate isolation of the USDW from CO_2 injectate.

4. SAPT tests that pressure the well annulus to 500 PSI for 30 minutes have been acquired through time. All SAPT's demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPT will be acquired before the start of injection and every five years thereafter.
5. If mechanical integrity issues are indicated through monitoring during injection, CTV will perform diagnostics and remediate as necessary.

Tubing and Packer

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed and inspected prior to injection. A suitable corrosion-resistant alloy will be installed once the CO_2 stream impurities and impurity concentrations have been determined. The grade identified in Table 2 is anticipated to be acceptable.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	8,470	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8,430	30.3	26 – 32	5.875	4.00

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with realtime injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

The following data have been acquired during the initial well construction or during subsequent operations. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be addressed in the Pre-Operational Testing plan document.

Deviation Checks During Drilling

Deviation checks for 357-7R were acquired during drilling every ten feet from 3,541 feet measured depth (MD) to bottom hole at 9,005 feet MD (Figure 1).

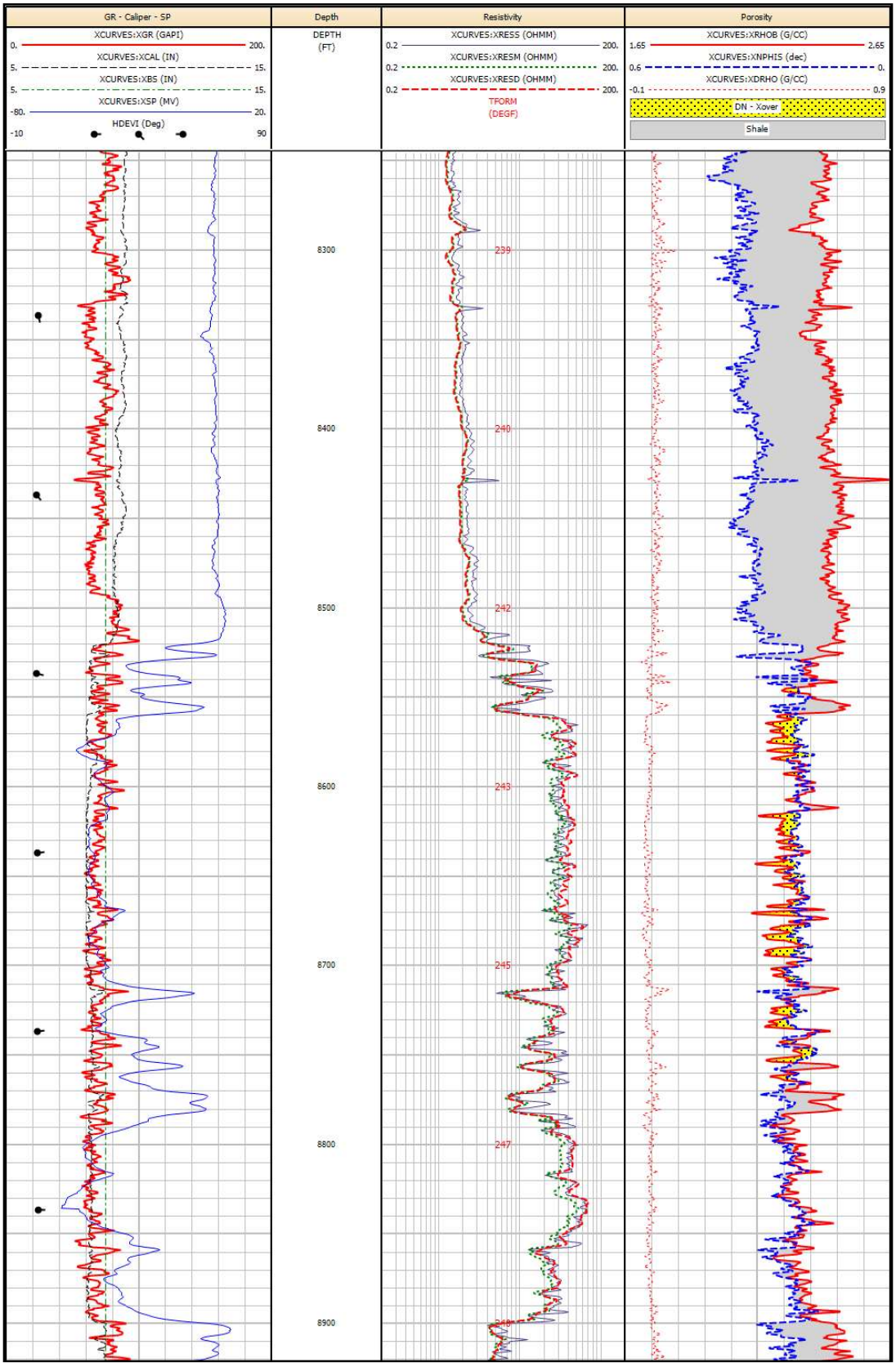
Figure 1: Deviation checks during drilling for the 357-7R well.

X ftUS	Y ftUS	Z ft	MD ft	Inclination deg	Azimuth GN deg	Azimuth TN deg	DX ftUS	DY ftUS	DX TN ftUS	DY TN ftUS	TVD (Well datum) ft	TWT ms	DLS deg/100ft
6100830.00	2309245.00	812.00	0.00	0.00	165.70	164.82	0.00	0.00	0.00	0.00	0.00		0.00
6100843.74	2309191.11	-2728.52	3541.10	1.80	165.70	164.82	13.74	-53.89	14.56	-53.68	3540.52		0.05
6100843.83	2309190.81	-2738.51	3551.10	1.80	158.50	157.62	13.83	-54.19	14.67	-53.97	3550.51		2.26
6100843.91	2309190.53	-2748.51	3561.10	1.50	170.00	169.12	13.91	-54.47	14.75	-54.25	3560.51		4.45
6100843.95	2309190.28	-2758.51	3571.10	1.40	174.30	173.42	13.95	-54.72	14.79	-54.50	3570.51		1.48
6100843.98	2309190.03	-2768.40	3581.00	1.60	170.00	169.12	13.98	-54.97	14.83	-54.75	3580.40		2.32
6100947.59	2308941.03	-8136.56	8957.60	2.30	76.40	75.52	117.59	-303.97	122.25	-302.14	8948.56		0.00
6100947.98	2308941.13	-8146.45	8967.50	2.30	75.00	74.12	117.98	-303.87	122.63	-302.03	8958.45		0.57
6100948.36	2308941.23	-8156.45	8977.50	2.30	76.40	75.52	118.36	-303.77	123.02	-301.93	8968.45		0.56
6100948.75	2308941.30	-8166.44	8987.50	2.20	80.70	79.82	118.75	-303.70	123.41	-301.84	8978.44		1.96
6100949.12	2308941.36	-8176.43	8997.50	2.10	82.10	81.22	119.12	-303.64	123.78	-301.78	8988.43		1.13
6100949.39	2308941.40	-8183.93	9005.00	2.10	82.10	81.22	119.39	-303.60	124.05	-301.74	8995.93		0.00

Open Hole Log Analysis

Open-hole wireline log data was acquired in 357-7R prior to installation of 7” casing long string. Figure 2 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3 (third from left), derived permeability in track 4 (fourth from left), and derived lithology in track 5 (rightmost).

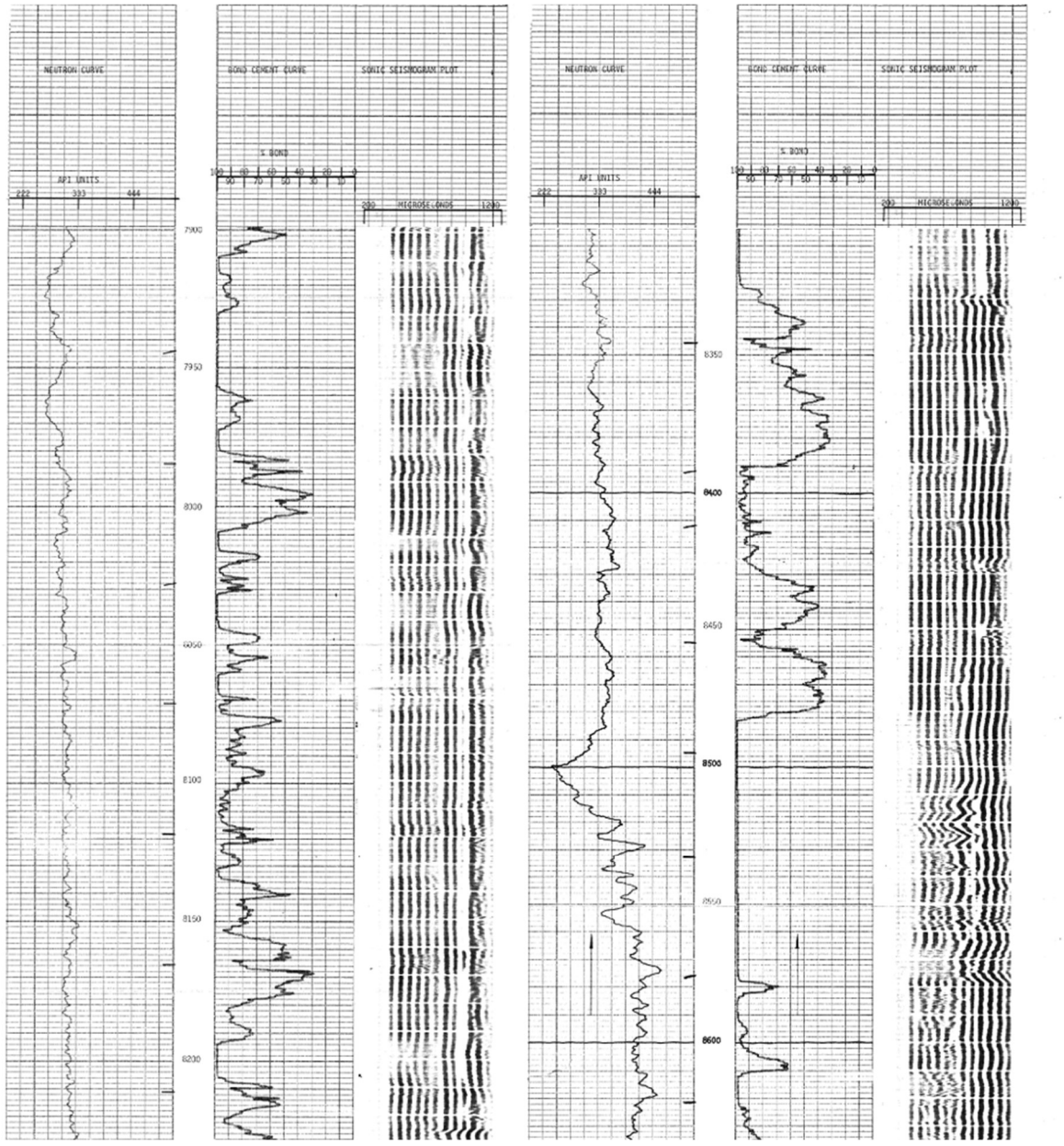
Figure 2: Open-hole well logs for 355-7R before installation of long string.



Cement Evaluation

The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing. The cement bond log seismogram and percent bond show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 3). Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7" casing interval.

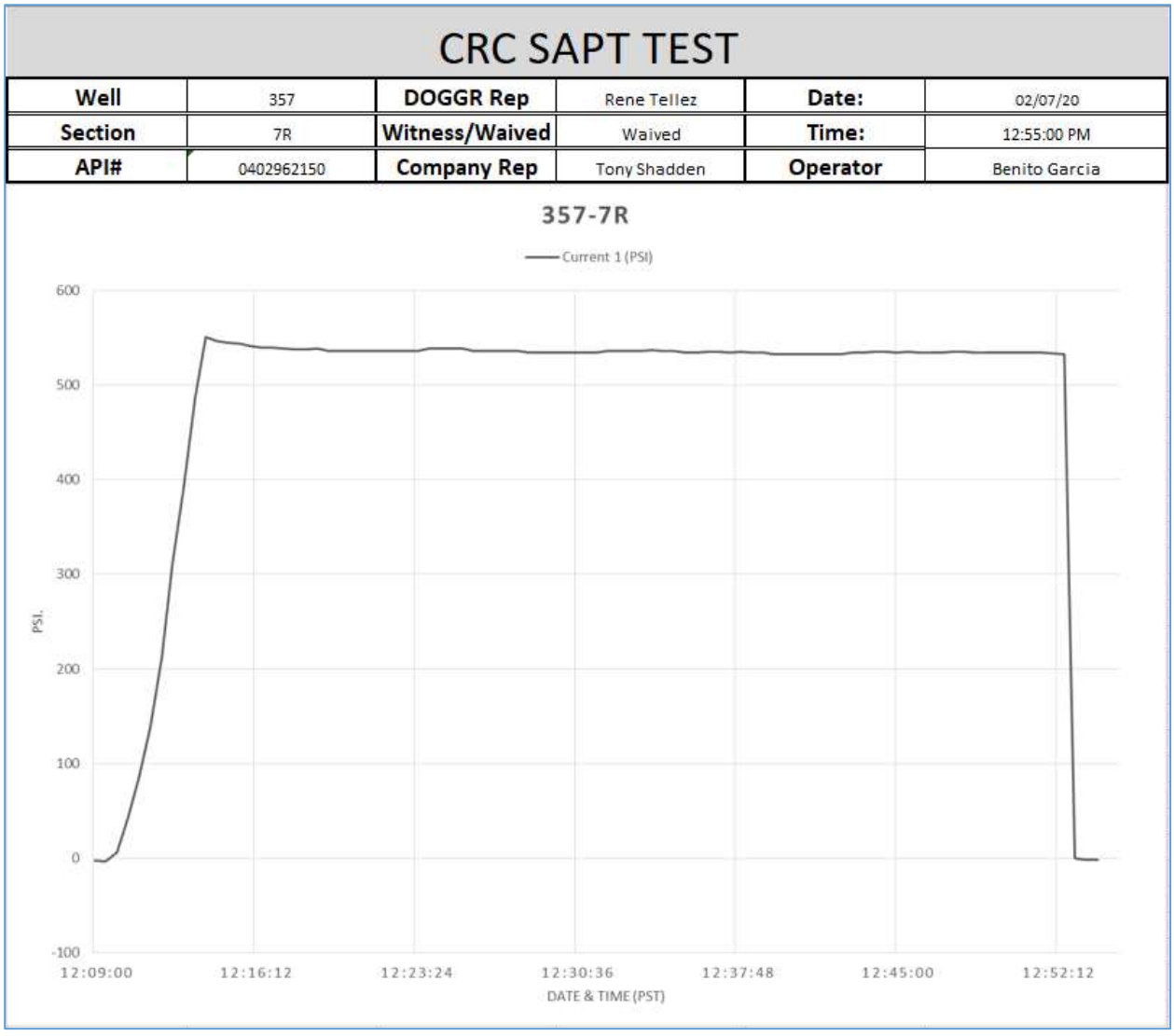
Figure 3: Cement bond log example for 357-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,518 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated February 7th, 2020, shows that the annulus can hold pressure more than 500 psi without gain or loss for 20 to 30 minutes indicating mechanical integrity of the tubing, casing and packer with the tubing and packer equipment currently in the well. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this will be addressed in the Pre-Operational Testing plan document.

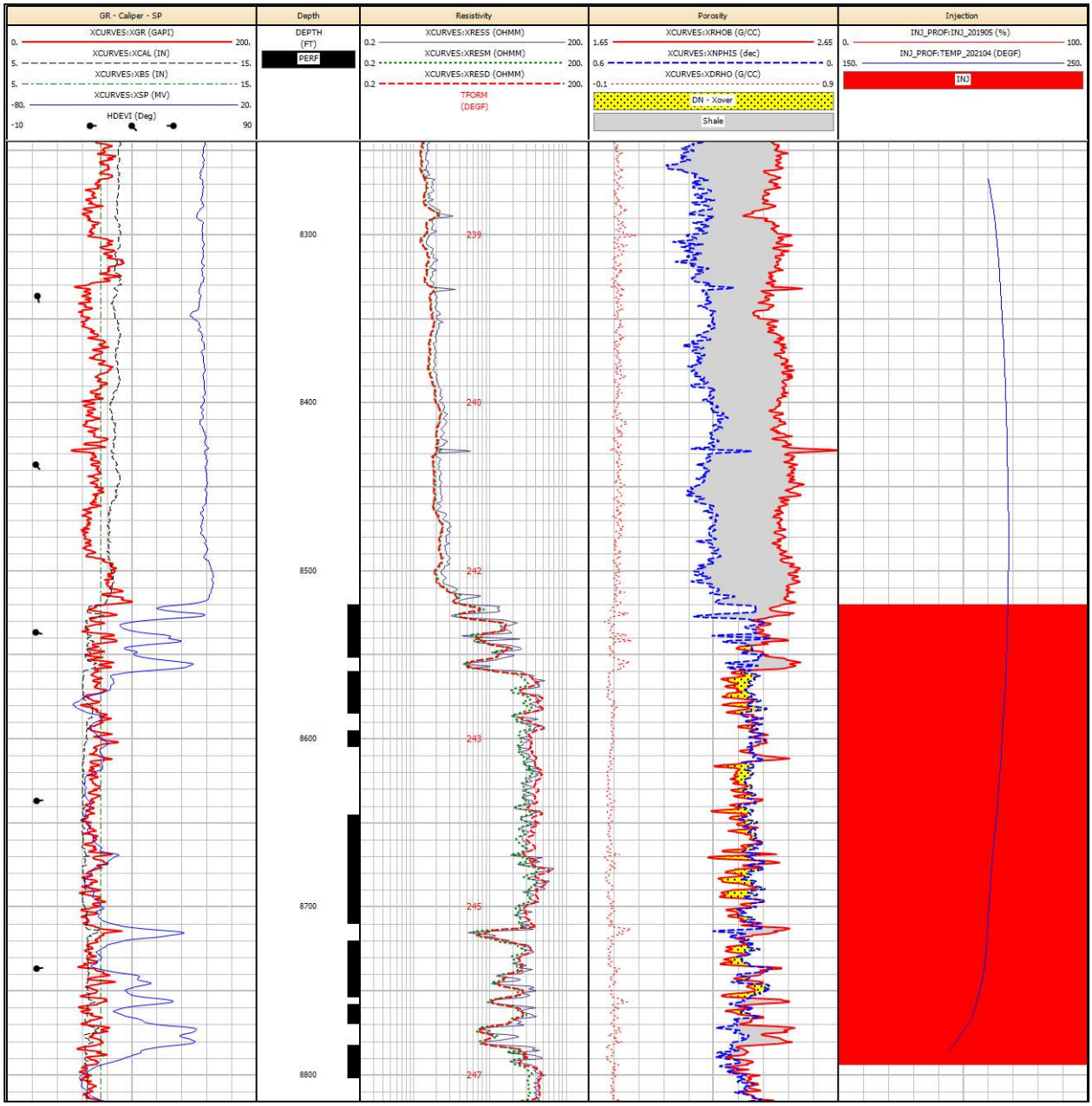
Figure 4: SAPT for 357-7R showing mechanical integrity of the tubing, casing, and packer.



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 5 below was acquired in 2019. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation or at the packer. The track on the right represents injection in percent of total rate with red shading showing 100% injection into A1-A2 perforations. The temperature curve shows that injection is confined below the packer as temperature trends toward geothermal gradient above the packer.

Figure 5: Radioactive tracer and temperature survey for well 355-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



Well Operation

Refer to 357-7R Operating Procedures appendix submitted to EPA on 3/31/2022. The final version of this document will include 357-7R Operational Procedures in this section.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 5 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be consistent with the properties of Class G portland cement used in well construction, and the cement plug will provide an effective, long-

term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The wells will have this cement placed as detailed in Table 5, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 20' MD due to the depth reference to the kelly bushing 20' above ground level during drilling.

Table 5: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.184	6.366	6.366	6.184
Depth to bottom of tubing or drill pipe (ft)	8,794	2,970	1,447	45
Sacks of cement to be used (each plug)	70	24	143	5
Slurry volume to be pumped (ft^3)	80	28	164	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,411	2,845	706	20
Bottom of plug (ft)	8,794	2,970	1,447	45
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Zone Monitoring Well, 353A-7R

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
353A-7R Injection Zone Monitoring Well

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment H1 – CP Details_353A-7R	1	08/30/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring the injection interval and one existing well for above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, logging, testing, and plugging plans for injection zone monitoring well 353A-7R.

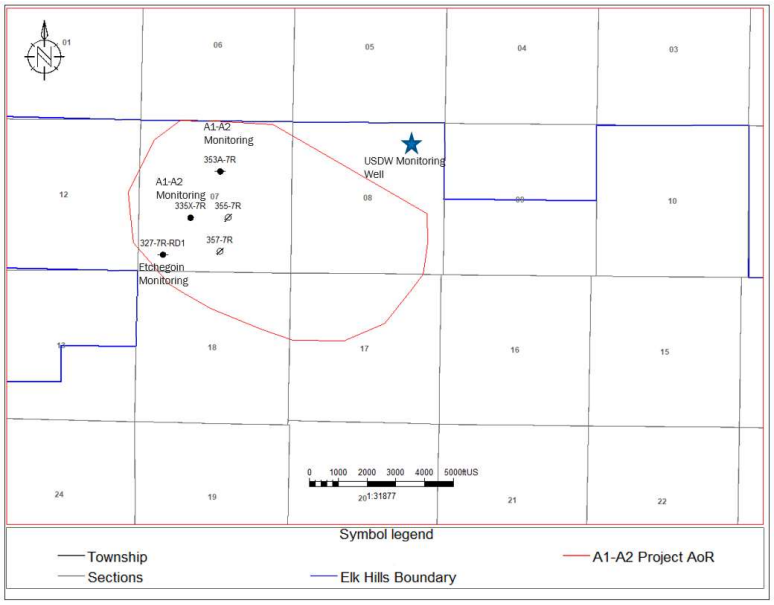


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 353A-7R is an existing oil and gas production well that was drilled in 2012 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of USDW

353A-7R was drilled in 2012, at which time there were no drilling and completion issues. The base of USDW is located at 961' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 7" production casing, multiple casing strings protect shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing was cemented with cement returns to surface. The 7" casing string was cemented with a theoretical volume to surface, but cement returns were not observed.
3. Cement bond logging was performed from the plugback depth of 7" casing at 9800' to 8000'. The resulting CBL indicates presence of cement in the production casing annulus well above the base of Reef Ridge Shale confining layer.
4. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
5. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
6. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.
7. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 353A-7R monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the CO_2 injectate to prevent loss of mechanical integrity in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.

3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.
4. Casing – the standard grade P-110 casing, which is currently installed, will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
5. Cement – portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Monterey Formation temperature in A1-A2 is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 353A-7R Monitoring Well

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	25' - 65'	20	19.124	94	-	-	2.62	-	--
Surface	25' - 2014'	9.625	8.921	36	J-55	Long	2.62	3520	2020
Long-String	25' - 8335' 8335' - 9900'	7	6.276 6.184	26 29	N-80 P-110	Long	2.62	7240 11220	5410 8510

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

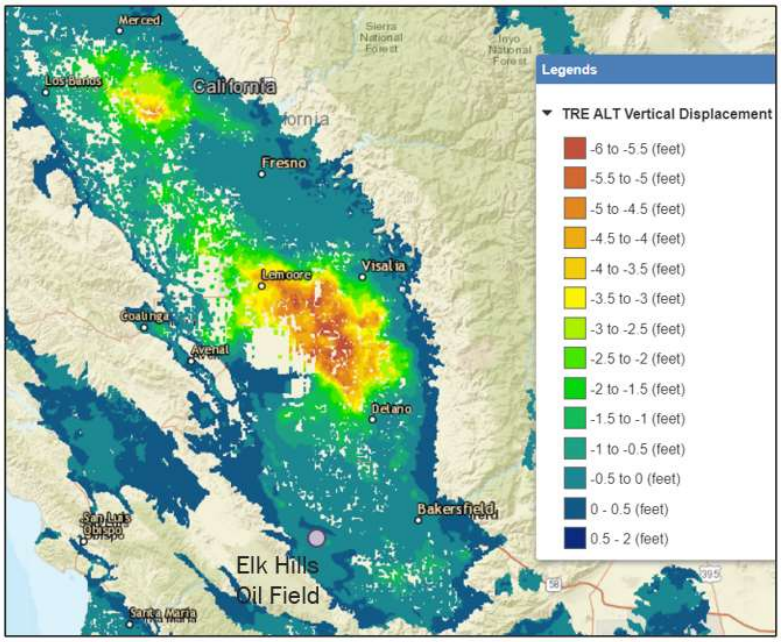


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class C portland cement has been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 9-5/8" surface casing string was cemented using Class C portland cement with 26 barrels of cement returns to surface. The 7" casing string was cemented in place with Class G portland cement. Subsequently, a CBL was run from 8000' – 9790' and indicates the presence of annular cement that provides isolation between the Monterey and Reef Ridge formations.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	8743'	2.875	2.441	6.5	L-80 CRA	Premium	10,570	11,170

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8713'	30.3	23 - 32	5.687	2.688

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	7500	7500	6.366	6.049

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant master valves and wing valves, and the valves will remain closed during normal injection operations. Safety valves or other automatic shut-off devices are not required for monitoring wells, in general. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
353A-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 7" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~158’ feet measured depth (MD) to bottom hole at 9900’ feet MD. Results of the survey are displayed in Table 5.

Table 5: Deviation checks during drilling for the 353A-7R well

MD	INC	AZI	TVD		MD	INC	AZI	TVD
158	0.23	139.02	158		5438	4.38	145.64	5428.8
257	0.28	191.78	257		5533	4.19	135.25	5523.6
349	0.2	132.87	349		5627	5.18	128.17	5617.3
439	0.18	149.89	439		5722	5.22	121.9	5711.9
529	0.33	119.37	529		5816	5.17	121.72	5805.5
620	0.15	67.22	620		5911	5.2	122.14	5900.1
712	0.27	147.78	712		6005	5.23	119.72	5993.7
804	0.25	128.58	804		6100	5.16	111.79	6088.3
896	0.33	130.54	896		6195	5.17	127.82	6182.9
988	0.47	127.11	988		6290	5.24	130.98	6277.6
1081	0.44	131.05	1081		6385	5.24	125.2	6372.2
1172	0.51	150.94	1172		6480	5.23	123.41	6466.8
1267	0.54	124.55	1267		6574	4.95	130.68	6560.4
1361	0.55	132.51	1361		6669	5.1	133.16	6655
1456	0.42	272.54	1456		6763	5.1	133.16	6748.7
1550	0.65	282.83	1550		6858	5.1	127.43	6843.3
1645	0.65	281.41	1645		6952	5.01	120.6	6936.9
1740	0.73	286.98	1740		7047	4.91	125.73	7031.6
1834	0.81	300.37	1833.9		7142	5.16	124.15	7126.2
1929	0.93	299.76	1928.9		7237	5.11	116.1	7220.8
2224	0.07	235.76	2223.9		7331	5.01	119.99	7314.4
2601	0.03	259.66	2600.9		7426	5.03	110.8	7409.1
2791	0.07	351.9	2790.9		7520	3.92	127.22	7502.8
2885	2.17	332.57	2884.9		7615	2.82	140.27	7597.6
2979	2.16	36.71	2978.8		7710	1.32	131.08	7692.6
3074	2.16	83.09	3073.8		7804	0.21	198.69	7786.6
3168	2.2	81.01	3167.7		7899	0.03	285.35	7881.6
3263	3.55	121.66	3262.6		7994	0.03	139.29	7976.6
3357	5	138.3	3356.3		8088	0.03	189.39	8070.6
3452	4.96	136.68	3451		8183	0.07	158.58	8165.6
3546	5	134.9	3544.6		8277	0.1	153.47	8259.6
3641	5.05	143.9	3639.3		8371	0.25	175.69	8353.6
3736	5.64	132.08	3733.9		8466	0.48	173.13	8448.6
3830	5.53	124.58	3827.4		8560	1.16	185.37	8542.5
3925	5.56	131.73	3922		8655	0	360	8637.5
4020	5.64	132.63	4016.5		8749	0.1	163.14	8731.5
4114	5.63	127.87	4110.1		8844	0.03	54.11	8826.5
4209	5.63	118.95	4204.6		8938	0	360	8920.5
4304	5.59	109.14	4299.2		9033	0.03	155.83	9015.5
4398	5.61	111.21	4392.7		9127	0.03	34.73	9109.5
4493	5.59	123.25	4487.3		9222	0.1	313.41	9204.5
4587	5.69	114.14	4580.8		9316	0.03	276.2	9298.5
4682	5.58	116.03	4675.3		9411	0.03	117.75	9393.5
4776	4.97	115.61	4768.9		9505	0.07	186.78	9487.5
4871	5.02	117.61	4863.6		9599	0.07	171.05	9581.5
4965	5.12	111.36	4957.2		9694	0.06	255.48	9676.5
5060	4.3	108.86	5051.9		9788	0	360	9770.5
5154	4.34	118.26	5145.6		9867	0.07	53.37	9849.5
5249	4.26	132.47	5240.4		9900	0.07	53.37	9882.5
5343	4.17	147.2	5334.1					

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of 7" long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), and neutron porosity and bulk density in track 3.

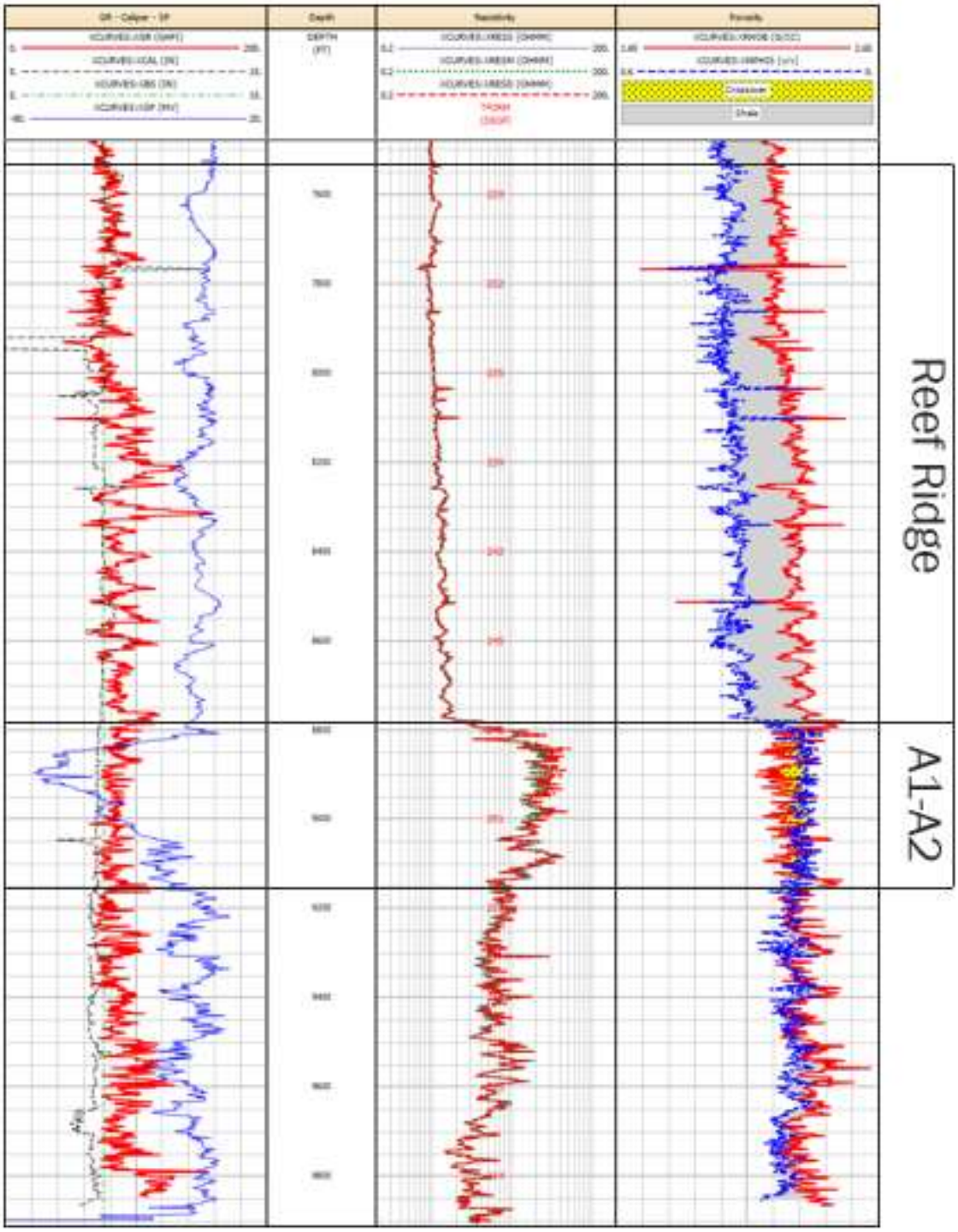


Figure 3: Open-hole well logs for 353A-7R before installation of long string for Reef Ridge Shale and Monterey Formations.

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was not logged across the entire 7" casing interval. The top of cement was not observed deeper than 8000', the top of the cement bond logging interval. As specified in the Pre-Operational Testing plan document, CTV will perform additional cement evaluation logging across the 7" casing string during pre-operational testing.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubular integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection and post-injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials, and methodology for monitoring well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 25' MD due to the depth reference to the kelly bushing 25' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.184	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	9140	3243	1645	50
Sacks of cement to be used (each plug)	85	24	147	5
Slurry volume to be pumped (ft^3)	98	28	169	6

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8673	3118	861	25
Bottom of plug (ft)	9140	3243	1645	50
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Zone Monitoring Well, 335X-7R

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
335X-7R Injection Zone Monitoring Well

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_335X-7R	1	11/4/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring of both the injection interval and one above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, recompletion, logging, testing, operating, and plugging plans for injection zone monitoring well 335X-7R.

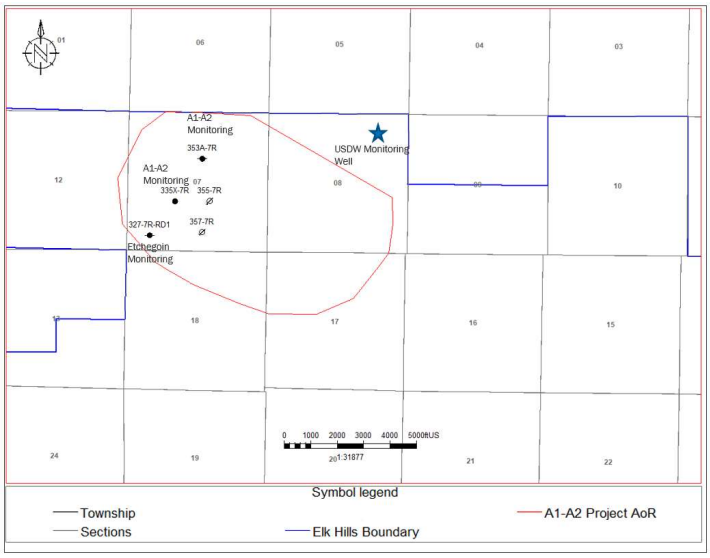


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 335X-7R is an existing oil and gas production well that was drilled in 2014 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of USDW

335X-7R was drilled in 2014, at which time there were no drilling and completion issues. The base of USDW is located at 854' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 7" production casing, multiple casing strings protect shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. Both surface casing and long string casing were cemented with returns to surface.
3. Cement bond logging was performed from the plugback depth of 7" casing around 9700' to surface. The resulting CBL indicates presence of cement in the production casing annulus well above the base of Reef Ridge Shale confining layer.
4. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
5. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
6. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.
7. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 335X-7R monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the mixture of CO_2 injectate and formation fluids to prevent corrosion in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.

4. Casing – the standard grade P-110 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
5. Cement – portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Monterey Formation temperature in A1-A2 is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 335X-7R Monitoring Well

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	25' - 65'	20	19.124	94	-	-	2.62	-	-
Surface	25' - 1993'	9.625	8.921	36	J-55	Long	2.62	3520	2020
Long-String	25' – 9790’	7	6.276	26	P-110	Long	2.62	9950	6230

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

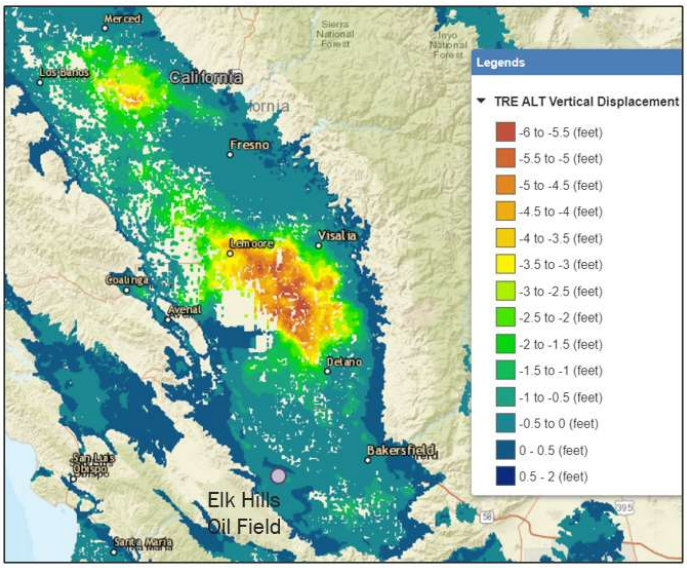


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class C and Class G portland cements have been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 9-5/8" surface casing string was cemented using Class C portland cement with 56 cubic feet of cement returns to surface. The 7" casing string was cemented in place using Class G portland cement with 67 cubic feet of cement returns to surface. Subsequently, a CBL was run from ~9700' to surface and indicates the presence of annular cement that provides isolation between the Monterey and Reef Ridge formations.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	8707’	2.875	2.441	6.5	L-80 CRA	Premium	10,570	11,170

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7” casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8677’	30.3	23 - 32	6	2.37

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	8000	8000	6.466	6.184

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7” casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant master valves and wing valves, and the valves will remain closed during normal injection operations. Safety valves or other automatic shut-off devices are not required for monitoring wells in general. The project does not anticipate risk factors that

warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided below. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
335X-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 7" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~184’ feet measured depth (MD) to bottom hole at 9839’ feet MD (Table 4).

Table 5: Deviation checks during drilling for the 335X-7R well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		6477	0.69	10.39	6475.9
184	0.1	54.1	184		6571	0.61	14.81	6569.9
274	0.4	82.8	274		6665	0.71	9.28	6663.9
553	1.3	45.2	553		6757	0.77	9.58	6755.9
843	1.1	42.7	842.9		6851	0.59	14.07	6849.9
1125	1	34.7	1124.9		6945	0.26	34.35	6943.9
1406	0.7	27.9	1405.8		7040	1.49	342.91	7038.9
1688	0.4	21.1	1687.8		7135	1.43	345.41	7133.8
1973	0.2	52.6	1972.8		7229	1.05	338.33	7227.8
2039	0.17	358.51	2038.8		7324	2.76	335.99	7322.7
2229	1.14	234.95	2228.8		7419	4.4	332.4	7417.6
2418	0.98	235.93	2417.8		7513	5.88	334.34	7511.2
2607	1.03	230.44	2606.7		7608	7.81	331.62	7605.5
2796	1	228.22	2795.7		7703	7.44	329.46	7699.7
2985	1.18	232.7	2984.7		7797	8.77	326.74	7792.7
3173	1.51	238.93	3172.6		7892	8.88	325.45	7886.6
3361	0.84	223.73	3360.6		7987	8.83	325.83	7980.5
3548	1.02	236.33	3547.6		8082	8.47	327.22	8074.4
3736	0.53	156.12	3735.5		8176	8.35	326.11	8167.4
3925	0.72	140.11	3924.5		8270	7.64	330.17	8260.5
4115	0.89	166.88	4114.5		8365	8.03	333.54	8354.6
4305	1.01	156.26	4304.5		8461	8.01	338.06	8449.6
4494	0.61	120.49	4493.5		8556	9.3	345.07	8543.5
4684	0.71	59.67	4683.5		8650	8.92	348.15	8636.4
4873	1.52	59.64	4872.4		8744	8.11	345.93	8729.3
5157	0.91	75.06	5156.4		8838	8.39	347.32	8822.4
5347	1.21	94.84	5346.3		8933	8.87	346.52	8916.3
5536	0.43	70.54	5535.3		9027	8.68	348.32	9009.2
5625	0.29	22.28	5624.3		9122	8.7	351.34	9103.1
5719	2.62	268.23	5718.3		9209	8.75	353.67	9189.1
5814	2.67	274.19	5813.2		9301	7.41	354.44	9280.2
5909	3.01	268.24	5908.1		9396	8.08	347.8	9374.3
6004	1.84	282.07	6003		9498	8.04	350.12	9475.3
6098	1.17	17.42	6096.9		9592	7.58	352.94	9568.4
6193	1.02	3.84	6191.9		9675	7.47	355.22	9650.7
6288	0.86	358.61	6286.9		9768	7.47	358.34	9742.9
6382	0.83	15.11	6380.9		9839	7.47	358.34	9813.3

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of 7" long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), and neutron porosity and bulk density in track 3.

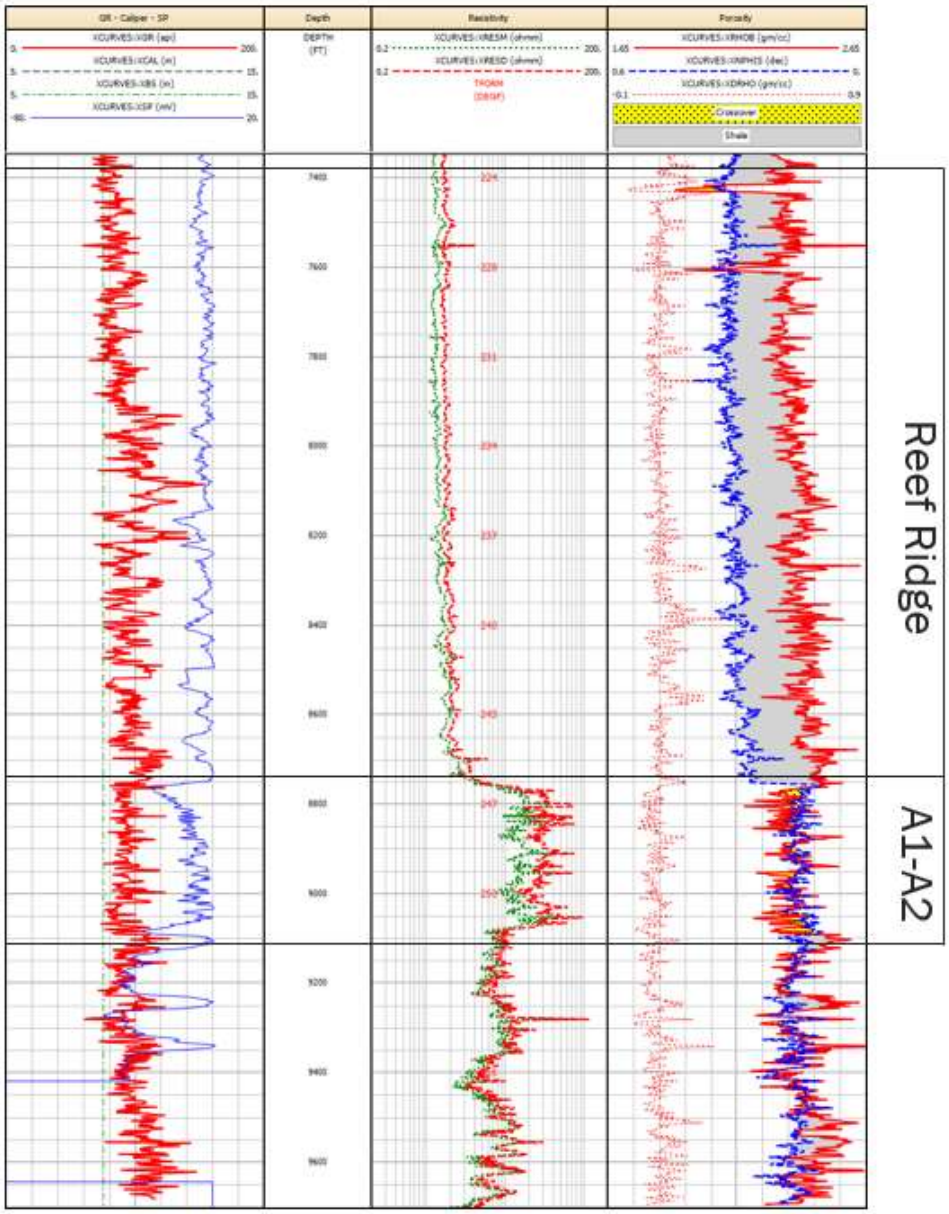


Figure 3: Open-hole well logs for 335X-7R before installation of long string for Reef Ridge Shale and Monterey Formations.

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was logged across the entire 7" casing interval. Figure 4 shows good cement throughout the injection zone, with evidence of continuous cement throughout the confining layer and to surface. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing.

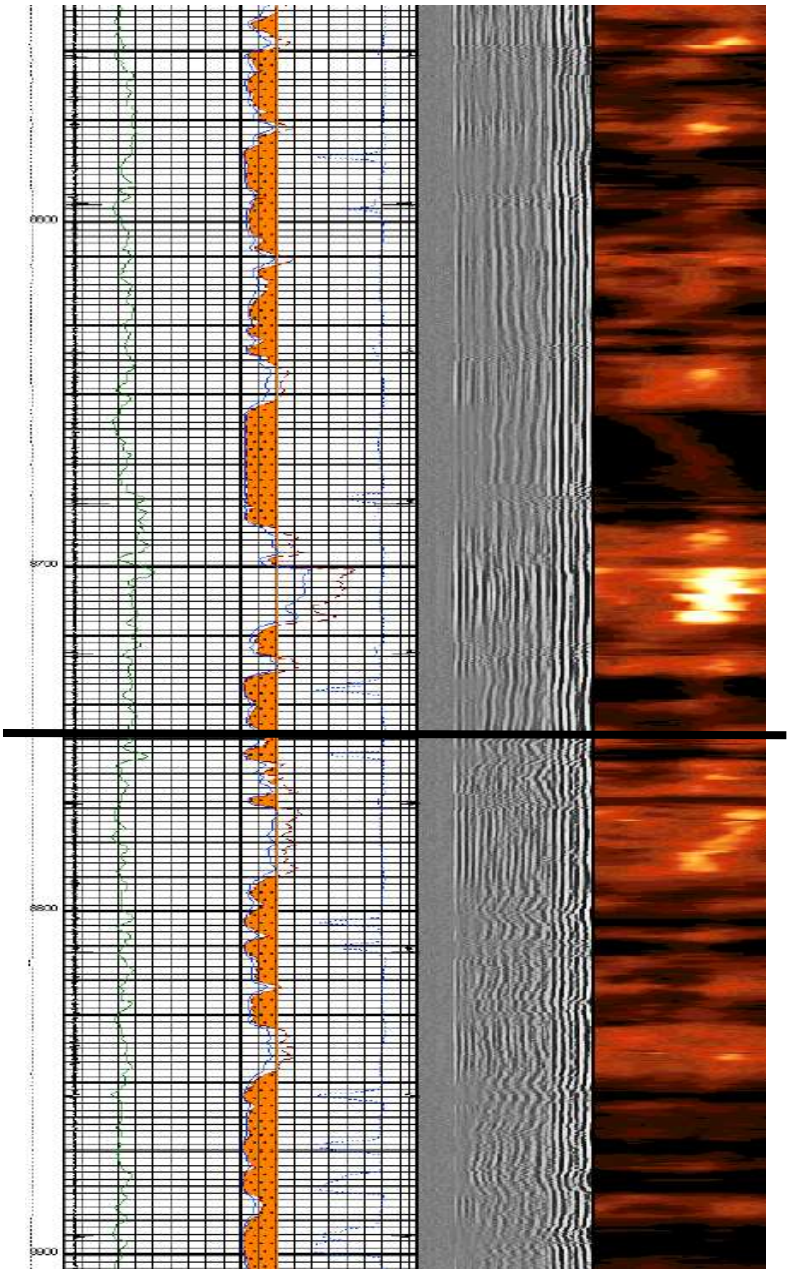


Figure 4: Cement bond log example for 335X-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,736 feet.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials, and methodology for monitoring well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 25' MD due to the depth reference to the kelly bushing 25' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	9060	3003	1503	50
Sacks of cement to be used (each plug)	80	24	141	5
Slurry volume to be pumped (ft^3)	92	28	162	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8634	2878	754	25
Bottom of plug (ft)	9060	3003	1503	50
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may

place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

- If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Above Zone Monitoring Well, 327-7R-RD1

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
327-7R-RD1 Above Zone Monitoring Well

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_327-7R-RD1	1	11/4/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring of both the injection interval and one above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, recompletion, logging, testing, operating, and plugging plans for above zone monitoring well 327-7R-RD1.

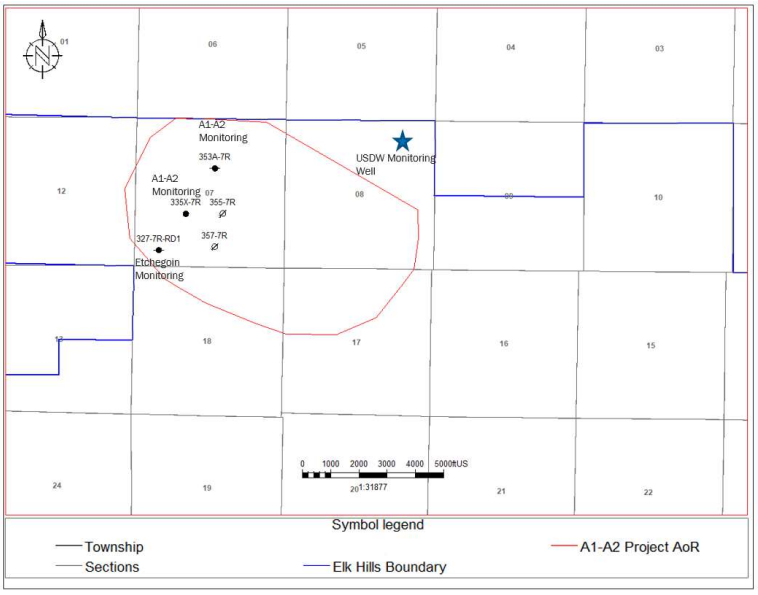


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 327-7R-RD1 is an existing oil and gas production well that was drilled in 2000 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of USDW

327-7R-RD1 was drilled in 2000, at which time there were no drilling and completion issues. The base of USDW is located at 849' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 9-5/8" production casing, multiple casing strings protects shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing was cemented with cement returns to surface. The 9-5/8" casing string was cemented with a theoretical volume to surface, but cement returns were not observed. The 5-1/2" liner was cemented successfully and will be isolated with cement plugs internally and above as part of the recompletion to monitor the reservoir above the confining layer.
3. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
4. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.
5. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 327-7R-RD1 monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Current well materials are compatible with the Etchegoin formation fluids and are suitable for the monitoring purposes intended.

1. Tubing – standard N-80 grade carbon steel tubing is appropriate and is consistent with accepted industry practices and field experience.
2. Wellhead – standard grade carbon steel material
3. Packer – standard carbon steel and elastomer material consistent with accepted industry practices.
4. Casing – the standard grade N-80 and P-110 casing is appropriate and is consistent with accepted industry practices and field experience

5. Cement – Class G and Class C portland cement used in constructing the well is appropriate for monitoring in the reservoir above the confining layer.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Etchegoin Formation temperature is approximately 170 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 327-7R-RD1 Monitoring Well

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20' - 60'	20	19.124	94	-	-	2.62	-	--
Surface	20' - 2337'	13.375	12.515	61	K-55	Short	2.62	3090	1540
Long-String	20' - 6382' 6382' - 8245'	9.625	8.755 8.681	43.5 47	N-80 P-110	Long	2.62	6330 9440	3810 5300
Liner	8059’ – 9842’	5.5	4.892	17	N-80	Long	2.62	7740	6390

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

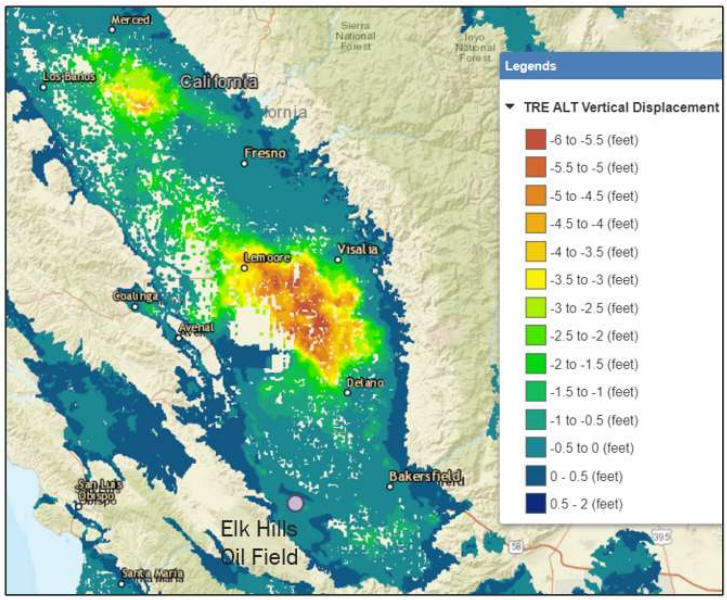


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Portland cements have been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing was cemented using Class C portland cement with 60 bbls returns to surface. The 9-5/8" production casing was cemented using Class G portland cement with circulation throughout the job and no cement returns. No cement evaluation log was acquired at the time of installation. Cement evaluation logging will be performed to ensure annular isolation and well integrity during conversion activities for Etchegoin reservoir monitoring.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c).

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	3762'	2.875	2.441	6.5	N-80	Short	10,570	11,170

Table 3 provides specifications of a hydraulic packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 9-5/8" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Hydraulic, low carbon alloy steel	3732'	30.3	40-47	8.452	2.416

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
50,000	10,000	10,000	8.835	8.681

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 9-5/8" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The

wellhead tree will include redundant valves. Safety valves or other automatic shut-off devices are not required for monitoring wells in general.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided below. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
327-7R-RD1	Cement Bond Log	Along the 9-5/8" casing to surface
	Casing Inspection Log	Along the 9-5/8" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 9-5/8" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~1007’ feet measured depth (MD) to bottom hole at 9843’ feet MD (Table 5).

Table 5: Deviation checks during drilling for the 327-7R-RD1 well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		8767	22.9	202.7	8714.7
1007	2	357	1006.8		8799	23.8	205.1	8744.1
1505	2	0.88	1504.5		8831	24.6	207.9	8773.2
2307	1.75	358	2306.1		8862	25.6	211.4	8801.3
2838	1.75	13	2836.8		8894	27.5	215	8829.9
3331	2.25	5	3329.5		8926	28.9	218.5	8858.1
3841	2.75	12	3839		8957	30.3	223	8885.1
4328	3	15	4325.4		8987	32.1	225.5	8910.8
4876	3.75	22	4872.5		9019	34.2	227.3	8937.6
5627	3	26	5622.2		9050	36.5	228.7	8962.8
6114	1	49	6108.8		9082	38.8	231.1	8988.2
6619	1.5	150	6613.8		9114	41.4	232.2	9012.7
7125	2	178	7119.5		9145	43.9	233.9	9035.5
7567	2	163	7561.3		9177	46.5	235	9058
7807	2.4	164.7	7801.1		9208	47.8	236.8	9079.1
7870	6.1	179.8	7863.9		9239	48.7	236.8	9099.7
7933	11.5	183.3	7926.1		9303	50.5	236.7	9141.2
7995	16.4	187.2	7986.3		9365	51.7	236.1	9180.1
8058	18	188.2	8046.5		9426	55.3	237.8	9216.4
8121	18.6	186.8	8106.3		9489	55	237.8	9252.4
8185	18.9	185.8	8166.9		9521	53	238.5	9271.2
8245	19.19	183.79	8223.6		9551	51.2	238.5	9289.7
8401	18.5	178	8371.3		9614	51.2	239.2	9329.1
8433	18.8	179.5	8401.6		9646	52.9	241.3	9348.8
8496	19.2	178.4	8461.2		9677	54	242	9367.3
8559	19.5	186.8	8520.6		9741	53.7	242	9405
8622	20.7	190.4	8579.8		9800	54	242	9439.8
8684	21.1	196.3	8637.7		9843	54	242	9465.1
8748	22.4	199.5	8697.1					

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of the long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and resistivity.

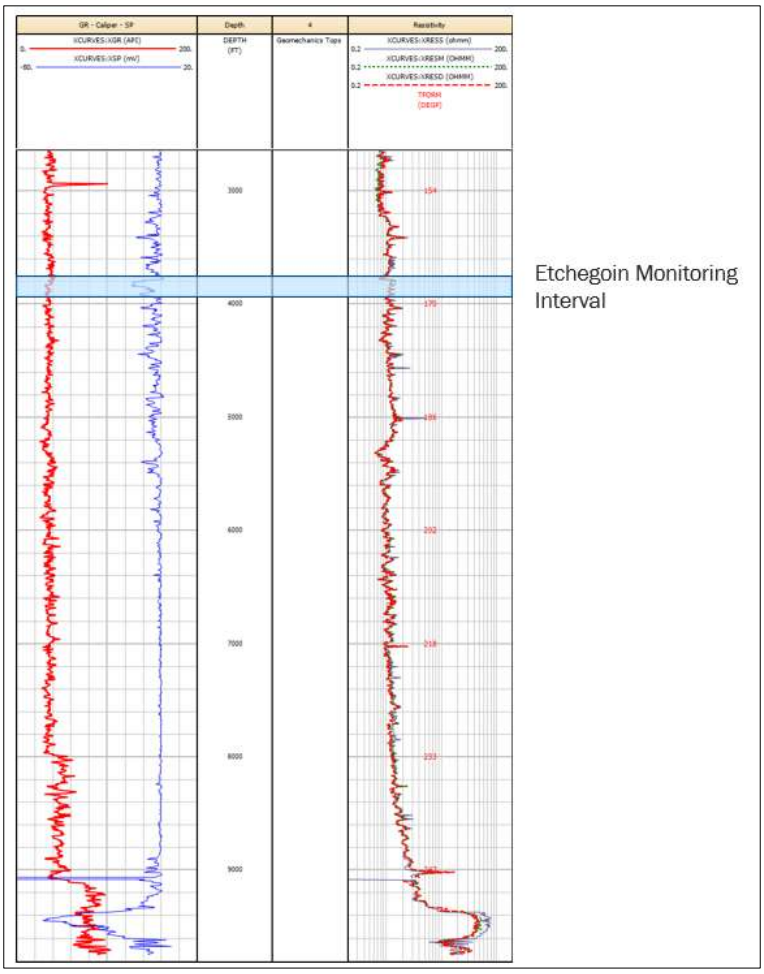


Figure 3: Open-hole well logs for 327-7R-RD1

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was not logged across the entire confining layer. Cement was observed at the top of the liner interval, but no cement bond log was run on the 9-5/8" casing. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 9-5/8" casing string during pre-operational testing.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and

procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials, and methodology for monitoring well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 20' MD due to the depth reference to the kelly bushing 20' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	8.681	8.755	8.755	8.755
Depth to bottom of tubing or drill pipe (ft)	8059	3934	1484	45
Sacks of cement to be used (each plug)	224	412	268	10
Slurry volume to be pumped (ft^3)	258	474	423	11
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	7433	2802	749	20
Bottom of plug (ft)	8059	3934	1484	45
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

WELL CONSTRUCTION, OPERATION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Well 355-7R

Version History

File Name	Version	Date	Description of Change
COP_355-7R_v1	1	05/16/22	Combines documents, incorporates corrections and EPA feedback dated 04/25/22. COP document supersedes well construction portion of Narrative A2 and Attachment G2
COP_355-7R_v2	2	11/30/22	Revisions based on EPA feedback dated 8/17/22

Introduction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. The wells are in Section 7R within the unit boundary of the Elk Hills Oil Field. 357-7R and 355-7R surface elevations are 792' and 714' above mean sea level, respectively. These injectors are currently approved by CalGEM for Class II injection of up to 50 million cubic feet per day gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. The wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

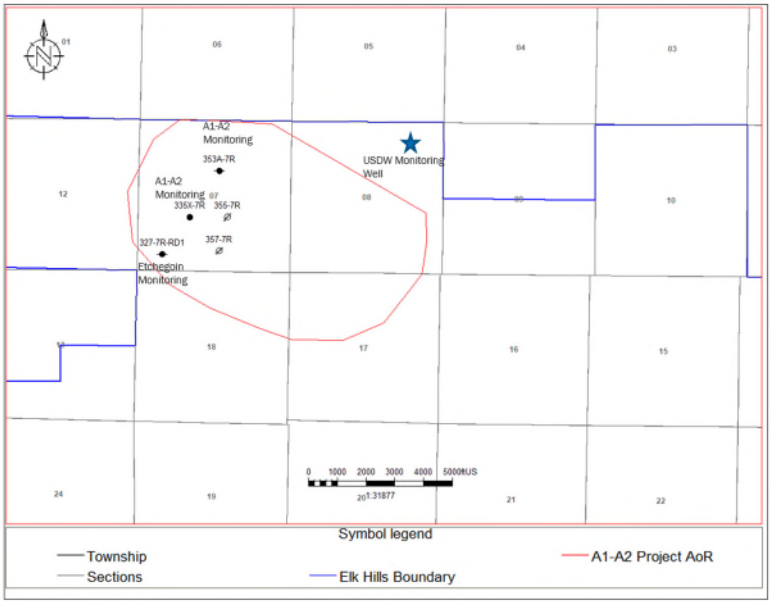


Figure 1: Map showing the location of injection wells and monitoring wells.

As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity. The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection wells with construction specifications and anticipated completion details in graphical and tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of the USDW

355-7R was drilled in 1973, at which time there were no drilling and completion issues. The base of USDW is located at 840’ MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production tubing
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing was cemented with cement returns to surface. The 7” casing string was cemented with a theoretical volume to surface, but cement returns were not observed.

4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval, from base of 7" casing to ~5200 feet.
5. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained and Mechanical Integrity Testing (MIT) to be conducted.
6. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
7. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
8. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

The 355-7R injection well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the CO_2 injectate to prevent loss of mechanical integrity in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.

4. Casing – the standard N-80 and K-55 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
5. Cement - Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

Table 1: Casing Specifications for the 355-7R injector

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 46	20.000	19.124	94	--	--	2.62	--	--
Surface	14 - 500	13.375	12.715	48	H-40	Short	2.62	1,730	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	2.62	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	2.62	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

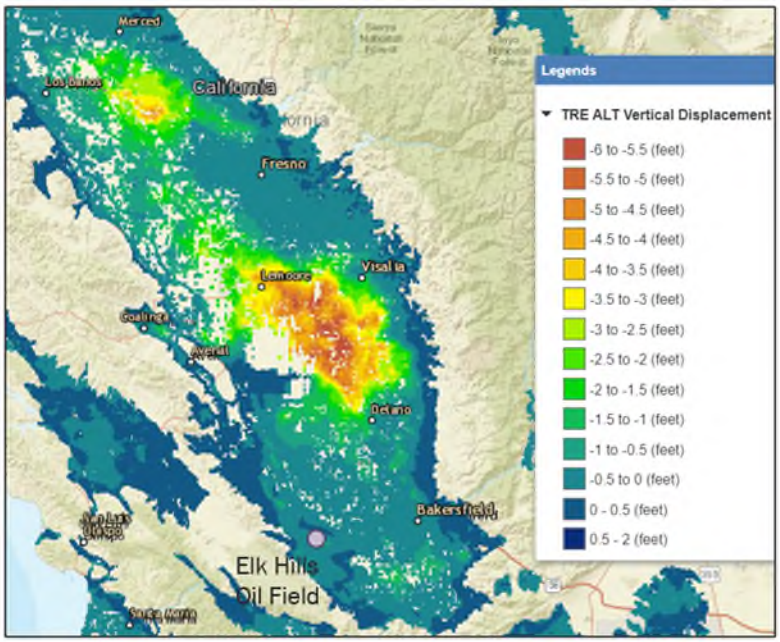


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing was cemented with returns to surface. The 9-5/8" casing string was cemented in place with circulation and top job to achieve cement to surface. The 7" casing string was cemented in place with Class G portland cement. Subsequently, a CBL was run from 5200' – 9400' and indicates the presence of annular cement that provides isolation between the Monterey and Reef Ridge formations.

Tubing and Packer

The information in Table 2 and Table 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications may be modified prior to conversion during pre-operational testing.

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,423	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8,397	30.3	26-32	5.875	4.000

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with realtime injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating

Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded. The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 355-7R with a surface shut-off valve at the wellhead and not a down-hole device.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, corrosivity, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Table 4: Summary of Anticipated Risk Factors

Risk Factor	Justification for A1-A2 Reservoir
Temperature	Less than 300 degrees Fahrenheit reservoir temperature
Pressure	Less than 10,000 psi operating pressure
Corrosivity	Less than 25 lb/mmscf water content in the CO2 stream
Presence of Hydrogen Sulfide	H2S not present in A1-A2 production gas analysis
Proximity to populated area	Project located in Elk Hills oil field, unpopulated area

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 5 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 5: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
355-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Temperature Log Oxygen Activation Log Noise Log	Along the 7" casing to surface
	Pressure Fall-off Testing	Injection Zone

Deviation Checks During Drilling

Deviation checks for 355-7R were acquired during drilling every 100 feet from 3,500 feet measured depth (MD) to bottom hole at 10,500 feet MD (Table 6).

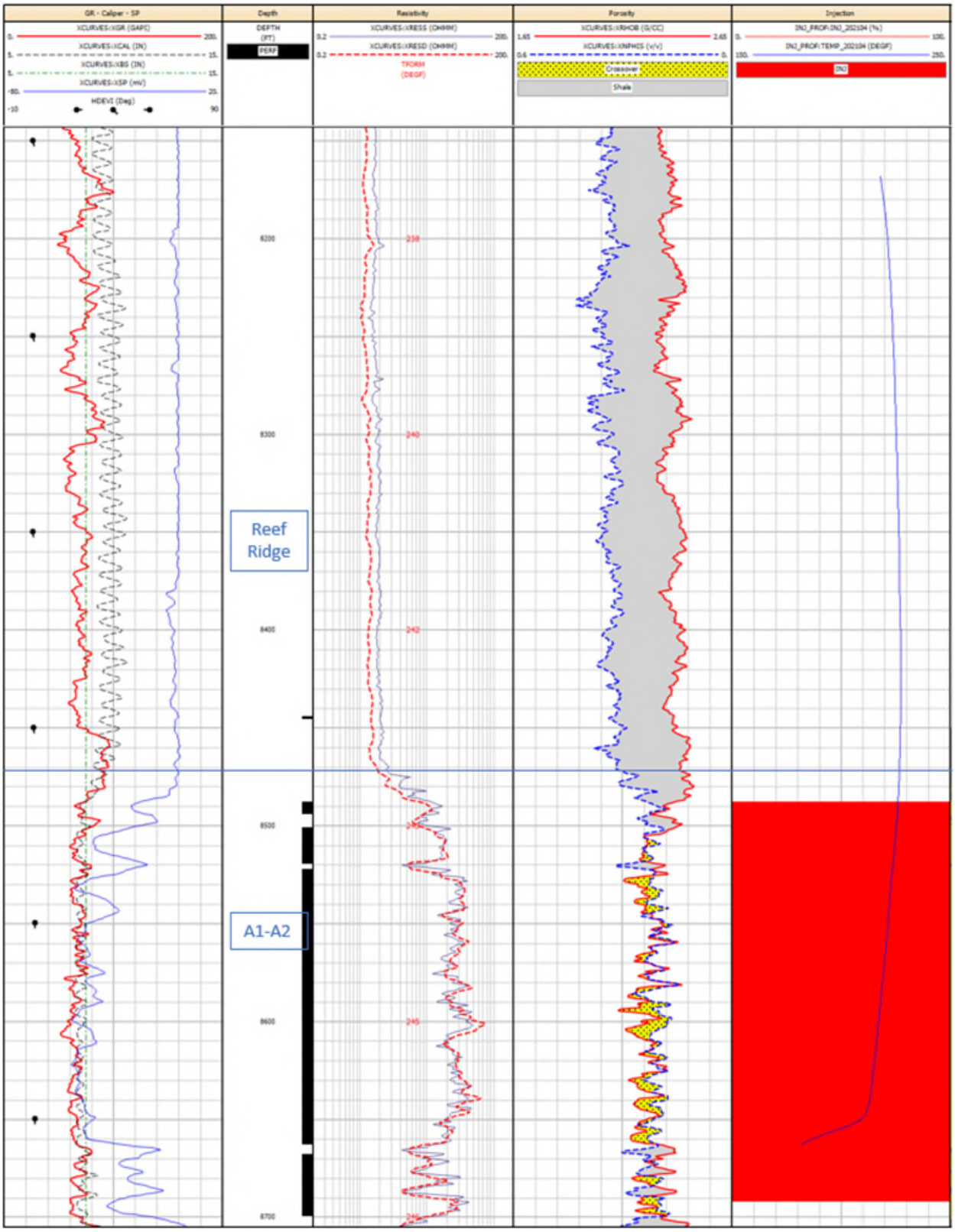
Table 6: Deviation checks during drilling for the 355-7R well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		7400	3	156.89	7396.6
3500	2	180.89	3499.3		7500	3	162.89	7496.4
3600	2	180.89	3599.2		7600	3	171.89	7596.3
3700	2	174.89	3699.2		7700	3	166.89	7696.2
3800	2	174.89	3799.1		7800	3	172.89	7796
3900	2	176.89	3899		7900	3	162.89	7895.9
4000	2	180.89	3999		8000	3	161.89	7995.8
4100	2	189.89	4098.9		8100	3	163.89	8095.6
4200	2	187.89	4198.9		8200	3	165.89	8195.5
4300	2	182.89	4298.8		8300	3	169.89	8295.4
4400	2	182.89	4398.7		8400	3	172.89	8395.2
4500	2	182.89	4498.7		8500	4	174.89	8495
4600	2	184.89	4598.6		8600	4	181.89	8594.8
4700	2	176.89	4698.6		8700	4	181.89	8694.5
4800	2	171.89	4798.5		8800	4	171.89	8794.3
4900	2	175.89	4898.4		8900	4	173.89	8894.1
5000	2	186.89	4998.4		9000	4	164.89	8993.8
5100	2	181.89	5098.3		9100	4	159.89	9093.6
5200	2	181.89	5198.3		9200	4	158.89	9193.3
5300	1	177.89	5298.2		9300	4	149.89	9293.1
5400	1	169.89	5398.2		9400	3	137.89	9392.9
5500	2	164.89	5498.2		9500	4	137.89	9492.7
5600	2	166.89	5598.1		9600	3	136.89	9592.5
5700	2	164.89	5698		9700	4	127.89	9692.3
5800	2	157.89	5798		9800	4	133.89	9792.1
5900	2	157.89	5897.9		9900	4	126.89	9891.8
6000	2	151.89	5997.9		10000	4	123.89	9991.6
6100	2	131.89	6097.8		10100	4	122.89	10091.4
6200	2	133.89	6197.7		10200	5	124.89	10191.1
6300	2	137.89	6297.7		10300	5	116.89	10290.7
6400	3	142.89	6397.6		10400	4	122.89	10390.4
6500	2	145.89	6497.5		10500	4	122.89	10490.1
7300	3	148.89	7296.7					

Open Hole Log Analysis

Open-hole wireline log data was acquired in 355-7R prior to installation of 7” casing long string. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3 (third from left).

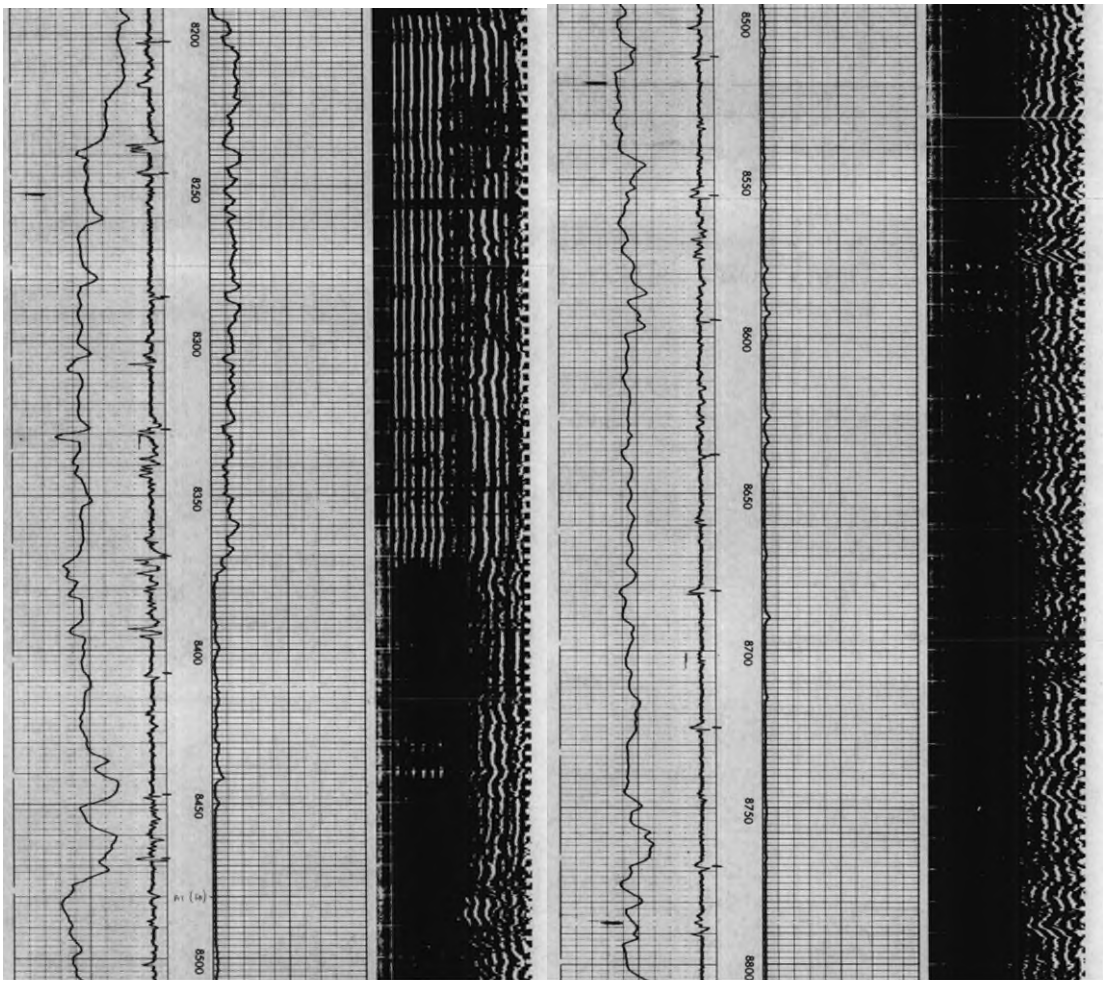
Figure 3: Open-hole well logs for 355-7R before installation of long string.



Cement Evaluation

The cement bond log seismogram and percent bond show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 4). Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7" casing interval. The top of cement was not observed deeper than 5200' - the top of the cement bond logging interval - and it is therefore shallower than 5200'. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing.

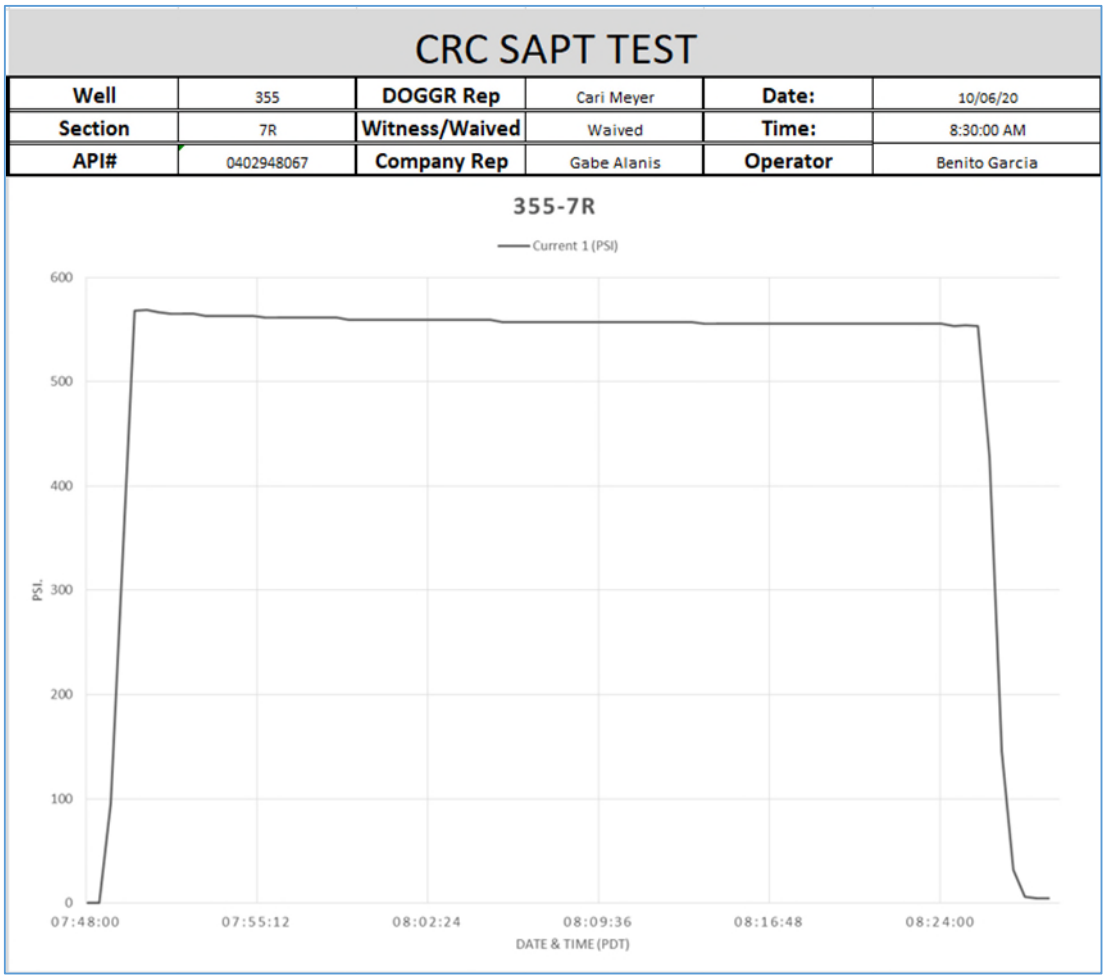
Figure 4: Cement bond log example for 355-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,470 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated October 6th, 2020, shows that the annulus can hold pressure more than 500 psi without gain or loss for 20 to 30 minutes indicating mechanical integrity of the tubing, casing and packer with the tubing and packer equipment currently in the well. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this will be addressed in the Pre-Operational Testing plan document.

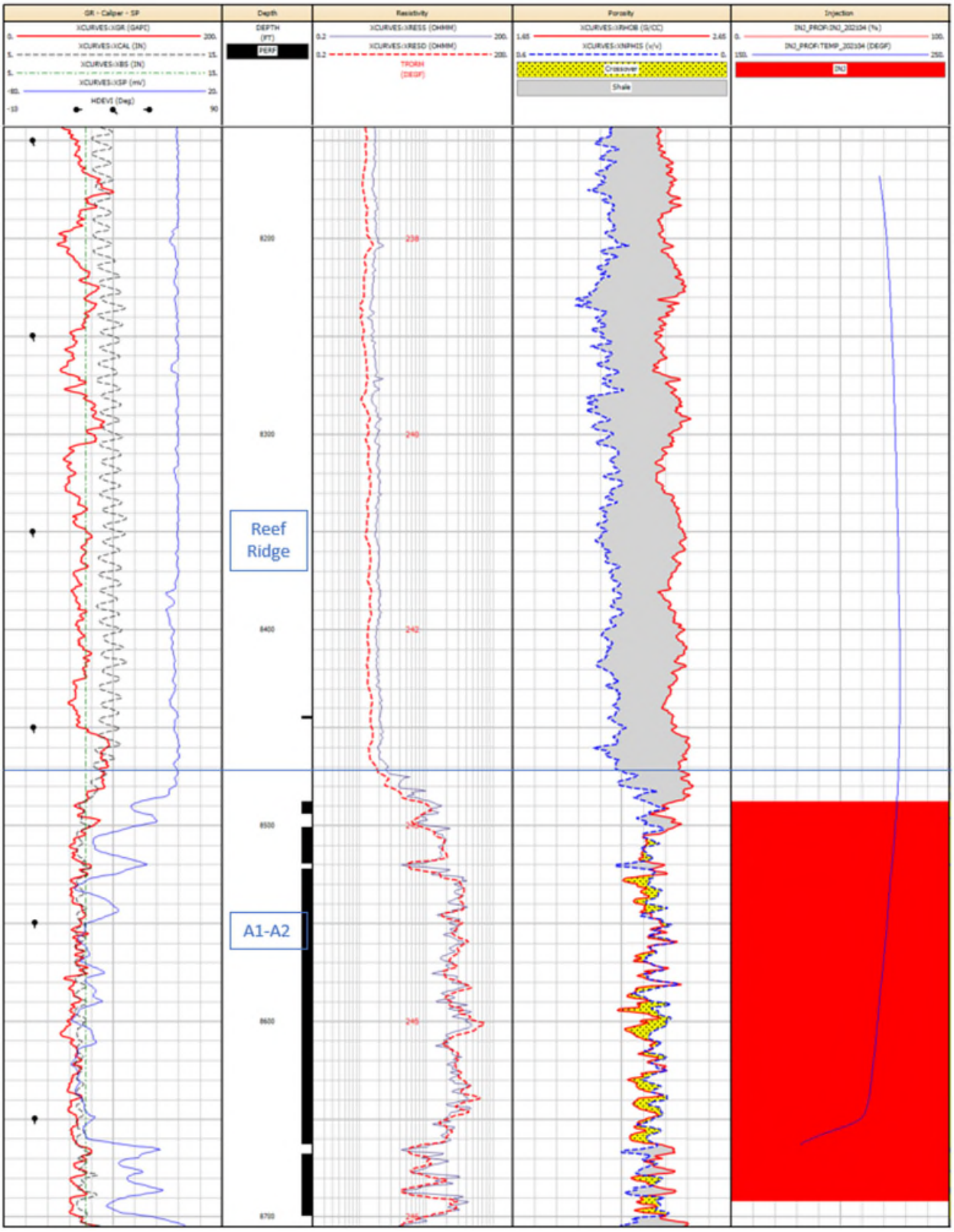
Figure 5: SAPT for 355-7R showing mechanical integrity of the tubing, casing, and packer.



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 6 was acquired on April 13th, 2021. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation at 8488' or at the packer at 8403'. The track on the right represents injection in percent of total rate with red shading showing 100% injection into A1-A2 perforations. The temperature curve shows that injection is confined below the packer as temperature trends toward geothermal gradient above the packer.

Figure 6: Radioactive tracer and temperature survey for well 355-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



Temperature logs, noise logs and oxygen activation logs are approved forms of external mechanical integrity by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Pressure Fall-off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. The testing procedure is described in the Testing and Monitoring document.

Well Operation

Injection operation conditions of 355-7R are detailed in the document titled Operating Procedures – 355-7R V2.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations

between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be consistent with the properties of Class G portland cement used in well construction, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The wells will have this cement placed as detailed in Table 7, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 14' MD due to the depth reference to the kelly bushing 14' above ground level during drilling.

Table 7: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.184	6.276	6.366	6.184
Depth to bottom of tubing or drill pipe (ft)	8,692	3,061	1,509	39
Sacks of cement to be used (each plug)	59	24	148	5
Slurry volume to be pumped (ft^3)	67	27	170	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,371	2,936	740	14
Bottom of plug (ft)	8,692	3,061	1,509	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

WELL CONSTRUCTION, OPERATION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Well 357-7R

Version History

File Name	Version	Date	Description of Change
COP_357-7R_v1	1	05/16/22	Combines documents, incorporates corrections and EPA feedback dated 04/25/22 COP document supersedes well construction portion of Narrative A2 and Attachment G2
COP_357-7R_v2	2	12/1/22	Revisions based on EPA feedback dated 8/17/22

Introduction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. The wells are in Section 7R within the unit boundary of the Elk Hills Oil Field. 357-7R and 355-7R surface elevations are 792' and 714' above mean sea level, respectively. These injectors are currently approved by CalGEM for Class II injection of up to 50 million cubic feet per day gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. The wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

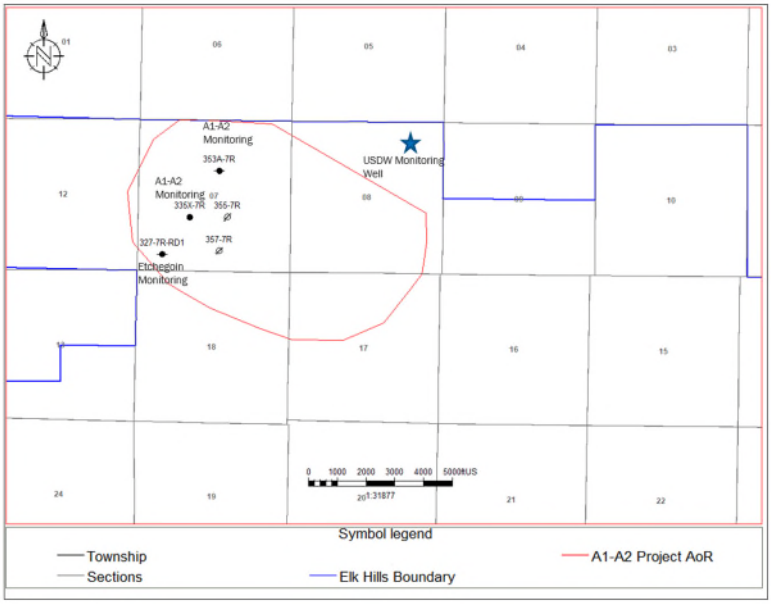


Figure 1: Map showing the location of injection wells and monitoring wells.

As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity. The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection wells with construction specifications and anticipated completion details in graphical and tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention Protection of the USDW

357-7R was drilled in 1980, during which time there were no drilling and completion issues. The base of USDW is located at 806' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production tubing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement with cement returns to surface.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with

cementing operations results. Cement is present throughout the entire CBL logging interval, from the base of 7" casing to ~6250'.

5. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
7. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions.
8. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

The 357-7R injection well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the CO_2 injectate to prevent loss of mechanical integrity in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.
4. Casing – the standard N-80 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.

5. Cement - Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

Table 1: Casing Specifications for the 357-7R injector

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20’ – 60’	20.000	19.124	94	--	--	2.62	--	--
Surface	20’ – 501’	13.375	12.715	48	H-40	Short	2.62	1,730	770
Intermediate	20’ – 3,517’	9.625	8.835	40	N-80	Long	2.62	5,750	3,090
Long-string	20’ – 76’ 76’ – 2,953’ 2,953’ – 6,158’ 6,158’ – 8,990’	7.000	6.184 6.366 6.276 6.184	29 23 26 29	N-80	Long	2.62	8,160 6,340 7,240 8,160	7,020 3,830 5,410 7,020

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

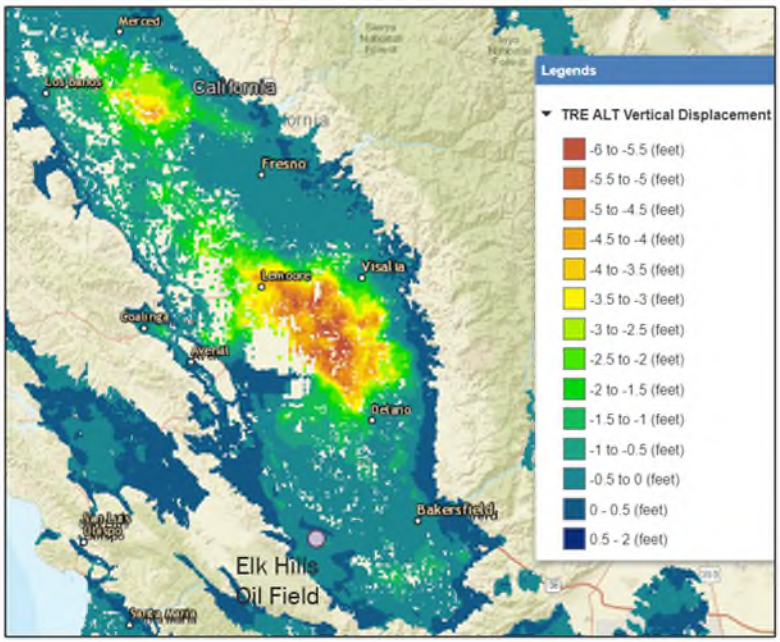


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8", 9-5/8", and 7" casing strings were cemented with returns to surface. Subsequently, a CBL was run from 6250' – 8970' and indicates annular isolation within the Monterey and Reef Ridge formations.

Tubing and Packer

The information in Table 2 and Table 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications may be modified prior to conversion during pre-operational testing.

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed and inspected prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	8,470	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8,430	30.3	26 – 32	5.875	4.00

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with realtime injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating

Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded. The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 357-7R with a surface shut-off valve at the wellhead and not a down-hole device.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, corrosivity, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Table 4: Summary of Anticipated Risk Factors

Risk Factor	Justification for A1-A2 Reservoir
Temperature	Less than 300 degrees Fahrenheit reservoir temperature
Pressure	Less than 10,000 psi operating pressure
Corrosivity	Less than 25 lb/mmscf water content in the CO2 stream
Presence of Hydrogen Sulfide	H2S not present in A1-A2 production gas analysis
Proximity to populated area	Project located in Elk Hills oil field, unpopulated area

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 5 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 5: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
357-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Temperature Log Oxygen Activation Log Noise Log	Along the 7" casing to surface
	Pressure Fall-off Testing	Injection Zone

Deviation Checks During Drilling

Deviation checks for 357-7R were acquired during drilling every ten feet from 3,541 feet measured depth (MD) to bottom hole at 9,005 feet MD (Figure 3).

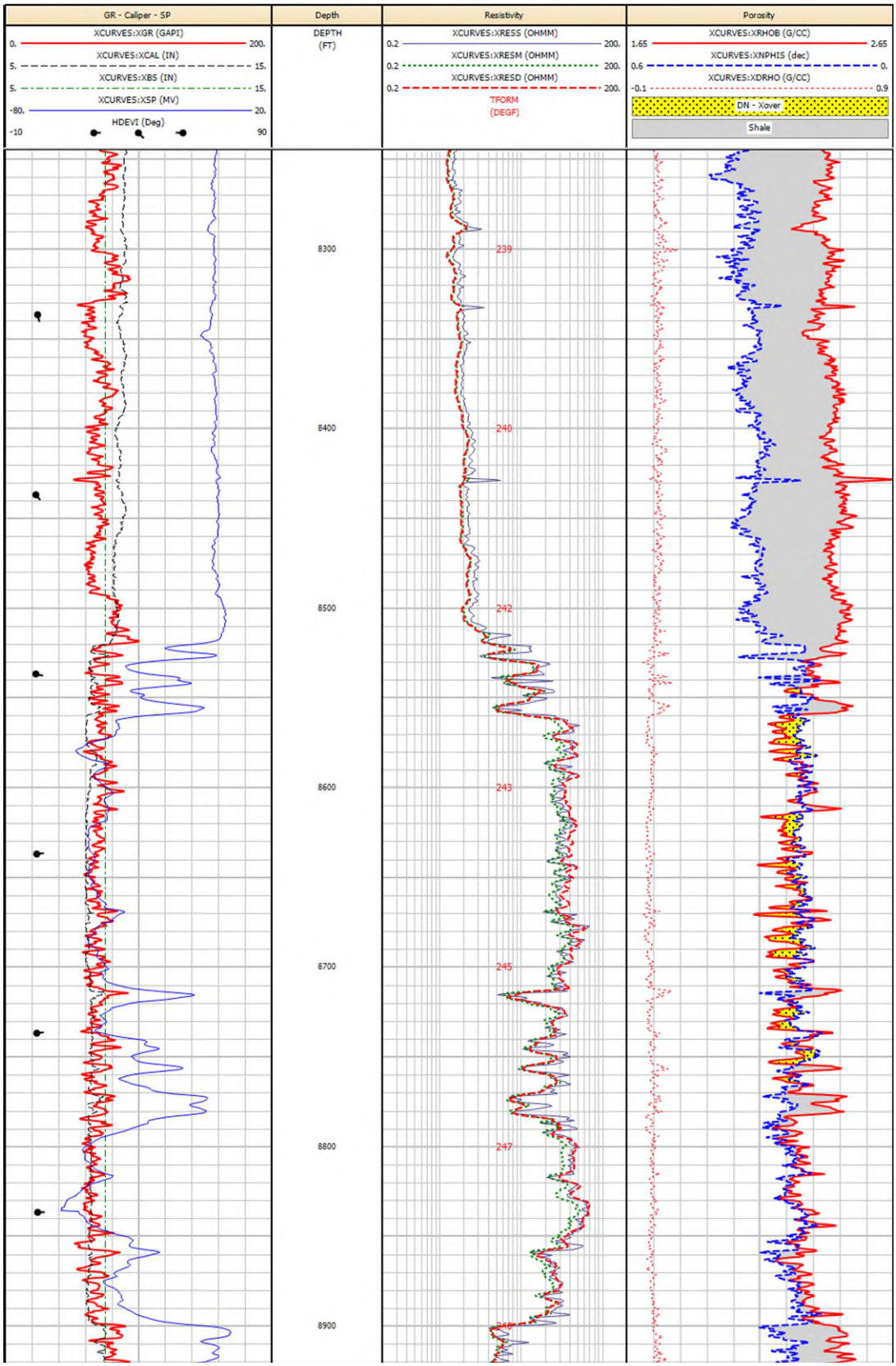
Figure 3: Deviation checks during drilling for the 357-7R well.

X ftUS	Y ftUS	Z ft	MD ft	Inclination deg	Azimuth GN deg	Azimuth TN deg	DX ftUS	DY ftUS	DX TN ftUS	DY TN ftUS	TVD (Well datum) ft	TWT ms	DLS deg/100ft
6100830.00	2309245.00	812.00	0.00	0.00	165.70	164.82	0.00	0.00	0.00	0.00	0.00		0.00
6100843.74	2309191.11	-2728.52	3541.10	1.80	165.70	164.82	13.74	-53.89	14.56	-53.68	3540.52		0.05
6100843.83	2309190.81	-2738.51	3551.10	1.80	158.50	157.62	13.83	-54.19	14.67	-53.97	3550.51		2.26
6100843.91	2309190.53	-2748.51	3561.10	1.50	170.00	169.12	13.91	-54.47	14.75	-54.25	3560.51		4.45
6100843.95	2309190.28	-2758.51	3571.10	1.40	174.30	173.42	13.95	-54.72	14.79	-54.50	3570.51		1.48
6100843.98	2309190.03	-2768.40	3581.00	1.60	170.00	169.12	13.98	-54.97	14.83	-54.75	3580.40		2.32
6100947.59	2308941.03	-8136.56	8957.60	2.30	76.40	75.52	117.59	-303.97	122.25	-302.14	8948.56		0.00
6100947.98	2308941.13	-8146.45	8967.50	2.30	75.00	74.12	117.98	-303.87	122.63	-302.03	8958.45		0.57
6100948.36	2308941.23	-8156.45	8977.50	2.30	76.40	75.52	118.36	-303.77	123.02	-301.93	8968.45		0.56
6100948.75	2308941.30	-8166.44	8987.50	2.20	80.70	79.82	118.75	-303.70	123.41	-301.84	8978.44		1.96
6100949.12	2308941.36	-8176.43	8997.50	2.10	82.10	81.22	119.12	-303.64	123.78	-301.78	8988.43		1.13
6100949.39	2308941.40	-8183.93	9005.00	2.10	82.10	81.22	119.39	-303.60	124.05	-301.74	8995.93		0.00

Open Hole Log Analysis

Open-hole wireline log data was acquired in 357-7R prior to installation of 7” casing long string. Figure 2 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3 (third from left), derived permeability in track 4 (fourth from left), and derived lithology in track 5 (rightmost).

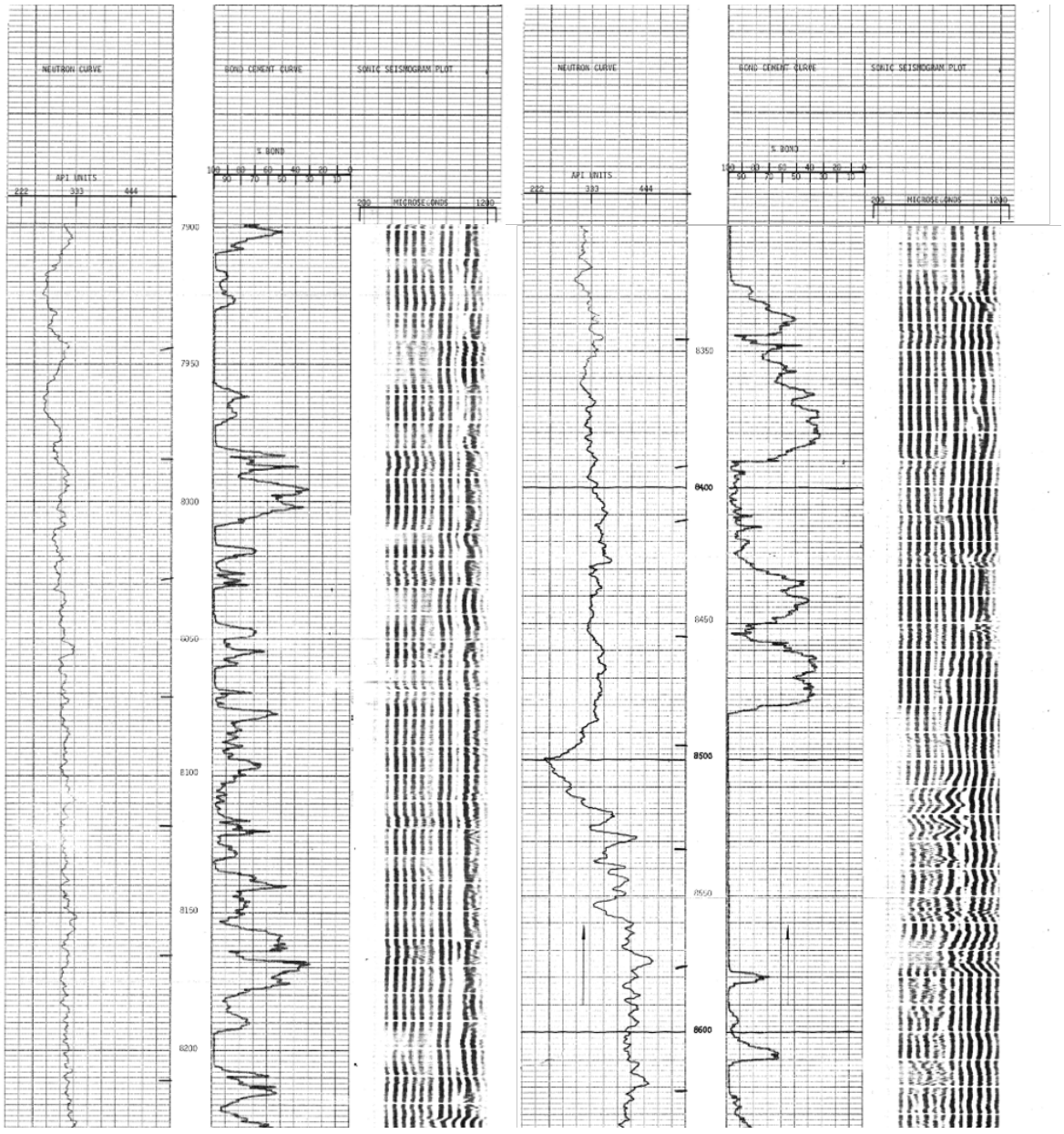
Figure 4: Open-hole well logs for 355-7R before installation of long string.



Cement Evaluation

The cement bond log seismogram and percent bond show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 5). Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7" casing interval. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing.

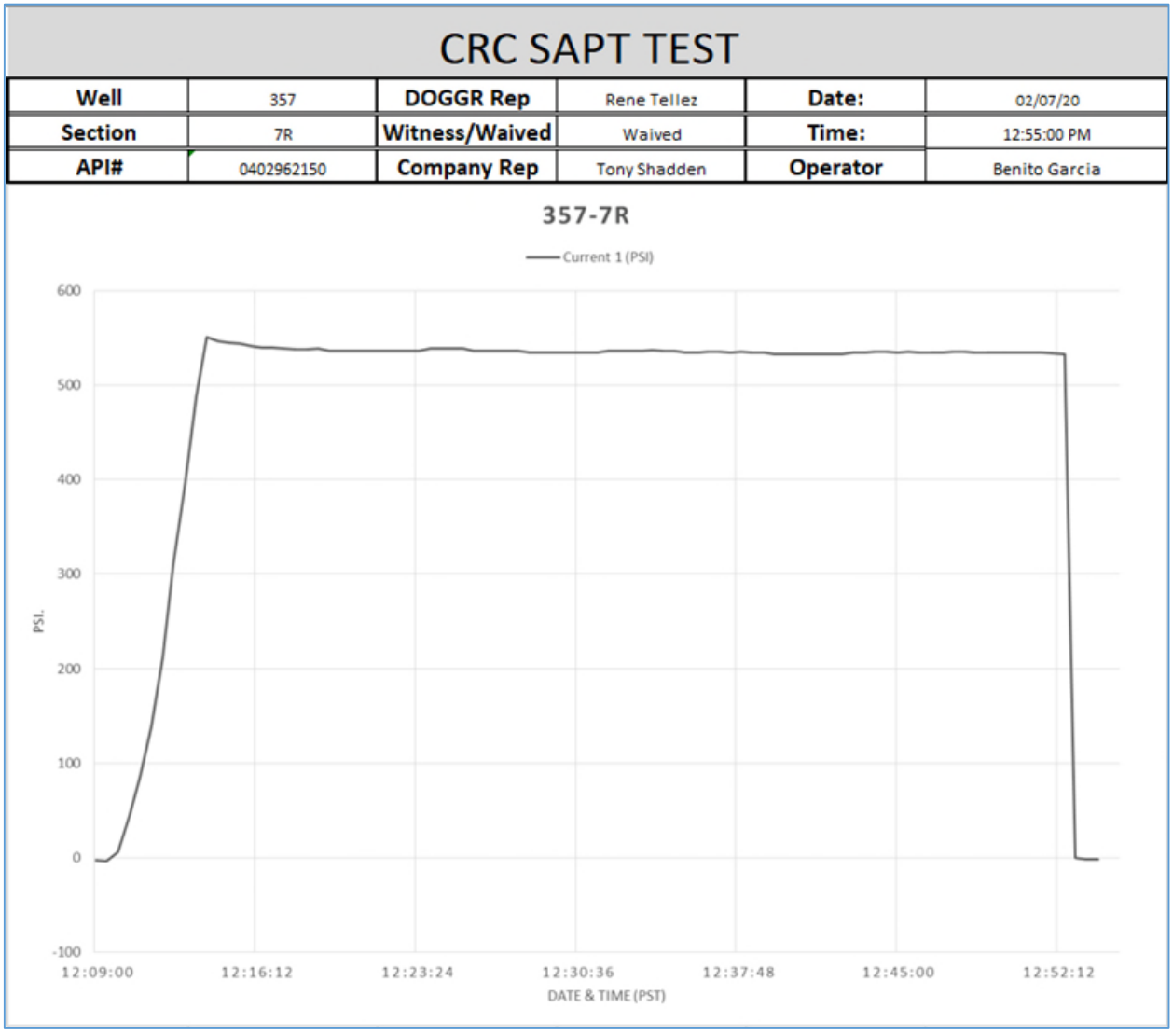
Figure 5: Cement bond log example for 357-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,518 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated February 7th, 2020, shows that the annulus can hold pressure more than 500 psi without gain or loss for 20 to 30 minutes indicating mechanical integrity of the tubing, casing and packer with the tubing and packer equipment currently in the well. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this will be addressed in the Pre-Operational Testing plan document.

Figure 6: SAPT for 357-7R showing mechanical integrity of the tubing, casing, and packer.



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 7 below was acquired in 2019. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation or at the packer. The track on the right represents injection in percent of total rate with red shading showing 100% injection into A1-A2 perforations. The temperature curve shows that injection is confined below the packer as temperature trends toward geothermal gradient above the packer.

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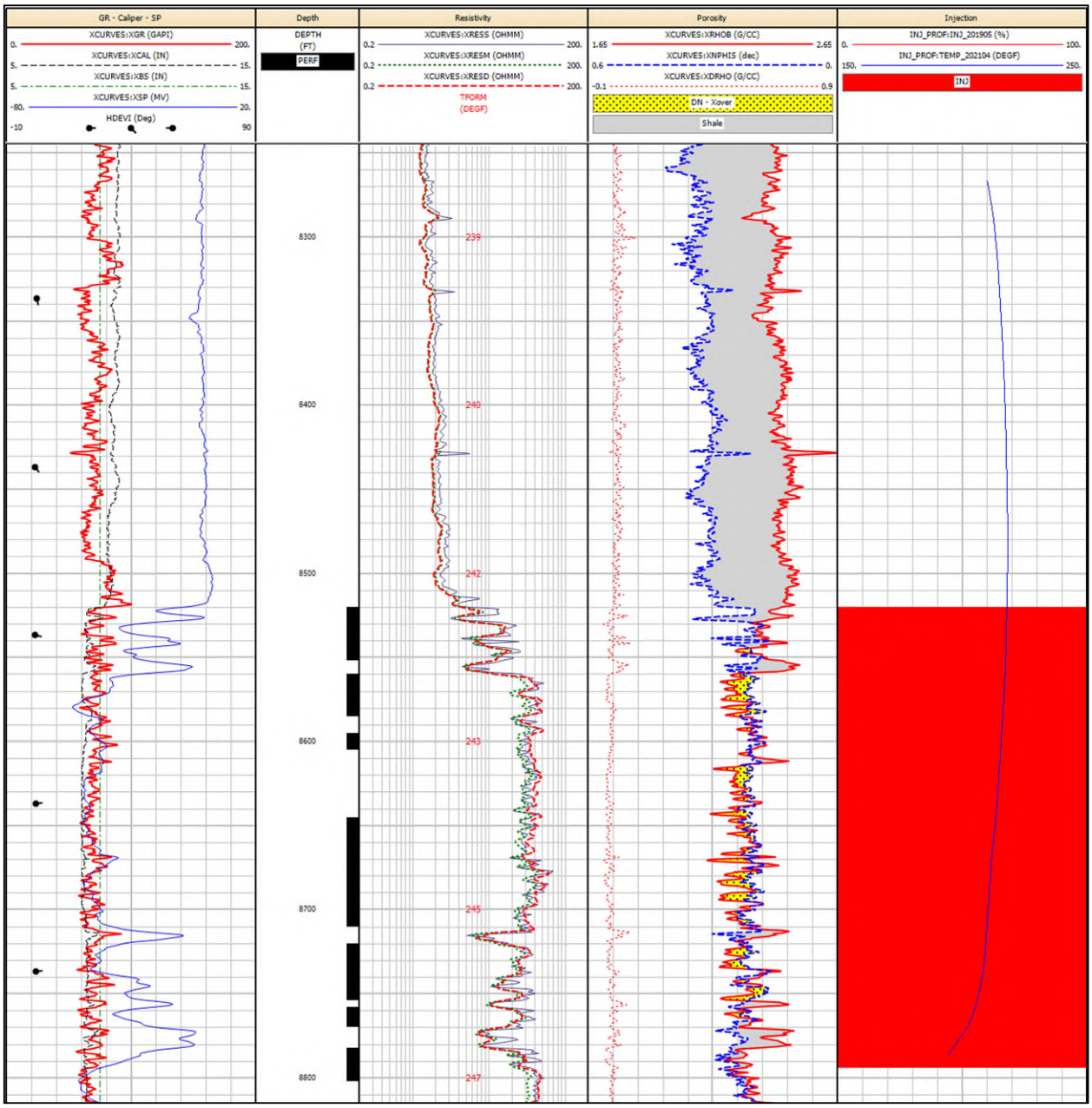

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Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. The testing procedure is described in the Testing and Monitoring document.

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Injection operation conditions of 357-7R are detailed in the document titled Operating Procedures – 357-7R V2

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CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

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Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

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Information on Plugs

CTV will use the materials and methods noted in Table 5 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be consistent with the properties of Class G portland cement used in well construction, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 20' MD due to the depth reference to the kelly bushing 20' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.184	6.366	6.366	6.184
Depth to bottom of tubing or drill pipe (ft)	8,794	2,970	1,447	45
Sacks of cement to be used (each plug)	70	24	143	5
Slurry volume to be pumped (ft^3)	80	28	164	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,411	2,845	706	20
Bottom of plug (ft)	8,794	2,970	1,447	45
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

CTV I A1-A2 Project Confidentiality

The following are proprietary to CTV and considered confidential:

1. Financial Responsibility Cost Estimates

Requests for these files can be made to Travis Hurst.

Phone: 661-342-2409
Email: Travis.Hurst@crc.com

CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

COST ESTIMATES DESCRIPTION
40 CFR 146.85

Elk Hills A1-A2 Storage Project

Description of Financial Responsibility Cost Estimates

Carbon TerraVault 1 LLC (CTV) utilized the EPA Cost Estimation Tool for Class VI Financial Responsibility Demonstration. The 2015 estimates provided by the EPA have been updated by CTV with an annual inflation rate of 2.5%.

Prior to injection and project approval CTV will provide updated estimates that are verified with a third party contractor.

Financial responsibility will be covered by the following:

1. **Letter of Credit** for Post-Injection Site Care and Closure and Injection Well Plugging.

2. **Insurance** coverage for Emergency and Remedial Response.

FINANCIAL RESPONSIBILITY

CLASS VI EMERGENCY AND REMEDIAL RESPONSE INSUREANCE
40 CFR 146.85

Elk Hills A1-A2 Storage Project

Emergency and Remedial Response Insurance

Carbon TerraVault 1 LLC (CTV) will provide financial assurance for **Emergency and Remedial Response** by procuring an environmental insurance policy. The limits will be determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills A1-A2 project environmental insurance policy will be placed with an A.M. Best A or higher rated carrier and will cover all emergency and remedial response activities arising from the assets. The selected insurance carrier will issue a financial assurance certificate in compliance with state and federal regulations.

FINANCIAL RESPONSIBILITY

CLASS VI INJECTION WELL PLUGGING AND POST-INJECTION SITE CARE AND CLOSURE LETTER OF CREDIT
40 CFR 146.85

Elk Hills A1-A2 Storage Project

Letter of Credit Description

Carbon TerraVault 1 LLC (CTV) will provide financial assurance for Injection Well Plugging and Post-injection Site Care and Site Closure by posting a letter of credit. The amount of each letter of credit would be determined by a reasonable estimate of the cost of these activities. At this time, the combined value of these two activities is approximately $22 million. CTV will provide an updated estimate from a third party prior to project approval.

The letter of credit will be backed by California Resources Corporation's (CRC) Credit Agreement with Citibank, N.A., as administrative agent, and certain other lenders as participants. This credit agreement consists of a senior revolving loan facility (Revolving Credit Facility) with an aggregate commitment of $492 million, which CRC is permitted to increase if CRC obtains additional commitments from new or existing lenders. The Revolving Credit Facility also includes a sub-limit of $200 million for the issuance of letters of credit. The letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

As of June 30, 2021, CRC had an undrawn Revolving Credit Facility, approximately $75 million available in letter of credit issuance capacity and $151 million of cash. CRC is currently making efforts to add to the aggregate commitment and the sub-limit for letters of credit.

Amount Needed to Show Financial Responsibility (2015$)

Project Task	Low End Cost Estimate ($/Project; includes 20% G&A)	Middle Cost Estimate ($/Project; includes 20% G&A)	High End Cost Estimate ($/Project; includes 20% G&A)
Performing Corrective Action on Deficient Well(s) in AoR			
Maintenance Rig Rental (Clean Out Deficient Wells)	$ -	$ -	$ -
Flush Deficient Wells	$ -	$ -	$ -
Plug Deficient Wells	$ -	$ -	$ -
Log Deficient Wells	$ -	$ -	$ -
Subtotal: Corrective Action Cost	**$ -**	**$ -**	**$ -**
Plugging Injection Well			
Maintenance Rig Rental (Clean Out Injection Well)	$ 41,000	$ 89,000	$ 101,000
Perform Mechanical Integrity Test Before Plugging Injection Well	$ 52,000	$ 52,000	$ 52,000
Flush Injection Well with a Buffer Fluid Before Plugging	$ 200	$ 1,700	$ 5,000
Plug Injection Well	$ 15,000	$ 20,000	$ 91,000
Log Injection Well	$ 4,000	$ 4,000	$ 18,000
Subtotal: Injection Well Plugging Cost	**$ 128,726**	**$ 193,669**	**$ 309,638**
Post-Injection Site Care (assume 0% discount rate)			
Post-Injection O&M for Monitoring Wells			
Post-Injection Seismic Survey	**$ 16,337,761**	**$ 22,760,143**	**$ 29,362,278**
Post-Injection Groundwater Monitoring			
Post-Injection Monitoring Reports to Regulators			
Site Closure			
Maintenance Rig Rental (Clean Out Monitoring Wells)	$ 89,000	$ 195,000	$ 222,000
Perform MIT Before Plugging Monitoring Wells	$ 161,000	$ 161,000	$ 161,000
Flush Monitoring Wells	$ 2,000	$ 14,000	$ 37,000
Plug Monitoring Wells (occurs at end of PISC; use 0% discounting)	$ 62,000	$ 81,000	$ 369,000
Log Monitoring Wells (occurs at end of PISC; use 0% discounting)	$ 14,000	$ 18,000	$ 72,000
Remove Injection Well Surface Equipment and Restore Vegetation at Injection Well	$ 19,000	$ 35,000	$ 50,000
Remove Monitoring Well Surface Equipment and Restore Vegetation (occurs at end of PISC; use 0% discounting)	$ 78,000	$ 138,000	$ 199,000
Document Plugging and Site Closure Process	$ 19,000	$ 19,000	$ 19,000
Subtotal: Site Closure Cost	**$ 514,904**	**$ 767,717**	**$ 1,309,294**
Emergency and Remedial Response, Scenario A: Remediate Leaking Injection Well			
Stop CO2 Injection	$ 1,000	$ 1,000	$ 3,000
Repair Injection Well	$ 16,000	$ 35,000	$ 40,000
Replace Tubing	$ 133,000	$ 133,000	$ 133,000
Create Hydraulic Barrier	$ 8,009,000	$ 9,096,000	$ 13,911,000
Subtotal: Scenario A	**$ 8,159,000**	**$ 10,744,560**	**$ 14,087,000**
Total Amount Needed to Show Financial Responsibility	**$ 26,444,489**	**$ 34,466,088**	**$ 47,317,811**

Note: Results may not add due to independent rounding.

IInstructions: Please fill out the green highlighted cells below with project -specific information from the Class VI permit application.

Project Information

Variable Name	Value
Project Name (Corporate entity)	CRC
Project Address/Location	28590 Highway 119 Tupman CA 93276
Contact Name	Travis Hurst
Contact Information for Project Operator	travis.hurst@crc.com 661-342-2409

Project Data

Variable Name	Value	Units (Click in Cell for Dropdown List)	
Size of Area of Review (AoR)	2.1	Square Miles	
Are There Underground Sources of Drinking Water (USDWs) in the AoR?	No		←If there are no USDWs, but there are other (non-USDW) types of groundwater in the AoR that the operator would be required to remediate (if contaminated by a well failure), select 'Yes'.
Mass of CO_2 to be Injected	8,000,000	Metric Tons	
Duration of Post-Injection Site Care	50	Years	
Depth of Injection Well	8,900	Feet	
Diameter of Injection Well	7.0	inches	

Information on Monitoring Wells *Note: Cost to clean out monitoring wells is based on a regression equation that is only valid for well depths greater than 2,000 ft. Model is run for all monitoring wells (where the shallow wells are conservatively assumed to be 2,001 ft deep).*

4 ←Number of Monitoring Wells

Enter the names, depths (feet), and diameters (inches) of monitoring wells in the table below.

Well Name	Monterey FM	Tulare USDW	Monterey FM	Etchegoin		[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]
Well Depth (feet)	9,900	2,500	9,900	5,000								
Well Diameter (inches)	7.0	16	7	7								

Information on Deficient Wells in the AoR Requiring Corrective Action

0 ←Number of Deficient Wells in the AoR that will be Remediated

Enter in the names, depths (feet), and diameters (inches) of deficient wells in the aor requiring corrective action in the table below.

Well Name	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	[Well Name]	
Well Depth (feet)												
Well Diameter (inches)												

355-7R OPERATING PROCEDURES

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 15MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. All calculations are done assuming a 100% CO_2 stream, and operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, as the A1-A2 reservoir is depleted in pressure, a surface and bottom hole injection pressure of 695 psi and 762 psi respectively, are only required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1,175 psi and 3,923 psi respectively, which is the maximum pressure CTV expects to operate the well at.

Based on the fracture stimulation data in the area, the expected fracture pressure gradient for the reservoir is 0.82 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 6,260psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. 40+ years of gas and water injection experience into the Monterey Formation A1-A2 reservoir supports that these operating limits are appropriate and effective.

The expected pressures for 355-7R over the life of the project are summarized in Table 1.

Table 1: 355-7R Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.82psi/ft frac gradient from data in the area	
Surface	2,990	psig
Downhole	6,260	psig
Injection Pressure	Average over time	
Surface Minimum / Maximum	695 / 1,175	psig
Downhole Minimum / Maximum	762 / 3,923	psig
Maximum Injection Rate	15	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd tonnes/day
Average Injection Volume and/or Mass	8 million	tonnes
Annulus Pressure	Average over time	
Surface Minimum / Maximum	100 / 299	psig
Downhole Minimum / Maximum	3,824 / 4,023	psig

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 1 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time CTV expects a maximum injection rate of 15 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3,923 psi. A threshold of 10% over these will be used to configure the automation and alarms, which equates to 16.5 million cubic feet per day and 4,315 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 130 tons per day over a 6-day period to ensure protection of health, safety, and the environment. This would be the same for routine well shutdown.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds, CTV will communicate with the EPA.

357-7R OPERATING PROCEDURES

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 15MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. All calculations are done assuming a 100% CO_2 stream, and operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, as the A1-A2 reservoir is depleted in pressure, a surface and bottom hole injection pressure of 670 psi and 695 psi respectively, are only required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1,140 psi and 3,909 psi respectively, which is the maximum pressure CTV expects to operate the well at.

Based on the fracture stimulation data in the area, the expected fracture pressure gradient for the reservoir is 0.82 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 6281 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP. 40+ years of gas and water injection experience into the Monterey Formation A1-A2 reservoir supports that these operating limits are appropriate and effective.

The expected pressures for 357-7R over the life of the project are summarized in Table 1.

Table 1: Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.82psi/ft frac gradient from data in the area	
Surface	2,993	psig
Downhole	6,281	psig
Injection Pressure	Average over time	
Surface Minimum / Maximum	670 / 1,140	psig
Downhole Minimum / Maximum	695 / 3,909	psig
Maximum Injection Rate	15	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd tonnes/day
Average Injection Volume and/or Mass	8 million	tonnes
Annulus Pressure	Average over time	psig
Surface Minimum / Maximum	100 / 267	psig
Downhole Minimum / Maximum	3842 / 4009	psig

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 1 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time CTV expects a maximum injection rate of 15 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3,909 PSI. A threshold of 10% over these will be used to configure the automation and alarms, which equates to 16.5 million cubic feet per day and 4,300psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 130 tons per day over a 6-day period to ensure protection of health, safety, and the environment. This would be the same for routine well shut-down.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

355-7R OPERATING PROCEDURES

Document Version History

Version	Submission Date	File Name	Description of Change
1	3/31/2022	355-7R Operating Procedures	Standalone document of Operating procedures for 355-7R submitted in response to EPA Evaluation responses dated 01/11/2022. Updated fracture gradient discussion, Table 1, Annulus pressure, Maximum Injection rate, Shut-down procedures, Automated shut-down system.
2	11/4/2022	355-7R Operating Procedures V2	Updated document to address EPA evaluation responses dated 07/20/2022. Updated "Maximum Injection rate" section, Table 1

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a maximum target rate of 15MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells.

At the start of injection, as the A1-A2 reservoir is depleted in pressure, a lower injection pressure is required. As the pressure in the reservoir builds up the injection pressure required is expected to rise. Over the life of the project an average surface injection pressure of 930 psi and average bottom hole pressure of 2343 psi is expected.

Based on the fracture stimulation data in the area, the expected fracture pressure gradient for the reservoir is 0.82 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the Maximum Injection Pressure for injector 355-7R is 6,260 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this maximum downhole pressure. 40+ years of gas and water injection experience into the Monterey Formation A1-A2 and other Monterey formation reservoirs support that these operating limits are appropriate and effective.

The expected pressures for 355-7R over the life of the project are summarized in Table 1.

Table 1. Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure using 0.82 psi/ft frac gradient from data in the area	
Surface	2,990	psig
Downhole	6,260	psig
Average Injection Pressure		
Surface	930 *	psig
Downhole	2423 **	psig
Maximum Injection Rate	15 per well	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd Tonnes/day
Average Injection Volume and/or Mass	8 million	tonnes
Average Annulus Pressure		
Surface	100	psig
Downhole	3820	psig
Annulus - Tubing pressure differential at Packer	1397 ***	psig

* *Average Surface injection pressure values shown over life of the project from the PROSPER modeling*
** *Average Downhole injection pressure values shown over life of the project from Plume simulation*
*** *Positive pressure indicates annular pressure higher than tubing pressure*

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88(c). The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to the Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 1 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

CTV expects a maximum average injection rate of 15 million cubic feet per day. To account for fluctuations in rate and pressure in daily operations, a threshold of 10% below the expected maximum injection rate and 10% below the Maximum Injection Pressure will be used to configure automation and alarms, which equates to 13.5 million cubic feet per day and 5,634 psi. This ensures that the well will not exceed the maximum downhole injection pressure of 6,260 psi. If either threshold is exceeded, the system will deliver alarms to indicate there is an issue, and CTV will take appropriate steps to resume operating within the acceptable ranges of injection rate and pressures.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO2 injection at a rate of 130 tons per day over a 6-day period to ensure protection of health, safety, and the environment. This would be the same for routine well shutdown.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

357-7R OPERATING PROCEDURES

Document Version History

Version	Submission Date	File Name	Description of Change
1	3/31/2022	357-7R Operating Procedures	Standalone document of Operating procedures for 357-7R submitted in response to EPA Evaluation responses dated 01/11/2022. Updated fracture gradient discussion, Table 1, Annulus pressure, Maximum Injection rate, Shut-down procedures, Automated shut-down system
2	11/4/2022	357-7R Operating Procedures V2	Updated document to address EPA evaluation responses dated 07/20/2022. Updated "Maximum Injection rate" section, Table 1

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a maximum target rate of 15MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells.

At the start of injection, as the A1-A2 reservoir is depleted in pressure, a lower injection pressure is required. As the pressure in the reservoir builds up the injection pressure required is expected to rise. Over the life of the project an average surface injection pressure of 905 psi and average bottom hole pressure of 2302 psi is expected.

Based on the fracture stimulation data in the area, the expected fracture pressure gradient for the reservoir is 0.82 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the Maximum Injection Pressure for 357-7R is 6281 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this maximum downhole pressure. 40+ years of gas and water injection experience into the Monterey Formation A1-A2 and other Monterey formation reservoirs supports that these operating limits are appropriate and effective.

The expected pressures for 357-7R over the life of the project are summarized in Table 1.

Table 1: Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	90% of Fracture pressure using 0.82 psi/ft frac gradient from data in the area	
Surface	2,993	psig
Downhole	6,281	psig
Average Injection Pressure		
Surface	905 *	psig
Downhole	2302 **	psig
Maximum Injection Rate	15 per well	mmscfpd
Injection Rate range	10-15 530-794	mmscfpd tonnes/day
Average Injection Volume and/or Mass	8 million	tonnes
Average Annulus Pressure		
Surface	100	psig
Downhole	3834	psig
Annulus - Tubing pressure differential at Packer	1531***	psig

* *Average Surface injection pressure values shown over life of the project from the PROSPER modeling*
** *Average Downhole injection pressure values shown over life of the project from Plume simulation*
*** *Positive pressure indicates annular pressure higher than tubing pressure*

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c). The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 1 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

CTV expects a maximum average injection rate of 15 million cubic feet per day. To account for fluctuations in rate and pressure in daily operations, a threshold of 10% below the expected maximum injection rate and 10% below the Maximum Injection Pressure will be used to configure automation and alarms, which equates to 13.5 million cubic feet per day and 5,653 psi. This ensures that the well will not exceed the maximum downhole injection pressure of 6,281 psi. If either threshold is exceeded, the system will deliver alarms to indicate there is an issue, and CTV will take appropriate steps to resume operating within the acceptable ranges of injection rate and pressures.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 130 tons per day over a 6-day period to ensure protection of health, safety, and the environment. This would be the same for routine well shutdown.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

CLASS VI MECHANICAL INTEGRITY TESTING

INJECTION WELL 357-7R
40 CFR 146.82(c)(7)-(8) and 146.87(a)(4)

ELK HILLS A1-A2 PROJECT

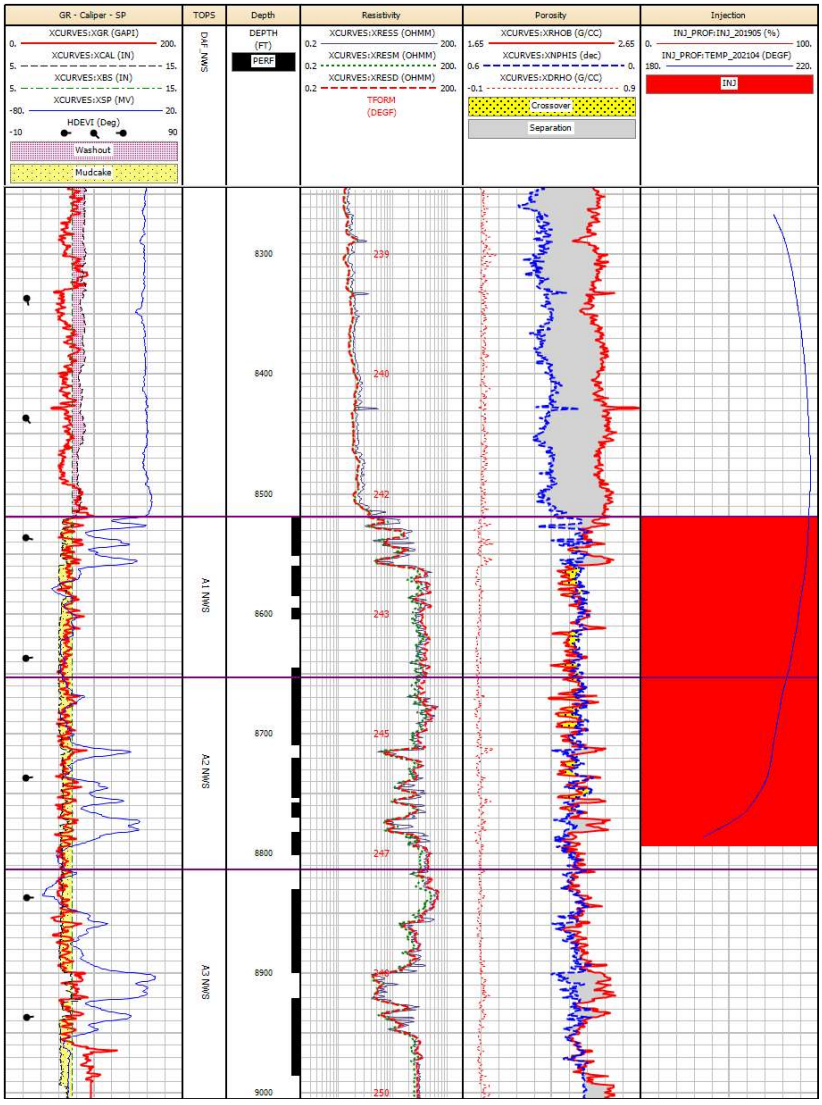
357-7R Mechanical Integrity Testing

The 357-7R and 355-7R injection wells are being repurposed for the Carbon TerraVault 1 LLC (CTV) Elk Hills A1-A2 project. These wells have been approved by California Geologic Energy Management (CalGEM) for Class II gas injection for pressure maintenance. As part of this approval and ongoing surveillance, mechanical integrity tests (MIT) and standard annular pressure tests (SAPT) have been conducted. CTV will acquire additional mechanical integrity tests prior to the injection of CO_2.

357-7R Gas Injection Survey

The gas injection survey (conducted in 2019) uses radioactive tracer to determine injection zone conformance. The interpreted log example below (Figure 1) shows 100% of the injection confined to 8520-8794 feet. The temperature curve shows that injection is confined below the packer as temperature trends toward gradient above the packer.

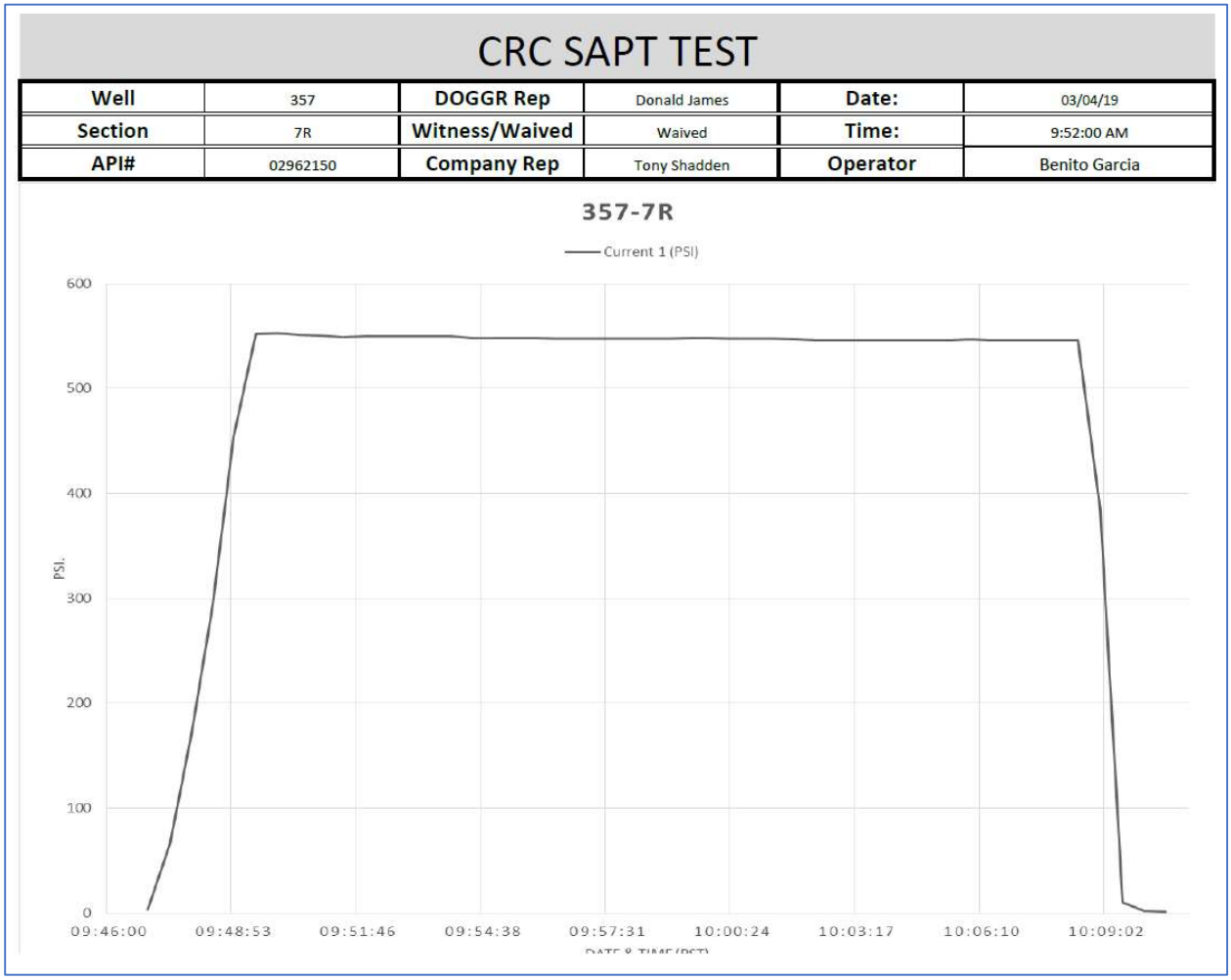
Figure 1: Radioactive tracer and temperature survey for well 357-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



357-7R Standard Annular Pressure Testing

The standard annular pressure test (Figure 2) shows that the annulus is capable of holding pressure without gain or loss for 20 to 30 minutes indicating mechanical integrity of the tubing, casing and packer.

Figure 2: SAPT for 357-7R showing mechanical integrity of the tubing, casing, and packer.



CLASS VI LOGGING AND TESTING

INJECTION WELL 357-7R
40 CFR 146.82(c)(4),(7) and 146.87(a)(1)-(3)

ELK HILLS A1-A2 PROJECT

Injection Well 357-7R Logging and Testing

The 357-7R injection well is being repurposed for the Elk Hills A1-A2 project. The 357-7R well has been approved by California Geologic Energy Management (CalGEM) for Class II pressure maintenance using gas as injectate.

Deviation Checks During Drilling

Deviation checks for 357-7R were acquired during drilling every ten feet from 3,540.52 feet true vertical depth (TVD) to bottom hole at 8,995.93 feet TVD (Figure 1).

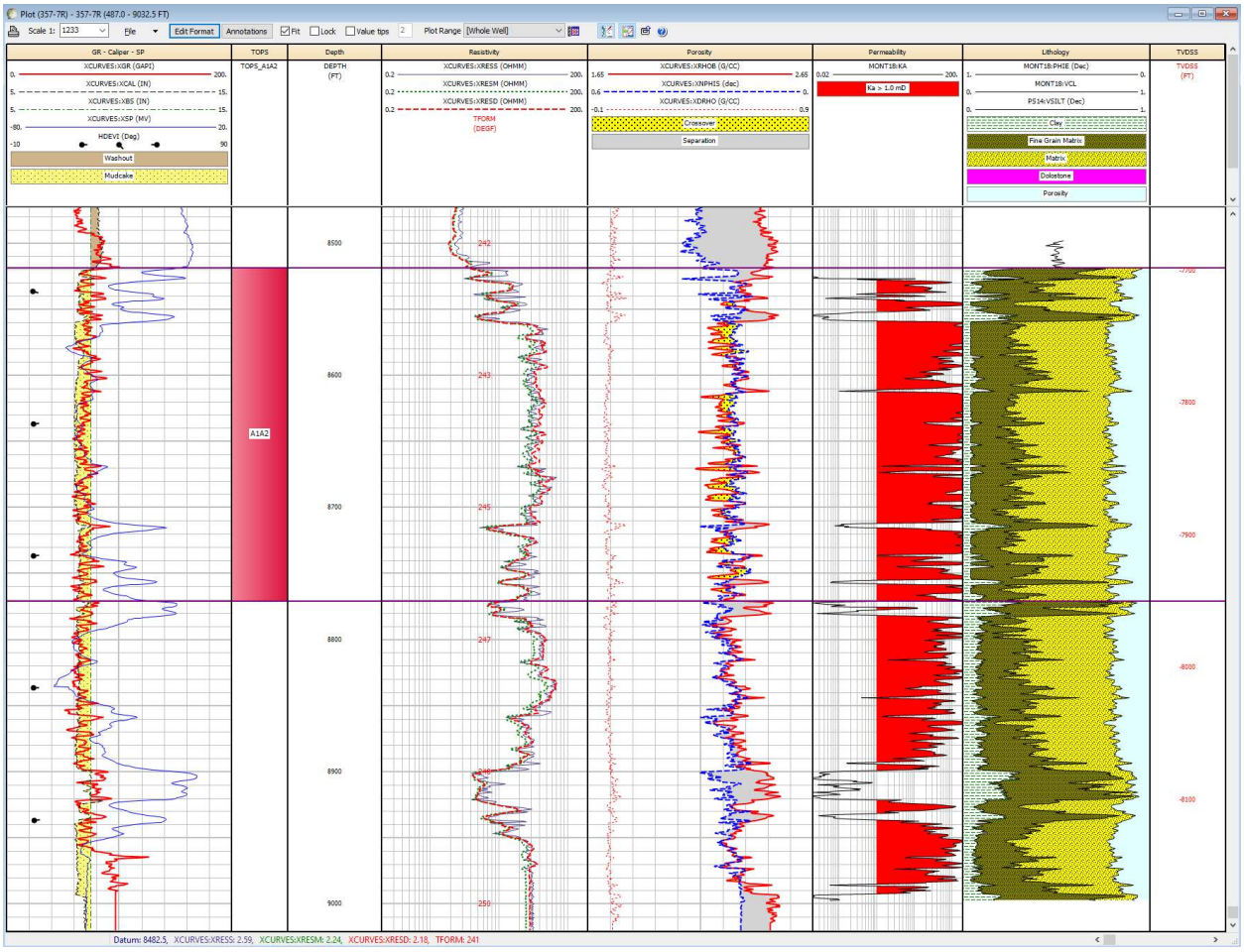
Figure 1: Deviation checks during drilling for the 357-7R well.

X *ftUS*	Y *ftUS*	Z *ft*	MD *ft*	Inclination *deg*	Azimuth GN *deg*	Azimuth TN *deg*	DX *ftUS*	DY *ftUS*	DX TN *ftUS*	DY TN *ftUS*	TVD (Well datum) *ft*	TWT *ms*	DLS *deg/100ft*
6100830.00	2309245.00	812.00	0.00	0.00	165.70	164.82	0.00	0.00	0.00	0.00	0.00		0.00
6100843.74	2309191.11	-2728.52	3541.10	1.80	165.70	164.82	13.74	-53.89	14.56	-53.68	3540.52		0.05
6100843.83	2309190.81	-2738.51	3551.10	1.80	158.50	157.62	13.83	-54.19	14.67	-53.97	3550.51		2.26
6100843.91	2309190.53	-2748.51	3561.10	1.50	170.00	169.12	13.91	-54.47	14.75	-54.25	3560.51		4.45
6100843.95	2309190.28	-2758.51	3571.10	1.40	174.30	173.42	13.95	-54.72	14.79	-54.50	3570.51		1.48
6100843.98	2309190.03	-2768.40	3581.00	1.60	170.00	169.12	13.98	-54.97	14.83	-54.75	3580.40		2.32
6100947.59	2308941.03	-8136.56	8957.60	2.30	76.40	75.52	117.59	-303.97	122.25	-302.14	8948.56		0.00
6100947.98	2308941.13	-8146.45	8967.50	2.30	75.00	74.12	117.98	-303.87	122.63	-302.03	8958.45		0.57
6100948.36	2308941.23	-8156.45	8977.50	2.30	76.40	75.52	118.36	-303.77	123.02	-301.93	8968.45		0.56
6100948.75	2308941.30	-8166.44	8987.50	2.20	80.70	79.82	118.75	-303.70	123.41	-301.84	8978.44		1.96
6100949.12	2308941.36	-8176.43	8997.50	2.10	82.10	81.22	119.12	-303.64	123.78	-301.78	8988.43		1.13
6100949.39	2308941.40	-8183.93	9005.00	2.10	82.10	81.22	119.39	-303.60	124.05	-301.74	8995.93		0.00

357-7R Open Hole Log Analysis: Before Installation of Long String

Open-hole wireline log data was acquired in 357-7R with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity, neutron porosity and bulk density (Figure 2).

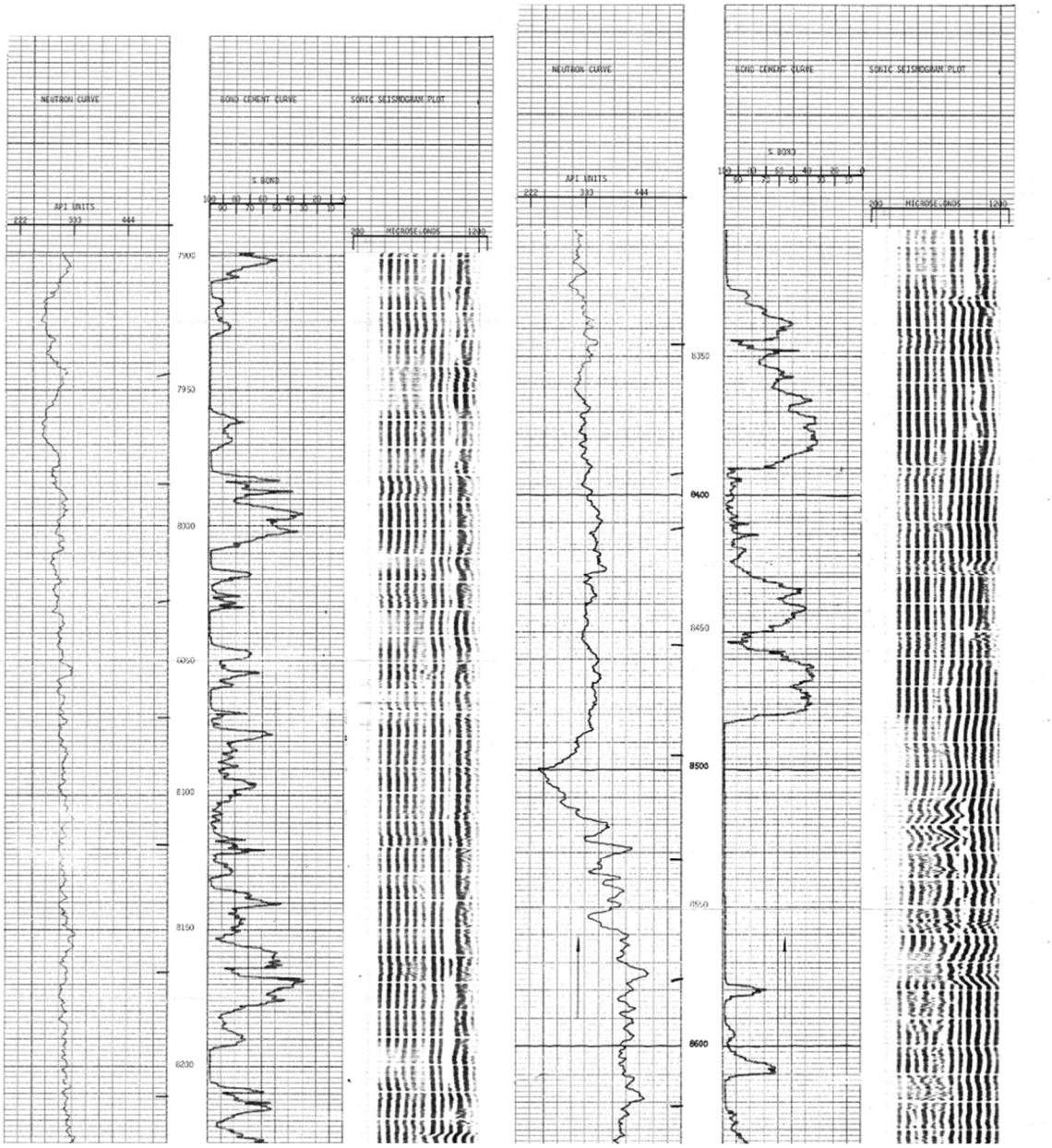
Figure 2: Open-hole well logs for 357-7R before installation of long string.



357-7R Cased Hole: After Installation of Long String

The cement bond log seismogram and percent bond show isolation between the injection zone and shallow formations. Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 3).

Figure 3: Cement bond log example for 357-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,518 feet.



CLASS VI INJECTION WELL TESTING

INJECTION WELL 357-7R
40 CFR 146.82(c)(4),(7) and 146.87(e)

ELK HILLS A1-A2 PROJECT

Well 357-7R Injection

The 357-7R injection well is being repurposed for the Elk Hills A1-A2 project. Injection was approved by California Geologic Energy Management (CalGEM) for Class II gas injection for pressure maintenance. Since 2011 3.5 billion cubic feet of gas has been injected in well 357-7R (Figure 1), with CO_2 composition as high as 44%. The maximum rate of injection for the 357-7R well since 2011 is 6.5 million cubic feet per day.

Gas injection for the purpose of supporting Monterey Formation A1-A2 reservoir pressure initiated in 1982. Cumulative gas injection is 175 billion cubic feet, with individual well injection rates as high as 30 million cubic feet per day.

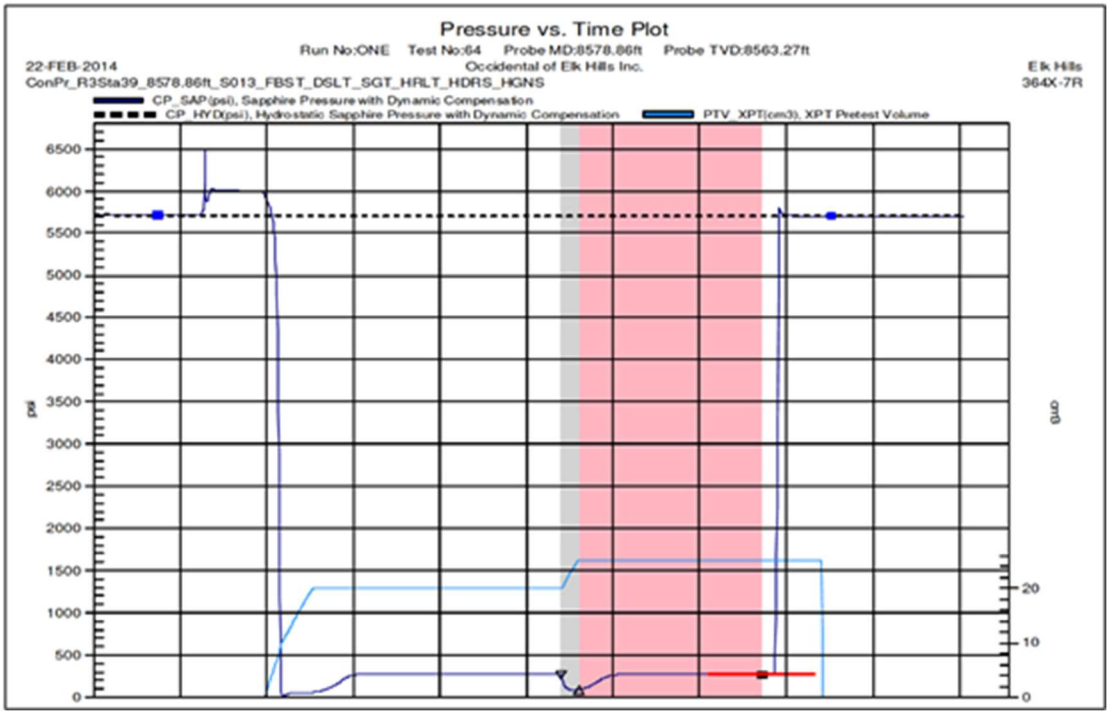
Figure 1: 357-7R gas injection rate.



Pressure Build-Up Test

Below (Figure 2) is an example build-up test from well 364X-7R taken at 8578.86 feet measured depth in the Monterey Formation A1-A2 reservoir.

Figure 2: Pressure build-up test for the Monterey Formation A1-A2 reservoir in well 364X-7R.


Pressure vs. Time Plot
Run No:ONE Test No:64 Probe MD:8578.86ft Probe TVD:8563.27ft
22-FEB-2014
Occidental of Elk Hills Inc.
Elk Hills
364X-7R
ConPr_R3Sta39_8578.86ft_S013_FBST_DSLT_SGT_HRLT_HDRS_HGNS
CP_SAP(psi), Sapphire Pressure with Dynamic Compensation
CP_HYD(psi), Hydrostatic Sapphire Pressure with Dynamic Compensation
PTV_XPT(cm3), XPT Pretest Volume
psi
cm3
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
20
10
0

ATTACHMENT G: CONSTRUCTION DETAILS
WELL 357-7R

Elk Hills A1-A2 Storage Project

Facility Information

Facility name:	Elk Hills A1-A2 Storage 357-7R
Facility contact:	Kenneth Haney / CCS Project Manager 28590 Highway 119 Tupman, CA 93276 (661) 763-6101/ Kenneth.Haney@crc.com
Well location:	Elk Hills Oil Field, Kern County, CA 35.32802963 / -119.5449982

Introduction

The testing activities at the 357-7R described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

Injection well 357-7R is an existing well approved for gas injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 3.5 billion cubic feet of gas. As part of the UIC approval, California Resources Corporation (CRC) has conducted annual MITs and SAPT tests every five years to ensure internal and external mechanical integrity.

Injection Well Construction Details

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

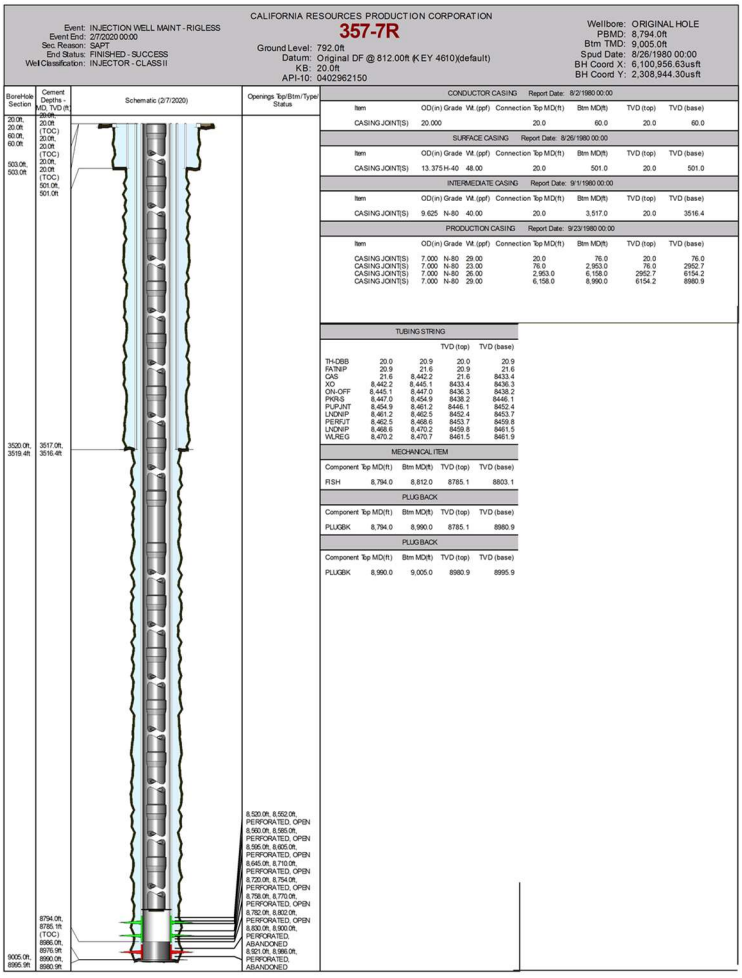
Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,447	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

Injection Well Construction Diagrams

Figure 1: Injection well 357-7R casing diagram.



Pre-Injection Testing Plan – Injection Well

The following tests and logs have been acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

Deviation Checks

Deviation measurements were conducted approximately every 10 feet during construction of the well.

Tests and Logs

The following logs were acquired during the drilling and prior to the completion of the 357-7R well:

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs
- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log
- Mud Log

The following cased-hole logs were acquired after the drilling and completion of the 357-7R well:

- Cement Bond Log
- Mechanical Integrity Tests (Temperature Log and SAPT)

Demonstration of mechanical integrity

Below is a summary of the tests to be performed prior to injection:

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Radioactive Tracer	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Pre-Injection Testing Plan – Deep Monitoring Wells 327-7R-RD1 and 342-7R-RD1

Deep monitoring wells proposed for the Elk Hills A1-A2 Storage project have already been drilled and completed.

Deviation Checks

Deviation measurements for 342-7R-RD1 and 327-7R-RD1 were recorded approximately every 35 and 156 feet respectively, during construction of the well.

Tests and Logs

The following logs were acquired during the drilling and prior to the completion of the 342-7R-RD1 and 327-7R-RD1 wells:

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs

- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log

Demonstration of mechanical integrity

CTV will run mechanical integrity logs and tests prior to injection operations.

Annulus Pressure Test Procedures for Injection Well 357-7R:

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

Annulus Pressure Test Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1:

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source(annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

Pressure Fall-Off Test Procedures:

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation A1-A2 reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas

injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

Testing details

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

CLASS VI CONFINING ZONE PROPERTIES

INJECTION WELL 357-7R
40 CFR 146.82(c)(4),(7) and 146.87(b)-(d)

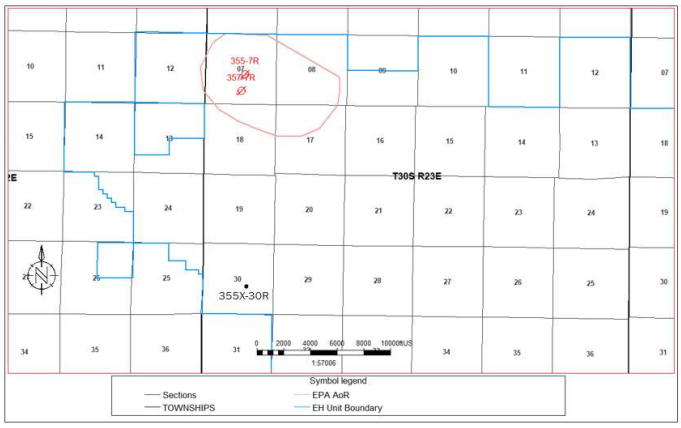
ELK HILLS A1-A2 PROJECT

Confining Zone Chemical and Physical Characteristics

Core Analysis

Given the marine depositional environemnt and continuity of the Reef Ridge shale the 355X-30R well core analysis is used to characterize the Reef Ridge Shale in the AoR.

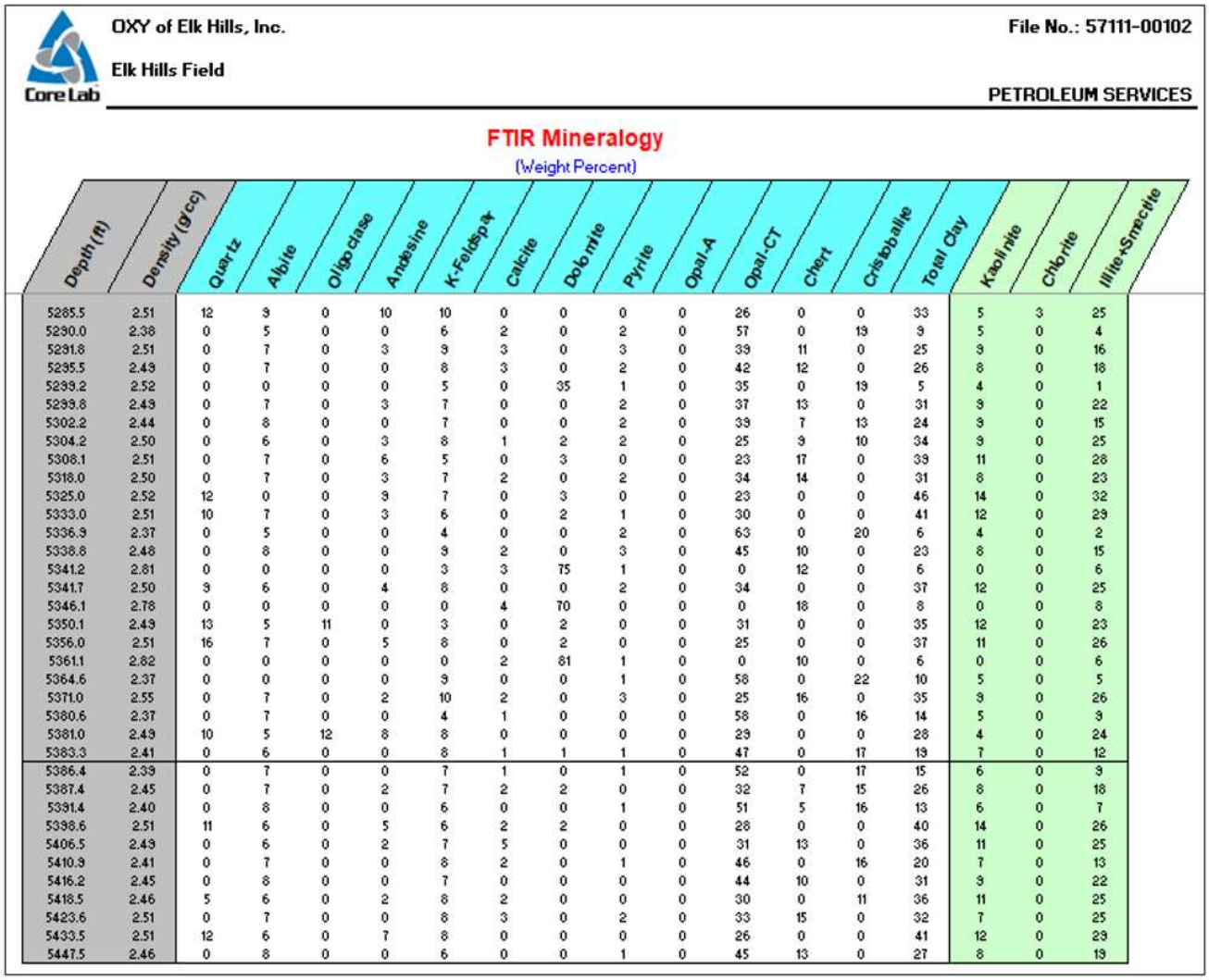
Figure 1: Location of Reef Ridge core well 355X-30R.



Mineralogy

Fourier Transform Infrared Spectroscopy (FTIR) is used to determine mineralogy of the confining zone from 36 points in one well (Figure 2). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

Figure 2: FTIR mineralogy for the Reef Ridge Shale in the 355X-30R well.



OXY of Elk Hills, Inc.

Elk Hills Field

File No.: 57111-00102

PETROLEUM SERVICES

FTIR Mineralogy

(Weight Percent)

Depth (ft)	Density (g/cc)	Quartz	Albite	Oligoclase	Andesine	K-Feldspar	Calcite	Dolomite	Pyrite	Opal-A	Opal-CT	Chert	Cristobalite	Total Clay	Kaolinite	Chlorite	Illite+Smectite
5285.5	2.51	12	9	0	10	10	0	0	0	0	26	0	0	33	5	3	25
5290.0	2.38	0	5	0	0	6	2	0	2	0	57	0	19	9	5	0	4
5291.8	2.51	0	7	0	3	9	3	0	3	0	39	11	0	25	9	0	16
5295.5	2.49	0	7	0	0	8	3	0	2	0	42	12	0	26	8	0	18
5299.2	2.52	0	0	0	0	5	0	35	1	0	35	0	19	5	4	0	1
5299.8	2.49	0	7	0	3	7	0	0	2	0	37	13	0	31	9	0	22
5302.2	2.44	0	8	0	0	7	0	0	2	0	39	7	13	24	9	0	15
5304.2	2.50	0	6	0	3	8	1	2	2	0	25	9	10	34	9	0	25
5308.1	2.51	0	7	0	6	5	0	3	0	0	23	17	0	39	11	0	28
5318.0	2.50	0	7	0	3	7	2	0	2	0	34	14	0	31	8	0	23
5325.0	2.52	12	0	0	9	7	0	3	0	0	23	0	0	46	14	0	32
5333.0	2.51	10	7	0	3	6	0	2	1	0	30	0	0	41	12	0	29
5336.9	2.37	0	5	0	0	4	0	0	2	0	63	0	20	6	4	0	2
5338.8	2.48	0	8	0	0	9	2	0	3	0	45	10	0	23	8	0	15
5341.2	2.81	0	0	0	0	3	3	75	1	0	0	12	0	6	0	0	6
5341.7	2.50	9	6	0	4	8	0	0	2	0	34	0	0	37	12	0	25
5346.1	2.78	0	0	0	0	0	4	70	0	0	0	18	0	8	0	0	8
5350.1	2.49	13	5	11	0	3	0	2	0	0	31	0	0	35	12	0	23
5356.0	2.51	16	7	0	5	8	0	2	0	0	25	0	0	37	11	0	26
5361.1	2.82	0	0	0	0	0	2	81	1	0	0	10	0	6	0	0	6
5364.6	2.37	0	0	0	0	9	0	0	1	0	58	0	22	10	5	0	5
5371.0	2.55	0	7	0	2	10	2	0	3	0	25	16	0	35	9	0	26
5380.6	2.37	0	7	0	0	4	1	0	0	0	58	0	16	14	5	0	9
5381.0	2.49	10	5	12	8	8	0	0	0	0	29	0	0	28	4	0	24
5383.3	2.41	0	6	0	0	8	1	1	1	0	47	0	17	19	7	0	12
5386.4	2.39	0	7	0	0	7	1	0	1	0	52	0	17	15	6	0	9
5387.4	2.45	0	7	0	2	7	2	2	0	0	32	7	15	26	8	0	18
5391.4	2.40	0	8	0	0	6	0	0	1	0	51	5	16	13	6	0	7
5398.6	2.51	11	6	0	5	6	2	2	0	0	28	0	0	40	14	0	26
5406.5	2.49	0	6	0	2	7	5	0	0	0	31	13	0	36	11	0	25
5410.9	2.41	0	7	0	0	8	2	0	1	0	46	0	16	20	7	0	13
5416.2	2.45	0	8	0	0	7	0	0	0	0	44	10	0	31	9	0	22
5418.5	2.46	5	6	0	2	8	2	0	0	0	30	0	11	36	11	0	25
5423.6	2.51	0	7	0	0	8	3	0	2	0	33	15	0	32	7	0	25
5433.5	2.51	12	6	0	7	8	0	0	0	0	26	0	0	41	12	0	29
5447.5	2.46	0	8	0	0	6	0	0	1	0	45	13	0	27	8	0	19

Permeability

Table 1 shows the Reef Ridge Shale permeability for the 355X-30R well.

Table 1: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006
TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

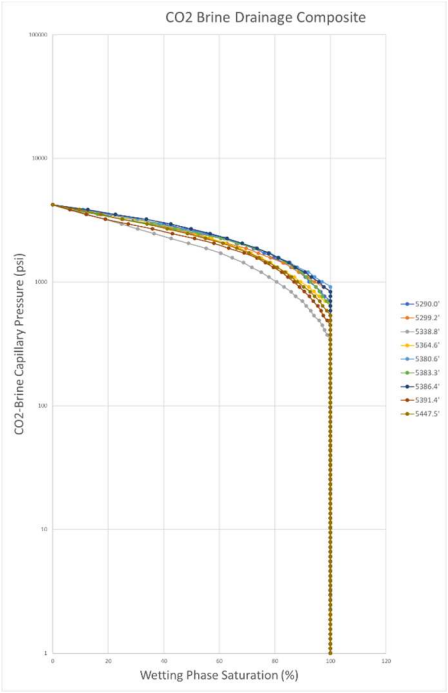
The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points in one well.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in one well.

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for the CO_2 to overcome capillary and interfacial forces and enter the pore space containing the water.

The capillary pressure of the confining zone is 4,220 PSI in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 3). The capillary pressure was determined by applying CO_2-brine corrections to the air-mercury data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-brine. A cosine of contact angle of 0.766 and 0.866 were also used for air-mercury and CO_2-brine respectively.

Figure 3: Capillary pressure graph for the 355X-30R well.



CLASS VI CORE ANALYSIS

INJECTION WELL 357-7R
40 CFR 146.82(c)(4),(7) and 146.87(b)

ELK HILLS A1-A2 PROJECT

Monterey Formation A1-A2 Core Analysis

Mineralogy

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the Area of Review. Offset well 367-7R supplies an example of the mineralogy for the reservoir (Figure 1). The location of well 367-7R is shown on the map in Figure 3.

Figure 1: 367-7R mineralogy for the Monterey Formation A1-A2 reservoir.

BECHTEL PETROLEUM OPERATIONS, INC.
367-7R
ELK HILLS FIELD

FILE # 17019

MINERALOG™ ANALYSIS (WEIGHT %)

DEPTH	GDI	SAMP. WT	QTZ	CHRT	OP-A	OP-CT	ALB	OLIG	ANDE	KSPAR	CALC	DOLO	PYR	KAOL	CHLOR	ILL/SMEC
8551.9	2.62	8.34	30	13	0	0	17	0	2	21	2	0	1	0	0	14
8552.0	2.62	9.41	28	13	0	0	14	10	0	15	3	0	0	0	3	14
8554.1	2.62	10.73	45	0	0	0	19	0	2	20	4	0	0	0	0	10
8560.6	2.62	11.57	44	0	0	0	15	11	0	17	5	0	0	2	0	6
8570.0	2.62	8.32	43	0	0	0	17	8	4	17	3	0	0	0	0	8
8593.0	2.62	14.88	45	0	0	0	15	11	0	18	4	0	0	0	0	7
8608.9	2.60	18.83	21	21	0	0	15	0	10	14	2	0	0	0	0	17
8634.9	2.62	21.65	44	0	0	0	16	13	1	17	3	0	0	0	0	6
8648.6	2.62	14.16	47	0	0	0	18	3	5	19	3	0	0	0	0	5
8649.2	2.62	15.56	49	0	0	0	18	0	4	18	3	0	0	2	0	6
8649.8	2.62	8.73	50	0	0	0	17	0	4	17	1	2	0	3	0	6
8650.9	2.62	11.24	45	0	0	0	14	9	4	17	2	1	0	2	0	6
8651.8	2.62	8.75	46	0	0	0	16	0	6	19	3	0	0	0	0	10
8656.0	2.63	23.81	38	0	0	0	14	10	4	14	12	2	0	0	0	6
8702.6	2.61	10.56	40	13	0	0	15	0	5	18	2	0	0	0	0	7

GDI = GRAIN DENSITY INDEX
SAMP. WT = WEIGHT OF FRESH SAMPLE CRUSHED FOR ANALYSIS
QTZ = QUARTZ
CHRT = CHERT
OP-A = OPAL-A
OP-CT = OPAL-CT
ALB = ALBITE
OLIG = OLIGOCLASE

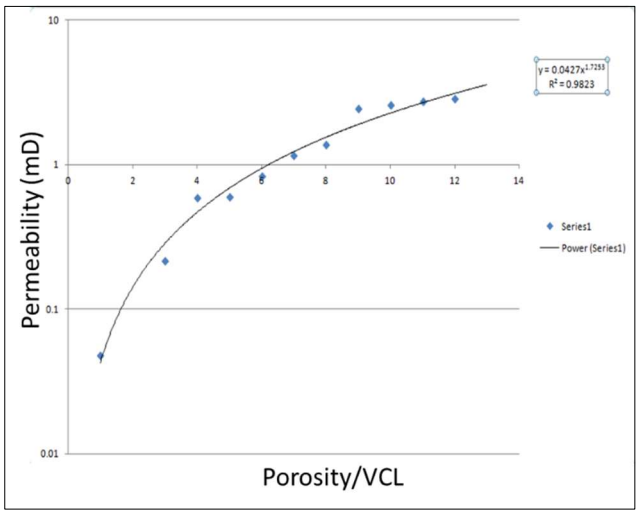
ANDE = ANDESINE
KSPAR = POTASSIUM FELDSPAR
CALC = CALCITE
DOLO = DOLOMITE
PYR = PYRITE
KAOL = KAOLINITE
CHLOR = CHLORITE
ILL/SMEC = ILLITE + SMECTITE

Clean reservoir sand intervals have an average of 43% quartz, 38% potassium feldspar, albite and oligoclase as well as 7% total clay.

Permeability

Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy (FTIR). Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated below (Figure 2).

Figure 2: Permeability function for the Monterey Formation A1-A2 reservoir. The function was defined by mercury injection capillary pressure analysis. Continuous permeability for the static model is calculated based on open-hole well log derived porosity and clay volume.



Example core report data of the MICP porosity and permeability from offset well 317-8R (Table 1). The location of well 317-8R is shown on the map in Figure 3.

Figure 3: Location of wells 367-7R and 317-8R.

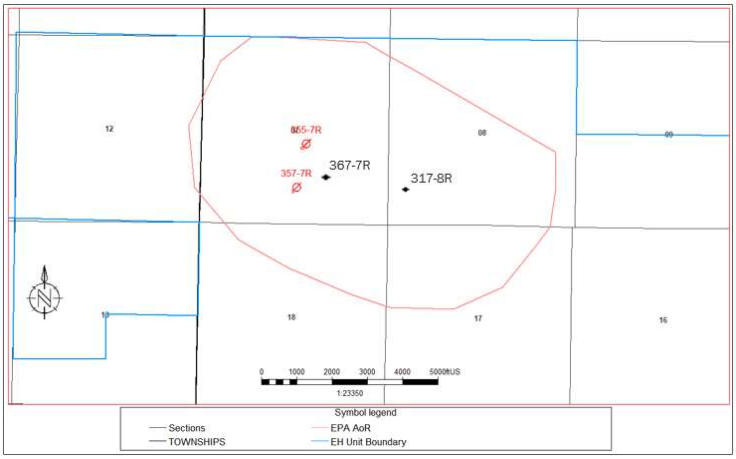


Table 1: Example core report data of the MICP porosity and permeability from well 317-8R.

DEPTH	ANALYSIS_LAB	DATE	SAMPLE_ID	CKHA	CPOR	CKHA_C	SYSTEM
feet				mD	%	mD	
8865	CORE LABORATORIES	8/6/1975	1	215	24	160	air-brine
8868	CORE LABORATORIES	8/6/1975	2	72	20.7	58	air-brine
8869	CORE LABORATORIES	8/6/1975	3	21	18.7	13	air-brine
8948	CORE LABORATORIES	8/6/1975	4	42	17	39	air-brine
8952	CORE LABORATORIES	8/6/1975	5	54	17.9	50	air-brine
8960	CORE LABORATORIES	8/6/1975	6	39	16.5	37	air-brine
8971	CORE LABORATORIES	8/6/1975	7	24	17.2	19	air-brine
8974	CORE LABORATORIES	8/6/1975	8	91	20.1	75	air-brine

CLASS VI INJECTION ZONE PROPERTIES

INJECTION WELL 357-7R
40 CFR 146.82(c)(4),(7) and 146.87(b)-(d)

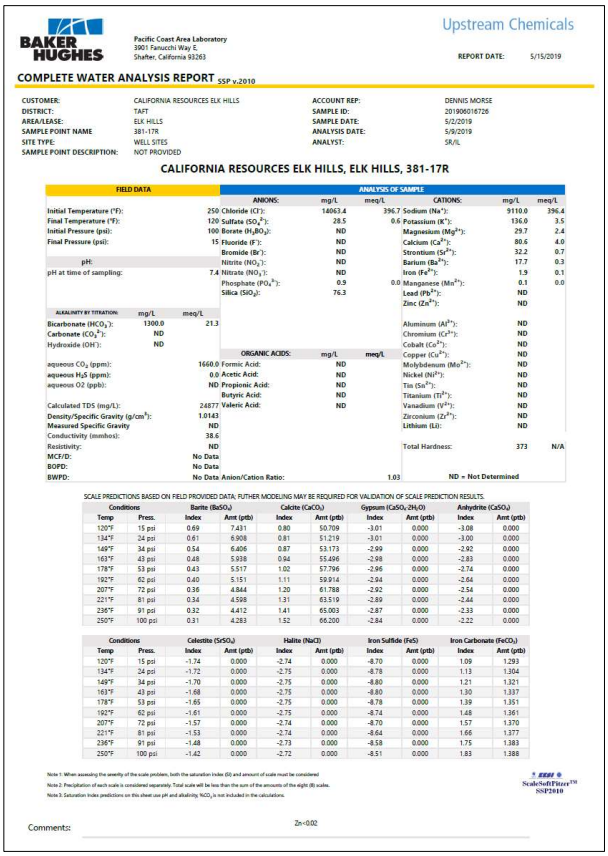
ELK HILLS A1-A2 PROJECT

Injection Zone Chemical and Physical Properties

Water Geochemistry

Produced water geochemistry shows that injection zone total dissolved solids are 24,000 -25,000 milligrams per liter (Figure 1). The Monterey Formation A1-A2 reservoir is depleted due to oil and gas production and has a low current water saturation. As such, the water sample shown in Figure 1 was taken from a sand directly underneath the Monterey Formation A1-A2 reservoir.

Figure 1: Water analysis report for the Monetary Formation reservoir from well 381-17R.



BAKER HUGHES

Pacific Coast Area Laboratory
3901 Fanucchi Way E.
Shafter, California 93263

Upstream Chemicals

REPORT DATE: 5/15/2019

COMPLETE WATER ANALYSIS REPORT SSP v.2010

CUSTOMER:	CALIFORNIA RESOURCES ELK HILLS	ACCOUNT REP:	DENNIS MORSE
DISTRICT:	TAFT	SAMPLE ID:	20190501726
AREA/LEASE:	ELK HILLS	SAMPLE DATE:	5/2/2019
SAMPLE POINT NAME	381-17R	ANALYSIS DATE:	5/9/2019
SITE TYPE:	WELL SITES	ANALYST:	SR/IL
SAMPLE POINT DESCRIPTION:	NOT PROVIDED		

CALIFORNIA RESOURCES ELK HILLS, ELK HILLS, 381-17R

FIELD DATA	
Initial Temperature (°F):	250
Final Temperature (°F):	120
Initial Pressure (psi):	100
Final Pressure (psi):	15
pH:	
pH at time of sampling:	7.4

ALKALINITY BY TITRATION:	mg/L	meq/L
Bicarbonate (HCO_3^-):	1300.0	21.3
Carbonate (CO_3^{2-}):	ND	
Hydroxide (OH^-):	ND	

aqueous CO_2 (ppm):	1660.0
aqueous H_2S (ppm):	0.0
aqueous O2 (ppb):	ND
Calculated TDS (mg/L):	24877
Density/Specific Gravity (g/cm³):	1.0143
Measured Specific Gravity	ND
Conductivity (mmhos):	38.6
Resistivity:	ND
MCF/D:	No Data
BOPD:	No Data
BWPD:	No Data

ANALYSIS OF SAMPLE

ANIONS:	mg/L	meq/L
Chloride (Cl^-):	14063.4	396.7
Sulfate (SO_4^{2-}):	28.5	0.6
Borate ($H_2BO_3^-$):	ND	
Fluoride (F^-):	ND	
Bromide (Br^-):	ND	
Nitrite (NO_2^-):	ND	
Nitrate (NO_3^-):	ND	
Phosphate (PO_4^{3-}):	0.9	0.0
Silica (SiO_2):	76.3	

ORGANIC ACIDS:	mg/L	meq/L
Formic Acid:	ND	
Acetic Acid:	ND	
Propionic Acid:	ND	
Butyric Acid:	ND	
Valeric Acid:	ND	

CATIONS:	mg/L	meq/L
Sodium (Na^+):	9110.0	396.4
Potassium (K^+):	136.0	3.5
Magnesium (Mg^{2+}):	29.7	2.4
Calcium (Ca^{2+}):	80.6	4.0
Strontium (Sr^{2+}):	32.2	0.7
Barium (Ba^{2+}):	17.7	0.3
Iron (Fe^{2+}):	1.9	0.1
Manganese (Mn^{2+}):	0.1	0.0
Lead (Pb^{2+}):	ND	
Zinc (Zn^{2+}):	ND	
Aluminum (Al^{3+}):	ND	
Chromium (Cr^{3+}):	ND	
Cobalt (Co^{2+}):	ND	
Copper (Cu^{2+}):	ND	
Molybdenum (Mo^{2+}):	ND	
Nickel (Ni^{2+}):	ND	
Tin (Sn^{2+}):	ND	
Titanium (Ti^{4+}):	ND	
Vanadium (V^{2+}):	ND	
Zirconium (Zr^{4+}):	ND	
Lithium (Li^+):	ND	
Total Hardness:	373	N/A

Anion/Cation Ratio: 1.03

ND = Not Determined

SCALE PREDICTIONS BASED ON FIELD PROVIDED DATA; FUTHER MODELING MAY BE REQUIRED FOR VALIDATION OF SCALE PREDICTION RESULTS.

Conditions		Barite ($BaSO_4$)		Calcite ($CaCO_3$)		Gypsum ($CaSO_4 \cdot 2H_2O$)		Anhydrite ($CaSO_4$)	
Temp	Press.	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)
120°F	15 psi	0.69	7.431	0.80	50.709	-3.01	0.000	-3.08	0.000
134°F	24 psi	0.61	6.908	0.81	51.219	-3.01	0.000	-3.00	0.000
149°F	34 psi	0.54	6.406	0.87	53.173	-2.99	0.000	-2.92	0.000
163°F	43 psi	0.48	5.938	0.94	55.496	-2.98	0.000	-2.83	0.000
178°F	53 psi	0.43	5.517	1.02	57.796	-2.96	0.000	-2.74	0.000
192°F	62 psi	0.40	5.151	1.11	59.914	-2.94	0.000	-2.64	0.000
207°F	72 psi	0.36	4.844	1.20	61.788	-2.92	0.000	-2.54	0.000
221°F	81 psi	0.34	4.598	1.31	63.519	-2.89	0.000	-2.44	0.000
236°F	91 psi	0.32	4.412	1.41	65.003	-2.87	0.000	-2.33	0.000
250°F	100 psi	0.31	4.283	1.52	66.200	-2.84	0.000	-2.22	0.000

Conditions		Celestite ($SrSO_4$)		Halite (NaCl)		Iron Sulfide (FeS)		Iron Carbonate ($FeCO_3$)	
Temp	Press.	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)	Index	Amt (ptb)
120°F	15 psi	-1.74	0.000	-2.74	0.000	-8.70	0.000	1.09	1.293
134°F	24 psi	-1.72	0.000	-2.75	0.000	-8.78	0.000	1.13	1.304
149°F	34 psi	-1.70	0.000	-2.75	0.000	-8.80	0.000	1.21	1.321
163°F	43 psi	-1.68	0.000	-2.75	0.000	-8.80	0.000	1.30	1.337
178°F	53 psi	-1.65	0.000	-2.75	0.000	-8.78	0.000	1.39	1.351
192°F	62 psi	-1.61	0.000	-2.75	0.000	-8.74	0.000	1.48	1.361
207°F	72 psi	-1.57	0.000	-2.74	0.000	-8.70	0.000	1.57	1.370
221°F	81 psi	-1.53	0.000	-2.74	0.000	-8.64	0.000	1.66	1.377
236°F	91 psi	-1.48	0.000	-2.73	0.000	-8.58	0.000	1.75	1.383
250°F	100 psi	-1.42	0.000	-2.72	0.000	-8.51	0.000	1.83	1.388

Note 1: When assessing the severity of the scale problem, both the saturation index (SI) and amount of scale must be considered
Note 2: Precipitation of each scale is considered separately. Total scale will be less than the sum of the amounts of the eight (8) scales.
Note 3: Saturation Index predictions on this sheet use pH and alkalinity. NO_3^- is not included in the calculations.

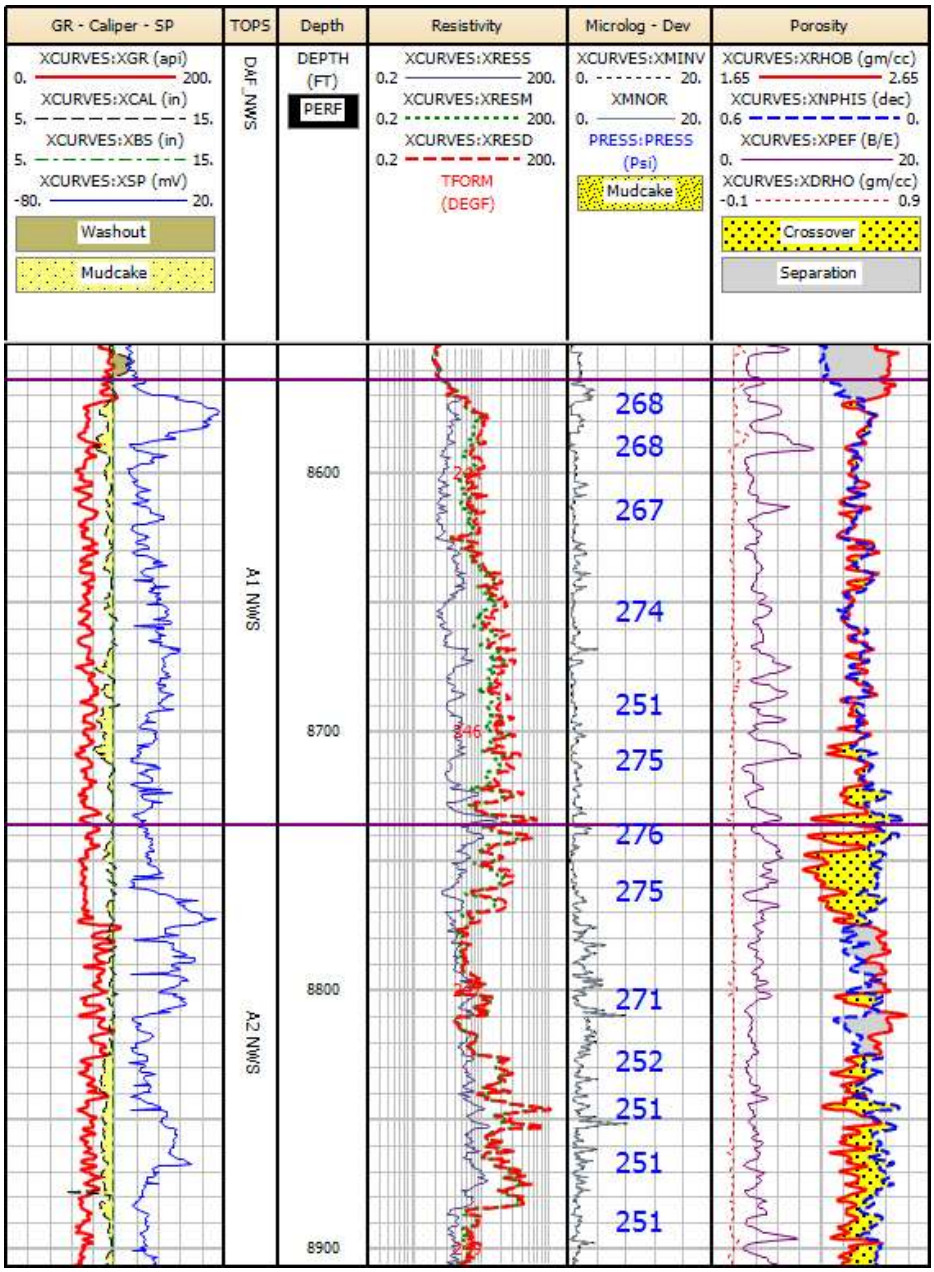
ScaleSoftPitzer™ SSP2010

Comments: Zn<0.02

Reservoir Pressure

Monterey Formation A1-A2 reservoir pressure taken by a wireline formation pressure testing tool in well 364X-7R is shown in Figure 2. Final wireline pressure is plotted numerically in the Microlog track showing pressure between 200 - 300 PSI. The location of well 364X-7R is shown in Figure 4.

Figure 2: Monterey Formation A1-A2 pressure from well 364X-7R.



Below (Figure 3) is an example build-up test from well 364X-7R taken at 8578.86 feet measured depth in the Monterey Formation A1-A2 reservoir. The location of well 364X-7R is shown in Figure 4.

Figure 3: Pressure build-up test for the Monterey Formation A1-A2 reservoir in well 364X-7R.

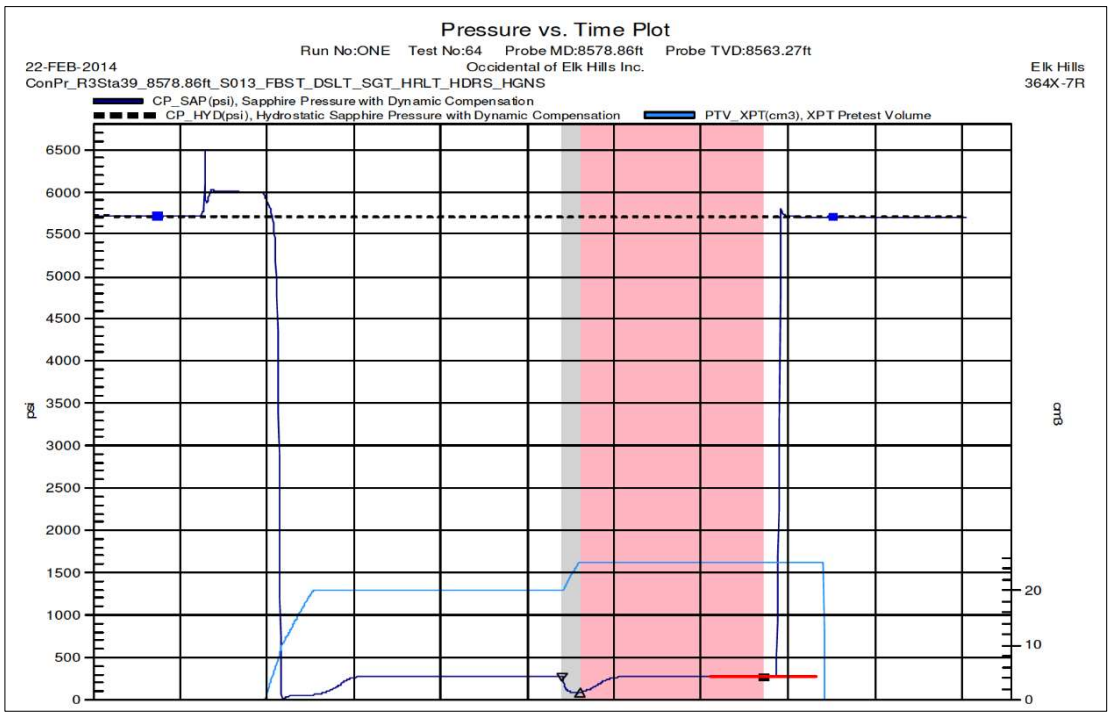
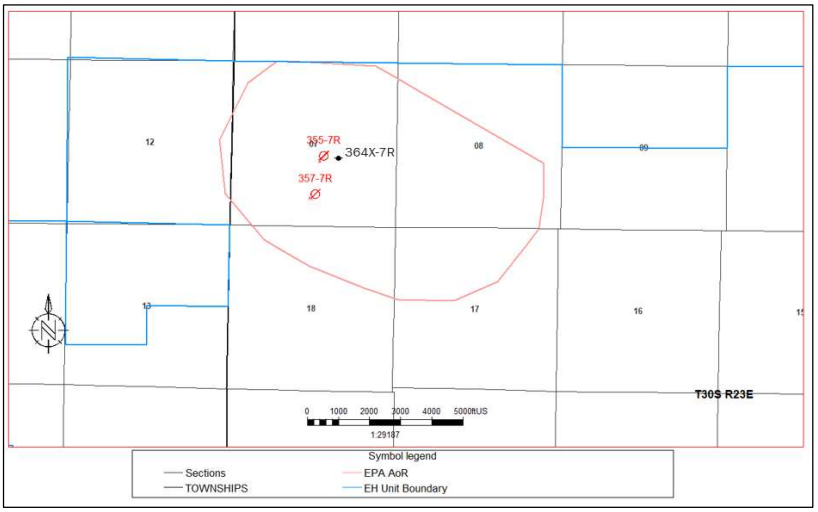


Figure 4: Location of well 364X-7R.



Fracture Gradient

A fracture gradient of 0.97 PSI per foot at 9,428 feet measured depth was acquired in well 327-7R-RD1 (Figure 5). The 327-7R-RD1 well location is shown on the map in Figure 6.

Figure 5: A fracture gradient of 0.97 PSI per foot was measured in well 327-7R-RD1.

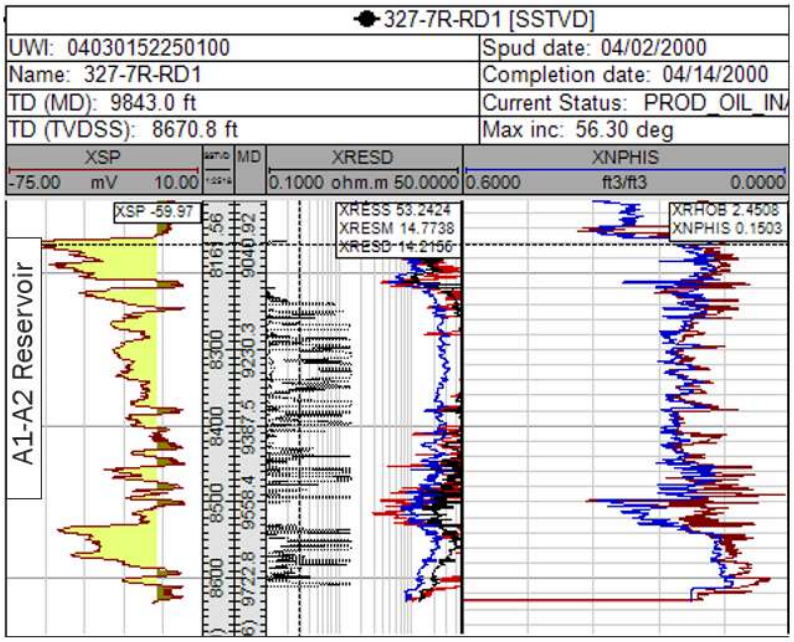
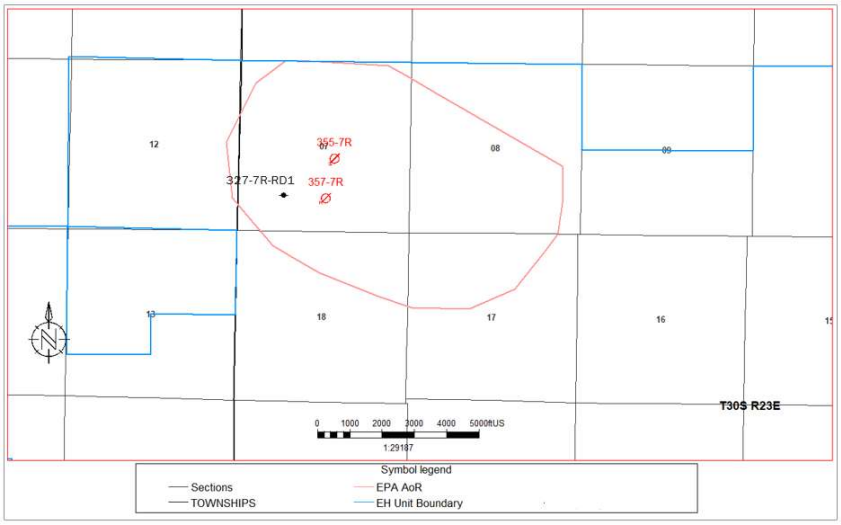


Figure 6: Location of well 327-7R-RD1.



CLASS VI TESTING

INJECTION WELL 357-7R
40 CFR 146.87

ELK HILLS A1-A2 PROJECT

Pre-Operational Testing Plan

The 357-7R and 355-7R injection wells are being repurposed for the CTV Elk Hills A1-A2 project. These wells have been approved by California Geologic Energy Management (CalGEM) for Class II injection of gas for pressure maintenance.

The Monterey Formation A1-A2 reservoir was discovered in the 1970's and has since been developed with water and gas injection for pressure maintenance. Operational history of the field has provided a robust dataset to fully characterize the reservoir, confining layer and USDW with (Table 1).

Table 1: Site characterization data for the Elk Hills A1-A2 project.

Deviation Checks	**Provided**
Cement Bond Log	**Provided**
Open-hole Well Logs	**Provided**
Mechanical Integrity Test	**Provided**
Standard Annulus Pressure Test (SAPT)	**Provided**
Injection Zone and Confining Layer Core	**Provided**
Reservoir Conditions and Fluid	**Provided**
Injection Zone and Confining Layer Fracture Gradients	**Provided**
Pressure Testing	**Provided**

CLASS VI TESTING

INJECTION WELL 357-7R
40 CFR 146.87

ELK HILLS A1-A2 PROJECT

Pre-Operational Testing Plan

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Standard Annulus Pressure Test (SAPT)	**Provided**
Injection Zone and Confining Layer Core	**Provided**
Reservoir Conditions and Fluid	**Provided**
Injection Zone and Confining Layer Fracture Gradients	**Provided**
Pressure Testing	**Provided**

Class VI Injection Well: Quality Assurance and Surveillance Plan

July 15, 2021

Prepared by:

Carbon TerraVault 1 LLC

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Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Elk Hills A1-A2 Storage facility. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

THurst

July 15, 2021

_____ _____

Signature Date

Travis Hurst

Geological Advisor

Distribution List

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Ken Haney: Project Manager
Travis Hurst: Geological Advisor

Carbon TerraVault
28590 Highway 119
Tupman, CA 93276

A. Project Management

A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The Elk Hill A1-A1 Storage project, led by Carbon TerraVault 1 LLC (CTV), includes participation from service providers. The responsibilities for Testing and Monitoring will be shared between CTV and the service providers.

CTV will be responsible for any data and submissions made to the EPA.

A.1.c. Independence from Project QA Manager and Data Gathering

CTV utilizes a third-party service provider to collect, transport and analyze samples as part of the Testing and Monitoring Plan.

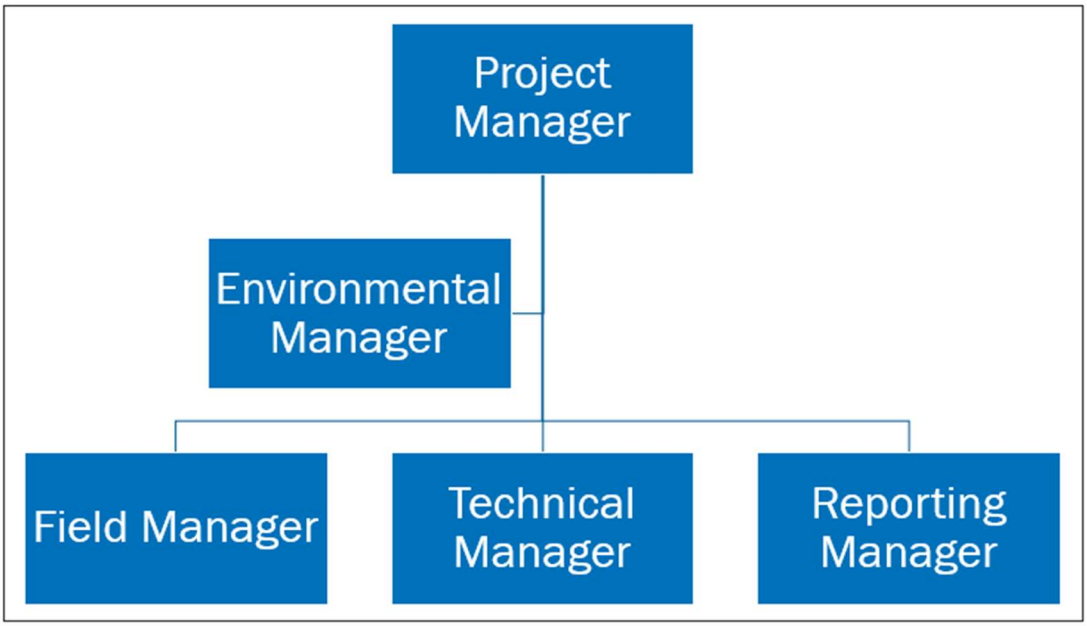
A.1.d. QA Project Plan Responsibility

CTV will be responsible for the Quality Assurance and Surveillance Plan. CTV will review the plan with service providers periodically.

A.1.e. Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure for the Elk Hills A1-A2 project. Although these roles have not been filled because the project is not operational, the chart shows the breakdown in responsibilities for future positions.

Figure 1: Organizational Chart.



A.2. Problem Definition/Background

A.2.a. Reasoning

The Elk Hills A1-A2 project will inject and sequester CO_2 from sources that include the Elk Hills Power Plant, renewable diesel refinery projects, and other industrial sources close to the field. The project requires a comprehensive monitoring plan that gathers data to assess confinement of the CO_2 injectate. To ensure accurate measurement and reporting this QASP outlines detail associated with the surveillance related to sampling, operating, and recording.

A.2.b. Reasons for Initiating the Project

CTV initiated the project for ESG purposes and to reduce carbon footprint for CTV operations and for external emissions. The Elk Hills Oil Field is a premier location for carbon sequestration in the San Joaquin Basin. The field has available pore space, proven confinement, and ideal surface/mineral ownership.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

CO_2 injection as per standard operating procedures and regulations requires that the injectate is confined in the reservoir and that groundwater is not impacted. As such the following monitoring is necessary:

1. Injection well mechanical integrity testing
2. Injection well testing and operating data collection
3. Groundwater monitoring
4. Validation of the CO_2 plume areal coverage as defined by numerical modeling

The information and data below define the steps to ensure that monitoring data quality provides the confidence and information to verify confinement.

A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed

Table 1. Summary of Testing and Monitoring.

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Injection well					
Carbon dioxide stream analysis	Compressor	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor Injectate
Injection rate and volume	Injection Well	Flow meter	Direct Measurement	NA	Monitor rate and volume
Injection pressure	Injection wellhead	Pressure gauge	Direct Measurement	NA	Monitor injection pressure
Annular pressure	Injection Wellhead	Pressure gauge	Direct Measurement	NA	Monitor annular pressure
Downhole pressure/ temperature	Injection Well	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure and temperature
Corrosion monitoring	Between compressor and wellhead	Corrosion Coupon	NA	Zalco Labs	Monitor corrosion of materials
Mechanical integrity	Injection Well	Internal: SAPT External: Temperature Log		NA	Wellbore Integrity
Cement Evaluation	Injection Well	Logging	Cement bond log	NA	Wellbore Integrity

Table 2. Monitoring Well Summary

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Monitoring Wells Above Confining Layer					
Fluid Sampling Tulare Formation (USDW)	61WS-8R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pressure Tulare Formation (USDW)	61WS-8R	Pressure gauge	Direct Measurement	Zalco Labs	Monitor pressure
Pressure Etchegoin Formation	346-7R-RD1	Pressure gauge	Direct Measurement	Zalco Labs	Monitor pressure
Monterey Formation A1-A2 Reservoir					
Pressure/Temperature	Monitoring Wells	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure and temperature
Pulse Neutron Log	Monitoring Wells	Wireline	Indirect	NA	CO_2 Saturation

A.3.c. Geographic Locations

A.3.d. Resource and Time Constraints

There are neither resource nor time constraints for theElk Hills A1-A2 storage project. CTV owns the mineral rights, pore space and surface access to the Elk Hills Oil Field.

Wells to be utilized for the project are available, and will be re-purposed. These wells will be accessible for the life of the project and for the post injection monitoring timeframe.

A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

Table 3. Summary of Analytical and Field Parameters for Fluid Samples in Tulare Formation water.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: [List specific cations]	ICP-OEC EPA200.7/6010B	0.05 to 5 mg/L	**15%**	Daily calibration of equipment/CCV/ Blank LCS, MS/MSD/ QC/ICV
Anions: [List specific anions]	Ion Chromatography EPA 300.0	0.1 to 2 mg/L	**15%**	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Dissolved CO_2	SM 4500-CO2-C	10 mg/L	**NA**	Duplicate analysis
Total dissolved solids	SM 2540 C	10 mg/L	**10%**	Daily balance calibration, duplicates, blanks
Alkalinity	SM 2320 B	10 mg/L	10%	Duplicate analysis
pH (field)	SPA 150.1/SM 4500-H+B	2 to 12.5pH	0.2 pH	Daily calibration, duplicates
Specific conductance (field)	SM 2510 B	10 ohms/cm	1%	Daily calibration, duplicates
Temperature (field)	Thermocouple	-5 to 50 C	0.2 C	Monthly calibration
[Dissolved Methane	RSK-175/ Gas Chromatography	NA	NA	Daily calibration/CCV

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 4. Summary of Analytical Parameters for CO_2 Stream.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Nitrogen	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Carbon monoxide	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total hydrocarbons	ASTM D 1945	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Methane	ASTM D 1945	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Hydrogen sulfide	ASTM D 1945/D6228	10 ppmv/1 ppmv	15%	Daily calibration/CCV, blank, QC sample
Ethanol	EPA 8260B	0.5 ppmv	20%	Daily calibration/CCV, blank, LCS, MS/MSD, ICV
CO_2 purity	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total Sulfur	ASTM D 3246	1 ppmv	15%	Daily calibration/CCV, blank, QC sample

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 5. Summary of Analytical Parameters for Corrosion Coupons.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE TM0169/ G31 EPA 1110A SW846	0.001 mg	10%	

Table 6. Summary of Measurement Parameters for Field Gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection tubing temperature	ANSI Z540-1-1994	0.001 Fahrenheit / 0 – 500 Fahrenheit	0.01 Fahrenheit	Annual calibration
Injection tubing pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Annulus pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection mass flow rate	NA	0.1 % of flow rate	0.01 lbs/hour	Annual calibration

Table 7. Actionable Testing and Monitoring Outputs.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
External and internal mechanical integrity (temperature log)	Temperature log indicates a mechanical integrity issue.	0.01 Fahrenheit	Results will be compared to baseline. Deviation may be indicative of mechanical issue.
Surface and downhole pressure	Action will be taken when pressure is outside of expected or modeled range.	0.001 PSI	No greater than the maximum operating pressure.
Water quality (Tulare USDW)	Action will be taken when water sample is outside of baseline analysis.	0.2 pH	CO_2 will decrease the water pH.
Above-confining-zone pressure (Etchegoin)	Action will be taken if the pressure of the Etchegoin Formation pressure increases.	0.001 PSI as per installed pressure gauge.	Reservoir pressure.

A.4.b. Precision

Field blanks will be collected once per sampling event to assess water sampling analysis accuracy. Service provider will be responsible for analytical precision as per their standard operating procedures.

A.4.c. Bias

Laboratory analysis bias will be assessed and addressed by the individual service provider as per their procedures and methodology.

There is no bias for direct pressure, temperature, and logging measurements.

A.4.d. Representativeness

CTV designed the monitoring network to ensure that samples acquired were representative of site conditions. Standard operating procedures during acquisition at the wellsite will ensure that samples are representative of the formation.

A.4.e. Completeness

Data completeness (amount of data obtained versus the expected data) of 90% for ground water sampling will be acceptable.

Direct measurements, such as pressure and temperature data, will be recorded 90% of the time.

A.4.f. Comparability

Data sets will always be compared to the baseline and previous analysis. Individual threshold changes will be assessed as well as small trend changes.

A.4.g. Method Sensitivity

The following tables provide detail on gauge sensitivities.

Table 8. Pressure and Temperature—Downhole Gauge Specifications.

Parameter	Value
Calibrated working pressure range	0 – 10,000 PSI
Initial pressure accuracy	< 2 PSI
Pressure resolution	0.005 PSI
Pressure drift stability	< 1 PSI per year
Calibrated working temperature range	77 – 266 degrees Fahrenheit
Initial temperature accuracy	< 0.9 Fahrenheit
Temperature resolution	0.009 Fahrenheit
Temperature drift stability	0.1 degrees Fahrenheit per year
Max temperature	302 degrees Fahrenheit
Instrument calibration frequency	Annual

Table 9. Representative Logging Tool Specifications.

Parameter	RST (Pulse Neutron)	CBL
Logging speed	200 feet/hour	1,800 feet/hour
Vertical resolution	15 inches	6 inches
Investigation	Mechanical integrity	Cement bond with casing and formation
Temperature rating	302 Fahrenheit	350 Fahrenheit
Pressure rating	15,000 PSI	20,000 PSI

Table 10. Pressure Field Gauge.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.04365 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 11. Pressure Field Gauge—Injection Tubing Pressure.

Parameter	Value
Calibrated working pressure range	0 – 3,000 PSI and 4-20 mA
Initial pressure accuracy	<0.03125%
Pressure resolution	0.001 PSI and 0.00001 mA
Pressure drift stability	0.125% of upper range limit for 60 months

Table 12. Pressure Field Gauge—Annulus Pressure.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.025 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 13. Temperature Field Gauge—Injection Tubing Temperature.

Parameter	Value
Calibrated working temperature range	0 to 500 degrees Fahrenheit and 4-20ma
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 degrees Fahrenheit and 0.0001 mA
Temperature drift stability	0.15% of output reading or 0.15 degrees Celsius

Table 14. Mass Flow Rate Field Gauge—CO_2 Mass Flow Rate.

Parameter	Value
Calibrated working flow rate range	0 to 3,000 PSI
Initial mass flow rate accuracy	0.1 % of upper range limit
Mass flow rate resolution	0.1 PSI
Mass flow rate drift stability	Estimate <0.3% of output reading for 12 months

A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

CTV will utilize lab and logging companies to acquire field data samples. All equipment will be provided and operated by the service provider.

A.5.b/c. Training Provider and Responsibility

Training will be provided and assessed by the individual service providers.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

CTV will prepare and submit semi-annual reports to the EPA. The reports will include all testing, data, and monitoring information as specified in the Testing and Monitoring Plan.

A.6.b. Other Project Documents, Records, and Electronic Files

CTV will prepare and provide all necessary documents, records or electronic files as required.

A.6.c/d. Data Storage and Duration

CTV will maintain the required project data collected in a datastore.

A.6.e. QASP Distribution Responsibility

The project manager will be responsible for ensuring that those on the distribution list, and other essential staff, receive the most current copy of the QASP.

B. Data Generation and Acquisition

B.1. Sampling Process Design

B.1.a. Design Strategy

Shallow Groundwater Monitoring Strategy

A pre-existing shallow groundwater monitoring well will assess potential changes in the Upper Tulare USDW and Lower Tulare Formation. The Upper Tulare USDW is not a water source in the AoR.

The Upper Tulare Formation USDW is an unconfined aquifer in the AoR. Due to drought conditions, water levels are continuously falling. As such, the 61WS-8R well was selected for the following reasons:

1. It is down gradient and has a thicker section of the Upper Tulare Formation USDW.
2. The well is completed across the Upper Tulare Formation USDW and Lower Tulare Formation. The Lower Tulare is not exempt outside the project area, and any pressure or fluid changes in the Lower Tulare Formation will occur before the Upper Tulare Formation USDW.

CTV will monitor pressure changes associated with the A1-A2 Storage project and fluid analysis.

Deep Groundwater Monitoring Strategy

Between the Reef Ridge confining layer and USDW is the Etchegoin Formation. A laterally continuous Etchegoin Formation water sand (3,500 feet TVD) will be pressure monitored for potential CO_2 leakage via the 346-7R-RD1 well. The sands have adequate continuity, porosity and permeability to ensure that the AoR is monitored with one well.

Any unlikely leakage from the A1A2 reservoir up through the Reef Ridge confining layer will dissipate in the Etchegoin Formation and increase its pressure.

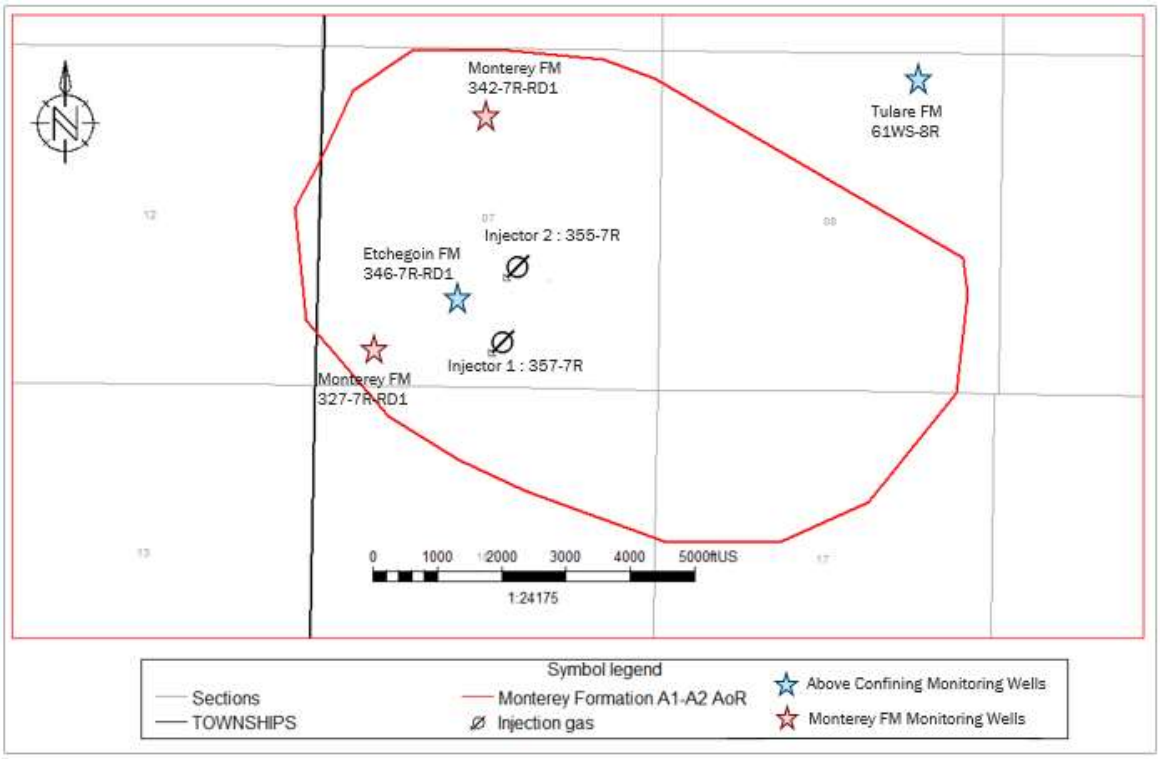
B.1.b. Type and Number of Samples/Test Runs

The sampling activities are summarized in Table 1.

B.1.c. Site/Sampling Locations

Locations for sampling are shown on the map below (Figure 2).

Figure 2: Monitoring well locations.



B.1.d. Sampling Site Contingency

CTV owns the mineral rights, pore space and surface access to the storage project.

B.1.e. Activity Schedule

The sampling activities are summarized in Table 1.

B.1.f. Critical/Informational Data

Documentation of information will include the following:

1. Sampling metadata that includes sample label, purging time and other sample collection procedures.
2. Data collected in the field (temperature and pH).
3. Chain of custody.
4. Data and analysis collected in the laboratory.
5. Calibration of Instrumentation and equipment.

B.1.g. Sources of Variability

Potential sources of variability include the following:

1. Natural and operational variability in fluid quality, temperature, and pressure.
2. Reservoir changes from outside the AoR (outside operator, precipitation/drought)
3. Changes in the sampling methods, service provider and instrumentation.

Variability will be minimized by the following:

1. Adhering to standard operating procedures.
2. Assessing data and results against baseline and previous results for trend and changes.
3. Service provider staff training.
4. Assessing calibration and calibrating procedures.
5. Quality control checks for samples.

B.2. Sampling Methods

B.2.a/b. Sampling SOPs

Refer to the table below for stabilization criteria during well purging.

Laboratory SOPs have been developed by the service provider.

All procedures for sampling shall be consistent with the U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCEAA Project Mangers (May 2002).

Table 15. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.

Field Parameter	Stabilization Criteria
pH	+/- 0.01
Temperature	+/- 1 C
Specific conductance	+/- 3%

B.2.c. In-situ Monitoring

In-situ monitoring of water chemistry is not currently planned.

B.2.d. Continuous Monitoring

Pressure will be collected from monitoring wells.

B.2.e. Sample Homogenization, Composition, Filtration

To obtain a representative sample, each well will be purged at a flow rate between 10 GPM and 5- GPM. Samples will be collected within 24 hours of the well being purged. If a monitoring well will not supply adequate water for sampling, the condition of the well will be investigated and it may be considered for replacement.

Purging will continue until three successive measurements of the indicator parameters meet the stabilization criteria per Table 15.

B.2.f. Sample Containers and Volumes

Sample collection devices will be carefully chosen to minimize the potential for altering the quality of the sample. Teflon and stainless steel are preferred materials, although PVC, HDPE and other similar materials are considered sufficient in some cases.

Refer to the tables below as needed for sample container, preservation, and holding time information.

B.2.g. Sample Preservation

Samples will be preserved as per Table 17.

B.2.h. Cleaning/Decontamination of Sampling Equipment

Equipment used for sampling and other activities associated with on-site work will be de-contaminated before and after performance of a given activity. Disposable items will be disposed of as solid waste in an approved, permitted client facility.

B.2.i. Support Facilities

Support facilities will be provided by the service provider responsible for sampling and analysis.

B.2.j. Corrective Action, Personnel, and Documentation

The service provider will be responsible for testing instruments and equipment and preforming corrective action on defective equipment. Corrective action taken on equipment will be documented.

B.3. Sample Handling and Custody

B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 16 and 17 for holding times.

B.3.b. Sample Transportation

CTV will ensure that samples are delivered to the laboratory for analysis by the service provider as soon as possible following sample collection. Samples will be transported to the laboratory on the same day as the sample collection.

During transportation, precautions will be implemented to ensure that sample integrity is not affected by extreme temperatures and/or excessive vibration.

Upon arrival at the service provider the samples will be reviewed to ensure the following:

1. The sample arrived intact without container leakage or breakage.

2. Chain of custody documentation and sample labels agree
3. Confirmation that the sample was preserved correctly.

B.3.c. Sampling Documentation

For each test in the field, a worksheet will be compiled for each test interval documenting the procedures and results.

B.3.d. Sample Identification

Samples will be identified with the well location, date sample identification, sampler, and sample type.

Table 16. Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Gas Stream Analysis.

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	One-liter tedlar bag	None	72 hours

Table 17. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: Ca, Fe, Mg, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Ti	100 mL plastic	Nitric acid	180 days
Anions: Br, Cl, F NO_2 and SO_4	100 mL plastic	None	48 hours
Dissolved CO_2	100 ml plastic	None	14 days
Isotopes: Carbon isotope 13	100 ml plastic	None	14 days
Alkalinity	100 mL plastic	None	14 days

B.3.e. Sample Chain-of-Custody

Sample transport and handling will be strictly controlled by the service provider field technician to reduce the opportunity for tampered samples. Upon delivery to the laboratory samples will be given unique laboratory sample numbers and recorded in a logbook indicating the client, well number, date, and time of delivery.

B.4. Analytical Methods

B.4.a. Analytical SOPs

All procedures to sample and analyze groundwater will be consistent with the U.S. Environmental Protection Agency Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002).

B.4.b. Equipment/Instrumentation Needed

Service providers are expected to provide and utilize the equipment and instruments necessary to perform the required testing and analysis.

Examples of equipment and instrumentation includes safety equipment, sample jars, decontamination supplies, pH meter, EC meters, temperature gauges, and materials to document chain of custody, results, and labels.

B.4.c. Method Performance Criteria

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well define. Method performance criteria is not necessary.

B.4.d. Analytical Failure

Service providers conducting analysis are responsible for assessing and addressing analytical failure per their internal procedures and standards.

B.4.e. Sample Disposal

Service providers conducting analysis are responsible for proper sample disposal per internal procedures and standards.

B.4.f. Laboratory Turnaround

Laboratory turnaround times will vary by the analysis being conducted. CTV will communicate to service providers that a 30-day turnaround time for most analysis' is expected.

B.4.g. Method Validation for Nonstandard Methods

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well defined. Method performance criteria is not necessary.

B.5. Quality Control

B.5.a. QC activities

Field quality control may involve the collection of two types of QC blanks, trip, and field blanks, to verify that the sample collection and handling processes have not impaired quality of the final samples.

Trip blank – Trip blanks are prepared for VOC analysis and transported with the empty sample container.

Field Blank- the field blank will be taken in the field to evaluate if certain sampling or cleaning procedures result in cross-contamination of site samples or if atmospheric contamination has occurred.

B.5.b. Exceeding Control Limits

In the case that control limits are exceeded, CTV will review the sampling procedures and results. In the case of a valid test, refer to the Emergency Response Plan for water contamination procedures.

B.5.c. Calculating Applicable QC Statistics

Charge Balance - Solutions must be electrically neutral, the total sum of all the positive charges (cations) must equal the total sum of all negative charges (anions).

$$\text{Charge Balance:} \qquad \sum cations = \sum anions$$

Charge balance error (shown below) will be less than ±5% for acceptable water analyses.

$$CBE = \frac{\sum cations - |\sum anions|}{\sum cations + |\sum anions|} \times 100$$

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

The service provider will test, inspect, and maintain the instrumentation and equipment used for testing, this will be completed as per the manufacturer's guidelines and the standard operating procedures.

B.7. Instrument/Equipment Calibration and Frequency

B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges will be calibrated according to the manufacturer's recommendations. Calibration certificates will be kept on file.

Lab instrumentation and calibration will be checked weekly to ensure that results are within the control range of parameters.

B.7.b. Calibration Methodology

Instruments will be calibrated for accurate readings. Calibrations will be conducted with individual instrument SOP's and in accordance with the manufacturer's supplied manual for each instrument.

B.7.c. Calibration Resolution and Documentation

Instrument calibration resolution will be consistent with the manufacturer's recommendations. Documentation for instrument calibration will be maintained in a database.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

The service provider responsible for completing sample collection and analysis will be responsible for supplies and consumables.

Supplies and consumables used for sample collection and analysis will be selected to minimize the potential for altering the quality of the sample and analysis results.

B.9. Nondirect Measurements

B.9.a. Data Sources

Induced seismicity will be monitored continuously to ensure data consistency. CTV will partner with or use a third party to process the data.

B.9.b. Relevance to Project

Passive seismic monitoring will be used to assess induced seismicity events as an indicator of stress changes in the subsurface. Thresholds and response for induced seismic eventsare discussed further in the Emergency Response Plan.

B.9.c. Acceptance Criteria

Industry standard practices will be utilized for data gathering, processing and interpretation.

B.9.d. Resources/Facilities Needed

CTV will use a service provider for all necessary resources and facilities for passive seismic monitoring.

B.9.e. Validity Limits and Operating Conditions

CTV and service provider professionals will ensure that all results and processes are conducted as per standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

CTV will maintain the A1-A2 Storage project data internally. Data will be backed up and held on secure servers.

B.10.b. Recordkeeping and Tracking Practices

All data associated with the project will be held securely and associated meta-data will be gathered and maintained to ensure tracking purposes.

B.10.c. Data Handling Equipment/Procedures

CTV employs robust data management procedures to ensure security of data gathered from the field and external data sources.

B.10.d. Responsibility

Project managers will be responsible for ensuring data management is properly maintained.

B.10.e. Data Archival and Retrieval

CTV will hold all data associated with the A1-A2 Storage project. A data store will be developed for reporting and retrieval.

B.10.f. Hardware and Software Configurations

CTV will ensure that software and hardware are appropriate to integrate the multiple data sources and maintain large quantities of data.

B.10.g. Checklists and Forms

CTV will generate forms, checklists, and procedures as necessary to ensure management, security and quality of all data collected.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Monitoring results will be obtained as per Table 1. Results will be reviewed for QC criteria as per section B.5. In the case of data failure, new samples will be collected and analyzed. Evaluation for data consistency will be performed per the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

CTV will utilize service providers to analyze sample data. These organizations will be responsible for conducting their own internal assessments.

C.1.c. Assessment Reporting

Assessment information will be reported to the project leads as outlined in A.1.

C.1.d. Corrective Action

CTV owns the surface and mineral rights in the Elk Hills Oil Field. Corrective action issues, data collection, and monitoring data will all be handled by CTV.

C.2. Reports to Management

C.2.a/b. QA status Reports

CTV will notify the EPA and project leaders of QA report status if there are changes to the Testing and Monitoring Plan or the QASP.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Data validation will include the review of the results, chain of custody information, and review of the blank and duplicate information. All results will be stored in a database and compared to baseline and previous results. Data will be graphed to inspect trends and anomalies.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

Data will be verified by CTV upon receipt of results.

If anomalous data is suspected, CTV and the service provider will review the metadata associated with the sample to assess whether sampling, collection and the analysis conducted caused spurious results. In addition, instrument calibration will be reviewed if necessary.

D.2.b. Data Verification and Validation Responsibility

Data will be verified by CTV upon receipt of results.

D.2.c. Issue Resolution Process and Responsibility

CTV will oversee sample handling and assessment process. CTV management will determine actions necessary to resolve issues.

D.2.d. Checklist, Forms, and Calculations

CTV will develop checklists and a GIS database to store data, complete surveillance and ensure that permit requirements are met.

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

CTV will develop a GIS database that will be used for surveillance. The database will ensure data quality using methods consistent with USEPA 2009 Unified Guidance.

D.3.b. Data Limitations Reporting

Service provider management will be responsible for ensuring that analysis in their laboratory is presented with data use limitations for reporting.

Project leaders and managers will be responsible for ensuring that results are vetted and evaluated to determine if performance criteria are met.

References

ASTM, 2005, Method D6517-00 (reapproved 2005), Standard guide for field preservation of groundwater samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

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Appendices

Schlumberger Wireline Log Quality Reference Manual

Schlumberger

Wireline Log Quality Control Reference Manual



Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST® and RSTPro® reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst® thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL® water flow log, and PVL® phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed[1]	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation[1]	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

[1] See Tool Planner application for advice on logging speed.
[2] Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	1 13/16 in [4.60 cm] With flask: 2 1/4 in [5.72 cm]	2 7/8 in [7.30 cm]
Borehole size—max.	9 5/8 in [24.45 cm] With flask: 9 5/8 in [24.45 cm]	9 5/8 in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

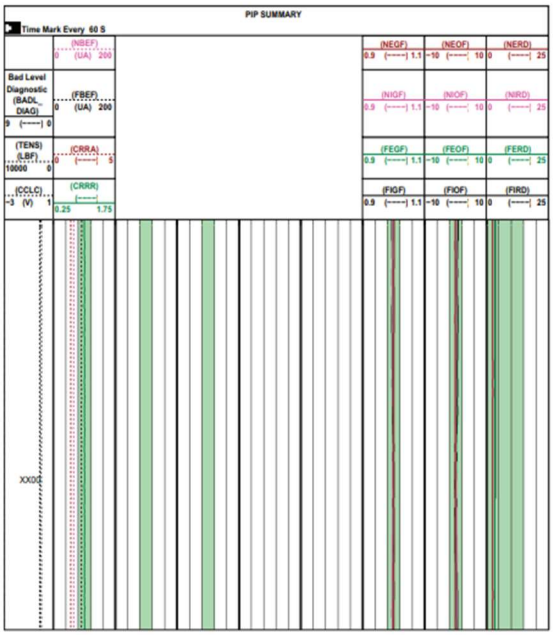

Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

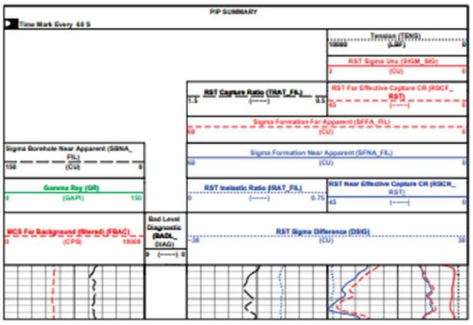

Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

Schlumberger

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density® log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h][1]
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

[1] Speed can be reduced depending on data quality.

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation[1]
SBI	Short bond index[1]
SCBL	Short synthetic CBL[1]
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

[1] In fast formations only.

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

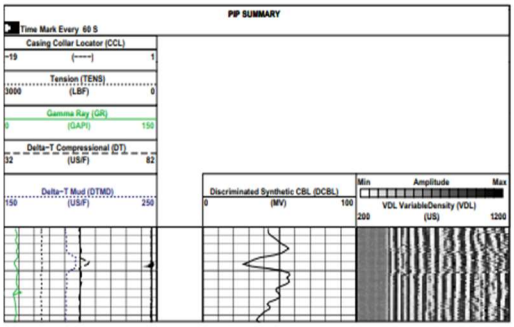

Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

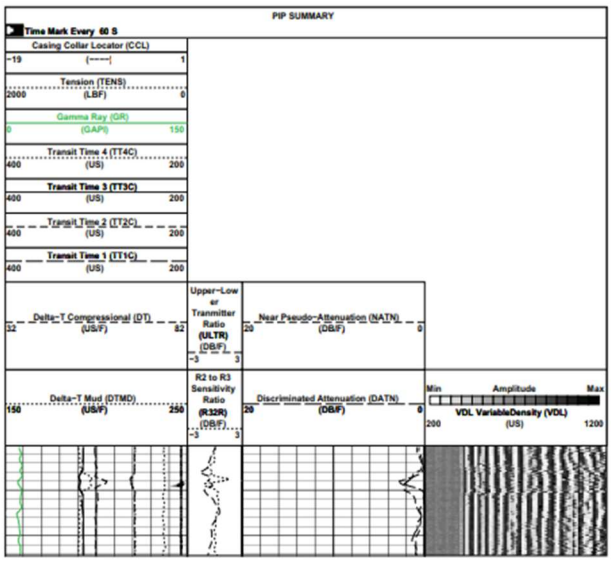

Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40[1]	52 ± 5	329	272	NM[2]

[1] Although the CBT operates in up to 13½-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.
[2] NM = not meaningful

Schlumberger

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications		
	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	**Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)**
Output	SLS-C, SLS-D, SLS-W, and SLS-E.[1] 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

[1] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications

	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID—min.	5 in [12.70 cm]	5 in [12.70 cm]	3½ in [8.89 cm]	4 in [10.16 cm]
Casing ID—max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3⅝ in [9.21 cm]	3¾ in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers: 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers: 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 lbf [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,570 N]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

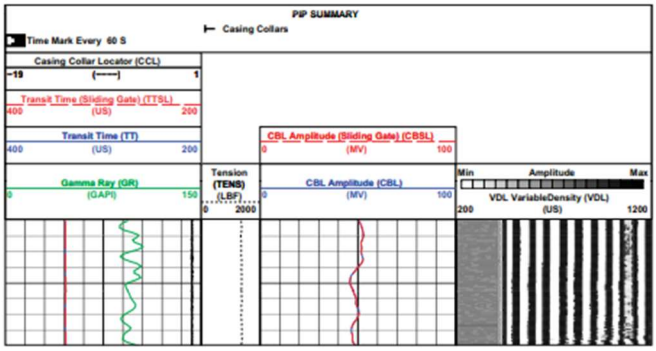

Figure 1. DSLT standard format.

Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4

Class VI Injection Well: Quality Assurance and Surveillance Plan

Update November 4, 2022

Prepared by:

Carbon TerraVault 1 LLC

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Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Elk Hills A1-A2 Storage facility. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

THurst

November 4, 2022

_____ _____

Signature Date

Travis Hurst

Distribution List

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Travis Hurst: CCS Project Manager

Carbon TerraVault
28590 Highway 119
Tupman, CA 93276

A. Project Management

A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The Elk Hill A1-A1 Storage project, led by Carbon TerraVault 1 LLC (CTV), includes participation from service providers. The responsibilities for Testing and Monitoring will be shared between CTV and the service providers.

CTV will be responsible for any data and submissions made to the EPA.

A.1.c. Independence from Project QA Manager and Data Gathering

CTV utilizes a third-party service provider to collect, transport and analyze samples as part of the Testing and Monitoring Plan.

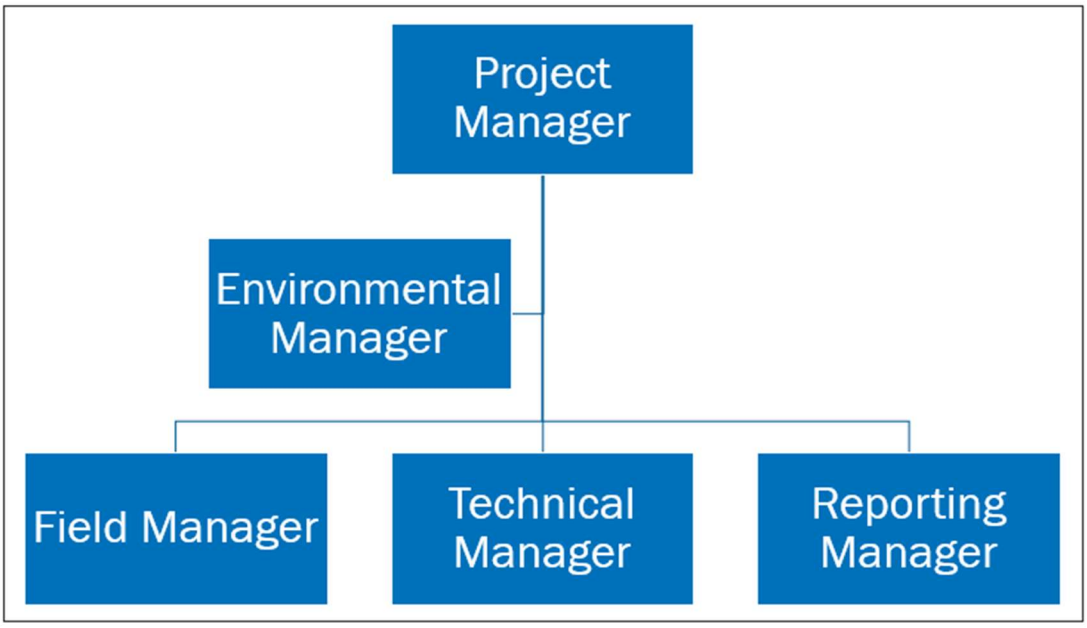
A.1.d. QA Project Plan Responsibility

CTV will be responsible for the Quality Assurance and Surveillance Plan. CTV will review the plan with service providers periodically.

A.1.e. Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure for the Elk Hills A1-A2 project. Although these roles have not been filled because the project is not operational, the chart shows the breakdown in responsibilities for future positions.

Figure 1: Organizational Chart.



A.2. Problem Definition/Background

A.2.a. Reasoning

The Elk Hills A1-A2 project will inject and sequester CO_2 from sources that include the Elk Hills Power Plant, renewable diesel refinery projects, and other industrial sources close to the field. The project requires a comprehensive monitoring plan that gathers data to assess confinement of the CO_2 injectate. To ensure accurate measurement and reporting this QASP outlines detail associated with the surveillance related to sampling, operating, and recording.

A.2.b. Reasons for Initiating the Project

CTV initiated the project for ESG purposes and to reduce carbon footprint for CTV operations and for external emissions. The Elk Hills Oil Field is a premier location for carbon sequestration in the San Joaquin Basin. The field has available pore space, proven confinement, and ideal surface/mineral ownership.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

CO_2 injection as per standard operating procedures and regulations requires that the injectate is confined in the reservoir and that groundwater is not impacted. As such the following monitoring is necessary:

1. Injection well mechanical integrity testing
2. Injection well testing and operating data collection
3. Groundwater monitoring
4. Validation of the CO_2 plume areal coverage as defined by numerical modeling

The information and data below define the steps to ensure that monitoring data quality provides the confidence and information to verify confinement.

A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed

Table 1. Summary of Testing and Monitoring.

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Injection well					
Carbon dioxide stream analysis	Compressor	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor Injectate
Injection rate and volume	Injection Well	Flow meter	Direct Measurement	NA	Monitor rate and volume
Injection pressure	Injection Wellhead	Pressure gauge	Direct Measurement	NA	Monitor injection pressure
Annular pressure	Injection Wellhead	Pressure gauge	Direct Measurement	NA	Monitor annular pressure
Temperature	Along Wellbore	DTS	Direct Measurement	NA	Monitor temperature
Downhole pressure/ temperature	Injection Well	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure and temperature
Corrosion monitoring	Between compressor and wellhead	Corrosion Coupon	NA	Zalco Labs	Monitor corrosion of materials
Mechanical Integrity	Injection Well	Temperature	NA	NA	Wellbore Integrity
Internal MIT	Injection Well	SAPT	NA	NA	Wellbore Integrity
Pressure Fall Off Test	Injection Well	Pressure gauge	Pressure Transient Analysis	NA	Reservoir Assessment

Table 2. Monitoring Well Summary

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Monitoring Wells Above Confining Layer					
Fluid Sampling Tulare Formation (USDW)	USDW Monitoring Well	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pressure/Temperature Tulare Formation (USDW)	USDW Monitoring Well	Guage	Direct Measurement	NA	Monitor pressure / temperature
Pressure/Temperature Etchegoin Formation	327-7R-RD1	Gauge	Direct Measurement	NA	Monitor pressure/Temperature
Temerature Etchegoin Formation	327-7R-RD1	DTS	Direct Measurement	NA	Monitor Temperature
Fluid Sampling Etchegoin Formation	327-7R-RD1	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality

Monterey Formation A1-A2 Reservoir					
Pressure/Temperature	353A-7R 335X7R	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure/temperature
Temperature	353A-7R 335X7R	DTS	Direct Measurement	NA	Temperature
Fluid Sampling	353A-7R 335X7R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pulse Neutron Log	353A-7R 335X-7R	Logging	Logging	NA	Saturation
Internal MIT	353A-7R 335X-7R	SAPT	NA	NA	Wellbore Integrity
Monterey Formation A3-A11 Reservoir					
Fluid Sampling	331-17R, 345-7R, 388X-7R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor produced fluids composition.

A.3.c. Geographic Locations

A.3.d. Resource and Time Constraints

There are neither resource nor time constraints for theElk Hills A1-A2 storage project. CTV owns the mineral rights, pore space and surface access to the Elk Hills Oil Field.

Wells to be utilized for the project are available, and will be re-purposed. These wells will be accessible for the life of the project and for the post injection monitoring timeframe.

A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

Table 3. Summary of Analytical and Field Parameters for Fluid Samples in Tulare, Etchegoin, and Monterey Formation water.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Ti)	ICP-MS EPA Method 6020	0.05 to 5 mg/L	15%	Daily calibration of equipment/CCV/ Blank LCS, MS/MSD/ QC/ICV
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B	0.1 to 2 mg/L	15%	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	0.02-0.13 mg/L	15%	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Dissolved CO_2	Coulometric titration ASTM D513-11	10 mg/L	NA	Duplicate analysis
Total dissolved solids	Gravimetry; Method 2540 C	10 mg/L	10%	Daily balance calibration, duplicates, blanks
Alkalinity	Method 2320B	10 mg/L	10%	Duplicate analysis
pH (field)	EPA 150.1	2 to 12.5pH	0.2 pH	Daily calibration, duplicates
Specific conductance (field)	APHA 2510	0-200 mS/cm	1%	Daily calibration, duplicates
Temperature (field)	Thermocouple	-5 to 50 C	0.2 C	Monthly calibration
δ13C	Isotope ratio mass spectrometry	12.2 mg/L HCO_3	0.15%	Duplicate analysis
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	1 mg/L	5-10% of reading	Daily calibration, duplicates

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 4. Summary of Analytical Parameters for CO_2 Stream.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID) GC/TCD	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Carbon monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total hydrocarbons	ISBT 10.0 THA (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Methane	ISBT 10.1 (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Hydrogen sulfide	ISBT 14.0 (GC/SCD)	10 ppmv/1 ppmv	15%	Daily calibration/CCV, blank, QC sample
Ethanol	ISBT 11.0 (GC/FID)	0.5 ppmv	20%	Daily calibration/CCV, blank, LCS, MS/MSD, ICV
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total Sulfur	ISBT 14.0 (GC/SCD)	1 ppmv	15%	Daily calibration/CCV, blank, QC sample

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 5. Summary of Analytical Parameters for Corrosion Coupons.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE TM0169/ G31 EPA 1110A SW846	0.001 mg	10%	Duplicate analysis

Table 6. Summary of Measurement Parameters for Field Gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection tubing temperature	ANSI Z540-1-1994	0.001 Fahrenheit / 0 – 500 Fahrenheit	0.01 Fahrenheit	Annual calibration
Injection tubing pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Annulus pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection mass flow rate	NA	0.1 % of flow rate	0.01 lbs/hour	Annual calibration

Table 7. Actionable Testing and Monitoring Outputs.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
External and internal mechanical integrity (temperature log)	Temperature log indicates a mechanical integrity issue.	0.01 Fahrenheit	Results will be compared to baseline. Deviation may be indicative of mechanical issue.
Surface and downhole pressure	Action will be taken when pressure is outside of expected or modeled range.	0.001 PSI	No greater than the maximum operating pressure.
Water quality (Tulare USDW)	Action will be taken when water sample is outside of baseline analysis.	0.2 pH	CO_2 will decrease the water pH.
Above-confining-zone pressure (Etchegoin)	Action will be taken if the pressure of the Etchegoin Formation pressure increases.	0.001 PSI as per installed pressure gauge.	Reservoir pressure.

A.4.b. Precision

Field blanks will be collected once per sampling event to assess water sampling analysis accuracy. Service provider will be responsible for analytical precision as per their standard operating procedures.

A.4.c. Bias

Laboratory analysis bias will be assessed and addressed by the individual service provider as per their procedures and methodology.

There is no bias for direct pressure, temperature, and logging measurements.

A.4.d. Representativeness

CTV designed the monitoring network to ensure that samples acquired were representative of site conditions. Standard operating procedures during acquisition at the wellsite will ensure that samples are representative of the formation.

A.4.e. Completeness

Data completeness (amount of data obtained versus the expected data) of 90% for ground water sampling will be acceptable.

Direct measurements, such as pressure and temperature data, will be recorded 90% of the time.

A.4.f. Comparability

Data sets will always be compared to the baseline and previous analysis. Individual threshold changes will be assessed as well as small trend changes.

A.4.g. Method Sensitivity

The following tables provide detail on gauge sensitivities.

Table 8. Pressure and Temperature—Downhole Gauge Specifications.

Parameter	Value
Calibrated working pressure range	0 – 10,000 PSI
Initial pressure accuracy	< 2 PSI
Pressure resolution	0.005 PSI
Pressure drift stability	< 1 PSI per year
Calibrated working temperature range	77 – 266 degrees Fahrenheit
Initial temperature accuracy	< 0.9 Fahrenheit
Temperature resolution	0.009 Fahrenheit
Temperature drift stability	0.1 degrees Fahrenheit per year
Max temperature	302 degrees Fahrenheit
Instrument calibration frequency	Annual

Table 9. Representative Logging Tool Specifications.

Parameter	RST (Pulse Neutron)	CBL
Logging speed	200 feet/hour	1,800 feet/hour
Vertical resolution	15 inches	6 inches
Investigation	Mechanical integrity	Cement bond with casing and formation
Temperature rating	302 Fahrenheit	350 Fahrenheit
Pressure rating	15,000 PSI	20,000 PSI

Table 10. Pressure Field Gauge.

Parameter	Value
Calibrated working pressure range	0 to 5,000 PSI
Initial pressure accuracy	< 0.05 %
Pressure resolution	0.01 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 11. Pressure Field Gauge—Injection Tubing Pressure.

Parameter	Value
Calibrated working pressure range	0 to 5,000 PSI and 4-20 mA
Initial pressure accuracy	< 0.05 %
Pressure resolution	0.01 PSI and 0.00001 mA
Pressure drift stability	0.125% of upper range limit for 60 months

Table 12. Pressure Field Gauge—Annulus Pressure.

Parameter	Value
Calibrated working pressure range	0 to 5,000 PSI
Initial pressure accuracy	< 0.05 %
Pressure resolution	0.01 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 13. Temperature Field Gauge—Injection Tubing Temperature.

Parameter	Value
Calibrated working temperature range	0 to 500 degrees Fahrenheit and 4-20ma
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 degrees Fahrenheit and 0.0001 mA
Temperature drift stability	0.15% of output reading or 0.15 degrees Celsius

Table 14. Mass Flow Rate Field Gauge—CO_2 Mass Flow Rate.

Parameter	Value
Calibrated working flow rate range	Range spanning maximum anticipated injection rate per well with typical precision and accuracy of 0.5%
Initial mass flow rate accuracy	0.5 % of upper range limit
Mass flow rate resolution	0.5% of upper range limit
Mass flow rate drift stability	Estimate <0.5% of output reading for 12 months

A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

CTV will utilize lab and logging companies to acquire field data samples. All equipment will be provided and operated by the service provider.

A.5.b/c. Training Provider and Responsibility

Training will be provided and assessed by the individual service providers.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

CTV will prepare and submit semi-annual reports to the EPA. The reports will include all testing, data, and monitoring information as specified in the Testing and Monitoring Plan.

A.6.b. Other Project Documents, Records, and Electronic Files

CTV will prepare and provide all necessary documents, records or electronic files as required.

A.6.c/d. Data Storage and Duration

CTV will maintain the required project data collected in a datastore.

A.6.e. QASP Distribution Responsibility

The project manager will be responsible for ensuring that those on the distribution list, and other essential staff, receive the most current copy of the QASP.

B. Data Generation and Acquisition

B.1. Sampling Process Design

B.1.a. Design Strategy

Shallow Groundwater Monitoring Strategy

A pre-existing shallow groundwater monitoring well will assess potential changes in the Upper Tulare USDW and Lower Tulare Formation. The Upper Tulare USDW is not a water source in the AoR.

The Upper Tulare Formation USDW is an unconfined aquifer in the AoR. Due to drought conditions, water levels are continuously falling. As such, the 61WS-8R well was selected for the following reasons:

1. It is down gradient and has a thicker section of the Upper Tulare Formation USDW.
2. The well is completed across the Upper Tulare Formation USDW and Lower Tulare Formation. The Lower Tulare is not exempt outside the project area, and any pressure or fluid changes in the Lower Tulare Formation will occur before the Upper Tulare Formation USDW.

CTV will monitor pressure changes associated with the A1-A2 Storage project and fluid analysis.

Deep Groundwater Monitoring Strategy

Between the Reef Ridge confining layer and USDW is the Etchegoin Formation. A laterally continuous Etchegoin Formation water sand (3,500 feet TVD) will be pressure monitored for potential CO_2 leakage via the 346-7R-RD1 well. The sands have adequate continuity, porosity and permeability to ensure that the AoR is monitored with one well.

Any unlikely leakage from the A1-A2 reservoir up through the Reef Ridge confining layer will dissipate in the Etchegoin Formation and increase its pressure.

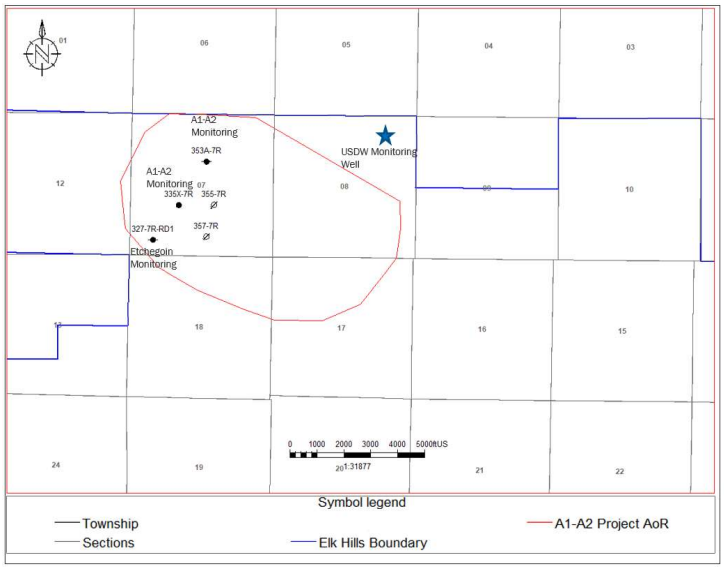
B.1.b. Type and Number of Samples/Test Runs

The sampling activities are summarized in Table 1.

B.1.c. Site/Sampling Locations

Locations for sampling are shown on the map below (Figure 2).

Figure 2: Monitoring well locations.



B.1.d. Sampling Site Contingency

CTV owns the mineral rights, pore space and surface access to the storage project.

B.1.e. Activity Schedule

The sampling activities are summarized in Table 1.

B.1.f. Critical/Informational Data

Documentation of information will include the following:

1. Sampling metadata that includes sample label, purging time and other sample collection procedures.
2. Data collected in the field (temperature and pH).
3. Chain of custody.
4. Data and analysis collected in the laboratory.
5. Calibration of Instrumentation and equipment.

B.1.g. Sources of Variability

Potential sources of variability include the following:

1. Natural and operational variability in fluid quality, temperature, and pressure.
2. Reservoir changes from outside the AoR (outside operator, precipitation/drought)
3. Changes in the sampling methods, service provider and instrumentation.

Variability will be minimized by the following:

1. Adhering to standard operating procedures.
2. Assessing data and results against baseline and previous results for trend and changes.
3. Service provider staff training.
4. Assessing calibration and calibrating procedures.
5. Quality control checks for samples.

B.2. Sampling Methods

B.2.a/b. Sampling SOPs

Refer to the table below for stabilization criteria during well purging.

Laboratory SOPs have been developed by the service provider.

All procedures for sampling shall be consistent with the U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCEAA Project Mangers (May 2002).

Table 15. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.

Field Parameter	Stabilization Criteria
pH	+/- 0.01
Temperature	+/- 1 C
Specific conductance	+/- 3%

B.2.c. In-situ Monitoring

In-situ monitoring of water chemistry is not currently planned.

B.2.d. Continuous Monitoring

Pressure will be collected from monitoring wells.

B.2.e. Sample Homogenization, Composition, Filtration

To obtain a representative sample, each well will be purged at a flow rate between 10 GPM and 5- GPM. Samples will be collected within 24 hours of the well being purged. If a monitoring well will not supply adequate water for sampling, the condition of the well will be investigated and it may be considered for replacement.

Purging will continue until three successive measurements of the indicator parameters meet the stabilization criteria per Table 15.

B.2.f. Sample Containers and Volumes

Sample collection devices will be carefully chosen to minimize the potential for altering the quality of the sample. Teflon and stainless steel are preferred materials, although PVC, HDPE and other similar materials are considered sufficient in some cases.

Refer to the tables below as needed for sample container, preservation, and holding time information.

B.2.g. Sample Preservation

Samples will be preserved as per Table 17.

B.2.h. Cleaning/Decontamination of Sampling Equipment

Equipment used for sampling and other activities associated with on-site work will be de-contaminated before and after performance of a given activity. Disposable items will be disposed of as solid waste in an approved, permitted client facility.

B.2.i. Support Facilities

Support facilities will be provided by the service provider responsible for sampling and analysis.

B.2.j. Corrective Action, Personnel, and Documentation

The service provider will be responsible for testing instruments and equipment and preforming corrective action on defective equipment. Corrective action taken on equipment will be documented.

B.3. Sample Handling and Custody

B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 16 and 17 for holding times.

B.3.b. Sample Transportation

CTV will ensure that samples are delivered to the laboratory for analysis by the service provider as soon as possible following sample collection. Samples will be transported to the laboratory on the same day as the sample collection.

During transportation, precautions will be implemented to ensure that sample integrity is not affected by extreme temperatures and/or excessive vibration.

Upon arrival at the service provider the samples will be reviewed to ensure the following:

1. The sample arrived intact without container leakage or breakage.
2. Chain of custody documentation and sample labels agree
3. Confirmation that the sample was preserved correctly.

B.3.c. Sampling Documentation

For each test in the field, a worksheet will be compiled for each test interval documenting the procedures and results.

B.3.d. Sample Identification

Samples will be identified with the well location, date sample identification, sampler, and sample type.

Table 16. Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Gas Stream Analysis.

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	One-liter tedlar bag	None	72 hours

Table 17. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: Ca, Fe, Mg, K, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Ti	100 mL plastic	Nitric acid	180 days
Anions: Br, Cl, F, NO_3 and SO_4	100 mL plastic	None	48 hours
Dissolved CO_2	100 ml plastic	None	14 days
Isotopes: Carbon isotope 13	100 ml plastic	None	14 days
Alkalinity	100 mL plastic	None	14 days

B.3.e. Sample Chain-of-Custody

Sample transport and handling will be strictly controlled by the service provider field technician to reduce the opportunity for tampered samples. Upon delivery to the laboratory samples will be given unique laboratory sample numbers and recorded in a logbook indicating the client, well number, date, and time of delivery.

B.4. Analytical Methods

B.4.a. Analytical SOPs

All procedures to sample and analyze groundwater will be consistent with the U.S. Environmental Protection Agency Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002).

B.4.b. Equipment/Instrumentation Needed

Service providers are expected to provide and utilize the equipment and instruments necessary to perform the required testing and analysis.

Examples of equipment and instrumentation includes safety equipment, sample jars, decontamination supplies, pH meter, EC meters, temperature gauges, and materials to document chain of custody, results, and labels.

B.4.c. Method Performance Criteria

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well define. Method performance criteria is not necessary.

B.4.d. Analytical Failure

Service providers conducting analysis are responsible for assessing and addressing analytical failure per their internal procedures and standards.

B.4.e. Sample Disposal

Service providers conducting analysis are responsible for proper sample disposal per internal procedures and standards.

B.4.f. Laboratory Turnaround

Laboratory turnaround times will vary by the analysis being conducted. CTV will communicate to service providers that a 30-day turnaround time for most analysis' is expected.

B.4.g. Method Validation for Nonstandard Methods

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well defined. Method performance criteria is not necessary.

B.5. Quality Control

B.5.a. QC activities

Field quality control may involve the collection of two types of QC blanks, trip, and field blanks, to verify that the sample collection and handling processes have not impaired quality of the final samples.

Trip blank – Trip blanks are prepared for VOC analysis and transported with the empty sample container.

Field Blank- the field blank will be taken in the field to evaluate if certain sampling or cleaning procedures result in cross-contamination of site samples or if atmospheric contamination has occurred.

B.5.b. Exceeding Control Limits

In the case that control limits are exceeded, CTV will review the sampling procedures and results. In the case of a valid test, refer to the Emergency Response Plan for water contamination procedures.

B.5.c. Calculating Applicable QC Statistics

Charge Balance - Solutions must be electrically neutral, the total sum of all the positive charges (cations) must equal the total sum of all negative charges (anions).

$$\text{Charge Balance:} \qquad \sum cations = \sum anions$$

Charge balance error (shown below) will be less than ±5% for acceptable water analyses.

$$CBE = \frac{\sum cations - |\sum anions|}{\sum cations + |\sum anions|} \times 100$$

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

The service provider will test, inspect, and maintain the instrumentation and equipment used for testing, this will be completed as per the manufacturer's guidelines and the standard operating procedures.

B.7. Instrument/Equipment Calibration and Frequency

B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges will be calibrated according to the manufacturer's recommendations. Calibration certificates will be kept on file.

Lab instrumentation and calibration will be checked weekly to ensure that results are within the control range of parameters.

B.7.b. Calibration Methodology

Instruments will be calibrated for accurate readings. Calibrations will be conducted with individual instrument SOP's and in accordance with the manufacturer's supplied manual for each instrument.

B.7.c. Calibration Resolution and Documentation

Instrument calibration resolution will be consistent with the manufacturer's recommendations. Documentation for instrument calibration will be maintained in a database.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

The service provider responsible for completing sample collection and analysis will be responsible for supplies and consumables.

Supplies and consumables used for sample collection and analysis will be selected to minimize the potential for altering the quality of the sample and analysis results.

B.9. Nondirect Measurements

B.9.a. Data Sources

Induced seismicity will be monitored continuously to ensure data consistency. CTV will partner with or use a third party to process the data.

B.9.b. Relevance to Project

Passive seismic monitoring will be used to assess induced seismicity events as an indicator of stress changes in the subsurface. Thresholds and response for induced seismic eventsare discussed further in the Emergency Response Plan.

B.9.c. Acceptance Criteria

Industry standard practices will be utilized for data gathering, processing and interpretation.

B.9.d. Resources/Facilities Needed

CTV will use a service provider for all necessary resources and facilities for passive seismic monitoring.

B.9.e. Validity Limits and Operating Conditions

CTV and service provider professionals will ensure that all results and processes are conducted as per standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

CTV will maintain the A1-A2 Storage project data internally. Data will be backed up and held on secure servers.

B.10.b. Recordkeeping and Tracking Practices

All data associated with the project will be held securely and associated meta-data will be gathered and maintained to ensure tracking purposes.

B.10.c. Data Handling Equipment/Procedures

CTV employs robust data management procedures to ensure security of data gathered from the field and external data sources.

B.10.d. Responsibility

Project managers will be responsible for ensuring data management is properly maintained.

B.10.e. Data Archival and Retrieval

CTV will hold all data associated with the A1-A2 Storage project. A data store will be developed for reporting and retrieval.

B.10.f. Hardware and Software Configurations

CTV will ensure that software and hardware are appropriate to integrate the multiple data sources and maintain large quantities of data.

B.10.g. Checklists and Forms

CTV will generate forms, checklists, and procedures as necessary to ensure management, security and quality of all data collected.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Monitoring results will be obtained as per Table 1. Results will be reviewed for QC criteria as per section B.5. In the case of data failure, new samples will be collected and analyzed. Evaluation for data consistency will be performed per the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

CTV will utilize service providers to analyze sample data. These organizations will be responsible for conducting their own internal assessments.

C.1.c. Assessment Reporting

Assessment information will be reported to the project leads as outlined in A.1.

C.1.d. Corrective Action

CTV owns the surface and mineral rights in the Elk Hills Oil Field. Corrective action issues, data collection, and monitoring data will all be handled by CTV.

C.2. Reports to Management

C.2.a/b. QA status Reports

CTV will notify the EPA and project leaders of QA report status if there are changes to the Testing and Monitoring Plan or the QASP.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Data validation will include the review of the results, chain of custody information, and review of the blank and duplicate information. All results will be stored in a database and compared to baseline and previous results. Data will be graphed to inspect trends and anomalies.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

Data will be verified by CTV upon receipt of results.

If anomalous data is suspected, CTV and the service provider will review the metadata associated with the sample to assess whether sampling, collection and the analysis conducted caused spurious results. In addition, instrument calibration will be reviewed if necessary.

D.2.b. Data Verification and Validation Responsibility

Data will be verified by CTV upon receipt of results.

D.2.c. Issue Resolution Process and Responsibility

CTV will oversee sample handling and assessment process. CTV management will determine actions necessary to resolve issues.

D.2.d. Checklist, Forms, and Calculations

CTV will develop checklists and a GIS database to store data, complete surveillance and ensure that permit requirements are met.

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

CTV will develop a GIS database that will be used for surveillance. The database will ensure data quality using methods consistent with USEPA 2009 Unified Guidance.

D.3.b. Data Limitations Reporting

Service provider management will be responsible for ensuring that analysis in their laboratory is presented with data use limitations for reporting.

Project leaders and managers will be responsible for ensuring that results are vetted and evaluated to determine if performance criteria are met.

References

ASTM, 2005, Method D6517-00 (reapproved 2005), Standard guide for field preservation of groundwater samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), Standard guide for field filtration of ground-water samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D513-11, Standard test methods for total and dissolved carbon dioxide in water, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

U.S. Bureau of Reclamation (USBR), 1995, *Ground Water Manual*, U.S. Dept. of Interior, Bureau of Reclamation, Washington, D.C.

U.S. Environmental Protection Agency (USEPA), 2009, Statistical analysis of groundwater monitoring data at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.

U.S. Environmental Protection Agency (EPA). 1995. Ground Water Sampling - A Workshop Summary. U.S. Environmental Protection Agency, Washington, D.C. EPA/600/R-94/205.

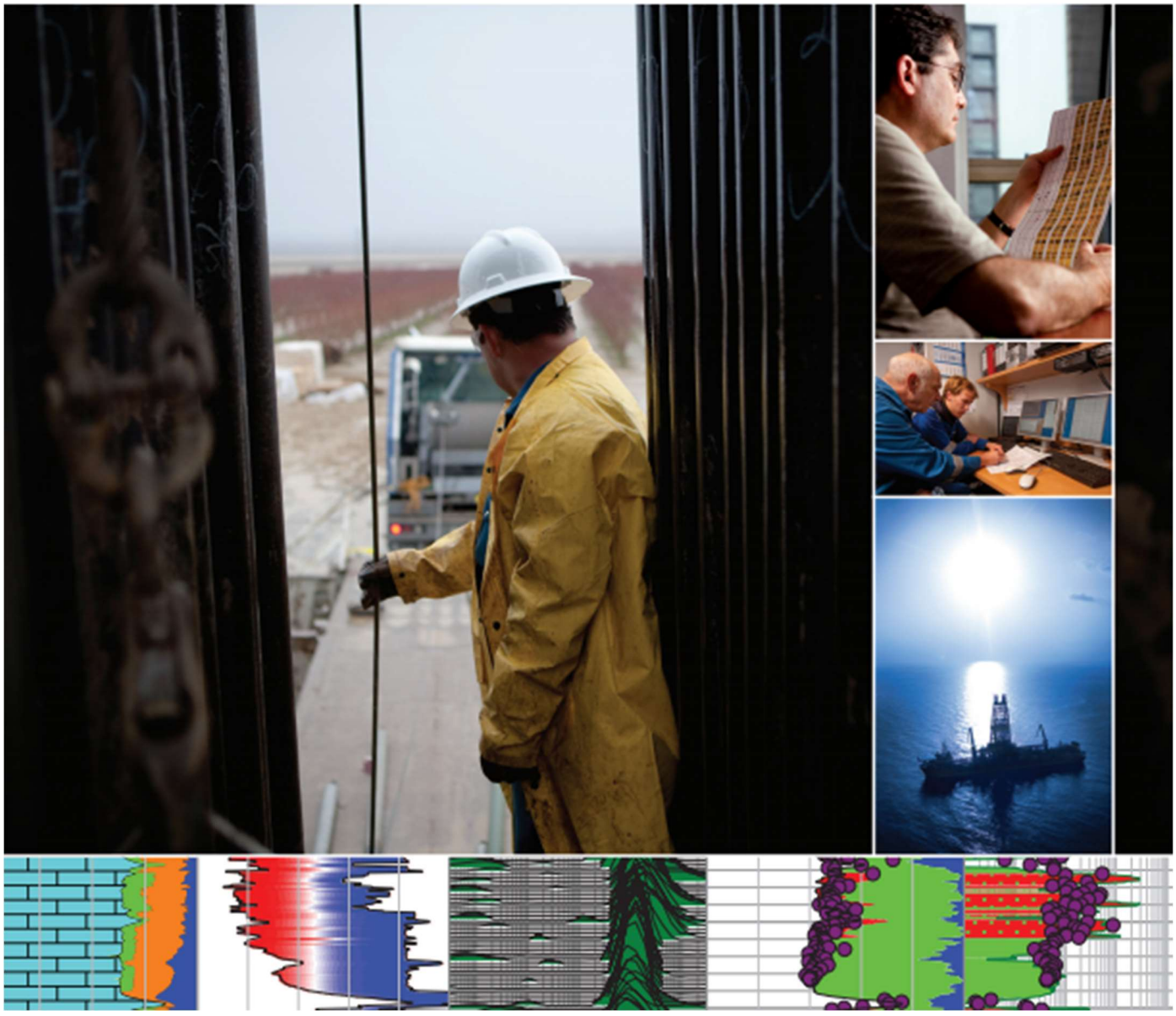
U.S. Environmental Protection Agency (EPA). 1993. Subsurface Characterization and Monitoring Techniques; A Desk Reference Guide. Volume 1: Solids and Ground Water. U.S. Environmental Protection Agency, Washington, D.C. EPA/625/R-93/003a.

Appendices

Schlumberger Wireline Log Quality Reference Manual

Schlumberger

Wireline Log Quality Control Reference Manual



Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed[1]	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation[2]	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

[1] See Tool Planner application for advice on logging speed.
[2] Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	1 13/16 in [4.60 cm] With flask: 2¼ in [5.72 cm]	2⅞ in [7.30 cm]
Borehole size—max.	9⅝ in [24.45 cm] With flask: 9⅝ in [24.45 cm]	9⅝ in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

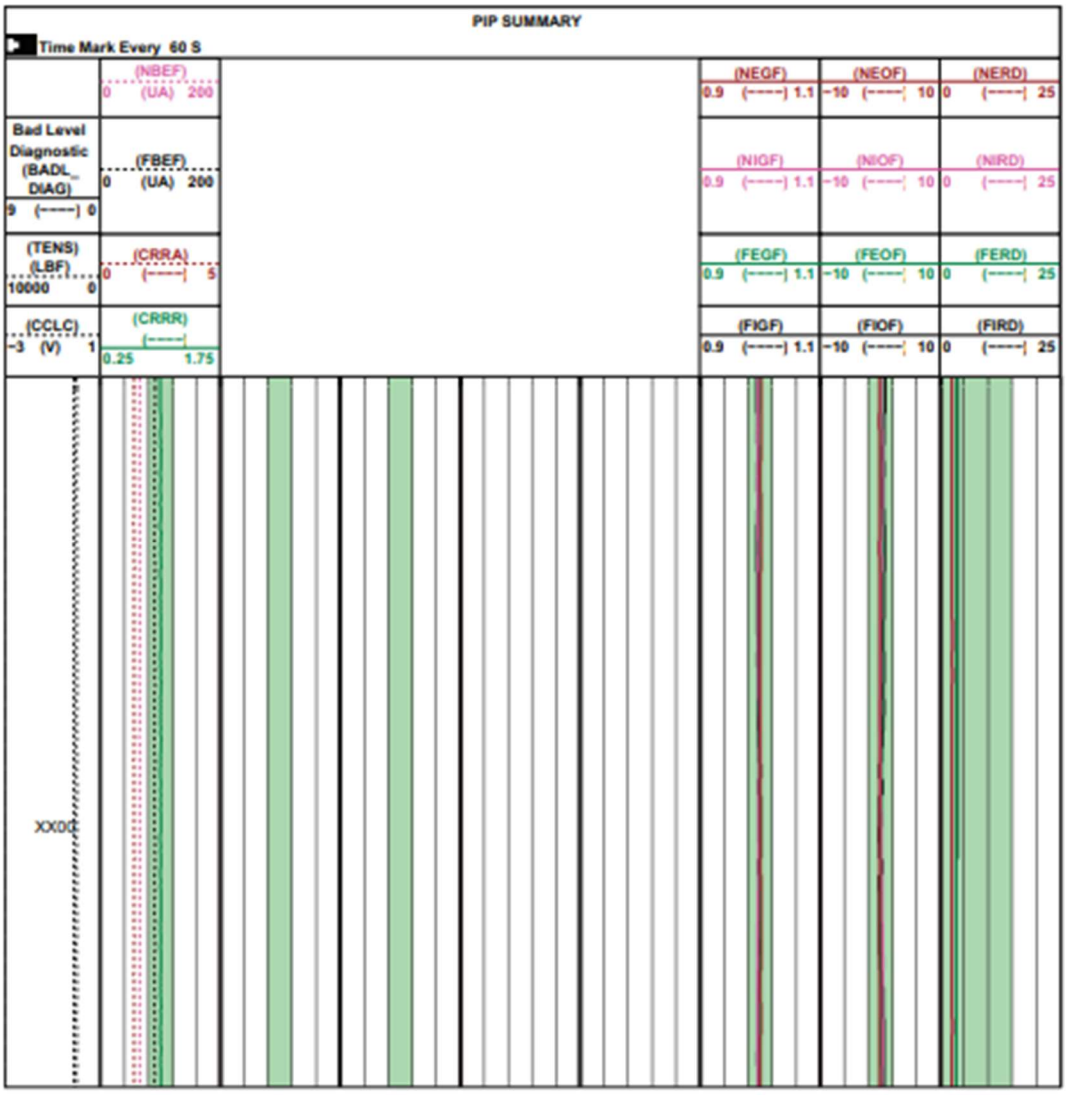


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

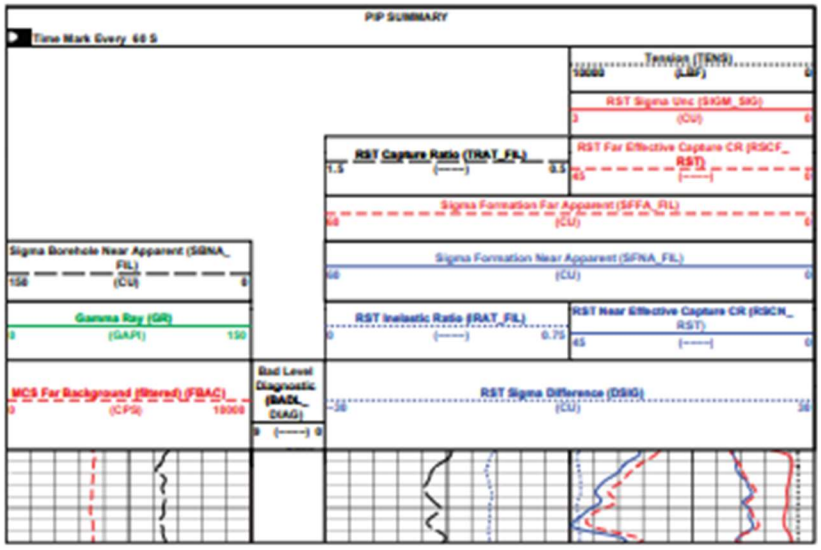


Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

Schlumberger

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h][†]
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

[†] Speed can be reduced depending on data quality.

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation[†]
SBI	Short bond index[†]
SCBL	Short synthetic CBL[†]
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

[†] In fast formations only

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

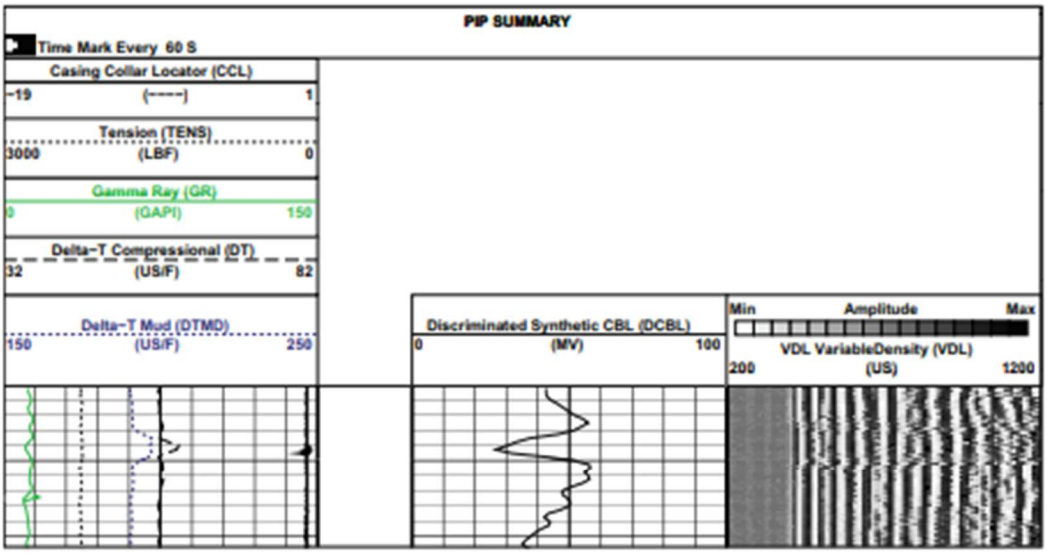


Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

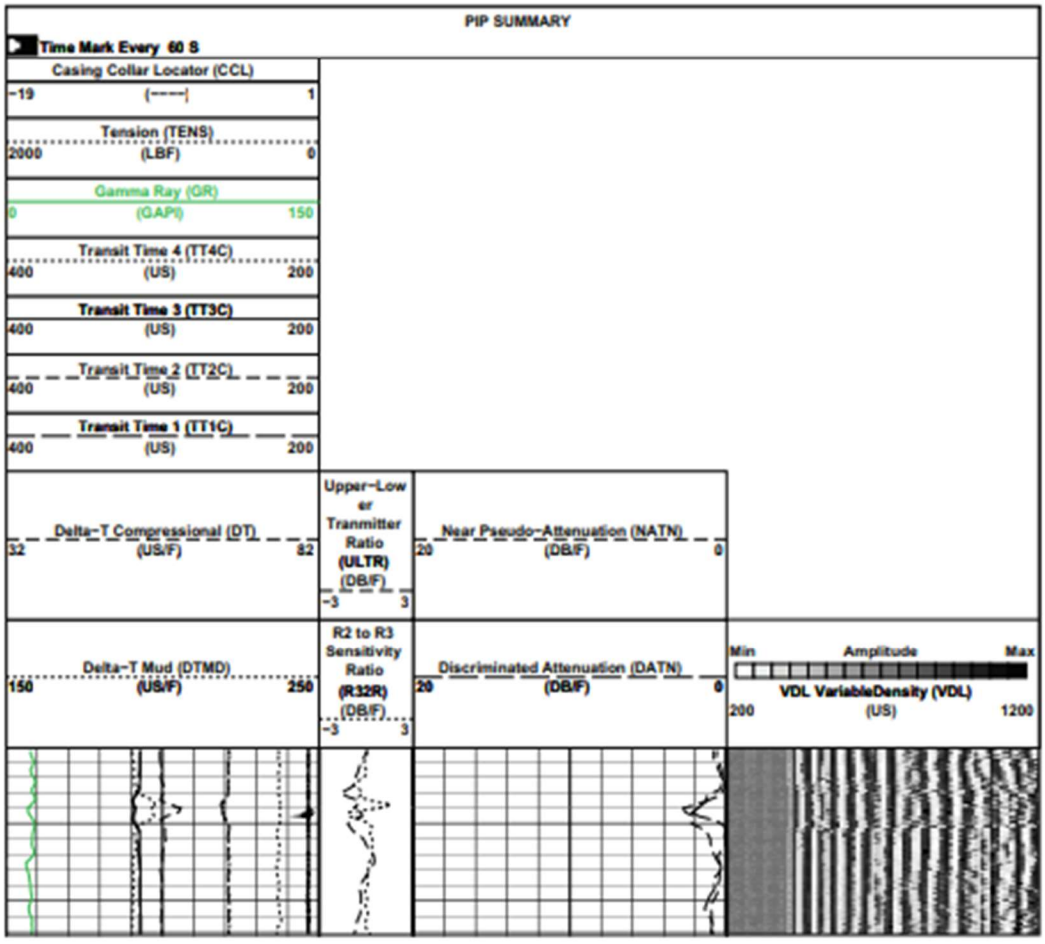


Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40[1]	52 ± 5	329	272	NM[2]

[1] Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.
[2] NM = not meaningful

Schlumberger

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)
Output	SLS-C, SLS-D, SLS-W, and SLS-E:[1] 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

[1] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications				
	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID—min.	5 in [12.70 cm]	5 in [12.70 cm]	3½ in [8.89 cm]	4 in [10.16 cm]
Casing ID—max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3⅝ in [9.21 cm]	3¾ in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers: 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers: 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 lbf [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,570 N]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

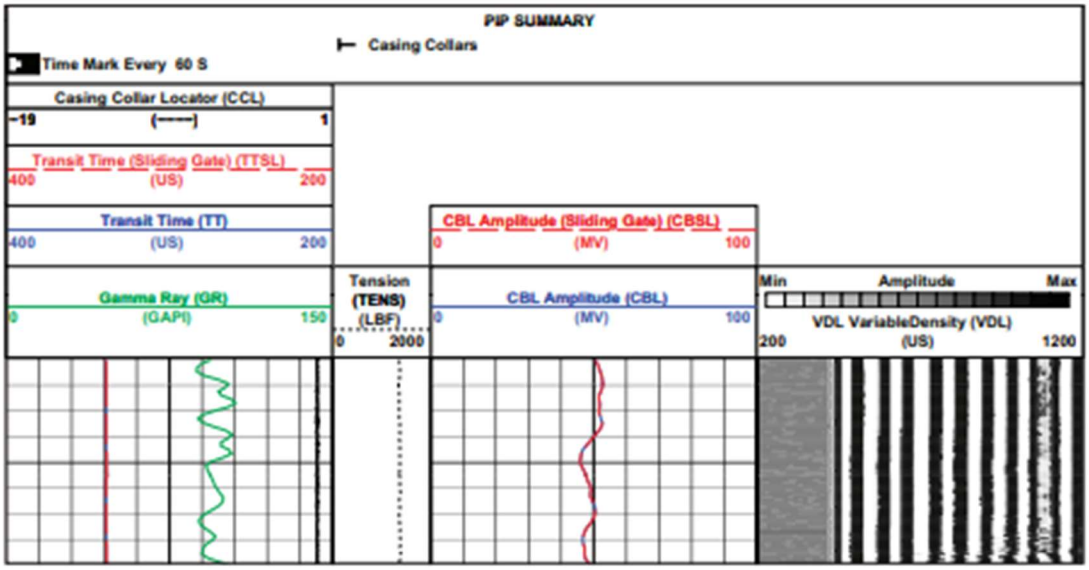


Figure 1. DSLT standard format.

Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4

Class VI Injection Well: Quality Assurance and Surveillance Plan

Update March 31, 2022

Prepared by:

Carbon TerraVault 1 LLC

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Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Elk Hills A1-A2 Storage facility. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

THurst

March 31, 2022

_____ _____

Signature Date

Travis Hurst

Distribution List

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Travis Hurst: CCS Project Manager

Carbon TerraVault
28590 Highway 119
Tupman, CA 93276

A. Project Management

A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The Elk Hill A1-A1 Storage project, led by Carbon TerraVault 1 LLC (CTV), includes participation from service providers. The responsibilities for Testing and Monitoring will be shared between CTV and the service providers.

CTV will be responsible for any data and submissions made to the EPA.

A.1.c. Independence from Project QA Manager and Data Gathering

CTV utilizes a third-party service provider to collect, transport and analyze samples as part of the Testing and Monitoring Plan.

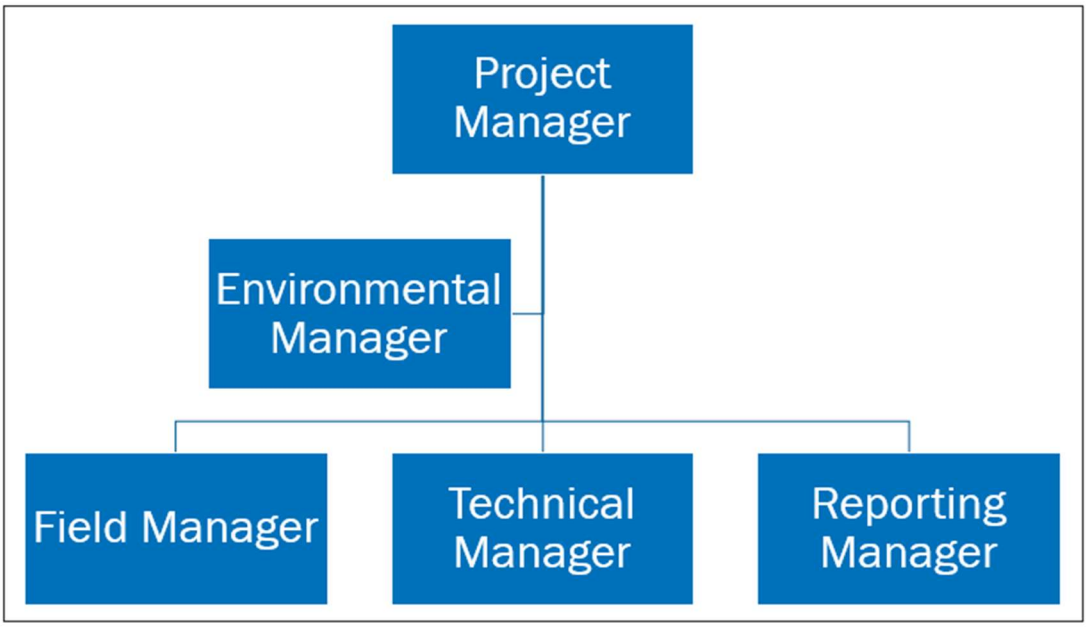
A.1.d. QA Project Plan Responsibility

CTV will be responsible for the Quality Assurance and Surveillance Plan. CTV will review the plan with service providers periodically.

A.1.e. Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure for the Elk Hills A1-A2 project. Although these roles have not been filled because the project is not operational, the chart shows the breakdown in responsibilities for future positions.

Figure 1: Organizational Chart.



A.2. Problem Definition/Background

A.2.a. Reasoning

The Elk Hills A1-A2 project will inject and sequester CO_2 from sources that include the Elk Hills Power Plant, renewable diesel refinery projects, and other industrial sources close to the field. The project requires a comprehensive monitoring plan that gathers data to assess confinement of the CO_2 injectate. To ensure accurate measurement and reporting this QASP outlines detail associated with the surveillance related to sampling, operating, and recording.

A.2.b. Reasons for Initiating the Project

CTV initiated the project for ESG purposes and to reduce carbon footprint for CTV operations and for external emissions. The Elk Hills Oil Field is a premier location for carbon sequestration in the San Joaquin Basin. The field has available pore space, proven confinement, and ideal surface/mineral ownership.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

CO_2 injection as per standard operating procedures and regulations requires that the injectate is confined in the reservoir and that groundwater is not impacted. As such the following monitoring is necessary:

1. Injection well mechanical integrity testing
2. Injection well testing and operating data collection
3. Groundwater monitoring
4. Validation of the CO_2 plume areal coverage as defined by numerical modeling

The information and data below define the steps to ensure that monitoring data quality provides the confidence and information to verify confinement.

A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed

Table 1. Summary of Testing and Monitoring.

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Injection well					
Carbon dioxide stream analysis	Compressor	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor Injectate
Injection rate and volume	Injection Well	Flow meter	Direct Measurement	NA	Monitor rate and volume
Injection pressure	Injection wellhead	Pressure gauge	Direct Measurement	NA	Monitor injection pressure
Annular pressure	Injection Wellhead	Pressure gauge	Direct Measurement	NA	Monitor annular pressure
Temperature	Along Wellbore	DTS	Direct Measurement	NA	Monitor temperature
Downhole pressure/ temperature	Injection Well	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure and temperature
Corrosion monitoring	Between compressor and wellhead	Corrosion Coupon	NA	Zalco Labs	Monitor corrosion of materials
Mechanical integrity	Injection Well	Temperature		NA	Wellbore Integrity
Pressure Fall Off Test	Injection Well	Pressure gauge	Pressure Transient Analysis	NA	Reservoir Assessment

Table 2. Monitoring Well Summary

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Monitoring Wells Above Confining Layer					
Fluid Sampling Tulare Formation (USDW)	USDW Monitoring Well	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pressure/Temperature Tulare Formation (USDW)	USDW Monitoring Well	Guage	Direct Measurement	NA	Monitor pressure / temperature
Pressure/Temperature Etchegoin Formation	327-7R-RD1	Gauge	Direct Measurement	NA	Monitor pressure/Temperature
Temerature Etchegoin Formation	327-7R-RD1	DTS	Direct Measurement	NA	Monitor Temperature
Fluid Sampling Etchegoin Formation	327-7R-RD1	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Monterey Formation A1-A2 Reservoir					

Pressure/Temperature	353A-7R 335X7R	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure/temperature
Temerature	353A-7R 335X7R	DTS	Direct Measurement	NA	Temperature
Fluid Sampling	353A-7R 335X7R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pulse Neutron Log	353A-7R and 335X-7R	Logging	Logging	NA	Saturation
Monterey Formation A3-A11 Reservoir					
Fluid Sampling	331-17R, 345-7R, 388X-7R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor produced fluids composition.

A.3.c. Geographic Locations

A.3.d. Resource and Time Constraints

There are neither resource nor time constraints for theElk Hills A1-A2 storage project. CTV owns the mineral rights, pore space and surface access to the Elk Hills Oil Field.

Wells to be utilized for the project are available, and will be re-purposed. These wells will be accessible for the life of the project and for the post injection monitoring timeframe.

A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

Table 3. Summary of Analytical and Field Parameters for Fluid Samples in Tulare, Etchegoin and Monterey Formation water.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, SB, Se, Zn, Ti)	ICP-MS EPA Method 6020	0.05 to 5 mg/L	**15%**	Daily calibration of equipment/CCV/ Blank LCS, MS/MSD/ QC/ICV
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B	0.1 to 2 mg/L	**15%**	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	0.02-0.13 mg/L	**15%**	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Dissolved CO_2	Coulometric titration ASTM D513-11	10 mg/L	**NA**	Duplicate analysis
Total dissolved solids	Gravimetry; Method 2540 C	10 mg/L	**10%**	Daily balance calibration, duplicates, blanks
Alkalinity	Method 2320B	10 mg/L	10%	Duplicate analysis
pH (field)	EPA 150.1	2 to 12.5pH	0.2 pH	Daily calibration, duplicates
Specific conductance (field)	SM 2510 B	10 ohms/cm	1%	Daily calibration, duplicates
Temperature (field)	Thermocouple	-5 to 50 C	0.2 C	Monthly calibration
δ13C	Isotope ratio mass spectrometry	12.2 mg/L HCO_3	0.15%	Duplicate analysis
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	1 mg/L	5-10% of reading	Daily calibration, duplicates

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 4. Summary of Analytical Parameters for CO_2 Stream.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Nitrogen	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Carbon monoxide	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total hydrocarbons	ASTM D 1945	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Methane	ASTM D 1945	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Hydrogen sulfide	ASTM D 1945/D6228	10 ppmv/1 ppmv	15%	Daily calibration/CCV, blank, QC sample
Ethanol	EPA 8260B	0.5 ppmv	20%	Daily calibration/CCV, blank, LCS, MS/MSD, ICV
CO_2 purity	ASTM D 1945	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total Sulfur	ASTM D 3246	1 ppmv	15%	Daily calibration/CCV, blank, QC sample

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 5. Summary of Analytical Parameters for Corrosion Coupons.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE TM0169/ G31 EPA 1110A SW846	0.001 mg	10%	Duplicate analysis

Table 6. Summary of Measurement Parameters for Field Gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection tubing temperature	ANSI Z540-1-1994	0.001 Fahrenheit / 0 – 500 Fahrenheit	0.01 Fahrenheit	Annual calibration
Injection tubing pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Annulus pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection mass flow rate	NA	0.1 % of flow rate	0.01 lbs/hour	Annual calibration

Table 7. Actionable Testing and Monitoring Outputs.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
External and internal mechanical integrity (temperature log)	Temperature log indicates a mechanical integrity issue.	0.01 Fahrenheit	Results will be compared to baseline. Deviation may be indicative of mechanical issue.
Surface and downhole pressure	Action will be taken when pressure is outside of expected or modeled range.	0.001 PSI	No greater than the maximum operating pressure.
Water quality (Tulare USDW)	Action will be taken when water sample is outside of baseline analysis.	0.2 pH	CO_2 will decrease the water pH.
Above-confining-zone pressure (Etchegoin)	Action will be taken if the pressure of the Etchegoin Formation pressure increases.	0.001 PSI as per installed pressure gauge.	Reservoir pressure.

A.4.b. Precision

Field blanks will be collected once per sampling event to assess water sampling analysis accuracy. Service provider will be responsible for analytical precision as per their standard operating procedures.

A.4.c. Bias

Laboratory analysis bias will be assessed and addressed by the individual service provider as per their procedures and methodology.

There is no bias for direct pressure, temperature, and logging measurements.

A.4.d. Representativeness

CTV designed the monitoring network to ensure that samples acquired were representative of site conditions. Standard operating procedures during acquisition at the wellsite will ensure that samples are representative of the formation.

A.4.e. Completeness

Data completeness (amount of data obtained versus the expected data) of 90% for ground water sampling will be acceptable.

Direct measurements, such as pressure and temperature data, will be recorded 90% of the time.

A.4.f. Comparability

Data sets will always be compared to the baseline and previous analysis. Individual threshold changes will be assessed as well as small trend changes.

A.4.g. Method Sensitivity

The following tables provide detail on gauge sensitivities.

Table 8. Pressure and Temperature—Downhole Gauge Specifications.

Parameter	Value
Calibrated working pressure range	0 – 10,000 PSI
Initial pressure accuracy	< 2 PSI
Pressure resolution	0.005 PSI
Pressure drift stability	< 1 PSI per year
Calibrated working temperature range	77 – 266 degrees Fahrenheit
Initial temperature accuracy	< 0.9 Fahrenheit
Temperature resolution	0.009 Fahrenheit
Temperature drift stability	0.1 degrees Fahrenheit per year
Max temperature	302 degrees Fahrenheit
Instrument calibration frequency	Annual

Table 9. Representative Logging Tool Specifications.

Parameter	RST (Pulse Neutron)	CBL
Logging speed	200 feet/hour	1,800 feet/hour
Vertical resolution	15 inches	6 inches
Investigation	Mechanical integrity	Cement bond with casing and formation
Temperature rating	302 Fahrenheit	350 Fahrenheit
Pressure rating	15,000 PSI	20,000 PSI

Table 10. Pressure Field Gauge.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.04365 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 11. Pressure Field Gauge—Injection Tubing Pressure.

Parameter	Value
Calibrated working pressure range	0 – 3,000 PSI and 4-20 mA
Initial pressure accuracy	<0.03125%
Pressure resolution	0.001 PSI and 0.00001 mA
Pressure drift stability	0.125% of upper range limit for 60 months

Table 12. Pressure Field Gauge—Annulus Pressure.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.025 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 13. Temperature Field Gauge—Injection Tubing Temperature.

Parameter	Value
Calibrated working temperature range	0 to 500 degrees Fahrenheit and 4-20ma
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 degrees Fahrenheit and 0.0001 mA
Temperature drift stability	0.15% of output reading or 0.15 degrees Celsius

Table 14. Mass Flow Rate Field Gauge—CO_2 Mass Flow Rate.

Parameter	Value
Calibrated working flow rate range	0 to 3,000 PSI
Initial mass flow rate accuracy	0.1 % of upper range limit
Mass flow rate resolution	0.1 PSI
Mass flow rate drift stability	Estimate <0.3% of output reading for 12 months

A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

CTV will utilize lab and logging companies to acquire field data samples. All equipment will be provided and operated by the service provider.

A.5.b/c. Training Provider and Responsibility

Training will be provided and assessed by the individual service providers.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

CTV will prepare and submit semi-annual reports to the EPA. The reports will include all testing, data, and monitoring information as specified in the Testing and Monitoring Plan.

A.6.b. Other Project Documents, Records, and Electronic Files

CTV will prepare and provide all necessary documents, records or electronic files as required.

A.6.c/d. Data Storage and Duration

CTV will maintain the required project data collected in a datastore.

A.6.e. QASP Distribution Responsibility

The project manager will be responsible for ensuring that those on the distribution list, and other essential staff, receive the most current copy of the QASP.

B. Data Generation and Acquisition

B.1. Sampling Process Design

B.1.a. Design Strategy

Shallow Groundwater Monitoring Strategy

A pre-existing shallow groundwater monitoring well will assess potential changes in the Upper Tulare USDW and Lower Tulare Formation. The Upper Tulare USDW is not a water source in the AoR.

The Upper Tulare Formation USDW is an unconfined aquifer in the AoR. Due to drought conditions, water levels are continuously falling. As such, the 61WS-8R well was selected for the following reasons:

1. It is down gradient and has a thicker section of the Upper Tulare Formation USDW.
2. The well is completed across the Upper Tulare Formation USDW and Lower Tulare Formation. The Lower Tulare is not exempt outside the project area, and any pressure or fluid changes in the Lower Tulare Formation will occur before the Upper Tulare Formation USDW.

CTV will monitor pressure changes associated with the A1-A2 Storage project and fluid analysis.

Deep Groundwater Monitoring Strategy

Between the Reef Ridge confining layer and USDW is the Etchegoin Formation. A laterally continuous Etchegoin Formation water sand (3,500 feet TVD) will be pressure monitored for potential CO_2 leakage via the 346-7R-RD1 well. The sands have adequate continuity, porosity and permeability to ensure that the AoR is monitored with one well.

Any unlikely leakage from the A1A2 reservoir up through the Reef Ridge confining layer will dissipate in the Etchegoin Formation and increase its pressure.

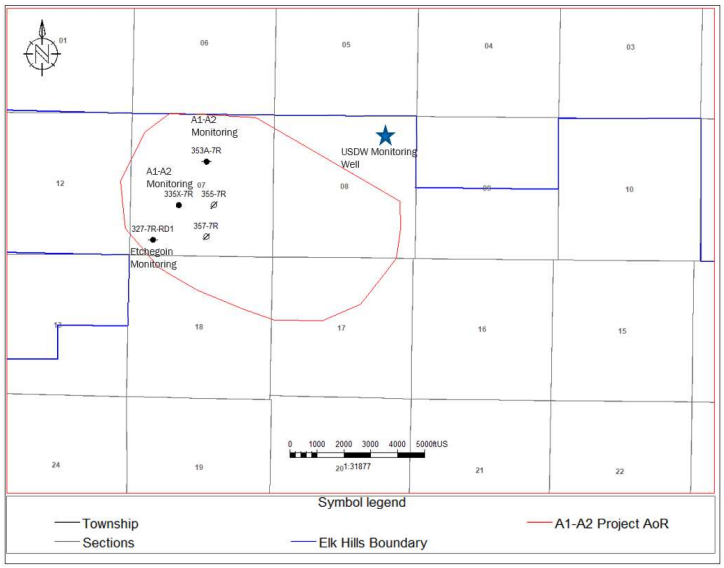
B.1.b. Type and Number of Samples/Test Runs

The sampling activities are summarized in Table 1.

B.1.c. Site/Sampling Locations

Locations for sampling are shown on the map below (Figure 2).

Figure 2: Monitoring well locations.



B.1.d. Sampling Site Contingency

CTV owns the mineral rights, pore space and surface access to the storage project.

B.1.e. Activity Schedule

The sampling activities are summarized in Table 1.

B.1.f. Critical/Informational Data

Documentation of information will include the following:

1. Sampling metadata that includes sample label, purging time and other sample collection procedures.
2. Data collected in the field (temperature and pH).
3. Chain of custody.
4. Data and analysis collected in the laboratory.
5. Calibration of Instrumentation and equipment.

B.1.g. Sources of Variability

Potential sources of variability include the following:

1. Natural and operational variability in fluid quality, temperature, and pressure.
2. Reservoir changes from outside the AoR (outside operator, precipitation/drought)
3. Changes in the sampling methods, service provider and instrumentation.

Variability will be minimized by the following:

1. Adhering to standard operating procedures.
2. Assessing data and results against baseline and previous results for trend and changes.
3. Service provider staff training.
4. Assessing calibration and calibrating procedures.
5. Quality control checks for samples.

B.2. Sampling Methods

B.2.a/b. Sampling SOPs

Refer to the table below for stabilization criteria during well purging.

Laboratory SOPs have been developed by the service provider.

All procedures for sampling shall be consistent with the U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCEAA Project Mangers (May 2002).

Table 15. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.

Field Parameter	Stabilization Criteria
pH	+/- 0.01
Temperature	+/- 1 C
Specific conductance	+/- 3%

B.2.c. In-situ Monitoring

In-situ monitoring of water chemistry is not currently planned.

B.2.d. Continuous Monitoring

Pressure will be collected from monitoring wells.

B.2.e. Sample Homogenization, Composition, Filtration

To obtain a representative sample, each well will be purged at a flow rate between 10 GPM and 5- GPM. Samples will be collected within 24 hours of the well being purged. If a monitoring well will not supply adequate water for sampling, the condition of the well will be investigated and it may be considered for replacement.

Purging will continue until three successive measurements of the indicator parameters meet the stabilization criteria per Table 15.

B.2.f. Sample Containers and Volumes

Sample collection devices will be carefully chosen to minimize the potential for altering the quality of the sample. Teflon and stainless steel are preferred materials, although PVC, HDPE and other similar materials are considered sufficient in some cases.

Refer to the tables below as needed for sample container, preservation, and holding time information.

B.2.g. Sample Preservation

Samples will be preserved as per Table 17.

B.2.h. Cleaning/Decontamination of Sampling Equipment

Equipment used for sampling and other activities associated with on-site work will be de-contaminated before and after performance of a given activity. Disposable items will be disposed of as solid waste in an approved, permitted client facility.

B.2.i. Support Facilities

Support facilities will be provided by the service provider responsible for sampling and analysis.

B.2.j. Corrective Action, Personnel, and Documentation

The service provider will be responsible for testing instruments and equipment and preforming corrective action on defective equipment. Corrective action taken on equipment will be documented.

B.3. Sample Handling and Custody

B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 16 and 17 for holding times.

B.3.b. Sample Transportation

CTV will ensure that samples are delivered to the laboratory for analysis by the service provider as soon as possible following sample collection. Samples will be transported to the laboratory on the same day as the sample collection.

During transportation, precautions will be implemented to ensure that sample integrity is not affected by extreme temperatures and/or excessive vibration.

Upon arrival at the service provider the samples will be reviewed to ensure the following:

1. The sample arrived intact without container leakage or breakage.
2. Chain of custody documentation and sample labels agree
3. Confirmation that the sample was preserved correctly.

B.3.c. Sampling Documentation

For each test in the field, a worksheet will be compiled for each test interval documenting the procedures and results.

B.3.d. Sample Identification

Samples will be identified with the well location, date sample identification, sampler, and sample type.

Table 16. Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Gas Stream Analysis.

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	One-liter tedlar bag	None	72 hours

Table 17. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: Ca, Fe, Mg, K, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Ti	100 mL plastic	Nitric acid	180 days
Anions: Br, Cl, F, NO_3 and SO_4	100 mL plastic	None	48 hours
Dissolved CO_2	100 ml plastic	None	14 days
Isotopes: Carbon isotope 13	100 ml plastic	None	14 days
Alkalinity	100 mL plastic	None	14 days

B.3.e. Sample Chain-of-Custody

Sample transport and handling will be strictly controlled by the service provider field technician to reduce the opportunity for tampered samples. Upon delivery to the laboratory samples will be given unique laboratory sample numbers and recorded in a logbook indicating the client, well number, date, and time of delivery.

B.4. Analytical Methods

B.4.a. Analytical SOPs

All procedures to sample and analyze groundwater will be consistent with the U.S. Environmental Protection Agency Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002).

B.4.b. Equipment/Instrumentation Needed

Service providers are expected to provide and utilize the equipment and instruments necessary to perform the required testing and analysis.

Examples of equipment and instrumentation includes safety equipment, sample jars, decontamination supplies, pH meter, EC meters, temperature gauges, and materials to document chain of custody, results, and labels.

B.4.c. Method Performance Criteria

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well define. Method performance criteria is not necessary.

B.4.d. Analytical Failure

Service providers conducting analysis are responsible for assessing and addressing analytical failure per their internal procedures and standards.

B.4.e. Sample Disposal

Service providers conducting analysis are responsible for proper sample disposal per internal procedures and standards.

B.4.f. Laboratory Turnaround

Laboratory turnaround times will vary by the analysis being conducted. CTV will communicate to service providers that a 30-day turnaround time for most analysis' is expected.

B.4.g. Method Validation for Nonstandard Methods

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well defined. Method performance criteria is not necessary.

B.5. Quality Control

B.5.a. QC activities

Field quality control may involve the collection of two types of QC blanks, trip, and field blanks, to verify that the sample collection and handling processes have not impaired quality of the final samples.

Trip blank – Trip blanks are prepared for VOC analysis and transported with the empty sample container.

Field Blank- the field blank will be taken in the field to evaluate if certain sampling or cleaning procedures result in cross-contamination of site samples or if atmospheric contamination has occurred.

B.5.b. Exceeding Control Limits

In the case that control limits are exceeded, CTV will review the sampling procedures and results. In the case of a valid test, refer to the Emergency Response Plan for water contamination procedures.

B.5.c. Calculating Applicable QC Statistics

Charge Balance - Solutions must be electrically neutral, the total sum of all the positive charges (cations) must equal the total sum of all negative charges (anions).

$$\text{Charge Balance:} \qquad \sum cations = \sum anions$$

Charge balance error (shown below) will be less than ±5% for acceptable water analyses.

$$CBE = \frac{\sum cations - |\sum anions|}{\sum cations + |\sum anions|} \times 100$$

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

The service provider will test, inspect, and maintain the instrumentation and equipment used for testing, this will be completed as per the manufacturer's guidelines and the standard operating procedures.

B.7. Instrument/Equipment Calibration and Frequency

B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges will be calibrated according to the manufacturer's recommendations. Calibration certificates will be kept on file.

Lab instrumentation and calibration will be checked weekly to ensure that results are within the control range of parameters.

B.7.b. Calibration Methodology

Instruments will be calibrated for accurate readings. Calibrations will be conducted with individual instrument SOP's and in accordance with the manufacturer's supplied manual for each instrument.

B.7.c. Calibration Resolution and Documentation

Instrument calibration resolution will be consistent with the manufacturer's recommendations. Documentation for instrument calibration will be maintained in a database.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

The service provider responsible for completing sample collection and analysis will be responsible for supplies and consumables.

Supplies and consumables used for sample collection and analysis will be selected to minimize the potential for altering the quality of the sample and analysis results.

B.9. Nondirect Measurements

B.9.a. Data Sources

Induced seismicity will be monitored continuously to ensure data consistency. CTV will partner with or use a third party to process the data.

B.9.b. Relevance to Project

Passive seismic monitoring will be used to assess induced seismicity events as an indicator of stress changes in the subsurface. Thresholds and response for induced seismic eventsare discussed further in the Emergency Response Plan.

B.9.c. Acceptance Criteria

Industry standard practices will be utilized for data gathering, processing and interpretation.

B.9.d. Resources/Facilities Needed

CTV will use a service provider for all necessary resources and facilities for passive seismic monitoring.

B.9.e. Validity Limits and Operating Conditions

CTV and service provider professionals will ensure that all results and processes are conducted as per standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

CTV will maintain the A1-A2 Storage project data internally. Data will be backed up and held on secure servers.

B.10.b. Recordkeeping and Tracking Practices

All data associated with the project will be held securely and associated meta-data will be gathered and maintained to ensure tracking purposes.

B.10.c. Data Handling Equipment/Procedures

CTV employs robust data management procedures to ensure security of data gathered from the field and external data sources.

B.10.d. Responsibility

Project managers will be responsible for ensuring data management is properly maintained.

B.10.e. Data Archival and Retrieval

CTV will hold all data associated with the A1-A2 Storage project. A data store will be developed for reporting and retrieval.

B.10.f. Hardware and Software Configurations

CTV will ensure that software and hardware are appropriate to integrate the multiple data sources and maintain large quantities of data.

B.10.g. Checklists and Forms

CTV will generate forms, checklists, and procedures as necessary to ensure management, security and quality of all data collected.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Monitoring results will be obtained as per Table 1. Results will be reviewed for QC criteria as per section B.5. In the case of data failure, new samples will be collected and analyzed. Evaluation for data consistency will be performed per the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

CTV will utilize service providers to analyze sample data. These organizations will be responsible for conducting their own internal assessments.

C.1.c. Assessment Reporting

Assessment information will be reported to the project leads as outlined in A.1.

C.1.d. Corrective Action

CTV owns the surface and mineral rights in the Elk Hills Oil Field. Corrective action issues, data collection, and monitoring data will all be handled by CTV.

C.2. Reports to Management

C.2.a/b. QA status Reports

CTV will notify the EPA and project leaders of QA report status if there are changes to the Testing and Monitoring Plan or the QASP.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Data validation will include the review of the results, chain of custody information, and review of the blank and duplicate information. All results will be stored in a database and compared to baseline and previous results. Data will be graphed to inspect trends and anomalies.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

Data will be verified by CTV upon receipt of results.

If anomalous data is suspected, CTV and the service provider will review the metadata associated with the sample to assess whether sampling, collection and the analysis conducted caused spurious results. In addition, instrument calibration will be reviewed if necessary.

D.2.b. Data Verification and Validation Responsibility

Data will be verified by CTV upon receipt of results.

D.2.c. Issue Resolution Process and Responsibility

CTV will oversee sample handling and assessment process. CTV management will determine actions necessary to resolve issues.

D.2.d. Checklist, Forms, and Calculations

CTV will develop checklists and a GIS database to store data, complete surveillance and ensure that permit requirements are met.

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

CTV will develop a GIS database that will be used for surveillance. The database will ensure data quality using methods consistent with USEPA 2009 Unified Guidance.

D.3.b. Data Limitations Reporting

Service provider management will be responsible for ensuring that analysis in their laboratory is presented with data use limitations for reporting.

Project leaders and managers will be responsible for ensuring that results are vetted and evaluated to determine if performance criteria are met.

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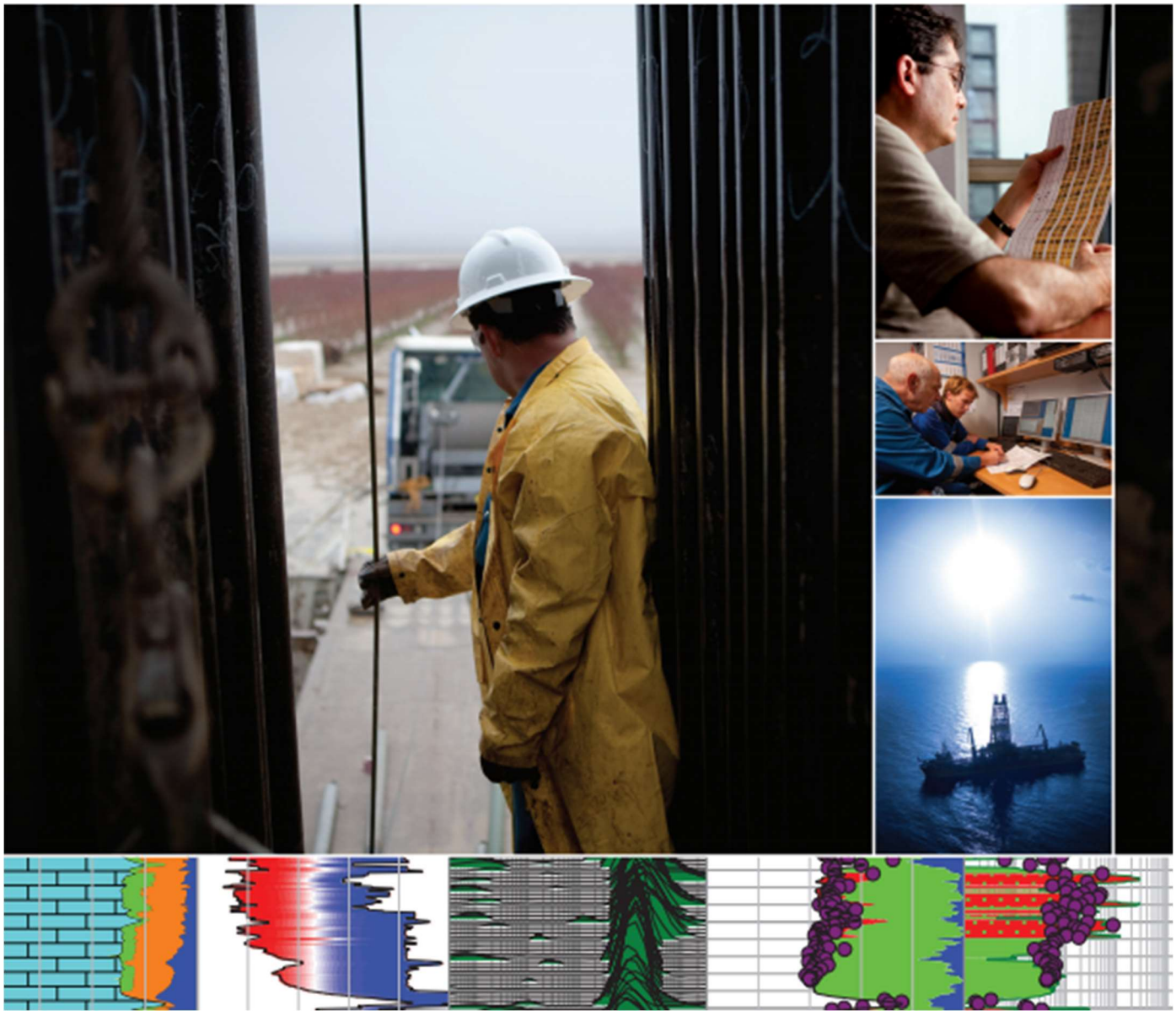
Appendices

Schlumberger Wireline Log Quality Reference Manual

Schlumberger

Wireline Log Quality Control Reference Manual



Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed[1]	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation[2]	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

[1] See Tool Planner application for advice on logging speed.
[2] Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	1 13/16 in [4.60 cm] With flask: 2¼ in [5.72 cm]	2⅞ in [7.30 cm]
Borehole size—max.	9⅝ in [24.45 cm] With flask: 9⅝ in [24.45 cm]	9⅝ in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

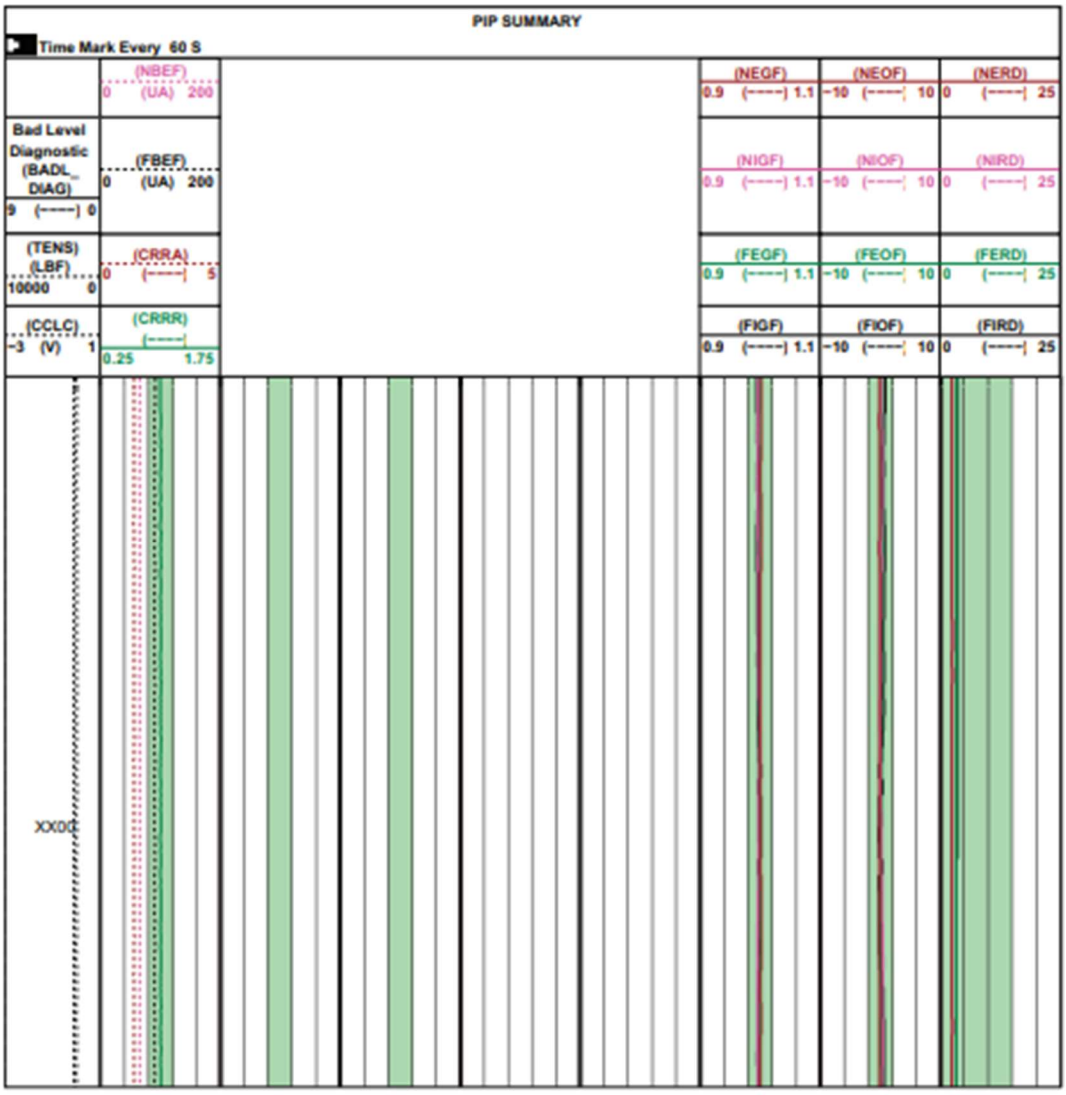


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

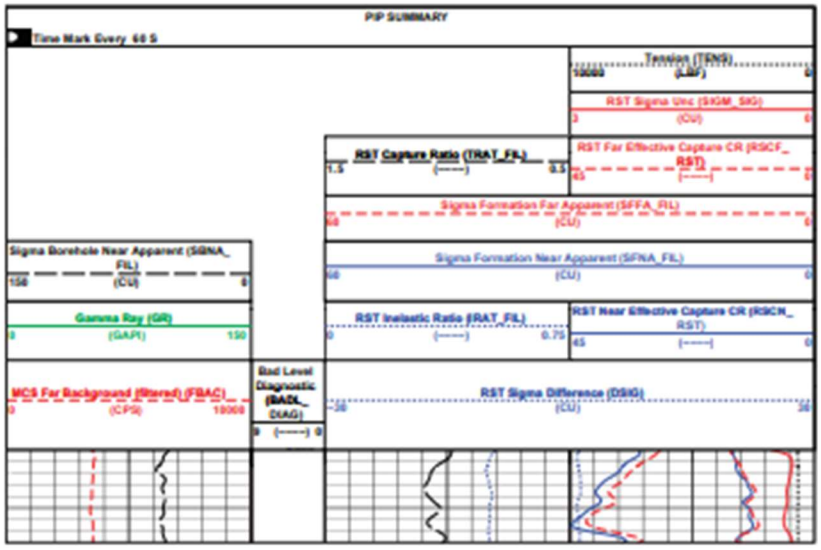


Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

Schlumberger

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h][†]
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

[†] Speed can be reduced depending on data quality.

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation[†]
SBI	Short bond index[†]
SCBL	Short synthetic CBL[†]
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

[†] In fast formations only

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

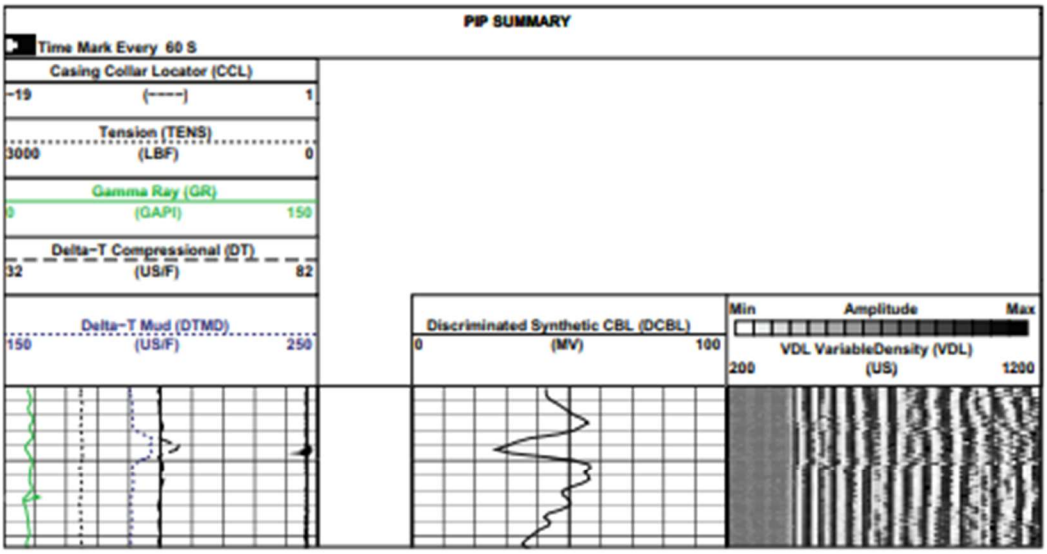


Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

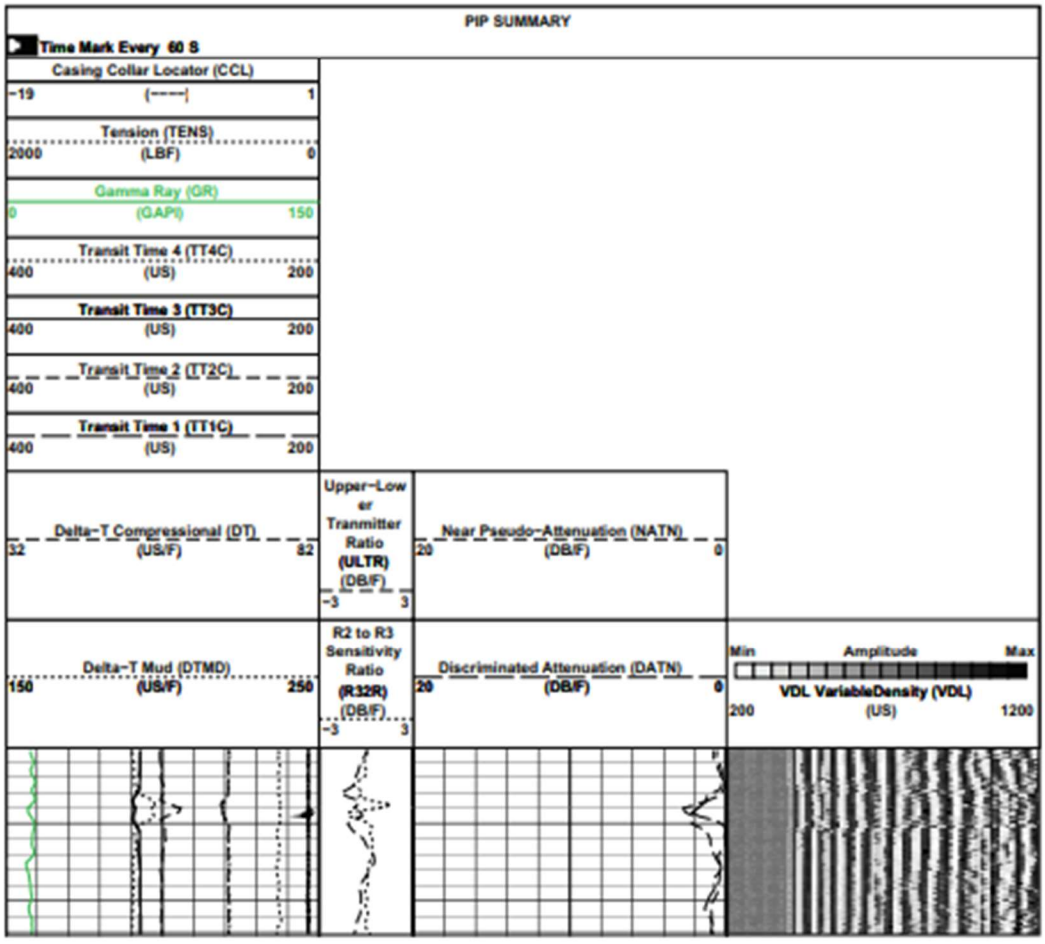


Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40[1]	52 ± 5	329	272	NM[2]

[1] Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.
[2] NM = not meaningful

Schlumberger

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)
Output	SLS-C, SLS-D, SLS-W, and SLS-E:[1] 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

[1] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications				
	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID—min.	5 in [12.70 cm]	5 in [12.70 cm]	3½ in [8.89 cm]	4 in [10.16 cm]
Casing ID—max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3⅝ in [9.21 cm]	3¾ in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers: 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers: 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 lbf [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,570 N]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

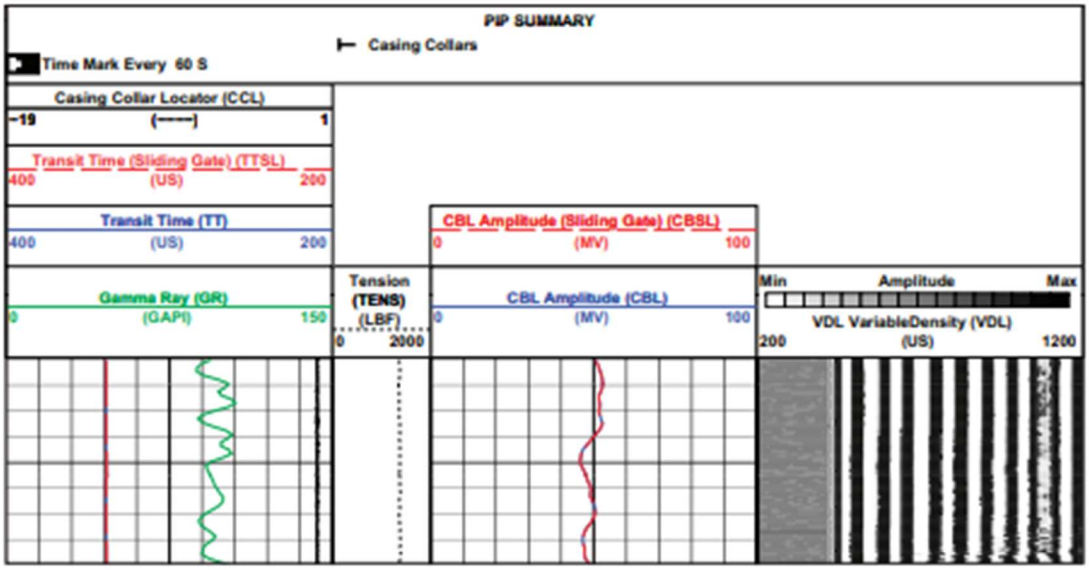


Figure 1. DSLT standard format.

Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4

Class VI Injection Well: Quality Assurance and Surveillance Plan

Update May 2023

Prepared by:

Carbon TerraVault 1 LLC

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Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Elk Hills A1-A2 Storage facility. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

THurst

November 4, 2022

_____ _____

Signature Date

Travis Hurst

Distribution List

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Travis Hurst: CCS Project Manager

Carbon TerraVault
28590 Highway 119
Tupman, CA 93276

A. Project Management

A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The Elk Hill A1-A1 Storage project, led by Carbon TerraVault 1 LLC (CTV), includes participation from service providers. The responsibilities for Testing and Monitoring will be shared between CTV and the service providers.

CTV will be responsible for any data and submissions made to the EPA.

A.1.c. Independence from Project QA Manager and Data Gathering

CTV utilizes a third-party service provider to collect, transport and analyze samples as part of the Testing and Monitoring Plan.

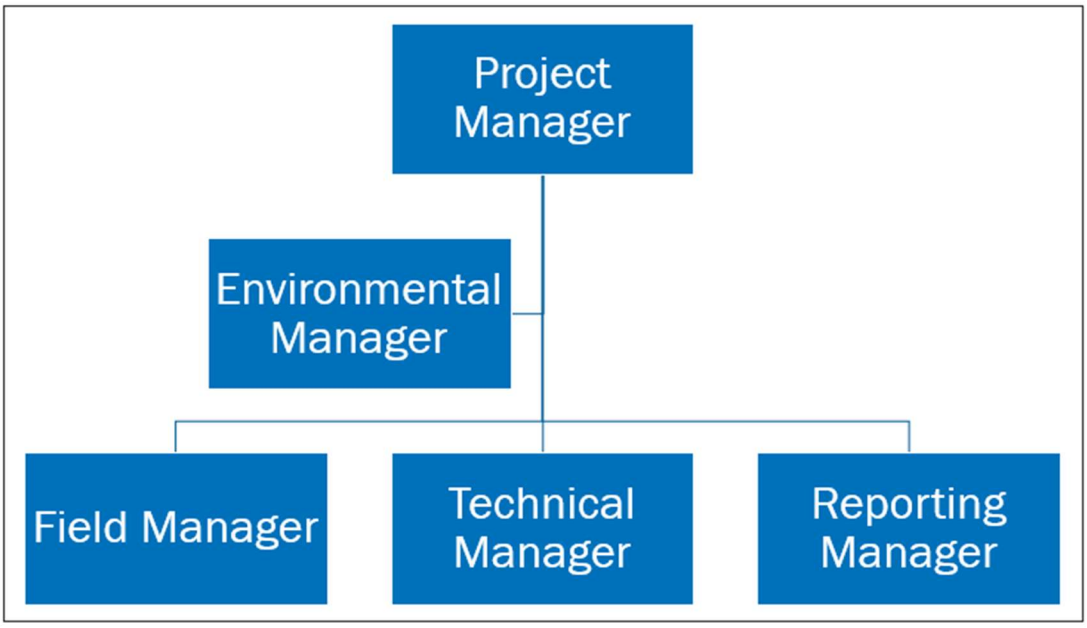
A.1.d. QA Project Plan Responsibility

CTV will be responsible for the Quality Assurance and Surveillance Plan. CTV will review the plan with service providers periodically.

A.1.e. Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure for the Elk Hills A1-A2 project. Although these roles have not been filled because the project is not operational, the chart shows the breakdown in responsibilities for future positions.

Figure 1: Organizational Chart.



A.2. Problem Definition/Background

A.2.a. Reasoning

The Elk Hills A1-A2 project will inject and sequester CO_2 from sources that include the Elk Hills Power Plant, renewable diesel refinery projects, and other industrial sources close to the field. The project requires a comprehensive monitoring plan that gathers data to assess confinement of the CO_2 injectate. To ensure accurate measurement and reporting this QASP outlines detail associated with the surveillance related to sampling, operating, and recording.

A.2.b. Reasons for Initiating the Project

CTV initiated the project for ESG purposes and to reduce carbon footprint for CTV operations and for external emissions. The Elk Hills Oil Field is a premier location for carbon sequestration in the San Joaquin Basin. The field has available pore space, proven confinement, and ideal surface/mineral ownership.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

CO_2 injection as per standard operating procedures and regulations requires that the injectate is confined in the reservoir and that groundwater is not impacted. As such the following monitoring is necessary:

1. Injection well mechanical integrity testing
2. Injection well testing and operating data collection
3. Groundwater monitoring
4. Validation of the CO_2 plume areal coverage as defined by numerical modeling

The information and data below define the steps to ensure that monitoring data quality provides the confidence and information to verify confinement.

A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed

Table 1. Summary of Testing and Monitoring.

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Injection well					
Carbon dioxide stream analysis	Compressor	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor Injectate
Injection rate and volume	Injection Well	Flow meter	Direct Measurement	NA	Monitor rate and volume
Injection pressure	Injection Wellhead	Pressure gauge	Direct Measurement	NA	Monitor injection pressure
Annular pressure	Injection Wellhead	Pressure gauge	Direct Measurement	NA	Monitor annular pressure
Temperature	Along Wellbore	DTS	Direct Measurement	NA	Monitor temperature
Downhole pressure/ temperature	Injection Well	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure and temperature
Corrosion monitoring	Between compressor and wellhead	Corrosion Coupon	NA	Zalco Labs	Monitor corrosion of materials
Mechanical Integrity	Injection Well	Temperature	NA	NA	Wellbore Integrity
Internal MIT	Injection Well	SAPT	NA	NA	Wellbore Integrity
Pressure Fall Off Test	Injection Well	Pressure gauge	Pressure Transient Analysis	NA	Reservoir Assessment

Table 2. Monitoring Well Summary

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Monitoring Wells Above Confining Layer					
Fluid Sampling Tulare Formation (USDW)	USDW Monitoring Well	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pressure/Temperature Tulare Formation (USDW)	USDW Monitoring Well	Guage	Direct Measurement	NA	Monitor pressure / temperature
Pressure/Temperature Etchegoin Formation	327-7R-RD1	Gauge	Direct Measurement	NA	Monitor pressure/Temperature
Temerature Etchegoin Formation	327-7R-RD1	DTS	Direct Measurement	NA	Monitor Temperature
Fluid Sampling Etchegoin Formation	327-7R-RD1	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality

Monterey Formation A1-A2 Reservoir					
Pressure/Temperature	353A-7R 335X7R	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure/temperature
Temperature	353A-7R 335X7R	DTS	Direct Measurement	NA	Temperature
Fluid Sampling	353A-7R 335X7R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pulse Neutron Log	353A-7R 335X-7R	Logging	Logging	NA	Saturation
Internal MIT	353A-7R 335X-7R	SAPT	NA	NA	Wellbore Integrity
Monterey Formation A3-A11 Reservoir					
Fluid Sampling	331-17R, 345-7R, 388X-7R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor produced fluids composition.

A.3.c. Geographic Locations

A.3.d. Resource and Time Constraints

There are neither resource nor time constraints for theElk Hills A1-A2 storage project. CTV owns the mineral rights, pore space and surface access to the Elk Hills Oil Field.

Wells to be utilized for the project are available, and will be re-purposed. These wells will be accessible for the life of the project and for the post injection monitoring timeframe.

A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

Table 3. Summary of Analytical and Field Parameters for Fluid Samples in Tulare, Etchegoin, and Monterey Formation water.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020	0.05 to 5 mg/L	15%	Daily calibration of equipment/CCV/ Blank LCS, MS/MSD/ QC/ICV
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B	0.1 to 2 mg/L	15%	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)	0.02-0.13 mg/L	15%	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Dissolved CO_2	Coulometric titration ASTM D513-11	10 mg/L	NA	Duplicate analysis
Total dissolved solids	Gravimetry; Method 2540 C	10 mg/L	10%	Daily balance calibration, duplicates, blanks
Alkalinity	Method 2320B	10 mg/L	10%	Duplicate analysis
pH (field)	EPA 150.1	2 to 12.5pH	0.2 pH	Daily calibration, duplicates
Specific conductance	APHA 2510	0-200 mS/cm	1%	Daily calibration, duplicates
Temperature (field)	Thermocouple	-5 to 50 C	0.2 C	Monthly calibration
δ13C	Isotope ratio mass spectrometry	12.2 mg/L HCO_3	0.15%	Duplicate analysis
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	1 mg/L	5-10% of reading	Daily calibration, duplicates
Water Density (field)	Oscillating body method	0.0000 to 2.0000	0.0002 g/ml	Daily calibration, duplicates
Dissolved Methane	SM 6211 B or 6211 C	0.1 mg/L	NA	Duplicate analysis

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 4. Summary of Analytical Parameters for CO_2 Stream.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID) GC/TCD	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Carbon monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total hydrocarbons	ISBT 10.0 THA (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Methane	ISBT 10.1 (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Hydrogen sulfide	ISBT 14.0 (GC/SCD)	10 ppmv/1 ppmv	15%	Daily calibration/CCV, blank, QC sample
Ethanol	ISBT 11.0 (GC/FID)	0.5 ppmv	20%	Daily calibration/CCV, blank, LCS, MS/MSD, ICV
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total Sulfur	ISBT 14.0 (GC/SCD)	1 ppmv	15%	Daily calibration/CCV, blank, QC sample

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 5. Summary of Analytical Parameters for Corrosion Coupons.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE TM0169/ G31 EPA 1110A SW846	0.001 mg	10%	Duplicate analysis

Table 6. Summary of Measurement Parameters for Field Gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection tubing temperature	ANSI Z540-1-1994	0.001 Fahrenheit / 0 – 500 Fahrenheit	0.01 Fahrenheit	Annual calibration
Injection tubing pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Annulus pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection mass flow rate	NA	0.1 % of flow rate	0.01 lbs/hour	Annual calibration

Table 7. Actionable Testing and Monitoring Outputs.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
External and internal mechanical integrity (temperature log)	Temperature log indicates a mechanical integrity issue.	0.01 Fahrenheit	Results will be compared to baseline. Deviation may be indicative of mechanical issue.
Surface and downhole pressure	Action will be taken when pressure is outside of expected or modeled range.	0.001 PSI	No greater than the maximum operating pressure.
Water quality (Tulare USDW)	Action will be taken when water sample is outside of baseline analysis.	0.2 pH	CO_2 will decrease the water pH.
Above-confining-zone pressure (Etchegoin)	Action will be taken if the pressure of the Etchegoin Formation pressure increases.	0.001 PSI as per installed pressure gauge.	Reservoir pressure.

A.4.b. Precision

Field blanks will be collected once per sampling event to assess water sampling analysis accuracy. Service provider will be responsible for analytical precision as per their standard operating procedures.

A.4.c. Bias

Laboratory analysis bias will be assessed and addressed by the individual service provider as per their procedures and methodology.

There is no bias for direct pressure, temperature, and logging measurements.

A.4.d. Representativeness

CTV designed the monitoring network to ensure that samples acquired were representative of site conditions. Standard operating procedures during acquisition at the wellsite will ensure that samples are representative of the formation.

A.4.e. Completeness

Data completeness (amount of data obtained versus the expected data) of 90% for ground water sampling will be acceptable.

Direct measurements, such as pressure and temperature data, will be recorded 90% of the time.

A.4.f. Comparability

Data sets will always be compared to the baseline and previous analysis. Individual threshold changes will be assessed as well as small trend changes.

A.4.g. Method Sensitivity

The following tables provide detail on gauge sensitivities.

Table 8. Pressure and Temperature—Downhole Gauge Specifications.

Parameter	Value
Calibrated working pressure range	0 – 10,000 PSI
Initial pressure accuracy	< 2 PSI
Pressure resolution	0.005 PSI
Pressure drift stability	< 1 PSI per year
Calibrated working temperature range	77 – 266 degrees Fahrenheit
Initial temperature accuracy	< 0.9 Fahrenheit
Temperature resolution	0.009 Fahrenheit
Temperature drift stability	0.1 degrees Fahrenheit per year
Max temperature	302 degrees Fahrenheit
Instrument calibration frequency	Annual

Table 9. Representative Logging Tool Specifications.

Parameter	RST (Pulse Neutron)	CBL
Logging speed	200 feet/hour	1,800 feet/hour
Vertical resolution	15 inches	6 inches
Investigation	Mechanical integrity	Cement bond with casing and formation
Temperature rating	302 Fahrenheit	350 Fahrenheit
Pressure rating	15,000 PSI	20,000 PSI

Table 10. Pressure Field Gauge.

Parameter	Value
Calibrated working pressure range	0 to 5,000 PSI
Initial pressure accuracy	< 0.05 %
Pressure resolution	0.01 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 11. Pressure Field Gauge—Injection Tubing Pressure.

Parameter	Value
Calibrated working pressure range	0 to 5,000 PSI and 4-20 mA
Initial pressure accuracy	< 0.05 %
Pressure resolution	0.01 PSI and 0.00001 mA
Pressure drift stability	0.125% of upper range limit for 60 months

Table 12. Pressure Field Gauge—Annulus Pressure.

Parameter	Value
Calibrated working pressure range	0 to 5,000 PSI
Initial pressure accuracy	< 0.05 %
Pressure resolution	0.01 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 13. Temperature Field Gauge—Injection Tubing Temperature.

Parameter	Value
Calibrated working temperature range	0 to 500 degrees Fahrenheit and 4-20ma
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 degrees Fahrenheit and 0.0001 mA
Temperature drift stability	0.15% of output reading or 0.15 degrees Celsius

Table 14. Mass Flow Rate Field Gauge—CO_2 Mass Flow Rate.

Parameter	Value
Calibrated working flow rate range	Range spanning maximum anticipated injection rate per well with typical precision and accuracy of 0.5%
Initial mass flow rate accuracy	0.5 % of upper range limit
Mass flow rate resolution	0.5% of upper range limit
Mass flow rate drift stability	Estimate <0.5% of output reading for 12 months

A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

CTV will utilize lab and logging companies to acquire field data samples. All equipment will be provided and operated by the service provider.

A.5.b/c. Training Provider and Responsibility

Training will be provided and assessed by the individual service providers.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

CTV will prepare and submit semi-annual reports to the EPA. The reports will include all testing, data, and monitoring information as specified in the Testing and Monitoring Plan.

A.6.b. Other Project Documents, Records, and Electronic Files

CTV will prepare and provide all necessary documents, records or electronic files as required.

A.6.c/d. Data Storage and Duration

CTV will maintain the required project data collected in a datastore.

A.6.e. QASP Distribution Responsibility

The project manager will be responsible for ensuring that those on the distribution list, and other essential staff, receive the most current copy of the QASP.

B. Data Generation and Acquisition

B.1. Sampling Process Design

B.1.a. Design Strategy

Shallow Groundwater Monitoring Strategy

A pre-existing shallow groundwater monitoring well will assess potential changes in the Upper Tulare USDW and Lower Tulare Formation. The Upper Tulare USDW is not a water source in the AoR.

The Upper Tulare Formation USDW is an unconfined aquifer in the AoR. Due to drought conditions, water levels are continuously falling. As such, the 61WS-8R well was selected for the following reasons:

1. It is down gradient and has a thicker section of the Upper Tulare Formation USDW.
2. The well is completed across the Upper Tulare Formation USDW and Lower Tulare Formation. The Lower Tulare is not exempt outside the project area, and any pressure or fluid changes in the Lower Tulare Formation will occur before the Upper Tulare Formation USDW.

CTV will monitor pressure changes associated with the A1-A2 Storage project and fluid analysis.

Deep Groundwater Monitoring Strategy

Between the Reef Ridge confining layer and USDW is the Etchegoin Formation. A laterally continuous Etchegoin Formation water sand (3,500 feet TVD) will be pressure monitored for potential CO_2 leakage via the 346-7R-RD1 well. The sands have adequate continuity, porosity and permeability to ensure that the AoR is monitored with one well.

Any unlikely leakage from the A1-A2 reservoir up through the Reef Ridge confining layer will dissipate in the Etchegoin Formation and increase its pressure.

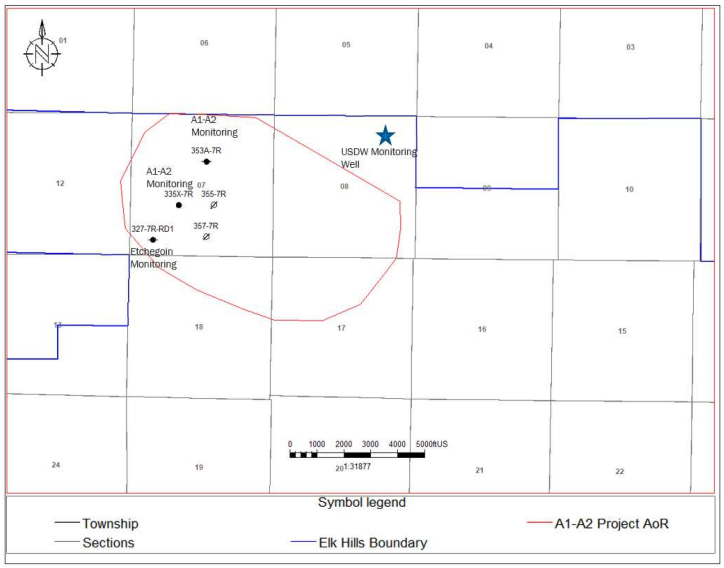
B.1.b. Type and Number of Samples/Test Runs

The sampling activities are summarized in Table 1.

B.1.c. Site/Sampling Locations

Locations for sampling are shown on the map below (Figure 2).

Figure 2: Monitoring well locations.



B.1.d. Sampling Site Contingency

CTV owns the mineral rights, pore space and surface access to the storage project.

B.1.e. Activity Schedule

The sampling activities are summarized in Table 1.

B.1.f. Critical/Informational Data

Documentation of information will include the following:

1. Sampling metadata that includes sample label, purging time and other sample collection procedures.
2. Data collected in the field (temperature and pH).
3. Chain of custody.
4. Data and analysis collected in the laboratory.
5. Calibration of Instrumentation and equipment.

B.1.g. Sources of Variability

Potential sources of variability include the following:

1. Natural and operational variability in fluid quality, temperature, and pressure.
2. Reservoir changes from outside the AoR (outside operator, precipitation/drought)
3. Changes in the sampling methods, service provider and instrumentation.

Variability will be minimized by the following:

1. Adhering to standard operating procedures.
2. Assessing data and results against baseline and previous results for trend and changes.
3. Service provider staff training.
4. Assessing calibration and calibrating procedures.
5. Quality control checks for samples.

B.2. Sampling Methods

B.2.a/b. Sampling SOPs

Refer to the table below for stabilization criteria during well purging.

Laboratory SOPs have been developed by the service provider.

All procedures for sampling shall be consistent with the U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCEAA Project Mangers (May 2002).

Table 15. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.

Field Parameter	Stabilization Criteria
pH	+/- 0.01
Temperature	+/- 1 C
Specific conductance	+/- 3%

B.2.c. In-situ Monitoring

In-situ monitoring of water chemistry is not currently planned.

B.2.d. Continuous Monitoring

Pressure will be collected from monitoring wells.

B.2.e. Sample Homogenization, Composition, Filtration

To obtain a representative sample, each well will be purged at a flow rate between 10 GPM and 5- GPM. Samples will be collected within 24 hours of the well being purged. If a monitoring well will not supply adequate water for sampling, the condition of the well will be investigated and it may be considered for replacement.

Purging will continue until three successive measurements of the indicator parameters meet the stabilization criteria per Table 15.

B.2.f. Sample Containers and Volumes

Sample collection devices will be carefully chosen to minimize the potential for altering the quality of the sample. Teflon and stainless steel are preferred materials, although PVC, HDPE and other similar materials are considered sufficient in some cases.

Refer to the tables below as needed for sample container, preservation, and holding time information.

B.2.g. Sample Preservation

Samples will be preserved as per Table 17.

B.2.h. Cleaning/Decontamination of Sampling Equipment

Equipment used for sampling and other activities associated with on-site work will be de-contaminated before and after performance of a given activity. Disposable items will be disposed of as solid waste in an approved, permitted client facility.

B.2.i. Support Facilities

Support facilities will be provided by the service provider responsible for sampling and analysis.

B.2.j. Corrective Action, Personnel, and Documentation

The service provider will be responsible for testing instruments and equipment and preforming corrective action on defective equipment. Corrective action taken on equipment will be documented.

B.3. Sample Handling and Custody

B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 16 and 17 for holding times.

B.3.b. Sample Transportation

CTV will ensure that samples are delivered to the laboratory for analysis by the service provider as soon as possible following sample collection. Samples will be transported to the laboratory on the same day as the sample collection.

During transportation, precautions will be implemented to ensure that sample integrity is not affected by extreme temperatures and/or excessive vibration.

Upon arrival at the service provider the samples will be reviewed to ensure the following:

1. The sample arrived intact without container leakage or breakage.
2. Chain of custody documentation and sample labels agree
3. Confirmation that the sample was preserved correctly.

B.3.c. Sampling Documentation

For each test in the field, a worksheet will be compiled for each test interval documenting the procedures and results.

B.3.d. Sample Identification

Samples will be identified with the well location, date sample identification, sampler, and sample type.

Table 16. Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Gas Stream Analysis.

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	One-liter tedlar bag	None	72 hours

Table 17. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: Ca, Fe, Mg, K, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl	100 mL plastic	Nitric acid	180 days
Anions: Br, Cl, F, NO_3 and SO_4	100 mL plastic	None	48 hours
Dissolved CO_2	100 ml plastic	None	14 days
Isotopes: Carbon isotope 13	100 ml plastic	None	14 days
Alkalinity	100 mL plastic	None	14 days
H2S	100 mL plastic	NaOH	14 days
TDS	100 mL plastic	None	14 days

B.3.e. Sample Chain-of-Custody

Sample transport and handling will be strictly controlled by the service provider field technician to reduce the opportunity for tampered samples. Upon delivery to the laboratory samples will be given unique laboratory sample numbers and recorded in a logbook indicating the client, well number, date, and time of delivery.

B.4. Analytical Methods

B.4.a. Analytical SOPs

All procedures to sample and analyze groundwater will be consistent with the U.S. Environmental Protection Agency Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002).

B.4.b. Equipment/Instrumentation Needed

Service providers are expected to provide and utilize the equipment and instruments necessary to perform the required testing and analysis.

Examples of equipment and instrumentation includes safety equipment, sample jars, decontamination supplies, pH meter, EC meters, temperature gauges, and materials to document chain of custody, results, and labels.

B.4.c. Method Performance Criteria

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well define. Method performance criteria is not necessary.

B.4.d. Analytical Failure

Service providers conducting analysis are responsible for assessing and addressing analytical failure per their internal procedures and standards.

B.4.e. Sample Disposal

Service providers conducting analysis are responsible for proper sample disposal per internal procedures and standards.

B.4.f. Laboratory Turnaround

Laboratory turnaround times will vary by the analysis being conducted. CTV will communicate to service providers that a 30-day turnaround time for most analysis' is expected.

B.4.g. Method Validation for Nonstandard Methods

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well defined. Method performance criteria is not necessary.

B.5. Quality Control

B.5.a. QC activities

Field quality control may involve the collection of two types of QC blanks, trip, and field blanks, to verify that the sample collection and handling processes have not impaired quality of the final samples.

Trip blank – Trip blanks are prepared for VOC analysis and transported with the empty sample container.

Field Blank- the field blank will be taken in the field to evaluate if certain sampling or cleaning procedures result in cross-contamination of site samples or if atmospheric contamination has occurred.

B.5.b. Exceeding Control Limits

In the case that control limits are exceeded, CTV will review the sampling procedures and results. In the case of a valid test, refer to the Emergency Response Plan for water contamination procedures.

B.5.c. Calculating Applicable QC Statistics

Charge Balance - Solutions must be electrically neutral, the total sum of all the positive charges (cations) must equal the total sum of all negative charges (anions).

$$\text{Charge Balance:} \qquad \sum cations = \sum anions$$

Charge balance error (shown below) will be less than ±5% for acceptable water analyses.

$$CBE = \frac{\sum cations - |\sum anions|}{\sum cations + |\sum anions|} \times 100$$

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

The service provider will test, inspect, and maintain the instrumentation and equipment used for testing, this will be completed as per the manufacturer's guidelines and the standard operating procedures.

B.7. Instrument/Equipment Calibration and Frequency

B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges will be calibrated according to the manufacturer's recommendations. Calibration certificates will be kept on file.

Lab instrumentation and calibration will be checked weekly to ensure that results are within the control range of parameters.

B.7.b. Calibration Methodology

Instruments will be calibrated for accurate readings. Calibrations will be conducted with individual instrument SOP's and in accordance with the manufacturer's supplied manual for each instrument.

B.7.c. Calibration Resolution and Documentation

Instrument calibration resolution will be consistent with the manufacturer's recommendations. Documentation for instrument calibration will be maintained in a database.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

The service provider responsible for completing sample collection and analysis will be responsible for supplies and consumables.

Supplies and consumables used for sample collection and analysis will be selected to minimize the potential for altering the quality of the sample and analysis results.

B.9. Nondirect Measurements

B.9.a. Data Sources

Induced seismicity will be monitored continuously to ensure data consistency. CTV will partner with or use a third party to process the data.

B.9.b. Relevance to Project

Passive seismic monitoring will be used to assess induced seismicity events as an indicator of stress changes in the subsurface. Thresholds and response for induced seismic eventsare discussed further in the Emergency Response Plan.

B.9.c. Acceptance Criteria

Industry standard practices will be utilized for data gathering, processing and interpretation.

B.9.d. Resources/Facilities Needed

CTV will use a service provider for all necessary resources and facilities for passive seismic monitoring.

B.9.e. Validity Limits and Operating Conditions

CTV and service provider professionals will ensure that all results and processes are conducted as per standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

CTV will maintain the A1-A2 Storage project data internally. Data will be backed up and held on secure servers.

B.10.b. Recordkeeping and Tracking Practices

All data associated with the project will be held securely and associated meta-data will be gathered and maintained to ensure tracking purposes.

B.10.c. Data Handling Equipment/Procedures

CTV employs robust data management procedures to ensure security of data gathered from the field and external data sources.

B.10.d. Responsibility

Project managers will be responsible for ensuring data management is properly maintained.

B.10.e. Data Archival and Retrieval

CTV will hold all data associated with the A1-A2 Storage project. A data store will be developed for reporting and retrieval.

B.10.f. Hardware and Software Configurations

CTV will ensure that software and hardware are appropriate to integrate the multiple data sources and maintain large quantities of data.

B.10.g. Checklists and Forms

CTV will generate forms, checklists, and procedures as necessary to ensure management, security and quality of all data collected.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Monitoring results will be obtained as per Table 1. Results will be reviewed for QC criteria as per section B.5. In the case of data failure, new samples will be collected and analyzed. Evaluation for data consistency will be performed per the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

CTV will utilize service providers to analyze sample data. These organizations will be responsible for conducting their own internal assessments.

C.1.c. Assessment Reporting

Assessment information will be reported to the project leads as outlined in A.1.

C.1.d. Corrective Action

CTV owns the surface and mineral rights in the Elk Hills Oil Field. Corrective action issues, data collection, and monitoring data will all be handled by CTV.

C.2. Reports to Management

C.2.a/b. QA status Reports

CTV will notify the EPA and project leaders of QA report status if there are changes to the Testing and Monitoring Plan or the QASP.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Data validation will include the review of the results, chain of custody information, and review of the blank and duplicate information. All results will be stored in a database and compared to baseline and previous results. Data will be graphed to inspect trends and anomalies.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

Data will be verified by CTV upon receipt of results.

If anomalous data is suspected, CTV and the service provider will review the metadata associated with the sample to assess whether sampling, collection and the analysis conducted caused spurious results. In addition, instrument calibration will be reviewed if necessary.

D.2.b. Data Verification and Validation Responsibility

Data will be verified by CTV upon receipt of results.

D.2.c. Issue Resolution Process and Responsibility

CTV will oversee sample handling and assessment process. CTV management will determine actions necessary to resolve issues.

D.2.d. Checklist, Forms, and Calculations

CTV will develop checklists and a GIS database to store data, complete surveillance and ensure that permit requirements are met.

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

CTV will develop a GIS database that will be used for surveillance. The database will ensure data quality using methods consistent with USEPA 2009 Unified Guidance.

D.3.b. Data Limitations Reporting

Service provider management will be responsible for ensuring that analysis in their laboratory is presented with data use limitations for reporting.

Project leaders and managers will be responsible for ensuring that results are vetted and evaluated to determine if performance criteria are met.

References

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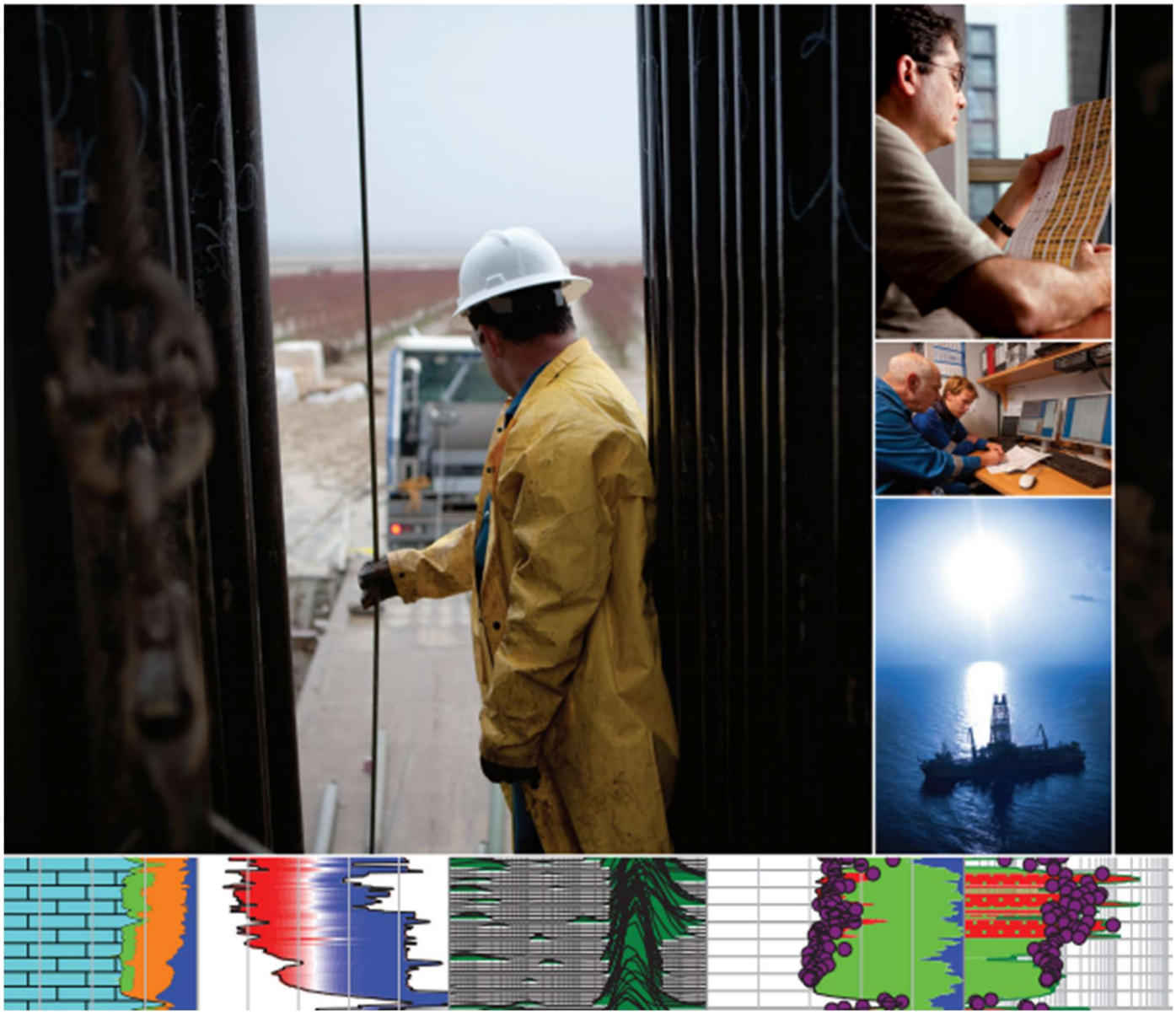
Appendices

Schlumberger Wireline Log Quality Reference Manual

Schlumberger

Wireline Log Quality Control Reference Manual



Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed[1]	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation[2]	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

[1] See Tool Planner application for advice on logging speed.
[2] Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	1 13/16 in [4.60 cm] With flask: 2¼ in [5.72 cm]	2⅞ in [7.30 cm]
Borehole size—max.	9⅝ in [24.45 cm] With flask: 9⅝ in [24.45 cm]	9⅝ in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

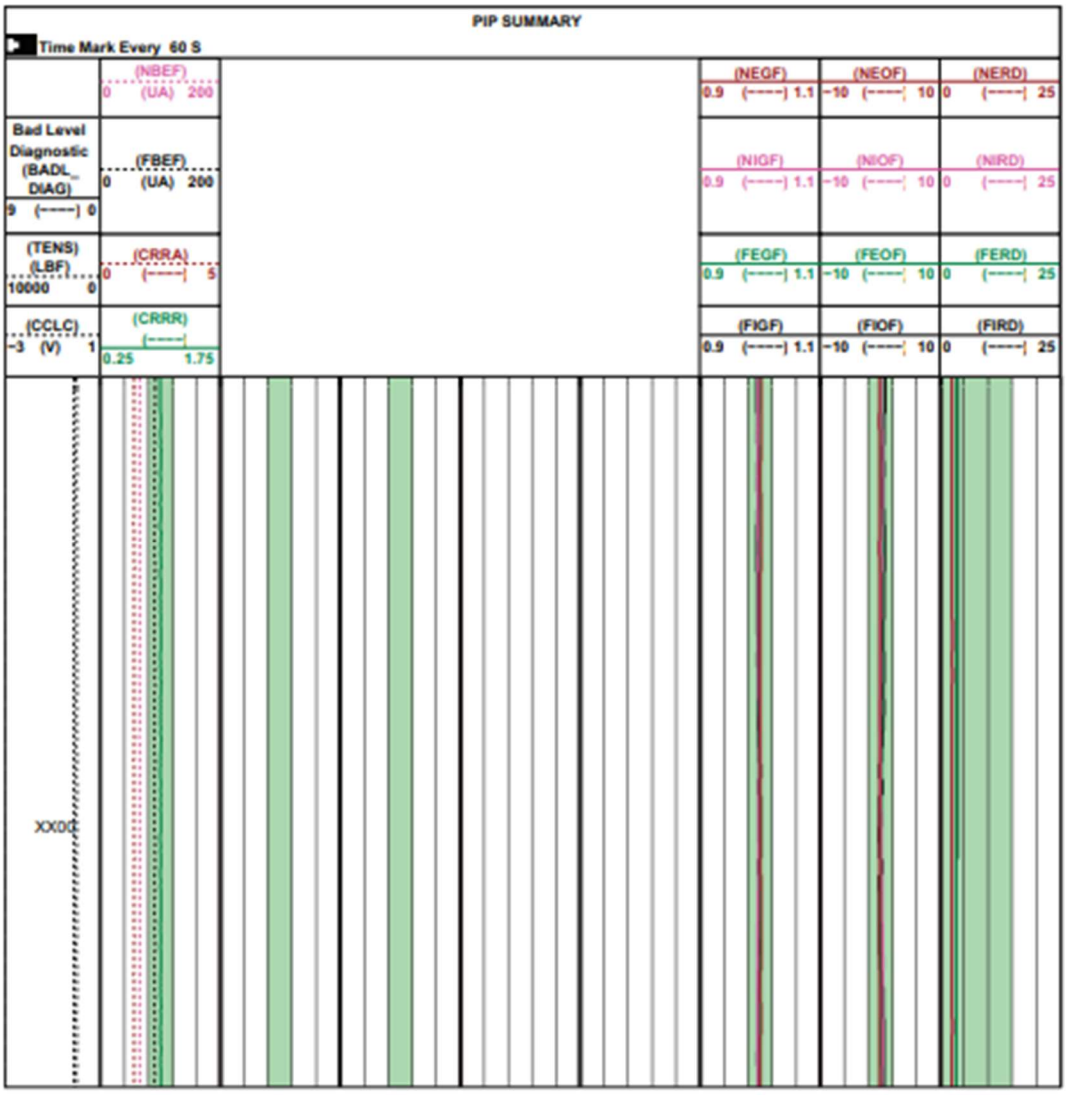


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

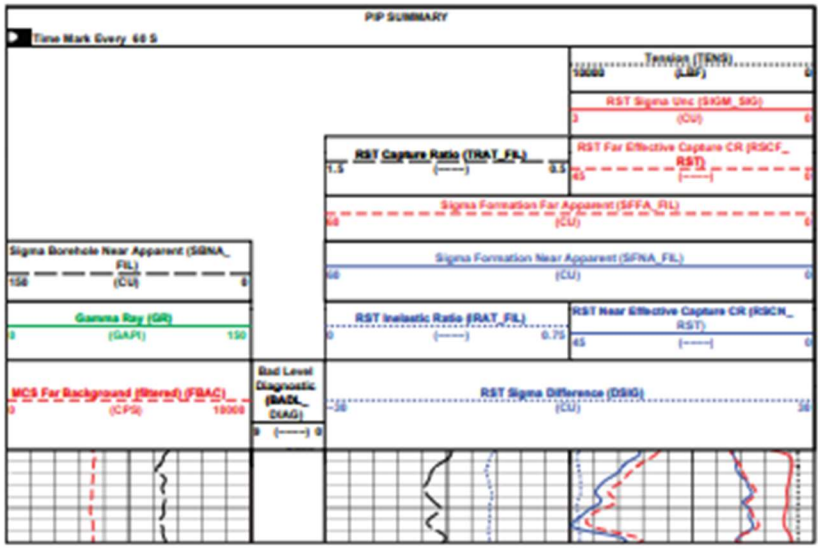


Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

Schlumberger

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h][†]
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

[†] Speed can be reduced depending on data quality.

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation[†]
SBI	Short bond index[†]
SCBL	Short synthetic CBL[†]
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

[†] In fast formations only

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

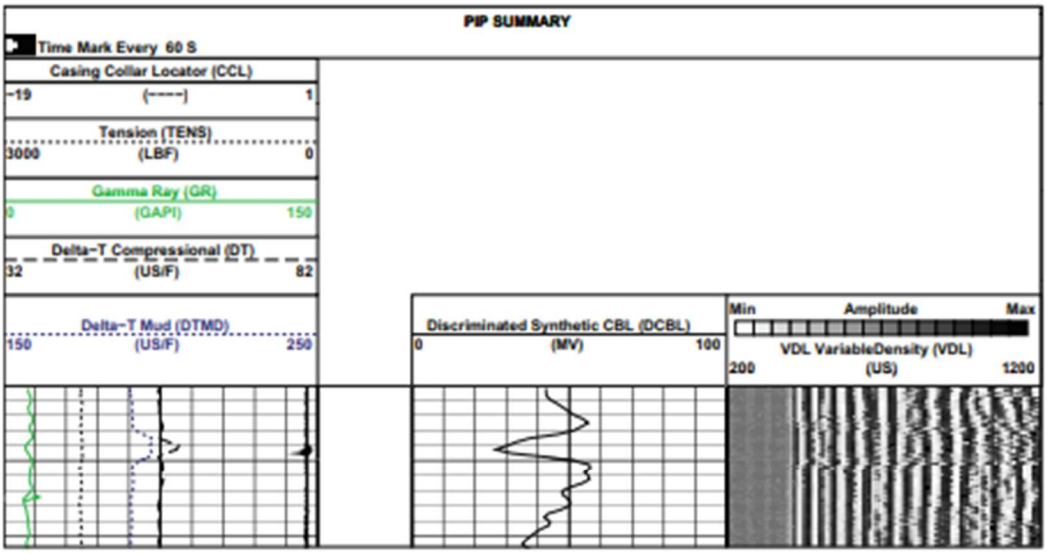


Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

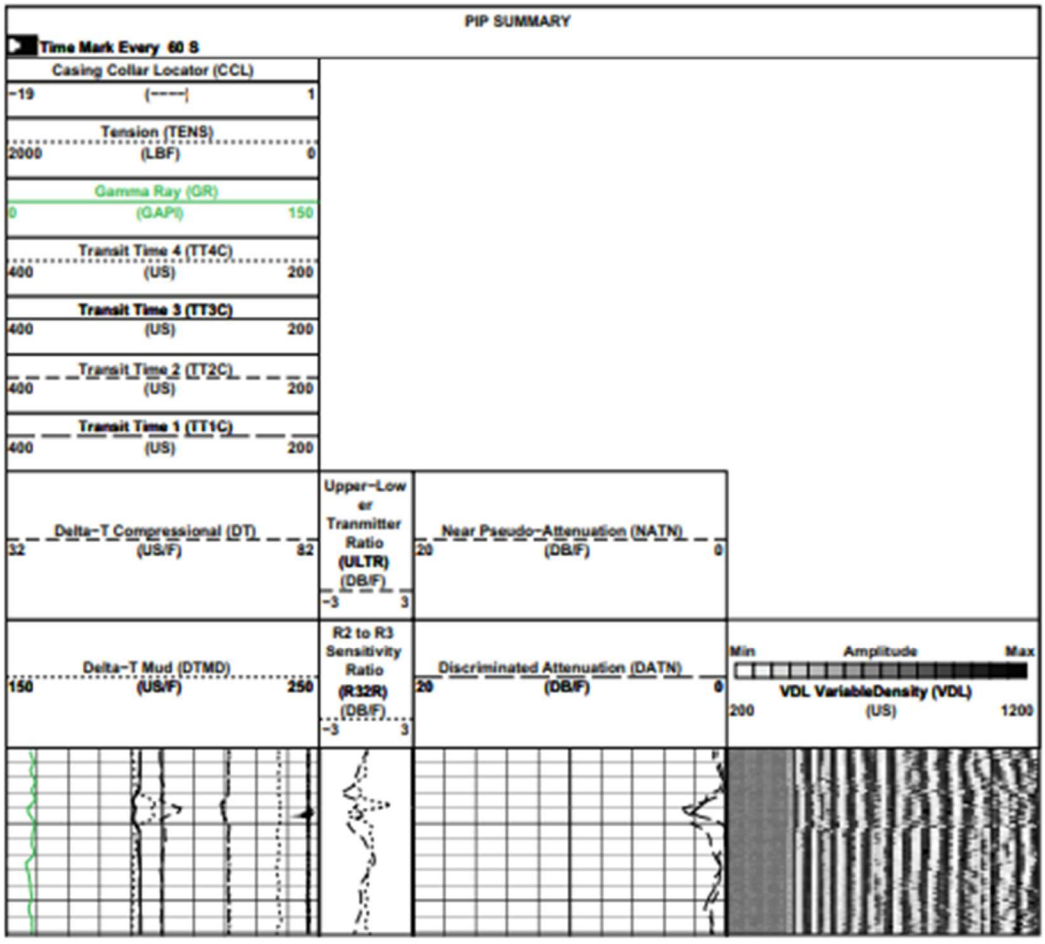


Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40[1]	52 ± 5	329	272	NM[2]

[1] Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.
[2] NM = not meaningful

Schlumberger

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)
Output	SLS-C, SLS-D, SLS-W, and SLS-E:[1] 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

[1] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications				
	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID—min.	5 in [12.70 cm]	5 in [12.70 cm]	3½ in [8.89 cm]	4 in [10.16 cm]
Casing ID—max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3⅝ in [9.21 cm]	3¾ in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers: 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers: 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 lbf [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,570 N]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

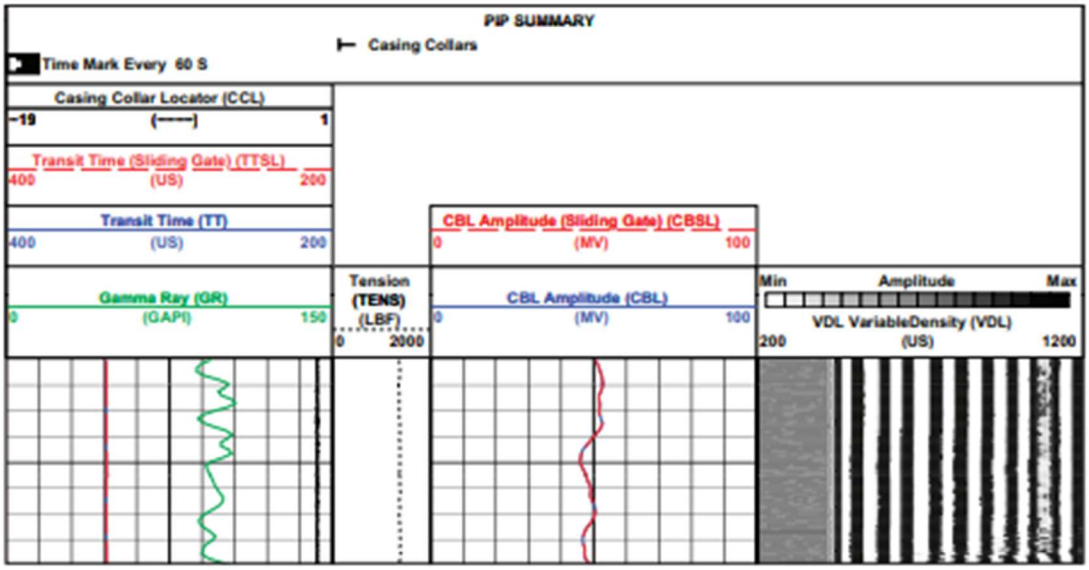


Figure 1. DSLT standard format.

Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4

ATTACHMENT I: STIMULATION PLAN

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: CTV I Elk Hills A1-A2 Project
357-7R and 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35°19'40.9189"N / 119°32'41.9057"W

Version History

File Name	Version	Date	Description of Change
Att I – Stimulation Plan_v1	1	05/16/22	Original document

Stimulation Plan

The need for stimulation to enhance the injectivity potential of the Monterey Formation A1-A2 reservoir is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 9 for review and approval prior to conducting any stimulation.

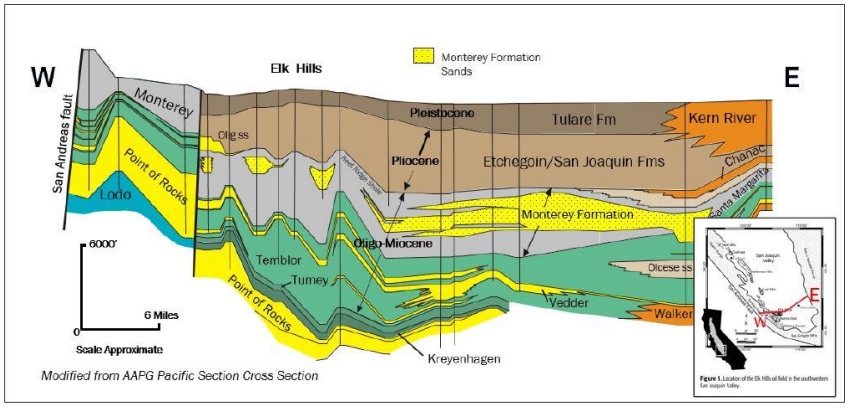
Computational and Static Modeling Evaluation of CTV A1-A2 Permit Nos. R9UIC-CA6-FY21-1.1 and R9UIC-CA6-FY21-1.2

This Computational and Static Modeling Evaluation report for the proposed Carbon TerraVault 1 LLC (CTV) Elk Hills A1-A2 Class VI geologic sequestration project summarizes EPA's review of the computational modeling performed by CTV as described in the Area of Review and Corrective Action Plan (AoR CA), which is Attachment B Version 3 (submitted November 4, 2022). This report also summarizes EPA's review of the geologic narrative submitted as Attachment A Version 3 (submitted June 20, 2022) of the permit application. Clarifying questions or requests for additional information are provided below in ***bold, italic*** text.

Static Modeling Comments and Geologic Site Conditions

This portion of the review assessed whether the information presented in Attachments A and B of the application could be independently verified with the data presented. The review evaluated whether statements and claims made in the text were supported by data. The comments below include requests that are necessary to determine if the statements made in the text are accurate.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



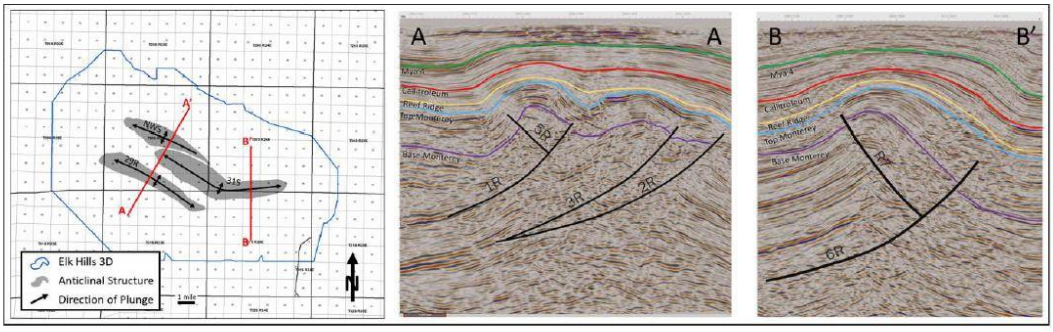
- Figure 3 in Attachment A, shown above, suggests that the Reef Ridge and Monterey Sands are time equivalent formations.
    - ***Please add a description to clarify that the Reef Ridge Formation is at the very top of the Monterey Formation.***
- Page 8 of Attachment A describes the San Joaquin Formation and Etchegoin Formation.
    - ***Is the base of the San Joaquin Formation an unconformity?***
    - It is stated that "This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW". However, there is no

analysis to support this statement. ***Please provide an analysis or data to support this statement.***

- When describing the Etchegoin Formation it is stated "Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below". ***What well data supports this statement? Please provide data to support this claim.***

- Page 9 of Attachment A describes the Monterey Formation.
  - It is stated that "Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer." ***What data was used to reach this determination?***
  - In the Summary section for the Monterey Formation, it is claimed "Both datasets support the geological framework establishing sand continuity and as well as vertical confinement by the Reef Ridge Shale and lateral reservoir confinement." The sentence is unclear and seems to be a circular reasoning. The statement also lacks supporting data and information. ***Please provide well correlations, seismic correlation and well communication data from previous production/injection to support the claim that static and dynamic data sets are consistent and prove sand continuity and vertical confinement.***
- Page 9 of Attachment A describes the A3-A11 reservoir.
  - ***Will there be concurrent operations between the A3-A11 reservoir waterflood and the A1-A2 reservoir CO2 injection? If yes, please describe the potential impact of having two concurrent operations.***

Figure 11: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.

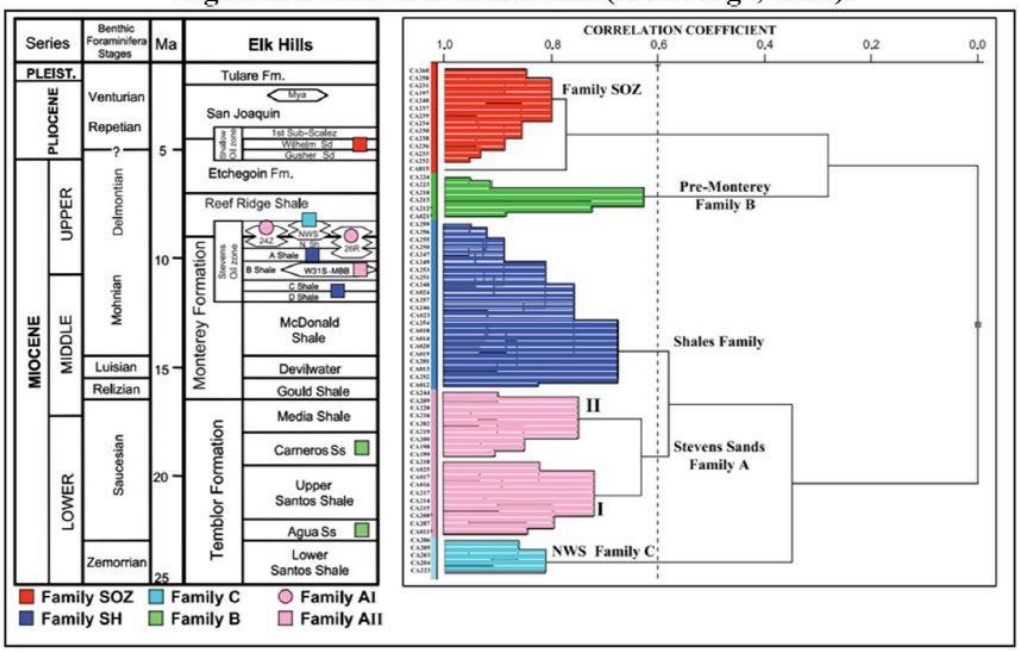


- Figure 11 in Attachment A, shown above, depicts the structure of the Elk Hills Oil Field (EHOF) anticlines.
  - ***Are there any wells that could be depicted in the cross section for reference? If so, please include the wells in the figure.***
  - ***Please include a scale on the figure.***

- ***The A' symbol is missing from the A-A' cross section. Please indicate which side of the cross section is A'.***
- ***Is the sharp kink in the top of the Monterey Formation in the A-A' cross section evidence of a fault? Please include reasoning as to why or why not.***

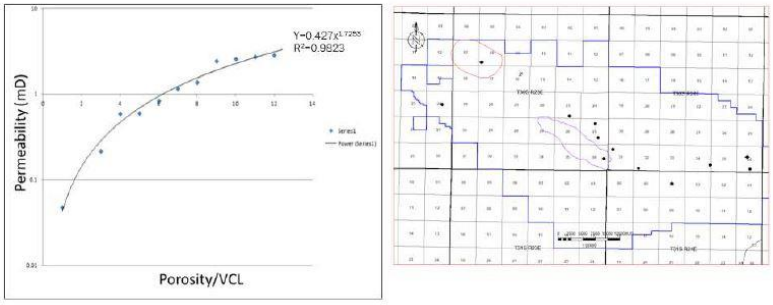
- The seismic control of the formation is described on page 13 of Attachment A.
  - It is stated that "The Reef Ridge is a thick continuous shale over the San Joaquin Basin." ***Please include a regional seismic diagram to verify the statement and Figure 12.***
  - Page 13 includes the statement "In the EHOF, the thickness averages 1,100 feet (Figure 12) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale." ***Please provide or explain the well data and seismic analysis that led to this determination.***

Figure 14: Elk Hills oil families (Zumberge, 2005).



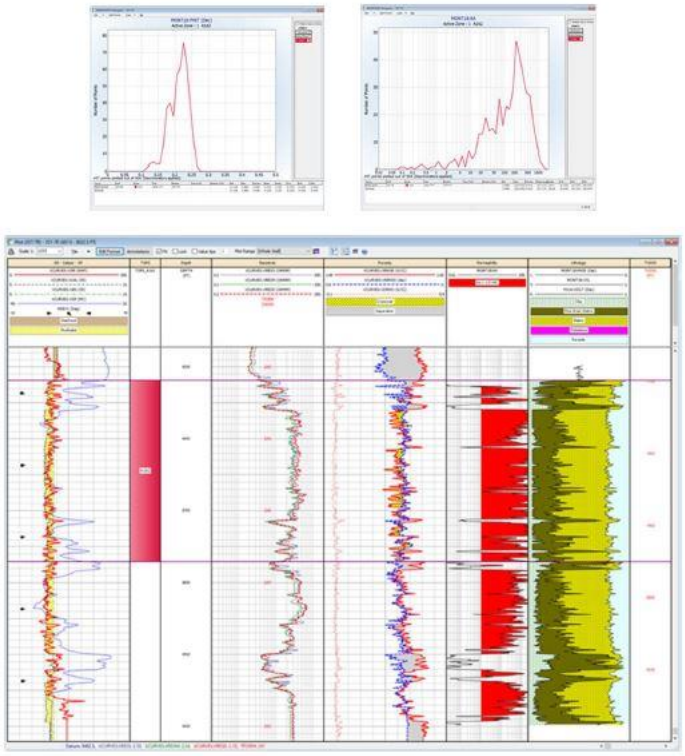
- Figure 14 in Attachment A (above) depicts the oil analysis performed in the Monterey and overlying formations.
  - ***Please provide the geochemical cross-plots to identify the hydrocarbon families***
  - ***Please include a discussion on how the geochemical data compares to the pressure plots.***

Figure 19: Permeability function developed based on mercury injection capillary pressure data and calculated from log derived porosity and clay volume. Map shows the locations for wells with Monterey Formation sand core data used in the function.



- Figure 19 in Attachment A, show above, includes a permeability curve, however there is little context, and it is difficult to interpret.
    - ***Does Figure 19 show an example or subset of the total data used to derive the permeability function in the figure?***
    - ***Please explain how the data in the figure relate to the permeability range of 3 mD to 1,500 mD and the average permeability of 45 mD?***
    - ***What location and depths were the permeability data collected from?***

Figure 20: Porosity and permeability for well 357-7R, showing the distribution and the input and output log curves.



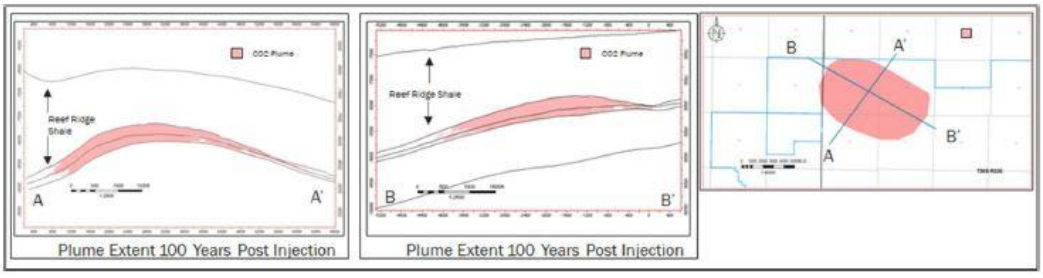
- Figure 20 in Attachment A, shown above, describes the porosity and permeability for well 357-7R. The lithology log shows no difference between the Reef Ridge Shale and the Monterey Sand.

    - ***Please described how the lithology log was created.***
    - ***Are the percentages of clay, fine grain matrix, matrix, and porosity very similar for the Monterey Formation and Reef Ridge Formation?***
    - ***Why does the lithology porosity percentage appear so similar between the two formations when the average porosity for the Monterey Formation is 21% and the average porosity for the Reef Ridge Formation is 7%?***
- The Reef Ridge ductility is described on page 23 of Attachment A.
    - ***If there is a leak-off test, or formation-integrity test data to demonstrate seal integrity of the Reef Ridge Formation, please submit it***.
- In the seismic risk section, the statement on page 31 "Has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected." This statement is misleading since the field was created by faults.
    - ***Please revise the statement to read accurately. For example, "free of known earthquake-prone faults" or "free of known active faults".***
- The statement on page 31 of Attachment A "There are no faults or fractures identified in the AoR that will impact the confinement of CO_2 injectate." This statement is misleading since the anticlines in the area are fault controlled.
    - ***Please revise the statement to represent that faults will contribute to the containment of CO_2 injectate.***

Model Design

This section of the review evaluated how the computational modeling was designed and incorporated the injection zone and confining zone geology. The review evaluated the appropriateness of assumptions, boundary conditions and choice of grid spacing. The comments below include requests to design the model with greater detail and provide information on assumptions made.

Figure 38: Plume modeling results showing lateral confinement of the CO2 plume by the edges of the anticline structure.

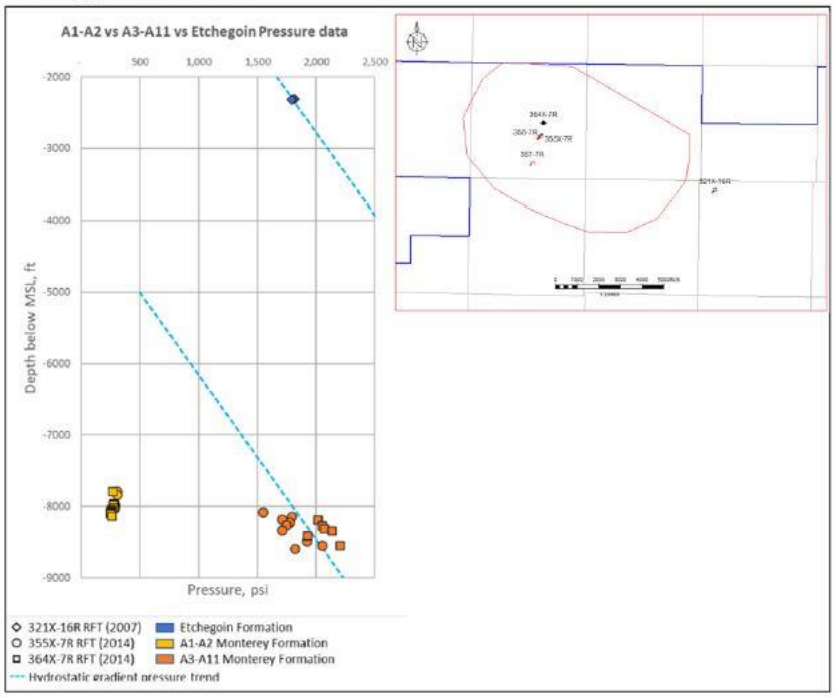


- Figure 38 in Attachment A, shown above, depicts the plume modeling results in the A1-A2 formation.

- ***Please add the injectors and monitoring wells to the figure or create a new figure to help illustrate where the penetrations in the injection zone are located with respect to the predicted CO_2 plume modeling results.***

- Page 5 of Attachment B states "Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties."
  - ***Was seismic data used to create the static model? If so, please describe how the data was incorporated.***
- Figure 4 in Attachment B states "The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale."
  - ***Please provide either a seismic section, well correlation panel, or both to support the statement made. Please show the pinchout and transitions to shale in both the dip and strike direction.***
- The Constitutive Relation section in Attachment B states "Material Balance is a well accepted method to determine the average saturations and fluid contacts in an oil and gas reservoir over time".
  - ***When was the last test or measurement that allowed for the determination of the gas-oil contact and oil-water contact at that time?***

Figure 11: Formation pressure data in the area gathered in 2007 and 2014, after the blowdown of the A1-A2 reservoir, showing large pressure differentials between the A1-A2 and the underlying (A3-A11) and overlying (Ethcegoin) reservoirs, which supports the conclusion of the A1-A2 reservoir being pressure isolated



- Figure 11 in Attachment B, shown above, presents pressure data from 2007-20014 in the AoR between different formations.

- ***This data was obtained during production operations. Is there any data representative of the initial project conditions, when production has ceased, that can demonstrate pressure isolation?***

Figure 112: Plan view showing the plume development through time for layer 15. Red dots ae the injectors, Blue dots are monitoring wells. Sections 8 and 17 have CO_2 in small quantities due to minor potential connected sand lenses, as the reservoir becomes shale dominated up-dip. It is highly unlikely that CO_2 will migrate to these areas.

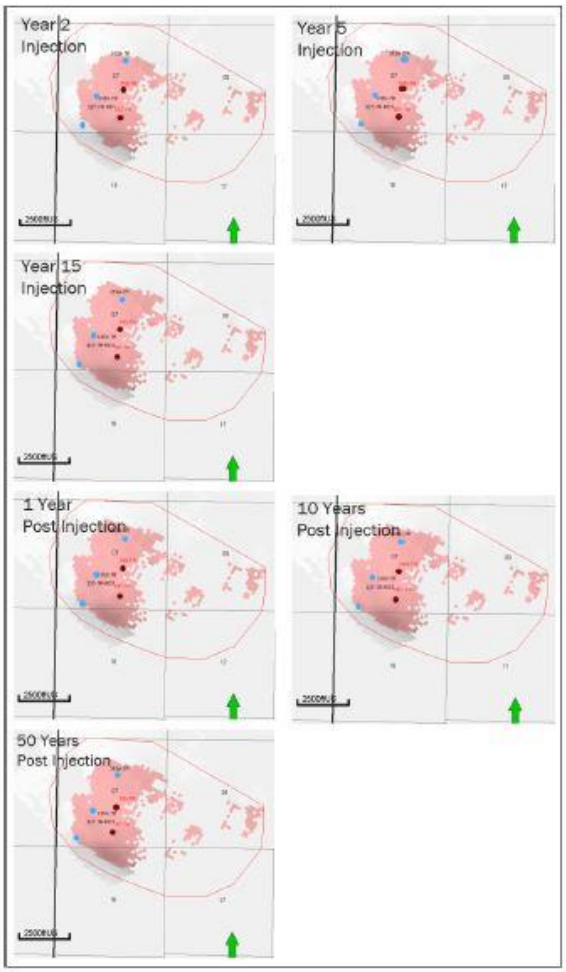
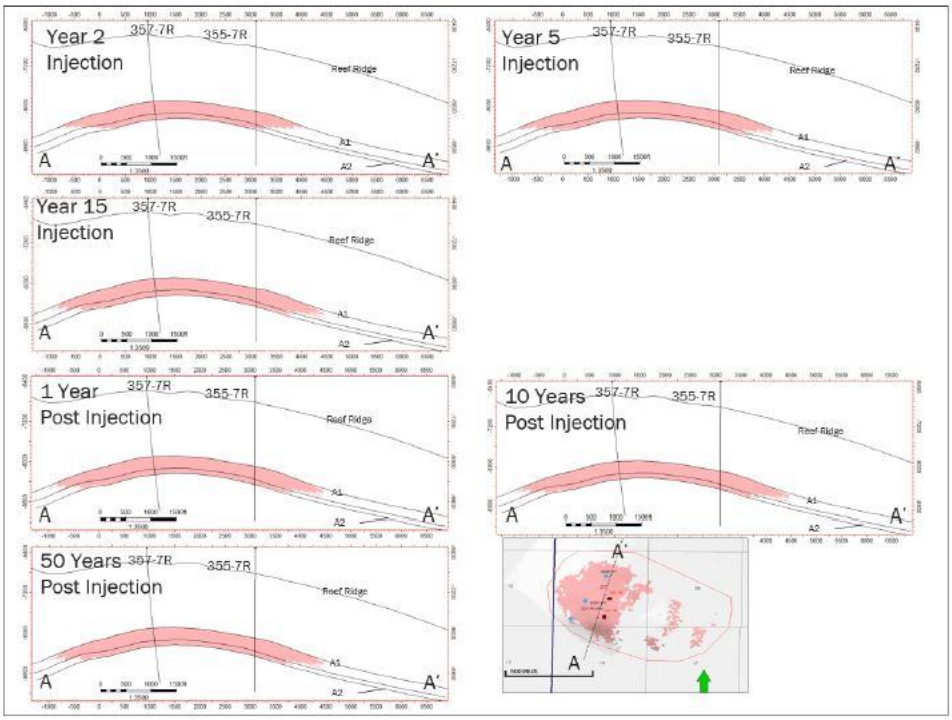


Figure 13: Cross-sections showing the plume development through varying times through the project.



- Figures 12 and 13 in Attachment B, shown above, illustrate plume development though various times of the project.
    - ***Please display the plume results to quantitatively show the saturation. Please include cross-sectional and plan view contour plots for both gas saturation and CO_2 saturation at various times in the project timeframe. Please include figures of the simulated pressure plume over time, both in plan and cross-sectional views.***
- Figure 13 in Attachment B (above) depicts the CO_2 plume reaching the upper boundary of the model.
    - ***Please explain how the spatial extent of the model is sufficient if the CO_2 plume reaches the boundaries.***
    - ***Please explain how no-flow boundary conditions are appropriate if the CO_2 plume reaches the boundaries.***
- The Model Calibration and Validation section in Attachment B describes the different sensitivities that were run.
    - ***Please describe any uncertainty there might be with the interpretation and imaging of the structure bounding faults.***
- The AoR Delineation section in Attachment B did not discuss whether there will be any concurrent operations in the area during the project timeframe.
    - ***Please include a description of known operations that will take place during the project timeframe and how that could affect the AoR delineation.***

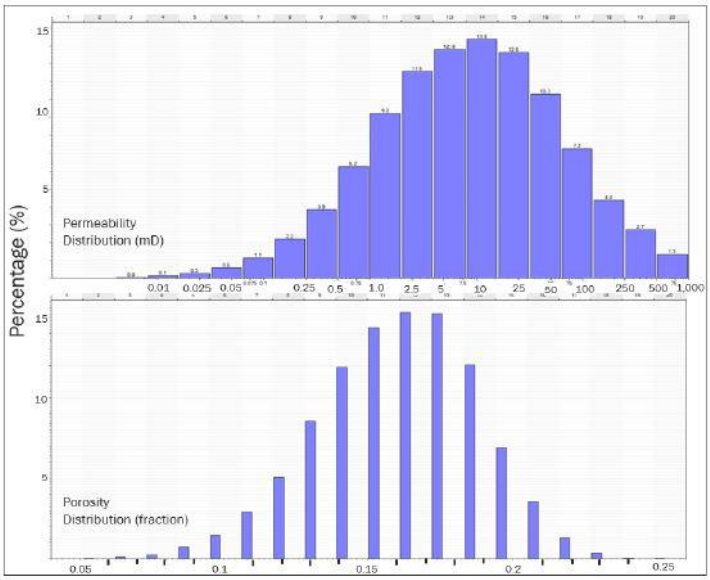
- The current x-y grid spacing around the injectors is too large to determine any near-field pressure effects.
    - ***Please analyze the reservoir with finer grid spacing around the injectors to illustrate near-field pressure buildup and determine that the maximum bottomhole pressure is accurately represented.***
- Attachment B does not describe how permeability anisotropy was incorporated.
    - ***Please discuss whether, or how permeability anisotropy was included in the model. Was any analysis done to determine differences between vertical and horizontal permeability?***
- Table 8 in Attachment B provides a summary of sensitivity cases. Case numbers 4 – 8 were run with increasing or decreasing the parameter by 10%. The 10% change appears to be arbitrary.
    - ***Please use a stochastic model to simulate sensitivities.***

Incorporation of Site-Specific Conditions

This section of the review verified that the geologic description provided in Attachment A was accurately incorporated in the computational model. This included reviewing the incorporation of initial site conditions and operating information. The comments below include requests that are necessary to understand the incorporation of the initial site data and ensure consistency.

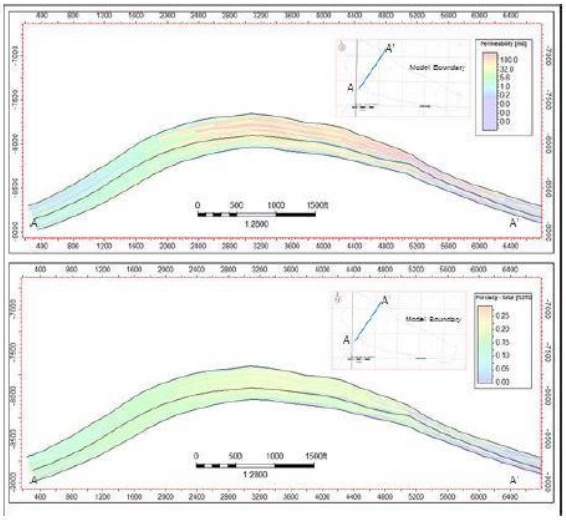
- Page 4 in Attachment B states "Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer." Recent profiles are important evidence for structural confinement.
    - ***Please provide recent pressure profiles and data.***
- Table 4 in Attachment B lists the initial reservoir temperature but there is no other information on how temperature was represented in the dynamic models.
    - ***Please explain how temperature was incorporated in the dynamic model initially and during injection.***

Figure 7: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.



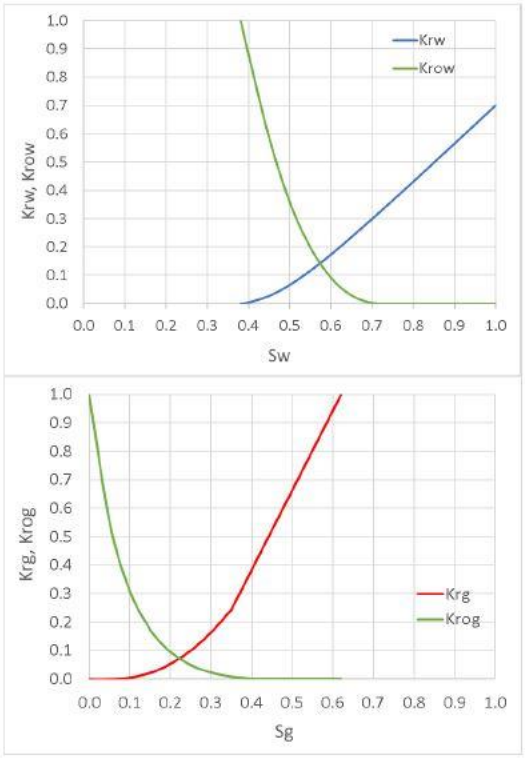
- Figure 7 in Attachment B shows porosity and permeability histograms for the Monterey Formation.
    - ***Please provide additional data (open-hole well log analysis) or other measured data that can be used to verify the permeability and porosity used in the static model.***

Figure 8: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



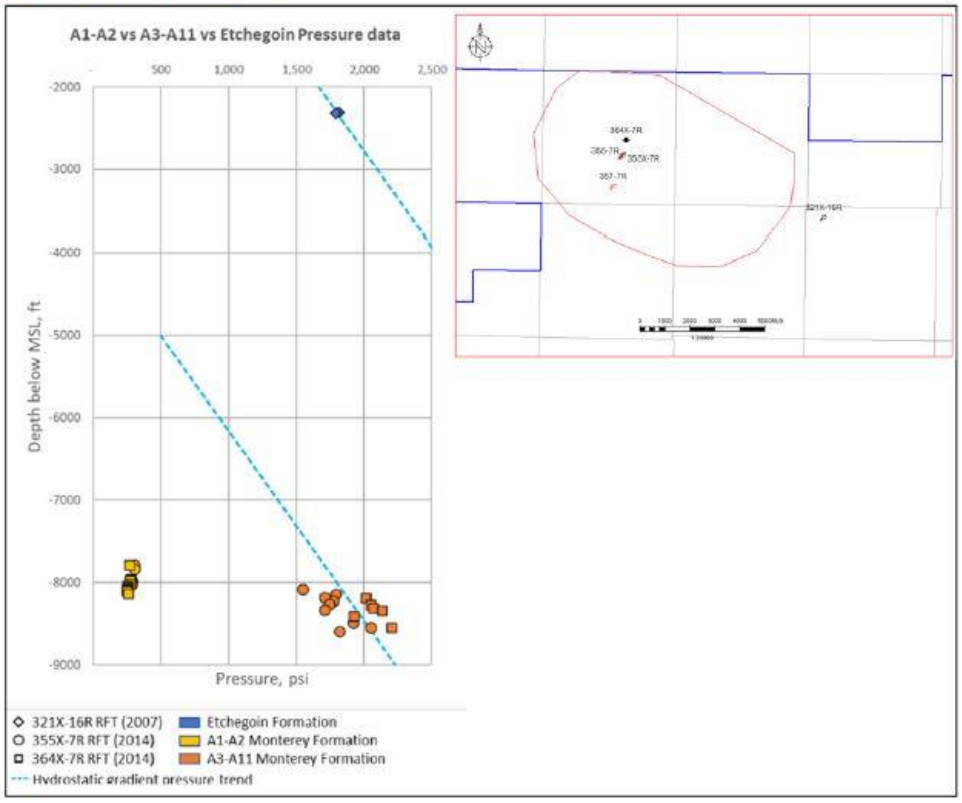
- Figure 8 in Attachment B shows the distribution of porosity and permeability of the reservoir at cross section A-A.
    - ***Additional visuals would help confirm the reservoir properties. Please provide a similar figure from a different cross section.***
- The Maps and Cross Sections of the AoR section in Attachment A mentions a "comprehensive database", however there is not a reference to the database or any other information about it.
    - ***Please include a reference for the database described.***
    - ***Which wells submitted in Figure 5 Attachment A provide the information in the permit application? What are the sources of information?***

Figure 9: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study (krow = relative permeability oil in an oil-water system, krg = relative permeability to gas in a gas-oil system, krw = relative permeability to water in an oil-water system, and krog = relative permeability to oil in a gas-oil system).



- Figure 9 in Attachment B shows the relative permeability curves used in the computational modeling.
    - ***Please provide the functional forms that were used to create the curves shown.***
    - ***Please include the data used to create the curves in a tabular form.***

Figure 11: Formation pressure data in the area gathered in 2007 and 2014, after the blowdown of the A1-A2 reservoir, showing large pressure differentials between the A1-A2 and the underlying (A3-A11) and overlying (Ethcegoin) reservoirs, which supports the conclusion of the A1-A2 reservoir being pressure isolated



- Figure 11 in Attachment B pressure data from 2014 for the A1-A2 and A3-A11 reservoirs are shown.
    - Pressure measured at different times is needed to assure there is no migration. ***Is there any measured pressure data over different times? If so, please provide it.***
    - Pressure in the Etchegoin Formation and A3-A11 reservoir is the same even though the y-axis shows their depth is very different. ***Please provide an explanation. If production from the A3-A11 reservoir resulted in pressure depletion, please include that in the explanation.***
- The fracture pressure (0.82 psi/ft) is based on stimulation performed on well 327-7R-RD1. However, no information is provided for the confining zone. It is stated on page 30 of Attachment A, "Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradient).".
    - ***Is there any data for the confining zone that supports the statement that the proposed injection pressure is lower than the confining zone fracture pressure? If so, please submit it.***
- The Geomechanical modeling section in Attachment A, describes a generic two-dimensional model constructed to represent the reservoir.

- ***How is the 2-D model with horizontal layering representative of the reservoir? Why was a 3-D model not used for the geomechanical evaluation?***

- Figure 35 in Attachment A shows the fluid composition for the A1-A2 reservoir, however detailed information on the fluid model for the dynamic model was not provided.
  - ***Please provide fluid composition (i.e., mole fraction of each component considered) and relevant model parameters (e.g., binary interaction coefficients for each pair for Peng-Robinson Equation of State (EoS) or adopted EoS, viscosity model and its coefficients).***
  - ***Please provide fluid model information based on results of the lab experiment (e.g., PVT experiment) analyzing up to date fluid sample from the site.***

Site Characterization Evaluation of the Carbon TerraVault (CTV) Class VI A1-A2 Permit Application

This geologic site characterization evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of the geologic narrative submitted as part of CTV's Class VI permit application (dated August 30, 2021). This review also identifies preliminary questions for the applicant. Where specific information is lacking based on the currently available information, this evaluation identifies testing objectives that EPA recommends be incorporated into the Pre-Operational Testing Plan.

Regional Geology and Geologic Structure

The Elk Hills Oil Field (EHOF) is in Kern County, California, in the southern San Joaquin Basin (Figures 1 and 2) CTV plans to inject CO_2 at the EHOF into the Monterey Formation via 2 injection wells, 355-7R and 357-7R, over a period of 15 years. The 2 injection wells are 1,250 feet apart and will inject into the Monterey Formation A1-A2 reservoir (Monterey A1-A2) at the Northwest Stevens Anticline at ~8,500 ft depth (Figure 8 and pg. 4).

The Monterey Formation at the EHOF also contains the Miocene Reef Ridge Shale (the primary confining zone), which directly overlies the Monterey A1-A2 and has been an effective seal for 40+ years of oil and gas operations (pg. 9). Figures 4 and 5 show the spatial distribution of wells in the EHOF and data available for use in characterizing the injection zone.

The Monterey A1-A2 consists of turbidite sands bounded above and below by siliceous shale (pg. 9). The application asserts that this depositional history has resulted in minimal lateral communication of the Monterey A1-A2 outside the EHOF (Cross Section Figure 3, pg. 4; pg. 9). The reservoir is continuous across the area of review (AoR), with pinch-outs on the channel edges (pg. 9).

The Upper Tulare Formation is the lowermost underground source of drinking water (USDW). The Tulare Formation consists of poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley (pg. 7). It is divided into the Upper Tulare and the Lower Tulare by the Amnicola Clay (a low permeability claystone). An aquifer exemption was approved for the Lower Tulare Formation in 2018, making the Upper Tulare Formation the lowermost USDW.

In addition to the Reef Ridge Shale, the Monterey A1-A2 Sands are separated from the lowermost USDW in the Upper Tulare Formation by the Amnicola Clay (pg. 31), the Lower Tulare Formation, the San Joaquin Formation, a depleted gas reservoir directly underlying the Tulare Formation, and the Etchegoin Formation (pg. 8). The Monterey A1-A2 Sands are separated from the underlying Monterey A3-A11 reservoir by a laterally continuous 20-foot shale known as the A2 Shale (Figure 9). The application asserts that they are not in communication, as evidenced by a pressure differential (of 200-300 psi in the A1-A2 and ~1,700 psi in the A3-A11), and the need for separate pressure maintenance strategies (pg. 10). The A3-A6 reservoir is also considered a viable target for future CO_2-EOR based on its existing waterflood injector infrastructure and high reservoir pressure (pg. 11).

Tests and logs performed during drilling and prior to completion of the 357-7R injection well and the 342-7R-RD1 and 327-7R-RD1 monitoring wells (which are completed in the Monterey Formation and are

located to the west and northwest of the injectors) include Array Compensated True Resistivity, SP logs, caliper logs, compensated spectral natural gamma log, spectral density dual spaced neutron log, and mud logs (Attachment G pg. 4-5). Cement bond logs and MIT tests (temperature log and SAPT) were also performed on the 357-7R injection well.

Questions/Requests for the Applicant:

- ***Please label the injection wells or the injection well site on Figure 2.***
- ***Was any data collected or testing performed during drilling of the 355-7R injection well? If so, please characterize this data.***
- ***The AoR and Corrective Action Plan (on pg. 3) states that, the "Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation." Please clarify the difference between the A2 Shale and the Lower Antelope Shale.***
- ***Does the Antelope Shale provide confinement? If so, please provide additional discussion of the confining properties.***
- ***What is the source of the statement about the pressure differential between the Monterey A1-A2 Sands and the Monterey A3-A11 Sands described on pg. 10?***
- ***Please provide pressure build-up test results for the 357-7R injection well.***
- ***Several of the figures in the narrative that contain data are difficult to read (e.g., Figures 14 and 15); please provide higher resolution versions of this information.***
- ***Please provide a map of the Elk Hills Oil Field that shows the 355-7R and 357-7R injection wells, along with the wells planned for the Elk Hills 26R Storage Project (with a scale that shows distances).***

Objectives for Pre-Operational Testing:

- ***Confirm hydraulic separation of the Monterey A1-A2 Sands and the Monterey Formation A3-A11 reservoir.***
- ***If no pressure build-up test results exist for the 357-7R injection well, perform pressure build-up testing as part of the Pre-Operational Testing Plan.***

Faults and Fractures

The 31S and Northwest Stevens (NWS) anticlines in the EHOF are separated by mid-Miocene thrust faults (pg. 12). The application states that the Reef Ridge Shale and Monterey Formation are well resolved based on seismic data, and there is no evidence of faults penetrating the Reef Ridge Shale or transecting the Monterey Formation (pg. 13). Figure 10 shows reverse faults in seismic profiles, however the resolution is too low to discern formation labels (pg.12). These reverse faults, oriented NW-SE, offset the NWS anticline (pg. 12).

Evidence for confinement includes 3D seismic and well data confirming the absence of faults penetrating the Reef Ridge Shale, 40+ years of previous waterflooding and gas injection operation, pressure differentials across formations (i.e., 230 psi in the Monterey A1-A2 Sands and 1,500 psi in the Etchegoin Formation for a 0.43 psi/ft pressure gradient at 3,600 ft depth), and geochemical analysis of 66 oil samples (Zumberge, 2005; Figure 12).

Questions/Requests for the Applicant:

- ***Please update Figure 10 to clearly label the formations in which the thrust faults terminate.***
- ***Where were the 66 oil samples collected within the EHOF described on pp 13-14, relative to faults within the field?***

Depth, Areal Extent, and Thickness of the Injection and Confining Zones

At the site of the injection wells, the stratigraphic sequence from top to bottom consists of the Tulare Formation, the San Joaquin and Etchegoin Formations, the Reef Ridge Shale confining zone, and the Monterey Formation injection zone (pg. 4, 7). The depths and thicknesses of the injection and confining zones were determined based on wireline logs and 3D seismic data and are presented in Table 1 of the application narrative. In the AoR, the Reef Ridge Shale thickness is controlled by the Monterey Formation deposition patterns and minimum thickness corresponds to a highpoint in the Monterey Formation Sand thickness (pg. 15).

The table below summarizes the depth and thickness of the formations of interest according to available data in the permit application narrative. Some depth/thickness information for the San Joaquin or Etchegoin Formations was not provided; however, this is not critical for the purposes of the application evaluation. Porosity and permeability data are presented as well; additional discussion of these characteristics is provided under "Geomechanical and Petrophysical Characterization."

Unit	**Average Depth within the AoR**	**Thickness Across the AoR**	**Porosity**	**Permeability**
Tulare Formation	600-2,500 ft (pg. 31)	1,200-1,500 ft (pg. 31)	34-40% (pg. 7)	1,410-8,150 mD (pg. 7)
San Joaquin Formation	Not given	Not Given	28%-45% (pg. 8)	64-6,810 mD (pg. 8)
Etchegoin Formation	1,500-4,000 ft (pg. 8)	Not Given	29-37% (pg. 9)	32-826 mD (pg. 9)
Reef Ridge Shale (Confining Zone)	6,929 ft-7,962 ft TVD (Table 1, Figure 13)	1,122-1,892 ft (Table 1, Figure 13)	7.7% (pg. 6); 7% (pg.9); 4 to 14% (Table 2)	0.01 mD (pg. 9); 0.00003 to 0.0917 mD (Table 2)
Monterey Formation A1-A2 Sands (Injection Zone)	8,403 ft – 9,598 ft TVD (Table 1, Figure 13)	27-548 ft (Table 1, Figure 13)	11%-27% (Figures 16 and 17); 16% (pg. 9)	0.1-1,300 mD (Figures 16 and 17); 60 mD (pg. 9)

Questions/Requests for the Applicant:

- ***The depths listed in Table 1 for the Monterey A1-A2 Sands are inconsistent with the logs in Figure 9. It appears, based on the log, that the depth to the Monterey A1-A2 Sands is ~8,500 feet MD or ~7,700 feet TVD at the 357-7R injection well, not 8,403 feet TVD as stated in Table 1. The mean depth to the Monterey Formation is also listed as 5,907 ft when the low and high depths are listed as 8,403 ft and 9,589 ft respectively. Please clarify the discrepancy or revise Table 1.***

- ***There is a typo on Figure 16, "Capitally" for Mercury Injection Capillary* Pressure. Please fix this when the application is updated.**
- ***Please characterize, name, and provide depth and permeability data for the underlying confining unit, if one exists.***

Hydrologic and Hydrogeologic Information

The Lower Tulare Formation, which conformably overlies the shallow marine deposits of the San Joaquin Formation, was approved as an exempt aquifer in 2018. The Upper Tulare Formation is the only USDW in the AoR (pg. 7). The regional extent of the exempted portions of the Lower Tulare Formation is shown in Figures 7, 26, and 29. It extends well beyond the AoR in the southern direction but closely borders the AoR to the north. The depth to the lowest USDW in the Upper Tulare is shown in Figure 28; however, the figure is difficult to read.

The San Joaquin Basin has no appreciable surface or subsurface outflow (pg. 35). The primary source of surface water and fresh groundwater is the Kern River, which drains to the southeast and terminates near the EHOF (pg. 35). Low precipitation rates and high evaporation rates result in almost no groundwater recharge from precipitation, leading to high salinity and TDS concentrations (pg. 35). CTV did not find any water supply wells within the AoR after a search of CALGEM, USGS, Kern County Water Agency (KCWA), West Kern Water District, and the GeoTracker Groundwater Ambient Monitoring and Assessment online database (pg. 36). CTV owns the surface area of the EHOF (pg.35).

Questions/Requests for the Applicant:

- ***It appears that Figure 26 provides information on the depth and regional extent of the area shown in cross section with wireline logs for TDS content, however the resolution is low (pg. 31). Please provide a higher resolution version of Figure 26.***
- ***What is the depth of the Upper Tulare Formation and the separation of this lowermost USDW from the injection zone and the confining zone within the AoR?***
- ***Is the Upper Tulare USDW present within the modeled AoR of the injection wells?***

Geochemistry/Geochemical Data

Limited baseline geochemical data for the Upper Tulare Formation (USDW) and Monterey Formation (injection zone) are provided in the application.

Figure 30 shows the results of water analysis performed on waters from the Upper and Lower Tulare Formations. The produced fluid has been collected during previous operations to establish a baseline and characterize the region. Hydrocarbon content in the injection zone was determined through fractional distillation and chromatography (pg. 37). Figure 30 is difficult to read, but it appears that the analysis is from 1995, and the analytes include some, but not all, of those planned as part of injection and post-injection phase monitoring. The TDS values of the Upper Tulare Formation appear to be 4,800-4,900 mg/L.

The application states that water sampling was not performed in the Monterey A1-A2 Sands because reservoir depletion has reduced water saturation to residual levels. However, geochemical analysis was

performed using fluid produced during oil and gas operations (pg.37). CTV provides an example of the water geochemistry analysis taken from well 381-17R from a sand underlying the Monterey A1-A2 Sands (Figure 31). Figure 33 presents a 2021 analysis from nearby Well 353-7R. The figure is difficult to read, so it is unclear what analytes were measured, and if all the analytes planned during operational testing are addressed. It appears that the TDS of the Monterey A1-A2 Sands is about 24,000 mg/L.

CTV's Testing and Monitoring Plan (Attachment C) includes monitoring the overlying Etchegoin/San Joaquin Formations and the Tulare Formation for groundwater quality and geochemical changes and the Monterey Formation as part of direct plume tracking activities. Water quality will need to be established in each of these formations prior to injection operations to provide a baseline for comparison to future monitoring results.

Questions/Requests for the Applicant:

- ***Please provide clear/legible versions of the sample analyses in Figures 30 and 31 to allow a review of the sampling performed.***
- ***Where is Well 381-17R?***
- ***What is the total dissolved solids (TDS) content of the Monterey Formation? Please indicate how many data points or measurements are available to support this measurement (i.e., based on past field operations) and, if they are not from throughout the AoR, please provide information to support a determination that the Monterey Formation is not a USDW.***
- ***Is any water quality data available for the Etchegoin Formation? If so, please provide this.***
- ***In the Testing and Monitoring Plan, CTV states that they obtained a baseline analysis for the 61WS-8R well (apparently for the Tulare Formation). Please provide this analysis if it is not the same as is provided in Figure 30.***

Objectives for Pre-Operational Testing:

- ***Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan.***

Geomechanical and Petrophysical Characterization

Capillary pressure was determined using mercury injection capillary pressure analysis from 18 wells. The average rock strength of the confining zone is 2,452 psi according to brittleness calculations and the average ductility of the confining zone is 1.24 as derived from compressional sonic data from 18 wells with 59,214 data points using a calculation methodology from Ingram and Urai (1999) and Ingram et al. (1997) (pg.23). The applicant concludes that brittleness of less than 2 is evidence that the confining layer is sufficiently ductile to "anneal" discontinuities and that there are no fractures for fluid migration (Figure 19). The application states that this conclusion is further supported by historical water and gas injection data at the site in addition to millions of years of confinement of oil and gas in the Monterey Formation by the Reef Ridge Shale (pg. 23).

In the EHOF, the maximum principal stress direction is northeast-southwest as determined by a study of EHOF fracture gradients and borehole breakout (Castillo, 1997; Figure 21) Table 3 of the application narrative is reproduced below.

Stress	Reef Ridge Shale Confining Layer (Well: 374A-7R-RD1)	Monterey Formation A1-A2 Reservoir (Well: 372-7R-RD1)
Pore Pressure Gradient (psi/foot)	0.433	0.2
Overburden Gradient (psi/foot)	0.93	0.94
Minimum Horizontal Stress Gradient (psi/foot)	0.73	0.97

The GEOMECH geomechanical model, along with the GEM equation of state compositional reservoir simulator, were used to determine failure pressures under a base case and three additional scenarios; this modeling is described on pages 25-28 of the application narrative. Descriptions of variations from the base case for other scenarios are given below:

- Reduced Young's Modulus: to model uncertainty in the cap rock Young's Modulus, a second case was run with a value of 8E05 psi.
- Reduced Injection Rate: sensitivity to injection rate was studied by reducing the injection rate to 20 million cbf per day.
- Thinner cap rock: the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet.

Table 4 of the application narrative, which presents the results of the modeling, is reproduced below:

Geomechanical Scenario Results	
Scenario	**Failure pressure (psi)**
Base Case	8,306
Reduced Young's Modulus	8,388
Reduced Injection Rate	8,340
Thinner Cap Rock	7,600

Figure 23 shows the change in normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. See also the evaluation of the AoR CA (Attachment B) for additional information.

Porosity and Permeability

As shown in the table under "Depth, Areal Extent, and Thickness of the Injection and Confining Zones," above, porosity values for the Reef Ridge Shale are approximately 7-14% and reported porosities of the Monterey A1-A2 Sands range from 11%-27%. The permeability of the Reef Ridge Shale is about 0.01 mD, and Monterey Formation permeability ranges from 0.1-1,300 mD. Permeability and porosity for the Reef Ridge Shale in the 355X-30R well are presented in Table 2 of the application.

Formation porosity and permeability used as inputs for the geomodel were determined using wireline log data, including SP logs, gamma ray, borehole caliper, resistivity, neutron porosity, and bulk density (pg. 17). Porosity is determined from bulk density using a 2.65 matrix density calibrated from particle density (Figure 15) and porosity data. Clay volume is determined from neutron-density separation and is calibrated to core data. A permeability function was calculated using mercury injection capillary

pressure porosity and clay values (Figure 16). The application states (on pg. 17) that core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. However, it is unclear which wells are the source of this data.

Questions/Requests for the Applicant:

- ***Please update Figure 23 to include base case pressure.***
- ***Please discuss the selection of the base case parameter values (i.e., Young's Modulus, thickness, etc.) in the geomechanical modeling.***
- ***Please explain what is meant by "anneal discontinuities" in the discussion on page 23.***
- ***The application references core data from 13 wells on page 17.***
    - ***To which wells does this refer and where are they located?***
    - ***If they are not distributed throughout the AoR, please describe how they are representative of the entire area that will be affected by injection.***
- ***Where are the 18 wells that are the source of ductility data referred to on pg. 23 located?***
- ***The application states that, "The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of .8 psi/foot," and that, "the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI" (pg. 46). Please clarify the sources of data used to determine failure pressure, fracture pressure, and fracture gradient.***

Mineralogy of the Injection and Confining Zones

X-ray diffraction (XRD) data from 108 data points in 9 wells was analyzed to determine injection zone mineralogy. Fourier Transform Infrared Spectroscopy from 36 points in 1 well located outside the AoR but within the EHOF was used to characterize confining zone mineralogy (pg. 16-17). Figure 14 presents an example XRD analysis from well 367-7R located within the AoR. The applicant addresses the use of a single well for characterizing the mineralogy of the confining zone, citing that it is representative of the formation because of depositional continuity and consistency of facies and properties within the EHOF (Figure 15).

The Monterey A1-A2 Sand intervals consist of 43% quartz, 38% potassium feldspar, albite, and oligoclase as well as 7% total clay. The Reef Ridge Shale consists of 47.1% silica polymorphs (Opal-CT, chert, and cristobalite), 29.5% total clay, 14.5% potassium feldspar, albite, and oligoclase, and 3.7% quartz (pg.16).

Questions/Requests for the Applicant:

- ***Please provide a map of the 9 well locations used for XRD described on pages 16-17.***
- ***What evidence is there for depositional continuity and facies consistency within the EHOF, as described on page 17?***

Seismic History and Seismic Risk

The application notes that the "EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills

area (DOE, 1997)" (pg.29). Seismic activity in the region stems from the San Andreas Fault (12 miles west of the project site) and the White Wolf fault (25 miles southeast of the site) (pg. 29). Regional seismic data dating back to 1932 was gathered from the Southern California Earthquake Data Center (SCEDC) and USGS databases (Pg.29).

Figure 24 shows the eight (8) magnitude 5.0 or greater earthquakes that have occurred within a 30-mile radius of the EHOF. These earthquakes have an average depth of 6.3 miles, well below the Monterey Formation (pg.29). It is stated that there have been no earthquakes within the EHOF greater than magnitude 3.0. Site characteristics, including low factor amplification due to thin sediment, high density soil, and soft rock, based on shear-wave velocity (V_S) are asserted to further reduce seismic risk. The largest known earthquake in the region was a 7.5 magnitude 1952 earthquake in nearby Kern County which did not affect reservoir containment (pg. 30).

CTV will install borehole and surface seismometers to establish a baseline and assess natural and induced seismicity (pg. 29).

The evaluation of seismic risk also reflects other elements of the comprehensive permit application review (described elsewhere in this report), including porosity and permeability of the injection and confining zones; regional structural features; information on faults in the vicinity of the project site; formation pressure; and the geomechanical properties of the injection and confining zones.

Seismic risk and risk mitigation will also be considered in the review of the following aspects of the permit application:

- Predictions of plume and pressure front behavior over time, including pressure build-up over time, and pressure dissipation following cessation of injection.
- The ability of the injection well to maintain mechanical integrity under stress.
- Wells within the project area and the status of well corrective action.
- Planned injection pressures.
- Seismic monitoring and emergency and remedial response planning.

Questions/Requests for the Applicant:

- ***Please include all earthquakes of magnitude 3.0 and above in Figure 24.***
- ***To inform an evaluation and documentation that there is no significant seismic risk, EPA recommends that CTV describe how the project:***
  - ***has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected.***
  - ***will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;***
  - ***will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and***
  - ***poses a low risk of inducing a felt seismic event.***

Objectives for Pre-Operational Testing:

- ***Establish baseline seismicity after borehole and surface seismometers are installed.***

Surface Air and/or Soil Gas Monitoring Data

No soil gas or surface air data were submitted with the permit application. At this point, we do not believe this will be necessary; however, if the results of future reviews necessitate surface air and/or soil gas monitoring, we would request baseline data.

Facies Changes in the Injection or Confining Zones

Depths to the confining and injection zones are presented on structural and isopach maps based on 3D seismic and wireline log data (Figure 13). However, the locations and number of wells used to characterize formation depths was not provided.

Figure 3 of the application shows a cross section of formations across the San Joaquin Basin and Figure 6 shows a stratigraphic cross section with well types for the Northwest Stevens anticline. Figure 12 shows a stratigraphic column with oil samples grouped into families. There appear to be logs on the figure used to correlate formations laterally, but they could not be distinguished.

Page 41 of the application describes the development of a geo-cellular model as part of the A1-A2 reservoir characterization and plume modeling. This is supported by cross sections in Figures 34 and 35 (which appear to be outputs of the AoR delineation model) that the applicant asserts also demonstrate the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers also supports predictable plume development. The application states that the modeled plume migration (Figures 34 and 35) is consistent with the structure of the anticline.

Figure 4 identifies "data coverage" for the Reef Ridge Shale and per Figures 5 and 8, several wells have core data in the Reef Ridge Shale and the Monterey Formation; however, it is unclear what information is available from the wells on the map and how it informed the application.

On page 11, the application concludes that the Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core data, as well as 3D seismic data. Discussion and questions for the applicant regarding lateral continuity of the Confining Zone are discussed above in the section on "Mineralogy of the Injection and Confining Zones."

Questions/Requests for the Applicant:

- ***Please clarify what data sources were used to determine inputs for the geomodel where applicable, e.g., the inputs for sand vs. shale facies as discussed on pg. 40.***
- ***Please also discuss how a sufficient number and distribution of formation characterization data are available to demonstrate a lack of local heterogeneities that could affect storage or confinement of CO_2.***
- ***Please specify the names, number, and locations of wells used to characterize formation thicknesses for the maps in Figure 13.***

Objectives for Pre-Operational Testing:

- ***Determine if there are any heterogeneities within the Monterey A1-A2 Sands that could affect its suitability for injection, including facies changes that could facilitate preferential flow.***

Structure of the Injection and Confining Zones

Regional structure of the injection and confining zones is controlled by San Andreas Fault development resulting in mid-Miocene anticlines (pg. 3). The application describes the anticlines that form the Elk Hills Oil Field, which CTV asserts will contribute to confinement. See the discussions of "Regional Geology and Geologic Structure" and "Faults and Fractures," above.

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

The proposed injectate will consist of at least 95% CO_2 with mixtures of water and oxygen that will be controlled for corrosion mitigation (pg. 46). The applicant states that corrosiveness of the stream will be "very low as long as the entrained water is kept in solution with the CO_2" which will be accomplished by limiting its water content (pg. 46).

Existing subsurface fluid information is based on extensive and ongoing CO_2 injection activity in the EHOF region. CTV has injected 6.3 billion cubic feet of gas containing up to 44% CO_2 into the Monterey A1-A2 Sands since 2011 without any changes to injectivity (pg. 38-39). A 2021 analysis from an oil sample in the 353-7R well showed a 6.5 mole % CO_2 content (pg. 38). The applicant states that low water volume in the formation (15% saturation in the gas cap and 85% in the thin oil band) and low residual oil saturation (15%) will also dissolve only a small amount of CO_2. Furthermore, the Monterey A1-A2 Sands is dominated by quartz and feldspar which are stable in the presence of CO_2 and carbonic acid (pg. 39).

There is no geochemical analysis of water samples from the Reef Ridge Shale because the shale will only provide fluid for analysis if stimulated (pg. 39). The CO_2 composition used for the geomodel and its interaction/solubility is established by the Peng-Robinson Equation of State (AoR and CA Plan, pg. 2).

Questions/Requests for the Applicant:

- ***Please provideevidence for the statement in the Application on page 39 that the quartz and feldspar in the Monterey A1-A2 Sands are stable in the presence of CO_2 and carbonic acid?***
- ***Please elaborate on why use of the Peng-Robinson Equation of State supports compatibility of the CO_2 with any fluid which may be contained within the Reef Ridge Shale.***

Objectives for Pre-Operational Testing:

- ***Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and provide verification that it will not react with the formation matrix.***

Injection Zone Storage Capacity

Modeled storage capacity of the Monterey Formation A1-A2 reservoir was 8-10 million tons of CO_2 (pg. 41). The forecasted/proposed injection rate is 0.25 - 0.75 million tons per year for 15 years; according to

Table 8 (Proposed operational procedures); an average estimate of 8 million tonnes and a maximum of 10 million tonnes will be injected.

Injection zone storage capacity is discussed in the Evaluation of the AoR CA and above in the "Structure of the Injection Zone and Confining Zone" section. Any additional follow up questions/requests for the applicant will be provided in the AoR modeling evaluation.

Confining Zone Integrity

Fluid confinement is supported by 3D seismic data (pg. 12) and historic operating experience in addition to core data (pg. 20) and geochemical analysis (pg. 13). The capillary entry pressure of the Reef Ridge Shale is 4,220 psi in a CO_2-brine system, reducing the likelihood of deformation (pg. 20). There are no faults extending into the Reef Ridge Shale. See additional discussion and questions for the applicant above.

Questions/Requests for the Applicant:

- ***Were any other tests performed to corroborate pressure measurements in the Reef Ridge Shale?***
- ***The application, on pg. 14, states that there is a pressure differential of 1,300 psi between the overlying Etchegoin Formation and Monterey Formation due to the sealing nature of the Reef Ridge Shale. What is the source of the pressure data for this statement?***

Objectives for Pre-Operational Testing:

- ***Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate via laboratory experiments.***
- ***A step rate test should be performed to establish the fracture pressure of the confining zone.***

Evaluation of the Proposed Emergency and Remedial Response Plan for the Carbon TerraVault Class VI A1-A2 Reservoir Project

EPA has completed a review of the proposed Emergency and Remedial Response Plan (ERP) for the proposed Carbon TerraVault1 (CTV) Class VI geologic sequestration (GS) project (Attachment F to CTV's August 2021 Class VI permit application). While the evaluation of certain response scenarios is pending other reviews (e.g., the presence of pathways for fluid movement based on the geologic evaluation) the plan appears to be complete. EPA has the following questions and recommendations for the applicant:

Local Resources and Infrastructure

a) Please include the nearest town/community and its distance to the project area as part of the nearby infrastructure.
b) Please provide a version of Figure 1 at a wider scale (i.e., that shows more than just the AoR) to provide context for the Emergency and Remedial Response Plan. Identify the injection wells on the map.

Potential Risk Scenarios

The list of items in this section does not match the events and scenarios described in the following section. Please revise the list.

Emergency Identification and Response Actions

EPA recommends some additions/revisions to the descriptions and response actions for the scenarios identified in the Emergency and Remedial Response Plan. These are presented in the table below:

Event/Scenario	EPA Comment/Recommendation
1. All	a) EPA recommends that the Actionable Testing limits methods in Table 7 of the QASP be referenced in the Emergency and Remedial Response Plan.
2. Well Integrity Failure	b) A mechanical integrity (MI) failure of a monitoring well can also occur in the post-injection time frame; please update the "timing of the event" accordingly. c) The statement that CTV must notify the UIC Program Director is not an event that may signal loss of MI. Please make this a separate statement outside of the list on page 3. d) Consider including "Limit access to wellhead to authorized personnel only" to the response actions for major and minor emergencies. e) The response to a major or minor MI failure should also include necessary actions to identify the location/nature of the damage to the well or wellhead and confirm internal and external integrity prior to restarting injection (upon approval of the UIC Program Director).
3. Well Integrity Failure – Major or Serious Emergency	a) Please clarify what would constitute a major or serious emergency (e.g., a verified loss or increase of pressure or fluid volumes and/or loss of mechanical integrity is discovered). b) Response to a major emergency may also include communicating with CTV personnel or other operators in the field and local authorities to initiate evacuation plans, as necessary.

Event/Scenario	EPA Comment/Recommendation
4. Well Integrity Failure –Minor Emergency	a) Please clarify what would constitute a minor emergency (e.g., downhole and surface sensor/monitoring equipment failure, procedural maintenance error or plant issue). b) Clarify that, if contamination is detected or a loss of integrity has occurred, then the situation becomes a major emergency and the actions under "Major or Serious Emergency" would be taken. c) "Initiate shutdown plan" is on the list of response actions twice.
5. Injection Well Monitoring Equipment Failure – Major or Serious Emergency	a) Please describe what constitutes a Major or Serious emergency (e.g., failure of sensors that will require shutdown of well to repair, extended repair time, and/or well reentry). b) Responses to a Major monitoring equipment failure emergency may also include: • Verifying whether any contamination has occurred (e.g., via handheld CO_2 monitors). • Communicating with CTV personnel/other operators in the field and local authorities to isolate the area or initiate evacuation plans, as necessary if contamination is detected. • Demonstrating internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director).
6. Injection Well Monitoring Equipment Failure –Minor Emergency	a) Please describe what constitutes a Minor emergency (e.g., sensor or monitoring failure that does not require shutdown of the well to repair). b) Potential response actions may also include actions to identify the location/nature of the damage and reset monitoring devices and/or confirm internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director). c) "Initiate shutdown plan" is on the list of response actions twice.
7. Potential Brine or CO_2 Leakage to USDW	a) EPA recommends that the introduction to this scenario be broadened to encompass any evidence of CO_2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address events associated with unanticipated fluid movement pathways, any potential USDW endangerment/unacceptable changes in water quality, and CO_2 leakage to the land surface. b) The severity of an event involving CO_2/brine leakage to a USDW would be serious, not low. c) Detection methods may also include pressure or water quality changes in the Etchegoin Formation monitoring well. d) The response actions should also address well integrity issues (e.g., by following responses under the MI failure scenario) or a risk to air quality (i.e., to isolate the nearby area and establish a perimeter using a hand-held air-quality monitors). e) The response equipment for this scenario should also include groundwater remediation equipment.

Event/Scenario	EPA Comment/Recommendation
8. Natural Disaster	a) The severity of these types of events could range up to serious or catastrophic. b) These types of events may occur in any of the project phases (e.g., construction and post-injection) not just the injection phase. c) For Major or Serious natural disasters, potential response actions may also include: • Initiating evacuation procedures; • Referencing the response actions described under the CO_2 leakage scenario if contamination or endangerment of a USDW is detected; or • Confirming mechanical integrity/taking appropriate steps if an injection/monitoring well has been damaged.
9. Induced Seismic Event	a) This section and the title should refer to induced or naturally occurring seismic events since all seismic events have the potential to affect the injection wells and the necessary responses would be the same. b) It is unclear whether the area encompassed by "the AoR inclusive of a ¼ mile buffer," as described on page 8 is as large as a 2-mile radius of the injection wells, as described on Table 2. Please modify the introductory statement to reflect the area addressed in Table 2. c) The severity of seismic events could be major. d) Seismic events that may necessitate a response could occur during the injection or post injection phases. e) Please clarify what is meant by "seismic monitoring wells" as a detection method; EPA assumes this refers to the monitoring network that is described in the Testing and Monitoring Plan, and therefore recommends that similar terminology be used.
10. Induced Seismic Event—Table 2	a) Please modify the title to Table 2 to be consistent with the magnitude in the green response level (i.e., M 1.5). b) Please explain how the selected seismic thresholds (i.e., magnitude, distance from the project) are considered protective of USDWs.
11. Induced Seismic Event—Table 2, Green Level	a) Add the response action: Document the event in semiannual reports to EPA.
11. Induced Seismic Event—Table 2, Yellow Level	a) Potential response actions should also include: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Review seismic and operational data to determine the location and magnitude of seismic event. If the event falls within or near the extents of the plume, estimate potential impact to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. • Document the event in semiannual reports to EPA.

Event/Scenario	EPA Comment/Recommendation
12. Induced Seismic Event—Table 2, Orange Level	a) EPA recommends the following additions to the response actions: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Document the event in semiannual reports to EPA. • Expand Step 3 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).
13. Induced Seismic Event—Table 2, Magenta Level	a) EPA recommends the following changes to the response actions: • Please describe the "rate reduction plan" in Step 1. Does this refer to gradual shutdown? • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event). • Add: Document the event in semiannual reports to EPA.
14. Induced Seismic Event—Table 2, Red Level	a) EPA recommends the following changes to the response actions: • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).

Response Personnel and Equipment

a) Are any of the personnel to be notified a 24-hour contact, such as a 24-hour emergency coordinator in the control room? If so, please include this in the plan.

b) In Table 3, EPA recommends the following additions/changes:

- The UIC Program Director will be an EPA Region 9 staff person (David Albright; albright.david@epa.gov.
- Consider also including: the local/community medical center, Poison Control Center, California Office of Emergency Services, and the State Water Quality Control Board.

Plan Review

EPA recommends that plan reviews take place within 30 days of significant changes or on a timeframe prescribed by the EPA Director.

Staff Training and Exercise Procedures

There are several typos in this section; please revise.

CTV-Elk Hills Oil Field Class VI A1-A2 Project
Review of Financial Responsibility Information

EPA reviewed the financial responsibility demonstration, including cost estimates and information about draft financial instruments, provided in the August 2021 Class VI permit application for the proposed Carbon TerraVault1 (CTV) Class VI geologic sequestration project.

Pursuant to 40 CFR 146.85, Class VI permit applicants must demonstrate financial responsibility for: performing corrective action on deficient wells in the area of review (AoR), plugging injection wells, post-injection site care (PISC) and site closure, and emergency and remedial response. To make this demonstration, they must estimate the cost of each of these activities and provide qualifying financial instruments.

Cost Estimates

It appears that CTV used EPA's Cost Estimation Tool for Class VI Financial Responsibility to develop their cost estimates. EPA's guidance recommends that the financial responsibility cost estimates in a Class VI permit application be based on a third-party cost estimate of the activities an applicant plans to perform. These project-specific estimates of the covered costs are necessary to ensure that sufficient resources are available to cover the costs of EPA engaging a third party to complete the activities, should an operator become financially insolvent.

Therefore, EPA requests that CTV provide an independent estimate of the costs of the activities described in the project plans for which financial responsibility is required, specifically:

- Plugging injection wells 357-7R and 355-7R. Separate estimates specific to each well are requested.
- Post-injection site care that includes all post-injection groundwater quality monitoring and plume and pressure front tracking activities described in the PISC and Site Closure Plan.
- Site closure that includes the cost of plugging all the monitoring wells at the site (including the Etchegoin, Tulare, and Monterey Formation monitoring wells).
    - EPA also requests that CTV elaborate on the ownership and planned future use of the EOR wells to be used for monitoring in the Monterey A3-11 Sands, as described on page 12 of the Testing and Monitoring Plan. (Financial assurance for plugging these wells may be needed.)
- Emergency and remedial response that describes all the response activities under the various emergency scenarios described in the Emergency and Remedial Response Plan.

Based on the information currently available in the AoR and Corrective Action Plan, it does not appear that any corrective action is needed. However, if, based on additional evaluation, a larger AoR is determined to be needed or there are any deficient wells in the AoR, the cost estimate would need to account for corrective action on these wells. The outcomes of other aspects of the permit application review may affect cost estimates for other activities.

Financial Instrument Demonstration

CTV plans to provide financial assurance for injection well plugging and PISC and site closure by posting a letter of credit (LOC) that will be backed by its Credit Agreement with Citibank, N.A. CTV will provide financial assurance for emergency and remedial response via an environmental insurance policy.

Limited information was provided with the permit application, and it is anticipated that CTV will provide additional information and draft financial instruments as the time for issuance of any Class VI permits for the facility nears. EPA recommends that CTV consult the *UIC Program Class VI Financial Responsibility Guidance* as it develops the instruments, including:

- The recommended specifications for a letter of credit (beginning on page 31) and insurance (on page 32), and
- The recommended financial instrument language provided in Appendix B of the Guidance (on page B-2 for a LOC and page B-17 for a certificate of insurance).

In addition, regarding the Letter of Credit, EPA requests that CTV clarify whether other liabilities are covered using the same line of credit and, if so, how the funds specified for Class VI financial responsibility under the LOC will be protected from other liabilities.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

June 16, 2023 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1.1 and R9UIC-CA6-FY21-1.2
Technical Review of Application

Dear Travis Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Computational and Static Modeling for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the Enclosure.

Please submit the information requested in the Enclosure by July 17, 2023. If you have any questions about this letter and the Enclosure, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2023.06.16 10:01:41 -07'00'

David Albright
Manager, Groundwater Protection Section

Enclosure: Computational and Static Modeling Evaluation

cc (via email): Chris Jones, CalGEM Inland District
Alex Olsen, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Emily Reader, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

August 17, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Construction and Plugging Plans for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below in the two Enclosures.

Please submit the information requested in the Enclosures by September 19, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2022.08.17 09:54:33 -07'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Construction and Plugging Plan Evaluation 355-7R
Construction and Plugging Plan Evaluation 357-7R

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

March 8, 2023 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Monitoring Plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below, and in the Enclosure.

Please submit the information requested in the Enclosures by April 10, 2023. If you have any questions about this letter and the Enclosure, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2023.03.08 11:51:22 -08'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Monitoring Plan Comments

cc (via email): Chris Jones, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Emily Reader, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

July 20, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the AoR Modeling, Operating Procedures, and Testing and Monitoring Plans for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below, and in the three Enclosures.

Please submit the information requested in the Enclosures by August 19, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2022.07.20 16:33:53 -07'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Operating Procedures Evaluation
Proposed Testing and Monitoring Evaluation
AoR Modeling Evaluation

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

November 4, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Site Characterization and Emergency and Remedial Response Plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the two Enclosures.

Please submit the information requested in the Enclosures by December 5, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.11.04 10:44:34 -07'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: Site Characterization Evaluation
Emergency and Remedial Response Plan Evaluation

cc (via email): William Long, Inland District, CalGEM
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Evaluation of Construction and Plugging Procedures for Injection Well 357-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

This well construction and plugging evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of several related activities associated with construction and plugging of the 357-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands. These activities are described in the permit application narrative, and Attachment D to the permit application dated August 30, 2021, and an updated version of Attachment G (a file entitled Attachment G—Final), submitted on December 2, 2021. This review also identifies preliminary questions for the applicant. (Note that the permit application contains common information that applies to both injection wells planned for the project. Therefore, there is some repetition between this evaluation and EPA's evaluation of the attachments relevant to Well 355-7R. This is necessary to provide a complete evaluation for each Class VI permit record.)

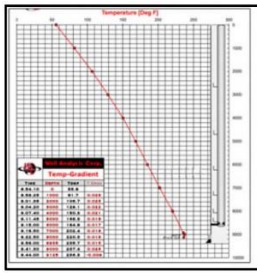
Injection Well Construction

Attachment A--Narrative (referred to as The Narrative herein) and Attachment G describe the well construction design for Well 357-7R. Well 357-7R is an existing Class II pressure maintenance well that is currently permitted by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 357–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2.

Well 357-7R was drilled in 1980; the Narrative contains the following brief construction details regarding Well 357-7R:

1. Descriptions of the conductor, surface, and intermediate casing.
2. Cement across each casing string with cement returns to surface during completion. A cement bond log was acquired to confirm cement along the well.
3. Casing specifications that exceed the operating conditions of the well (per Table 5 of the Narrative, reproduced below).
4. Long string casing diameter of seven inches with stainless steel tubing of 4.5 inches. This casing and tubing size will enable monitoring devices to be installed, cased hole logs to be acquired and Mechanical Integrity Testing (MIT) to be conducted.

Table 5: Temperature profile and casing construction data for the 357-7R injector.



Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Table 5 of the Narrative, pictured above, corresponds to the casing specifications listed in Attachment G for Well 357-7R, pictured below. Attachment G also includes tubing and packer specifications for Well

357-7R, which are excerpted below. The tubing and packer specifications in Attachment G mostly correspond to Table 7 of the Narrative, however the packer burst strength (psi) and collapse rating (psi) differ between the documents.

Injection Well 357-7R Construction Detials (Attachment G)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

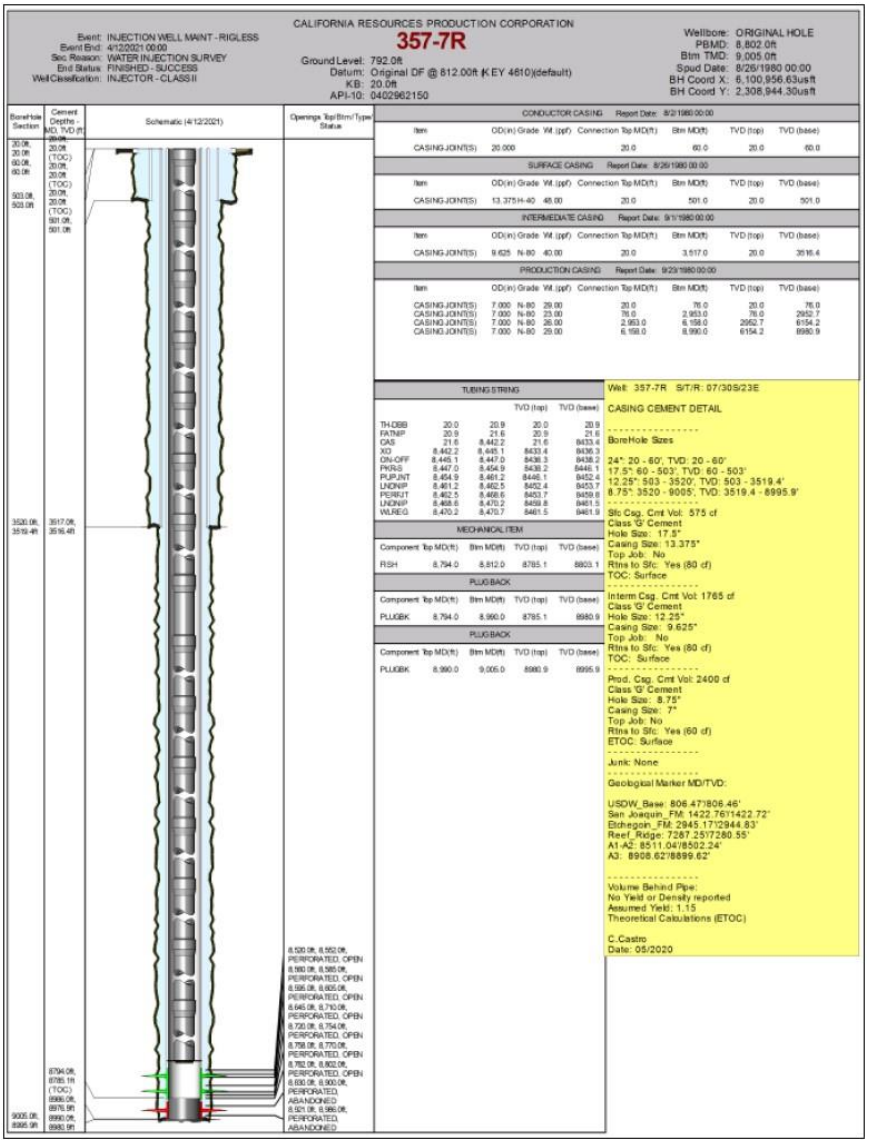
Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,447	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

All well materials noted in the tables above, in addition to the stainless-steel wellhead, are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are mostly consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. However, the surface pressure field gauges listed in Tables 10, 11, 12, and 14 of the QASP show a maximum calibrated working pressure of 3,000 psi, which is lower than the maximum surface injection pressure of 3,800 psi. The Applicant notes that the Class G Portland cement used to complete Well 357-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor, had cement returns to surface according to Figure 1 of Attachment G (reproduced below). The cement integrity is supported by data from existing wells and a cement bond log (CBL) in Well 357-7R. California Resources Corporation (CRC) has conducted MITs and standard annulus pressure test (SAPTs) every five years (no SAPT results were provided with the application materials, however). These tests will also be conducted prior to injection and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1: Injection Well 357-7R casing diagram (Attachment G)



Relevant geologic formation tops were noted in Figure 1 of Attachment G. The figure shows that the Base of the USDW is approximately 806 ft. TVD (true vertical depth), which is behind both the long string and intermediate casing. The surface casing is set to a depth of 501 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW in accordance with 40 CFR 146.86(a)(1). Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.

The San Joaquin and Etchegoin Formation tops are located at depths of 1,422 ft TVD and 2,945 ft TVD, respectively, and are also protected by the long string and intermediate casing. The Reef Ridge Shale

(confining zone), Monterey Formation A1-A2 (reservoir), and Monterey Formation A3 are located at depths of 7,281 ft TVD, 8,502 ft TVD, and 8,900 ft TVD, respectively; these three formations will be behind the long string casing. The depth of the Etchegoin Formation on the well diagram is consistent with information in the permit application narrative, and the depth of the Monterey Formation A1-A2 Sands differs from the depth reported on Figure 13 of the permit application narrative of 8,403 ft – 9,598 ft TVD.

The perforations for Well 357-7R are shown at depths of 8,782 to 8,830 feet. The perforations are also described in the AoR and Corrective Action Plan; however, they are presented in depth relative to mean sea level, so confirmation that the depths are consistent is not possible.

Multiple sources of anthropogenic CO_2 are being considered for the Elk Hills A1-A2 Injection Project. These include the Elk Hills NGCC Power Plant as well as third party existing and proposed industrial sources in the Southern San Joaquin Valley area. The CO_2 stream will be approximately 95% CO_2 by volume, also containing residual water (25#/mmscf) and oxygen (<50 parts per million) which will be controlled for corrosion mitigation. The applicant notes that the CO_2 stream corrosivity is low if the entrained water is kept in solution with the CO_2. The applicant states that the 25#/mmscf water volume specification is conservative and should allow for water solubility across super-critical CO_2 operating ranges. The water content of 25#/mmscf equates to approximately 0.4 ppm and is unlikely to present corrosion concerns. However, water solubility will vary with depth and time as temperatures and pressures change. Gas phase CO_2 is likely to exist in the lowered depths of the tubing string early in the injection phase, resulting in the possibility of existing free phase water. Stainless steel (13 CR-95) tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present. However, no details were provided as to the amount of time that free phase water can persist without severely damaging the tubing. According to Table 1 in *Attachment C – Testing and Monitoring Plan,* CTV will analyze the following CO_2 stream constituents based on established ASTM methods: O_2, N_2, CO, CH_4, H_2S, total hydrocarbons, total Sulfur, and CO_2 purity. It appears that H_2O was excluded from the CO_2 stream constituent analysis and will need to be included (a request was provided with the testing and monitoring evaluation). Additionally, the applicant does not state if the compatibility of the CO_2 stream and well construction components will be determined prior to well operation. Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.

Figure 1 of Attachment G, excerpted above, demonstrates the casing design for Well 357-7R. The well construction and cementing criteria described in the Narrative and Attachment G appear to be acceptable, except as noted in the questions below. However, the applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials. This will be needed prior to operation of Well 357-7R.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. However, the applicant did not describe safety valves and automated shut-off devices in Attachment G.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been

cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings).

Questions/requests for the applicant:

- *Please reconcile the following differences between Attachment G and Table 7 of the Narrative:*
  - *The burst rating of the packer is 8,160 psi on Table 7 of Attachment A and 8,000 psi on page G3, and*
  - *The tensile strength of the packer on page G3 has a typo, with an extra 0 in "10,0000."*
- *There are several discrepancies in the descriptions of Well 357-7R between tables 5, 6, and 7 of Attachment A and the tables on pages G2 and G3 of Attachment G. Please make the tables and the well bore diagram in Attachment G (if needed) consistent.*
  - *Attachment A, Table 5, and the Table on page G2 indicate that the intermediate casing in Well 357-7R is to a depth of 3,517 ft; on Table 6, this depth is 3,516 ft.*
  - *The conductor casing material is H-40 in Attachment A, Table 5 and Attachment G, and it is J-55 in Table 6.*
  - *The surface casing material is H-40 in Table 5 and in Attachment G, pg. 2, and it is H-80 in Table 6.*
- *Please verify that the annulus between the tubing and the long string casing is filled with a non-corrosive fluid, as required by 40 CFR 146.88(c), and describe the fluid.*
- *Please confirm that the surface casing extends through the base of the lowermost USDW, in accordance with 40 CFR 146.86(b)(2). If it does not, please explain how the well will otherwise meet the requirements of 40 CFR 146.86(a)(1).*
- *Is Well 357-7R equipped with real-time surface monitoring equipment and alarms and, if so, are these connected to automatic shutoff systems, as required at 146.88(e)(2)? If so, please describe these in Attachment G and describe how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G to include these required components.*
- *Please provide additional detail about the construction procedures for Well 357-7R, for example, to be consistent with the level of detail in the construction procedures for Well 355-7R on page 2 of Attachment A2.*
- *Please include relevant information from the narrative (Attachment A) about the construction of the well into Attachment G for completeness.*
- *In Figure 1 of Attachment G (Well 357-7R casing diagram), the top of cement for the existing bottom-hole plug is listed at 8,794 ft MD / 8,785 ft TVD while the base of the open perforated interval is 8,802 ft. Please revise Figure 1 to correct this inconsistency.*
- *Please label the well diagram to indicate that the well is a Class VI (i.e., not Class II) well.*
- *Please explain how the injection well's design will mitigate potential shallow compression resulting from land subsidence and comply with the requirement to cement to the surface.*
- *What is the surface elevation (i.e., relative to mean sea level) at the location of the well?*

- *Please discuss the duration that free phase water is expected to be present at the beginning of the injection phase and the corresponding impact on tubing integrity. For example, please provide additional discussion regarding the study of this phenomenon, e.g., in existing, nearby CO_2 injection wells.*
- *Please include alternative pressure monitoring devices to those listed in Tables 10, 11, 12, and 14 of the QASP with pressure field gauges with higher pressure ratings to function at the maximum surface injection pressure of 3,800 psi safely and reliably.*
- *Please provide the most recent SAPT reports for the well.*

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 357-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in the Narrative and in Attachment G. Table 1 of the Pre-Operational Testing Plan for Well 357-7R identifies several tests that CTV indicates have been performed, and that these were provided. These include deviation checks, cement bond log, open-hole well logs, mechanical integrity test, SAPT, injection zone and confining layer core, reservoir conditions and fluid, injection zone and confining layer fracture gradients, and pressure testing. Attachment G also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2 Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed. Despite the deficiencies listed here, the proposed testing and logging program is considered comprehensive and generally acceptable.

Questions/Requests for the applicant:

- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones.*

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation

program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
  - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
  - *Step-by-step procedures that would be employed during stimulation.*

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1?*

Injection Well Plugging Plan

Plugging details for Well 357-7R are provided in Table 1, which is reproduced below. Before plugging the injection well, CTV will determine the bottom-hole pressure needed to successfully squeeze cement for plugging operations. At least one external MIT will be conducted prior to plugging, including but not limited to a temperature log. The temperature log will be run over the entire depth of the well and the results will be compared to temperature logs performed before and during CO_2 injection. Generic procedures for plugging wells are described in the attachment. Specific plugging procedures will be needed.

Table 1: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.184	6.366	6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,785	2,970	1,448	25
Sacks of cement to be used (each plug)	65	25	25	5
Slurry volume to be pumped (ft^3)	75	28	28	6
Slurry weight (lb./gal)	15.6	15.6	15.6	15.6
Calculated top of plug (ft)	8,427	2,845	1,323	0
Bottom of plug (ft)	8,785	2,970	1,448	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

CTV states that, during plugging operations, the cement slurry and displacement fluids will be over-balanced to prevent reservoir fluids from entering the wellbore during cementing operations. Table 1 of Attachment D—Injection Well Plugging Plan describes the various types of plug information, which is excerpted below. The plugging details listed in Table 1 are consistent with injection well construction details, however the applicant did not provide a plugging diagram.

Plug #1 (bottom-hole cement plug) will cover all perforations and will extend at least 100 ft. above the uppermost perforations. However, based on Figure 1 of Attachment G, the uppermost perforations occur at 8,520 ft, resulting in the top of the plug occurring 93 ft above the uppermost perforation. The cement volume will need to be revised for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.

The Base of the USDW will be covered by Plugs #2 and #3. If cement exists behind the casing and across the Base of the USDW, a 100 ft. cement plug will be placed inside the casing across this interface. If the top of cement behind the casing is found to be below the Base of the USDW, a cement squeeze will be performed through perforations. Additionally, a 100 ft cement plug will be placed inside the casing across the freshwater-saltwater interface. However, Figure 1 of Attachment G lists the Base of the USDW at 806 ft TVD. The inconsistency in depth between Plugs #2, #3, and the Base of the USDW will need to be resolved, and the corresponding well construction and plugging information updated accordingly.

Plug #4 (the surface plug) will plug the casing at the surface with at least 25 ft of cement. All cement plugs will be composed of a Class G cement blend that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The applicant does not explicitly state if this is the same cement used to cement the casing strings in well construction.

The plugging procedures that will be used to place these plugs appear to be acceptable, provided responses to the questions below are adequate. The plugging plan does not include a schematic.

Questions/Requests for the applicant:

- *Please include "flushing" among the steps to be completed prior to injection well plugging, in accordance with 40 CFR 146.92(a).*
- *Please revise the cement volume for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.*
- *Please reconcile the inconsistency in depth between Plugs #2, #3, and the Base of the USDW as shown in Table 1 of Attachment D and Figure 1 of Attachment G.*
- *Please correct the typo in the second bullet at the bottom of Attachment D, pg. 3, referring to the ">10,000 mg/L DTS."*
- *Please provide a plugging schematic and label the USDW and other relevant formations (i.e., the injection and confining zones) and perforations on the plugging diagram.*
- *Please confirm that the Class G cement blend is the same as the Class G Portland cement that was used in the well's construction, and that this cement is CO_2-resistant.*

Evaluation of Construction and Plugging Procedures for Injection Well 357-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

This well construction and plugging evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of several related activities associated with construction and plugging of the 357-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands. These activities are described in the permit application narrative, and Attachment D to the permit application dated August 30, 2021, and an updated version of Attachment G (a file entitled Attachment G—Final), submitted on December 2, 2021. This review also identifies preliminary questions for the applicant. (Note that the permit application contains common information that applies to both injection wells planned for the project. Therefore, there is some repetition between this evaluation and EPA's evaluation of the attachments relevant to Well 355-7R. This is necessary to provide a complete evaluation for each Class VI permit record.)

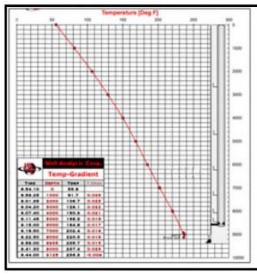
Injection Well Construction

Attachment A--Narrative (referred to as The Narrative herein) and Attachment G describe the well construction design for Well 357-7R. Well 357-7R is an existing Class II pressure maintenance well that is currently permitted by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 357–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2.

Well 357-7R was drilled in 1980; the Narrative contains the following brief construction details regarding Well 357-7R:

1. Descriptions of the conductor, surface, and intermediate casing.
2. Cement across each casing string with cement returns to surface during completion. A cement bond log was acquired to confirm cement along the well.
3. Casing specifications that exceed the operating conditions of the well (per Table 5 of the Narrative, reproduced below).
4. Long string casing diameter of seven inches with stainless steel tubing of 4.5 inches. This casing and tubing size will enable monitoring devices to be installed, cased hole logs to be acquired and Mechanical Integrity Testing (MIT) to be conducted.

Table 5: Temperature profile and casing construction data for the 357-7R injector.



Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Table 5 of the Narrative, pictured above, corresponds to the casing specifications listed in Attachment G for Well 357-7R, pictured below. Attachment G also includes tubing and packer specifications for Well

357-7R, which are excerpted below. The tubing and packer specifications in Attachment G mostly correspond to Table 7 of the Narrative, however the packer burst strength (psi) and collapse rating (psi) differ between the documents.

Injection Well 357-7R Construction Detials (Attachment G)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
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Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

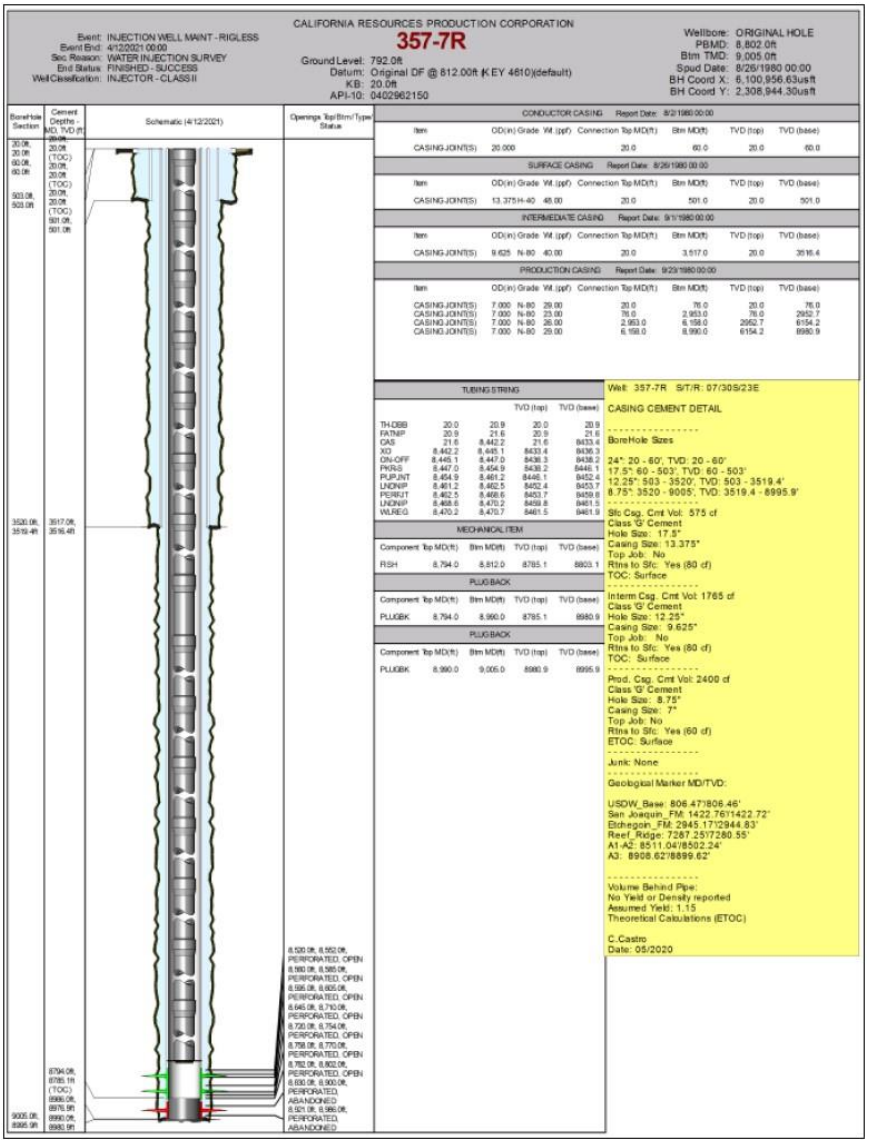
Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,447	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

All well materials noted in the tables above, in addition to the stainless-steel wellhead, are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are mostly consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. However, the surface pressure field gauges listed in Tables 10, 11, 12, and 14 of the QASP show a maximum calibrated working pressure of 3,000 psi, which is lower than the maximum surface injection pressure of 3,800 psi. The Applicant notes that the Class G Portland cement used to complete Well 357-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor, had cement returns to surface according to Figure 1 of Attachment G (reproduced below). The cement integrity is supported by data from existing wells and a cement bond log (CBL) in Well 357-7R. California Resources Corporation (CRC) has conducted MITs and standard annulus pressure test (SAPTs) every five years (no SAPT results were provided with the application materials, however). These tests will also be conducted prior to injection and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1: Injection Well 357-7R casing diagram (Attachment G)



Relevant geologic formation tops were noted in Figure 1 of Attachment G. The figure shows that the Base of the USDW is approximately 806 ft. TVD (true vertical depth), which is behind both the long string and intermediate casing. The surface casing is set to a depth of 501 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW in accordance with 40 CFR 146.86(a)(1). Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.

The San Joaquin and Etchegoin Formation tops are located at depths of 1,422 ft TVD and 2,945 ft TVD, respectively, and are also protected by the long string and intermediate casing. The Reef Ridge Shale

(confining zone), Monterey Formation A1-A2 (reservoir), and Monterey Formation A3 are located at depths of 7,281 ft TVD, 8,502 ft TVD, and 8,900 ft TVD, respectively; these three formations will be behind the long string casing. The depth of the Etchegoin Formation on the well diagram is consistent with information in the permit application narrative, and the depth of the Monterey Formation A1-A2 Sands differs from the depth reported on Figure 13 of the permit application narrative of 8,403 ft – 9,598 ft TVD.

The perforations for Well 357-7R are shown at depths of 8,782 to 8,830 feet. The perforations are also described in the AoR and Corrective Action Plan; however, they are presented in depth relative to mean sea level, so confirmation that the depths are consistent is not possible.

Multiple sources of anthropogenic CO_2 are being considered for the Elk Hills A1-A2 Injection Project. These include the Elk Hills NGCC Power Plant as well as third party existing and proposed industrial sources in the Southern San Joaquin Valley area. The CO_2 stream will be approximately 95% CO_2 by volume, also containing residual water (25#/mmscf) and oxygen (<50 parts per million) which will be controlled for corrosion mitigation. The applicant notes that the CO_2 stream corrosivity is low if the entrained water is kept in solution with the CO_2. The applicant states that the 25#/mmscf water volume specification is conservative and should allow for water solubility across super-critical CO_2 operating ranges. The water content of 25#/mmscf equates to approximately 0.4 ppm and is unlikely to present corrosion concerns. However, water solubility will vary with depth and time as temperatures and pressures change. Gas phase CO_2 is likely to exist in the lowered depths of the tubing string early in the injection phase, resulting in the possibility of existing free phase water. Stainless steel (13 CR-95) tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present. However, no details were provided as to the amount of time that free phase water can persist without severely damaging the tubing. According to Table 1 in *Attachment C – Testing and Monitoring Plan,* CTV will analyze the following CO_2 stream constituents based on established ASTM methods: O_2, N_2, CO, CH_4, H_2S, total hydrocarbons, total Sulfur, and CO_2 purity. It appears that H_2O was excluded from the CO_2 stream constituent analysis and will need to be included (a request was provided with the testing and monitoring evaluation). Additionally, the applicant does not state if the compatibility of the CO_2 stream and well construction components will be determined prior to well operation. Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.

Figure 1 of Attachment G, excerpted above, demonstrates the casing design for Well 357-7R. The well construction and cementing criteria described in the Narrative and Attachment G appear to be acceptable, except as noted in the questions below. However, the applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials. This will be needed prior to operation of Well 357-7R.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. However, the applicant did not describe safety valves and automated shut-off devices in Attachment G.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been

cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings).

Questions/requests for the applicant:

- *Please reconcile the following differences between Attachment G and Table 7 of the Narrative:*
  - *The burst rating of the packer is 8,160 psi on Table 7 of Attachment A and 8,000 psi on page G3, and*
  - *The tensile strength of the packer on page G3 has a typo, with an extra 0 in "10,0000."*
- *There are several discrepancies in the descriptions of Well 357-7R between tables 5, 6, and 7 of Attachment A and the tables on pages G2 and G3 of Attachment G. Please make the tables and the well bore diagram in Attachment G (if needed) consistent.*
  - *Attachment A, Table 5, and the Table on page G2 indicate that the intermediate casing in Well 357-7R is to a depth of 3,517 ft; on Table 6, this depth is 3,516 ft.*
  - *The conductor casing material is H-40 in Attachment A, Table 5 and Attachment G, and it is J-55 in Table 6.*
  - *The surface casing material is H-40 in Table 5 and in Attachment G, pg. 2, and it is H-80 in Table 6.*
- *Please verify that the annulus between the tubing and the long string casing is filled with a non-corrosive fluid, as required by 40 CFR 146.88(c), and describe the fluid.*
- *Please confirm that the surface casing extends through the base of the lowermost USDW, in accordance with 40 CFR 146.86(b)(2). If it does not, please explain how the well will otherwise meet the requirements of 40 CFR 146.86(a)(1).*
- *Is Well 357-7R equipped with real-time surface monitoring equipment and alarms and, if so, are these connected to automatic shutoff systems, as required at 146.88(e)(2)? If so, please describe these in Attachment G and describe how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G to include these required components.*
- *Please provide additional detail about the construction procedures for Well 357-7R, for example, to be consistent with the level of detail in the construction procedures for Well 355-7R on page 2 of Attachment A2.*
- *Please include relevant information from the narrative (Attachment A) about the construction of the well into Attachment G for completeness.*
- *In Figure 1 of Attachment G (Well 357-7R casing diagram), the top of cement for the existing bottom-hole plug is listed at 8,794 ft MD / 8,785 ft TVD while the base of the open perforated interval is 8,802 ft. Please revise Figure 1 to correct this inconsistency.*
- *Please label the well diagram to indicate that the well is a Class VI (i.e., not Class II) well.*
- *Please explain how the injection well's design will mitigate potential shallow compression resulting from land subsidence and comply with the requirement to cement to the surface.*
- *What is the surface elevation (i.e., relative to mean sea level) at the location of the well?*

- *Please discuss the duration that free phase water is expected to be present at the beginning of the injection phase and the corresponding impact on tubing integrity. For example, please provide additional discussion regarding the study of this phenomenon, e.g., in existing, nearby CO_2 injection wells.*
- *Please include alternative pressure monitoring devices to those listed in Tables 10, 11, 12, and 14 of the QASP with pressure field gauges with higher pressure ratings to function at the maximum surface injection pressure of 3,800 psi safely and reliably.*
- *Please provide the most recent SAPT reports for the well.*

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 357-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in the Narrative and in Attachment G. Table 1 of the Pre-Operational Testing Plan for Well 357-7R identifies several tests that CTV indicates have been performed, and that these were provided. These include deviation checks, cement bond log, open-hole well logs, mechanical integrity test, SAPT, injection zone and confining layer core, reservoir conditions and fluid, injection zone and confining layer fracture gradients, and pressure testing. Attachment G also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2 Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed. Despite the deficiencies listed here, the proposed testing and logging program is considered comprehensive and generally acceptable.

Questions/Requests for the applicant:

- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones.*

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation

program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
  - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
  - *Step-by-step procedures that would be employed during stimulation.*

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1?*

Injection Well Plugging Plan

Plugging details for Well 357-7R are provided in Table 1, which is reproduced below. Before plugging the injection well, CTV will determine the bottom-hole pressure needed to successfully squeeze cement for plugging operations. At least one external MIT will be conducted prior to plugging, including but not limited to a temperature log. The temperature log will be run over the entire depth of the well and the results will be compared to temperature logs performed before and during CO_2 injection. Generic procedures for plugging wells are described in the attachment. Specific plugging procedures will be needed.

Table 1: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.184	6.366	6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,785	2,970	1,448	25
Sacks of cement to be used (each plug)	65	25	25	5
Slurry volume to be pumped (ft^3)	75	28	28	6
Slurry weight (lb./gal)	15.6	15.6	15.6	15.6
Calculated top of plug (ft)	8,427	2,845	1,323	0
Bottom of plug (ft)	8,785	2,970	1,448	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

CTV states that, during plugging operations, the cement slurry and displacement fluids will be over-balanced to prevent reservoir fluids from entering the wellbore during cementing operations. Table 1 of Attachment D—Injection Well Plugging Plan describes the various types of plug information, which is excerpted below. The plugging details listed in Table 1 are consistent with injection well construction details, however the applicant did not provide a plugging diagram.

Plug #1 (bottom-hole cement plug) will cover all perforations and will extend at least 100 ft. above the uppermost perforations. However, based on Figure 1 of Attachment G, the uppermost perforations occur at 8,520 ft, resulting in the top of the plug occurring 93 ft above the uppermost perforation. The cement volume will need to be revised for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.

The Base of the USDW will be covered by Plugs #2 and #3. If cement exists behind the casing and across the Base of the USDW, a 100 ft. cement plug will be placed inside the casing across this interface. If the top of cement behind the casing is found to be below the Base of the USDW, a cement squeeze will be performed through perforations. Additionally, a 100 ft cement plug will be placed inside the casing across the freshwater-saltwater interface. However, Figure 1 of Attachment G lists the Base of the USDW at 806 ft TVD. The inconsistency in depth between Plugs #2, #3, and the Base of the USDW will need to be resolved, and the corresponding well construction and plugging information updated accordingly.

Plug #4 (the surface plug) will plug the casing at the surface with at least 25 ft of cement. All cement plugs will be composed of a Class G cement blend that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The applicant does not explicitly state if this is the same cement used to cement the casing strings in well construction.

The plugging procedures that will be used to place these plugs appear to be acceptable, provided responses to the questions below are adequate. The plugging plan does not include a schematic.

Questions/Requests for the applicant:

- *Please include "flushing" among the steps to be completed prior to injection well plugging, in accordance with 40 CFR 146.92(a).*
- *Please revise the cement volume for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.*
- *Please reconcile the inconsistency in depth between Plugs #2, #3, and the Base of the USDW as shown in Table 1 of Attachment D and Figure 1 of Attachment G.*
- *Please correct the typo in the second bullet at the bottom of Attachment D, pg. 3, referring to the ">10,000 mg/L DTS."*
- *Please provide a plugging schematic and label the USDW and other relevant formations (i.e., the injection and confining zones) and perforations on the plugging diagram.*
- *Please confirm that the Class G cement blend is the same as the Class G Portland cement that was used in the well's construction, and that this cement is CO_2-resistant.*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

January 11, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the area of review (AOR) delineation, testing and monitoring activities, and operating procedures for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the three Enclosures.

Please submit the information requested in the Enclosures by February 25, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Michele Dermer at (415) 972-3417.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.01.11 10:58:13 -08'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: AOR Delineation Modeling Approach
Testing and Monitoring Activities
Operating Procedures

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

January 11, 2022 Sent by email only

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Please submit the information requested in the Enclosures by February 25, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Michele Dermer at (415) 972-3417.

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David Albright
Manager, Groundwater Protection Section

Enclosures: AOR Delineation Modeling Approach
Testing and Monitoring Activities
Operating Procedures

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

December 15, 2021 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the site characterization, financial responsibility, and emergency and remedial response plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below, and in the three Enclosures.

Considerations of Specific Federal Laws

40 CFR §144.4 requires that EPA consider the potential applicability of several specific Federal Laws, including the Wild and Scenic Rivers Act (WSRA), National Historic Preservation Act (NHPA), Endangered Species Act (ESA), Coastal Zone Management Act (CZMA), and the Fish and Wildlife Conservation Act (FWCA). To expedite our consideration of these laws, please describe how the proposed project will satisfy applicable requirements under those Federal Laws. For the ESA and NHPA,we have included some guidance below to assist you with obtaining the required information.

Endangered Species Act (ESA)

The ESA requires EPA to ensure, in consultation with the U.S. Fish and Wildlife Services (FWS), that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or adversely affect its critical habitat. We recommend that you use FWS's project planning tool to map out your project area and do a search for potential endangered species within the project area. The tool can be accessed here: https://ecos.fws.gov/ipac/.

Based on the results of your search, you may need to hire a Wildlife Consultant to provide additional analysis or otherwise show how your project will not cause harm to endangered species with habitat located near the CTV A1-A2 project area. Please provide a report depicting the results of the FWS project planning tool, including a map of the project area and any listed endangered or threatened species habitat near the site. Please include any comments or reports made by a Wildlife Consultant, if applicable.

National Historic Preservation Act (NHPA)

NHPA §106 requires a federal agency to take certain steps before it commits to any "undertaking," including the issuance of a permit or license, that has the potential to adversely affect property that is listed, or eligible for listing, in the National Register for Historic Places. The NHPA requires EPA, before issuing a permit, to adopt measures when feasible to mitigate potential adverse effects of the permitted activity and properties listed or eligible for listing in the National Register of Historic Places. The Act's requirements are to be implemented in cooperation with State Historic Preservation Officer and upon notice to, and when appropriate, in consultation with the Advisory Council on Historic Preservation.

To facilitate EPA's consideration of NHPA compliance for CTV's proposed project, we request that you identify the Historic Places designated in the National Register for Historic Places (https://www.nps.gov/subjects/nationalregister/database- research.htm) in close proximity to the CTV A1-A2 project site. Based on the results of your review of the National Register of Historic Places listings in Kern County, you may need to hire an archaeologist to provide additional analysis or otherwise show how your project will not adversely affect the identified historic places located near the CTV A1-A2 project site. Please provide a list of the Historic Places near the site. Please include any comments or reports made by an archaeologist, if applicable.

Please submit the information requested in the Enclosures, and regarding compliance with the above referenced Federal Laws by January 21, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Michele Dermer at (415) 972-3417.

Sincerely,

DAVID ALBRIGHT

Digitally signed by DAVID ALBRIGHT
Date: 2021.12.15 15:52:18 -08'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Site Characterization
Financial Responsibility
Emergency and Remedial Response Plan

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Construction and Plugging Procedures for Injection Well 357-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

In February 2022, EPA provided questions to CTV (*blue, italic text*) about the construction and plugging of the 357-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands, submitted as part of CTV's Class VI permit application (dated August 30, 2021 and December 2, 2021) for the proposed CTV-Elk Hills Class VI geologic sequestration (GS) project. CTV provided updated operating procedures for the two wells to EPA on May 16, 2022. EPA's evaluation of how the update addresses its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Injection Well Construction

Attachment A--Narrative (referred to as The Narrative herein) and Attachment G describe the well construction design for Well 357-7R. Well 357-7R is an existing Class II pressure maintenance well that is currently permitted by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 357–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2. Well 357-7R was drilled in 1980; the Narrative A2 contains construction details regarding Well 357-7R.

Table 5 of the Narrative, corresponds to the casing specifications listed in Attachment G for Well 357-7R, pictured below. Attachment G also includes tubing and packer specifications for Well 357-7R, which are excerpted below. The tubing and packer specifications in Attachment G mostly correspond to Table 7 of the Narrative, however the packer burst strength (psi) and collapse rating (psi) differ between the documents.

Injection Well 357-7R Construction Details (Attachment G)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,447	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

All well materials noted in the tables above, in addition to the stainless-steel wellhead, are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are mostly consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. However, the surface pressure field gauges listed in Tables 10, 11, 12, and 14 of the QASP show a maximum calibrated working pressure of 3,000 psi, which is lower than the maximum surface injection pressure of 3,800 psi. The Applicant notes that the Class G Portland cement used to complete Well 357-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor, had cement returns to surface according to Figure 1 of Attachment G (reproduced below). The cement integrity is supported by data from existing wells and a cement bond log (CBL) in Well 357-7R. California Resources Corporation (CRC) has conducted MITs and standard annulus pressure test (SAPTs) every five years (no SAPT results were provided with the application materials, however). These tests will also be conducted prior to injection and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Relevant geologic formation tops were noted in Figure 1 of Attachment G. The figure shows that the Base of the USDW is approximately 806 ft. TVD (true vertical depth), which is behind both the long string and intermediate casing. The surface casing is set to a depth of 501 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW in accordance with 40 CFR 146.86(b)(2). (Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.)

The perforations for Well 357-7R are shown at depths of 8,782 to 8,830 feet. The perforations are also described in the AoR and Corrective Action Plan; however, they are presented in depth relative to mean sea level, so confirmation that the depths are consistent is not possible.

According to Table 1 in *Attachment C – Testing and Monitoring Plan,* CTV will analyze the following CO_2 stream constituents based on established ASTM methods: O_2, N_2, CO, CH_4, H_2S, total hydrocarbons, total Sulfur, and CO_2 purity. It appears that H_2O was excluded from the CO_2 stream constituent analysis and will need to be included (a request was provided with the testing and monitoring evaluation). Additionally, the applicant does not state if the compatibility of the CO_2 stream and well construction components will be determined prior to well operation. Following the pre-construction measurement of

the composition, properties, and corrosiveness of the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.

Figure 1 of Attachment G, excerpted below, demonstrates the casing design for Well 357-7R. The well construction and cementing criteria described in the Narrative and Attachment G appear to be acceptable, except as noted in the questions below. However, the applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. However, the applicant did not describe safety valves and automated shut-off devices in Attachment G.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings). Any design modifications to address the subsidence concern will need to meet the requirement that Class VI wells have cementing of the surface casing that extends to the surface.

Questions/requests for the applicant:

- *There are several discrepancies in the descriptions of Well 357-7R between tables 5, 6, and 7 of Attachment A and the tables on pages G2 and G3 of Attachment G. Please make the tables and the well bore diagram in Attachment G (if needed) consistent.*
  - *Attachment A, Table 5, and the Table on page G2 indicate that the intermediate casing in Well 357-7R is to a depth of 3,517 ft; on Table 6, this depth is 3,516 ft. The applicant removed this table from Attachment A and corrected the depth to 3,517 ft. The response is acceptable.*
  - *The conductor casing material is H-40 in Attachment A, Table 5 and Attachment G, and it is J-55 in Table 6. CTV removed the conductor casing grade from Table 1 and states that the conductor grade is not specified or relevant, but they did not explain why.*
  - *The surface casing material is H-40 in Table 5 and in Attachment G, pg. 2, and it is H-80 in Table 6. CTV changed the surface casing grade to H-40. The response is acceptable.*
- *Please confirm that the surface casing extends through the base of the lowermost USDW, as required per 40 CFR 146.86(b)(2). If it does not, please explain how the well will meet the requirements of 40 CFR 146.86(b)(2). A new Protection of USDW section on pg. 3 states that the surface casing is set and cemented within the USDW, not through the base of the USDW, and describes additional ways in which the surface casing is designed to protect the USDW. The applicant states that the intermediate string is set across the base of the USDW, and the annular cement will provide additional isolation. Cement bond logs in the 7" casing string indicate annular cement within and above the injection and confining zones.*
- *Is Well 357-7R equipped with real-time surface monitoring equipment and alarms and, if so, are these connected to automatic shutoff systems, as required at 146.88(e)(2)? If so, please describe*

these in Attachment G and describe how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G to include these required components. Under "Alarms and Shut-off Devices" on page 5, the applicant states that real time monitoring and automated shut off controls will be added to the system. CTV is required to provide information for EPA to review before installing the equipment; these should be included on final as-built schematics of the well ; these should be included on final as-built schematics of the well. CTV states that they do not plan to install down hole shut off systems due to the lack of risk factors (e.g., high temperatures and pressures or corrosive materials). Additional clarification on why these risk factors are considered low is required.

- *Please explain how the injection well's design will mitigate potential shallow compression resulting from land subsidence and comply with the requirement to cement to the surface. CTV describes in the Casing section on pages 2 and 3 that the well construction mimics other wells used in the area for injection with no operational issues related to structural strength. Additionally, the Construction, Operating and Plugging document (COP) states that subsidence has not been observed historically, and shallow compression is not anticipated as a concern. No evidence of this was provided, however.*
- *Please include alternative pressure monitoring devices to those listed in Tables 10, 11, 12, and 14 of the QASP with pressure field gauges with higher pressure ratings to function at the maximum surface injection pressure of 3,800 psi safely and reliably. CTV stated that the QASP will be updated to show equipment with pressure ratings of 5,000 psi. However, this change was not included in an updated QASP that CTV submitted on March 31.*
- *Please provide the most recent SAPT reports for the well. The most recent SAPT results from October 6, 2020, are provided on page 9 of the document, which shows the well maintaining pressure within the well annulus, demonstrating mechanical integrity. However, the SAPT was run for 20-30 minutes, and not the minimum of 60 minutes as described in the pre-injection testing in Appendix G2 submitted with the initial application materials. Because CTV will conduct an additional SAPT prior to injection, this response is acceptable at this point.*

Follow-up Questions for the Applicant:

- ***Please clarify why the risk factors (temperature, pressure and corrosivity) are considered to be low and include further justification as to why the downhole shutoff system is not necessary.***
- ***Please confirm the base of the lowermost USDW. Please note the definition of USDW (40 CFR 146.3) below.***

  (USDW) means an aquifer or its portion:
  (1)(i) Which supplies any public water system; or (ii) Which contains a sufficient quantity of ground water to supply a public water system; and
  (A) Currently supplies drinking water for human consumption; or
  (B) Contains fewer than 10,000 mg/l total dissolved solids; and
  (2) Which is not an exempted aquifer.
- ***Please provide data or sources as evidence that lead to the determination that no subsidence has occurred in the area.***

- ***EPA requests that, for clarity, the conductor casing grade (which was reported as H-40 in the initial application) be included on Table 1. If this information was incorrect, please explain how the conductor casing is suitable for CO_2 injection.***
- ***Because the tubing grade was changed from 13CR-95 to L-80 CRA, please ensure that the coupons used in the corrosion monitoring section of the Testing and Monitoring Plan are revised accordingly.***
- ***Please update the QASP to show equipment with pressure ratings of 5,000 psi.***
- ***Please update Attachment G2 to include the pre-operation testing plan for the deep monitoring wells.***
- ***Please provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.***

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 357-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in the Narrative and in Attachment G. Table 1 of the Pre-Operational Testing Plan for Well 357-7R identifies several tests that CTV indicates have been performed, and that these were provided. These include deviation checks, cement bond log, open-hole well logs, mechanical integrity test, SAPT, injection zone and confining layer core, reservoir conditions and fluid, injection zone and confining layer fracture gradients, and pressure testing. Attachment G also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2 Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed.

Questions/Requests for the applicant:

- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones. The applicant states that a full-well CBL will be completed during pre-operational testing and tubing removal. Please note that EPA will need to review and approve the results of the CBL prior to authorizing injection. Response is acceptable at this point.*

Follow-up Questions for the Applicant:

- ***Please provide an updated pre-operational testing plan that describes the tests identified in CTV's responses to questions in this document. For example, the plan should include: testing to confirm the plugback depth; a CBL along the full length of the well; an SAPT of an appropriate test duration; and MITs on monitoring wells 342-7R-RD1 and 327-7R-RD1.***

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
  - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
  - *Step-by-step procedures that would be employed during stimulation.*

The updated Attachment I (Stimulation Plan) states that stimulation is not anticipated and that a plan will be submitted for approval should stimulation be required; it contains no general description of stimulation procedures. EPA has communicated with CTV that a stimulation plan submitted after the permit is issued will necessitate a modification to the permit. CTV has chosen to not include a stimulation plan at this point.

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1? The applicant says that they will address this in their pre-operational testing plan. MITs referenced in the original Attachment G include annulus pressure tests only. For existing wells that are proposed to be converted, an external MIT will be required.*

Follow-up Requests for the Applicant

- ***Please include an external MIT in the pre-operational testing plan for wells that are proposed to be converted to monitoring wells***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions about the AoR Delineation Modeling Approach for the A1-A2 Class VI Project

In January 2022, EPA provided questions (*blue, italic text*) to CTV about the AoR modeling and modeling-relevant site characterization information in the permit application narrative and in the PISC and Site Closure Plan (Attachment E) submitted with CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated Area of Review and Corrective Action Plan and PISC and Site Closure Plan to EPA on March 31, 2022. EPA's evaluation of how the updated plans address its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

It is assumed, that planned pre-operational testing will confirm the site characterization information. Please note that modifications to the model parameters may be needed if this testing yields results that are significantly different than the model inputs.

Evaluation of the Geomodel

Geomechanical properties

The geomechanical properties of the Monterey Formation A1-A2 reservoir and Reef Ridge Shale confining zone were derived from compressional sonic data and MICP measurements in 18 wells. Borehole breakout data from the EHOF and literature reviews also aided in characterizing fracture behavior. A corresponding geomechanical model was generated to assess the failure pressures for the reservoir and confining zone. CTV included relevant discussion concerning geomechanical modeling and properties in the permit application narrative; please also see the geologic site characterization report for discussion.

A summary of fracture pressure data for the Monterey Formation A1-A2 reservoir is provided in Table 6 of the AoR CA, which is replicated below. The applicant states that injection pressure will be below 90% of the Monterey Formation A1-A2 fracture gradient at the shallowest point of the Reef Ridge Shale base in the AoR (8,403 ft as seen in Table 7 of the AoR CA, replicated below). The planned maximum subsurface wellbore injection pressure for the project is 4,500 PSI.

Table 6: Summary of the fracture pressure data for the Monterey Formation A1-A2 reservoir.

Interval	Fracture Gradient PSI/foot	Fracture Pressure (PSI) at base of Reef Ridge Shale (8,403 feet)
Monterey Formation A1-A2	0.97	8,150

Table 7. Injection pressure details.

Injection Pressure Details	Injection Well 1 357-7R	Injection Well 2 355-7R
Fracture gradient (psi/ft)	0.97	0.97
Maximum injection pressure (90% of fracture pressure) (psi)	7,335	7,335
Elevation corresponding to maximum injection pressure (ft MSL)	8,403	8,403
Elevation at the top of the perforated interval (ft MSL)	8,485	8,462
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,407	7,387
Planned maximum injection pressure / gradient (top of perforations)	4,500 / 0.53	4,500 / 0.53

Questions/Requests for the Applicant:

- *What data from which tests were used to establish the fracture pressure listed in Table 6 of the AoR CA? Additionally, please discuss how testing during the pre-operational phase will further establish the fracture pressure of the injection zone. If Step Rate Testing (SRT) will be used to determine fracture pressure, please describe the testing procedure, including the fluid to be used and how it is representative of the CO_2 injectate. CTV specifies that fracture gradient data in Table 6 (formerly Table 7) was obtained from well 327-7R-RD; however, the details of the tests conducted are not given. CTV added that they will be conducting a step rate test as per their pre-operational testing plan. The response is acceptable, pending receipt of an updated version of CTV's pre-operational testing plan that includes a SRT (which EPA requested as part of the initial geologic review).*

Objectives for Pre-Operational Testing:

- *Confirm the fracture pressure of the injection and confining zones, i.e., by performing an SRT in each zone.*

Evaluation of the Computational Model Design

The applicant's discussion of computational model design includes but is not limited to subsurface phase properties and behavior, CO_2 plume size and extent, boundary and initial conditions, timeframe and time steps, operational information, model calibration and sensitivity analysis, and injection zone storage capacity. EPA considers the applicant's evaluation of the computational model design and

associated components to be appropriate and relatively complete, however there are some outstanding questions that need to be addressed in order to consider the material in this section sufficient.

Boundary conditions

No-flow boundary conditions were established for the Monterey Formation A1-A2 reservoir in the computational modeling. The overlying confining unit, the Reef Ridge Shale, is continuous through the area, has a low permeability (less than 0.01 mD), and has confined oil and gas operations (that include injection) since discovery of the field. Well performance data from the Monterey Formation A1-A2 oil and gas reservoir, shown in Figure 9 of AoR CA, indicates no connection to an aquifer. Historical production shows minimal water production, supporting the lack of aquifer connectivity. Gas injection and subsequent gas blow-down supports lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir. Finally, reservoir pressure is approximately 230 psi and has not shown an increase due to aquifer influx.

Questions/Requests for the Applicant:

- *Please provide historical pressure data for the Monterey Formation A1-A2 reservoir demonstrating pressure isolation. CTV did not provide any information to address this question.*

Follow-up Questions/Requests for the Applicant:

- ***Please explain the basis for assuming isolation of the Monterey Formation A1-A2 reservoir in the model and provide data to justify the claim.***

Time Steps and Model Timeframe

The computational modeling results for CO_2 plume development at 4 different time-steps are shown in plan view (Figure 10) and cross-sectional view (Figure 11). The time-steps are Year 2 injection, Year 4 injection, Year 50 post injection, and year 100 post injection. The model simulation appears to have occurred over a 115-year timeframe (i.e., the 15-year injection phase plus 100 years post-injection), but this is not clear. For all layers within the model and at all time-steps, the CO_2 plume remains within the 2.1 square mile AoR. Within the first 2 years of injection, the CO_2 plume is largely defined. After 2 years, the CO_2 concentration within the plume increases until the 50 years post injection time-step. The CO_2 concentration is largely unchanged between the 50-year and 100-year post injection time-steps.

CO_2 injected into the Monterey Formation A1-A2 reservoir will be soluble in both water and oil. Due to the low remaining oil and water saturations in the reservoir, the injected CO_2 that will be dissolved in oil and water is predicted to be 0.5% and 1.3%, respectively. The remaining 98% of the injectate will be stored in the reservoir as supercritical CO_2. Figure 12 of the AoR CA demonstrates the cumulative storage for each of these mechanisms (oil, water, supercritical CO_2).

Questions/Requests for the Applicant:

- *Based on Figure 12, there is no additional CO_2 to be stored after year 5 of injection; however, the permit application narrative indicates injection will occur for 15 years. Please clarify this difference. CTV states that 5 years of injection represents the Base Case simulation, and 15 years represents a sensitivity case with a lower injection rate (see Table 7). Typically, the base case represents the anticipated operating conditions; however it is EPA's understanding that CTV plans to inject for 15 years.*

Follow-up Questions/Requests for the Applicant:

- ***Please confirm the injection phase duration and clarify which modeling scenario duration (i.e., 5 years or 15 years) reflects CTV's planned injection operations.***

Initial Conditions and Operational Information

Initial model conditions at the beginning of CO_2 injection have been established and verified over time during oil and gas production from the Monterey Formation A1-A2 reservoir. Initial conditions for the model are given in Table 4, which is replicated below. Operational information is presented in Table 5.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	240	Fahrenheit	8,300	Fluid Analysis
Formation pressure	200-300	Pounds per square inch	8,300	Pressure Test
Fluid density	61	Pounds per cubic foot	8,300	Water analysis
Salinity	25,000	Parts per million	8,300	Water analysis

Table 5. Operating details.

Operating Information	Injection Well 1 357-7R	Injection Well 2 355-7R
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft MSL) Z top Z bottom	 7,728 8,010	 7,774 7,949
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15
Injection rate (t/day)*	648 – 1,917	648 – 1,917

Questions/Requests for the Applicant:

- *The initial conditions in Table 4 were established at a depth of 8,300 ft MSL. The perforation intervals for Injection Wells 357-7R and 355-7R specified in Table 5 are above 8,300 ft MSL. Please explain how the initial conditions at a depth of 8,300 ft MSL would be representative of the perforation intervals in Injection Wells 357-7R and 355-7R. No explanation was provided.*

- *Please add the reference elevation to Table 4. Table 4 has not been changed. Since the perforated interval on Table 5 was changed to ft TVD, the units between Tables 4 and 5 no longer match.*

Follow-up Questions/Requests for the Applicant:

- ***Please update Table 4 as requested and to match Table 5, and explain how the initial conditions at a depth of 8,300 ft MSL would be representative of the perforation intervals in Injection Wells 357-7R and 355-7R.***
- ***Please update Table 4 or 5 as needed so that the perforation depths are consistent.***

Potential Pathways for Fluid Movement

Faults

CTV included relevant discussion concerning fault stability in the permit application narrative; please also see the geologic site characterization report for discussion.

Wells in the AoR

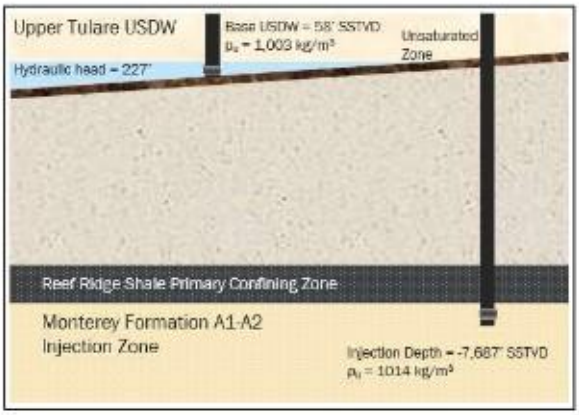
The AoR CA says that complete documentation of the 152 wells in the AoR (tabulated in Table 8 of the AoR CA) that penetrate the Reef Ridge Shale confining zone is given in Appendix 1, and Figure 15 of the AoR CA shows a map view of the 152 wells that penetrate the Reef Ridge Shale confining layer and Monterey Formation A1-A2 reservoir. However, it is unclear how many of the 152 wells penetrate the entire Reef Ridge Shale or are completed in the Reef Ridge Shale, and if they are accounted for in the computational model. Additional discussion regarding wells in the AoR is presented under "Corrective Action on Wells in the AoR," below.

Calculation of critical pressure

CTV submitted their critical pressure calculation to the GSDT in a file titled "Critical—Pressure—Calculation.PDF." Using the inputs from Figure 4 and equation listed on pg. 3 of the Critical—Pressure—Calculation PDF, the critical pressure was calculated to be 3,400 psi. The final pressure of the Monterey Formation A1-A2 reservoir will be at or below the initial reservoir pressure of 4,000 psi, ensuring that post-injection conditions replicate those of initial conditions to the extent possible. Therefore, the AoR is based on the extent of the modeled CO_2 plume.

$$\frac{P_{i,f}}{\rho_i g} + z_i = \frac{P_u}{\rho_u g} + z_u$$

Figure 4: Schematic section of the storage site with inputs to critical pressure calculation. Values for the USDW are based on the 326-7R well. The injection depth is based on the 357-7R injector. Using data from wells 357-7R injector and 326-7R the critical pressure is 3,400 PSI.



Questions/Requests for the Applicant:

- *If any of the 152 wells in the AoR penetrate the entire Reef Ridge Shale, please explain how they are accounted for in the geomodel. No information was provided to address this question within the context of the geomodel.*

Follow-up Questions/Requests for the Applicant:

- ***Please explain, in the context of the geomodel development, how any wells that penetrate the confining zone (and are potential conduits for fluid movement) are accounted for in the geomodel, or why it is appropriate to not include any of the wells that penetrate the confining zone in the AoR within the geomodel.***

Representation of Fluid Properties

Because a baseline injectate analysis has not yet been performed, limited information about the CO_2 stream is available and relevant CO_2 injectate fluid properties for the numerical modeling are not included in the AoR CA. The applicant did not submit an operating plan for the proposed wells with this information. Additionally, the applicant did not include reactive transport modeling as part of the overall modeling effort. It appears this might be due to the low water saturation (~15%) and dominant quartz/feldspar mineralogic framework of the reservoir, as noted in the permit application narrative. However, an explanation regarding the lack of reactive transport modeling is needed.

Questions/Requests for the Applicant:

- *Please update the AoR CA to include fluid properties for the CO_2 injectate used in the computational modeling, including but not limited to viscosity, density, salinity, and fluid compressibility. CTV did not provide this information.*

Follow-up Questions/Requests for the Applicant:

- ***Please describe the model assumptions related to the injectate properties as requested above.***

Objectives for Pre-Operational Testing:

- *Confirm that the properties of the CO_2 stream based on pre-operational injectate sampling are consistent with the model inputs.*

Model Calibration and Sensitivity Analyses

CTV used information derived from extensive past injection operations to inform a sensitivity analysis. The CO_2 plume model results were compared with the area of the reservoir that has been depleted by oil and gas operations.

As a computational model sensitivity, CTV maintained the injection rate for 9 years, with an increase in the final post-injection pressure and total CO_2 injected. The left panel in Figure 13 of the AoR CA represents this scenario, and the panel on the right demonstrates CO_2 plume development at a post injection reservoir pressure equivalent to the initial reservoir pressure. At a final reservoir pressure of 5,750 psi, which is greater than the initial reservoir pressure of 4,000 psi, the reservoir can store 193 BCF of CO_2, which is an increase of 61 BCF relative to initial reservoir pressure storage capacity. Both scenarios demonstrating the difference in CO_2 plume development are depicted in Figure 13 at 100 years post injection. The CO_2 plume remains within the AoR in both scenarios, with CO_2 concentrations increasing in the northwestern portion of the AoR. The applicant concludes that this scenario demonstrates that the AoR is consistent with a larger volume of injected CO_2 and the potential impact to the Upper Tulare USDW is conservative. Monitoring wells will be used for CO_2 plume and pressure front tracking, via fluid sampling and pressure and temperature monitoring. Reservoir pressures based on monitoring data and injection volumes will be integrated in order to complete material balance equations to verify pore volumes and AoR edges. Additionally, the CO_2 plume and water contact will be calculated from the monitoring well pressure, CO_2 saturation, and column height. If the reservoir pressure associated with injected volumes does not follow the anticipated trend from computational modeling, CTV will reevaluate the AoR. (Additional evaluation of the proposed plume and pressure front tracking will be presented in the Testing and Monitoring report.)

Questions/Requests for the Applicant:

- *Please discuss the genesis and evolution of minor CO_2 concentrations pictured in Figure 13 in the central to eastern portions of the AoR. CTV does not discuss this.*
- *Please provide a version of Figure 13 corresponding to the end of the injection period and/or the time at which the plume and pressure front are expected to be at their maximum extent. CTV has not provided an alternate version of Figure 14 (formerly Figure 13).*

Follow-up Questions/Requests for the Applicant:

- ***Please discuss the genesis and evolution of minor CO_2 concentrations depicted in Figure 13 in the central to eastern portions of the AoR.***
- ***Please provide a version of Figure 14 corresponding to the end of the injection period and/or the time at which the plume and pressure front are expected to be at their maximum extent as requested.***

Injection Zone Storage Capacity

As stated in the "Model Calibration and Sensitivity Analyses" section above, the storage capacity of the injection zone appears to be 132 BCF of CO_2 at initial reservoir pressure conditions of 4,000 psi (193 BCF minus 61 BCF as mentioned in the discussion of Model Calibration and Validation of the AoR CA, pg.15). The injection zone does have the potential to store an increased volume of CO_2 at higher pressures while the CO_2 remains within the defined AoR.

Questions/Requests for the Applicant:

- *The modeled injection zone storage capacity is not explicitly stated in the AoR CA. Please confirm if the volume of 132 BCF is correct. If it is not correct, please provide the correct volume. CTV did not revise the AoR CA (or the geologic narrative) to provide the requested information.*

Follow-up Questions/Requests for the Applicant:

- ***Please provide the information requested above about the storage capacity of the injection zone.***

Presentation of Model Results

Map and cross-sectional views of the simulated plume and pressure front were provided in the AoR CA. The maps show the position of the plume and pressure front after 2 years and 4 years of injection, and 50 years and 100 years post-injection. Figures 10 and 11 show the applicant's proposed AoR as delineated by the simulated CO_2 plume.

The differences in the predicted position of the plume and pressure front between the injection and post-injection time-steps were minor, suggesting that the plume movement may remain stable after injection ceases. Updated modeling will be necessary when pre-operational site data becomes available.

Corrective Action on Wells in the AoR

The AoR CA says that documentation of the 152 wells in the AoR that penetrate the Reef Ridge Shale confining zone is provided in Appendix 1. However, no tabulation of these wells is provided. There is an Excel file (AoR—Well--List) containing the name, surface location, and status of 152 wells, but it does not contain information on drill date, type, and depth to Reef Ridge Shale confining zone that is required at 40 CFR 146.84 (c)(2). Table 8 of the AoR CA indicates that 40 of the 152 wells are plugged (which corresponds to information in the Excel file). Figure 15 of the AoR CA shows a map view of the 152 wells that penetrate the Reef Ridge Shale confining layer and Monterey Formation A1-A2 Sands. These wells were reviewed for corrective action.

All 152 wells in the AoR penetrate the confining zone. This determination was made by reviewing open hole logs and deviation surveys of each well. The AoR CA plan says that well condition, mechanical

integrity and data completeness is routinely reviewed with CalGEM. The wells located within the AoR were last reviewed in Q1 of 2021.

The AoR CA also states (pg. 18) that 14 wells (shown in Table 9) will be plugged before commencement of CO_2 injection. These are abandoned wells that penetrate and are currently perforated in the Monterey Formation A1-A2 Sands or the Etchegoin Formation. It is unclear based on the text if these are the only wells that penetrate entirely through the Reef Ridge Shale, however.

The AoR CA plan says that the corrective action assessment for each well in Appendix 1 included the generation of wellbore/casing diagrams, determination of cement tops for each casing string, review of open perforations and cement plug depths. However, Appendix 1 has not been provided.

Protection of the USDW was determined by assessing all wells within the AoR that penetrate the Reef Ridge Shale. Wells were determined to not need corrective action if they had: surface or intermediate casing over the USDW; were cemented over the USDW; had cement in the intermediate casing-surface casing annulus, above the surface casing shoe; and there was cement in the production casing annulus, above the Reef Ridge Shale. The application states that all wells within the AoR meet these criteria.

Questions/Requests for the Applicant:

- *Please provide the plugging and abandonment (P&A) procedure for the 14 wells identified in Table 9 of the AoR CA to demonstrate that plugging will ensure isolation of the Monterey Formation A1-A2 Sands. CTV provided the P&A procedures in Appendix 2 for 31 of the 33 wells to be abandoned, and notes that the remaining 2 wells are being assessed and plugging procedures for them will be provided during pre-operational testing. The response is acceptable at this point; however, CTV should provide plugging procedures for the remaining two wells when they are available.*

AoR Reevaluation Schedule

CTV described the procedures and timing for AoR reevaluations to be performed during the injection and post-injection phases, and the information that will be considered in the reevaluations. At this point in the permit application review, the five-year default reevaluation schedule in the Class VI Rule appears to be appropriate.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An unscheduled reevaluation of the AoR will take place if any of the following scenarios occur:

1) Change in operations such as an increase in injection rates, or injection pressure.
2) Differences between the computational model for CO_2 plume development and observed CO_2 plume development, including unexpected changes in fluid content or pressure outside of the Monterey Formation A1-A2 reservoir that are not related to well integrity, or reservoir pressure that does not behave as predicted with increased injection volumes.
3) Seismic events occur that indicate the presence of faults near/intersecting the confining zone; events that are larger than a 3.5 magnitude and that could be associated with CO_2 injection.

CTV will discuss any such event with the UIC Program Director to determine if an AoR reevaluation is necessary. If an unscheduled reevaluation is triggered, the AoR reevaluation procedures described in the AoR CA plan will be initiated.

Questions/Requests for the Applicant:

- *Please describe the specific injection rate and injection pressure increase CTV referenced that would necessitate an AoR reevaluation, and how such an increase would not involve an exceedance of permit limits. CTV specified that changes in pressure or injection rates outside of three standard deviations from the average will trigger an unscheduled AoR evaluation. However, it is likely that injection pressures as high as three standard deviations above the permit limit would constitute a violation.*
- *Please clarify the degree of change in reservoir pressure (e.g., outside three standard deviations from the average) that would be needed to necessitate an AoR reevaluation. CTV did not specify this degree of change relative to the modeled predictions.*
- *Please clarify the timing for conducting an AoR reevaluation (i.e., within 6 months) if any of the triggering events occur. CTV states that, within six months of a triggering event, CTV will discuss with the UIC Program Director whether an AoR reevaluation is required. EPA recommends that such discussions commence sooner than six months after CTV becomes aware of them, and that the AoR reevaluation be completed within six months.*

Follow-up Questions/Requests for the Applicant:

- ***Please edit the first trigger to not reference an increase in injection pressure as high as 3 standard deviations or explain how such an increase would not be a violation of the injection pressure limit in the permit.***
- ***Please describe, in the second trigger, what degree of reservoir pressure increase relative to modeled predictions would trigger a reevaluation (or if <u>any</u> increase would trigger one).***
- ***Please revise the text at the bottom of page 23 to read, "CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event."***

Post-Injection Site Care Plan

Certain elements of the applicant's Post-Injection Site Care (PISC) and Site Closure Plan (Attachment E) are based on the modeling effort and the results and are evaluated below. See also the Testing and Monitoring report (for an evaluation of CTV's post-injection monitoring plan).

As required in 40 CFR 146.93(a)(2)(i) and (ii), the applicant presented the pre- and post-injection pressure differentials and associated maps in the AoR CA. Figure 3 of Attachment E shows the predicted maximum extent of the CO_2 plume and pressure front at site closure.

Figures 4 and 5 of Attachment E show the injection and monitoring wells, and the predicted extent of the CO_2 plume in plan view and cross-sectional view, respectively.

Questions/Requests for the Applicant:

- *Figure 1 in Attachment E shows the reservoir pressure stabilizing at the same time as injection cessation. Please clarify if reservoir pressure will stabilize at this point, or if pressure will stabilize a year after injection cessation as noted in Attachment E, "Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]." CTV states in its responses above that the plume will stabilize 1 year post-injection; however, it appears that the line in the figure that represents reservoir pressure becomes horizontal very soon after injection ceases.*
- *Please update Figure 1 to reflect the planned 15-year injection period. The figure was not revised. (As described elsewhere, the duration of CTV's planned injection phase remains unclear.)*

Follow-up Questions/Requests for the Applicant:

- ***Please confirm that injection pressures will stabilize within less than one year post-injection, and describe the basis for this, and update the curve in Figure 1 as needed.***
- ***Please update Figure 1 to reflect the planned 15-year injection period to be consistent with the narrative.***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Construction and Plugging Procedures for Injection Well 355-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

In February 2022, EPA provided questions to CTV (*blue, italic text*) about the construction and plugging of the 355-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands, submitted as part of CTV's Class VI permit application (dated August 30, 2021 and December 2, 2021) for the proposed CTV-Elk Hills Class VI geologic sequestration (GS) project. CTV provided updated operating procedures for the two wells to EPA on May 16, 2022. EPA's evaluation of how the update addresses its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Injection Well Construction

Narrative A2 and Attachment G2 describe the construction design for Well 355-7R. Well 355–7R is an existing Class II pressure maintenance well, approved by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 355–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2. Well 355-7R was drilled in 1973; Narrative A2 contains construction details regarding Well 355-7R.

Table 5 of the Narrative A2, matches the casing specifications listed in Attachment G2 for Well 355-7R (see below). Attachment G2 also includes tubing and packer specifications for Well 355-7R, which are excerpted below. The tubing and packer specifications in Attachment G2 mostly correspond to Table 7 of the Narrative A2, however there appear to be typos regarding: tubing outside diameter and weight (in the Narrative A2) and regarding packer tensile rating (in Attachment G2).

Injection Well 355-7R Construction Details (from Attachment G2)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)

Injection tubing	8,398	4.500	3.920	13.5	L-80	Long	9,020	8,540

Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

CTV states that all the well materials and the stainless-steel wellhead are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. The Applicant notes that the Class G Portland cement used to complete well 355-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor and long string (injection string), had cement returns to surface according to Narrative A2. A CBL indicated that the top of cement in the injection string annulus is above 5,200 ft, which is above the Reef Ridge Shale upper confining layer, reported as 6,929 ft-7,962 ft true vertical depth (TVD), per Table 1 of the Narrative A2.

The cement integrity is supported by information from existing wells and a CBL in Well 355-7R. California Resources Corporation (CRC) has conducted standard annulus pressure tests (SAPTs) historically to ensure continued internal mechanical integrity of the well. No SAPT results were provided in the permit application materials, however. These tests will also be conducted prior to injection and every five years thereafter and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1 of Attachment G2 is illegible, so information such as geologic formation tops (for the injection and confining zones and the Base of the USDW), perforation depths, and casing depths, cannot be evaluated. The applicant will need to resubmit an updated, resolvable casing diagram for Well 355-7R that demonstrates proper construction, including that the Base of the lowermost USDW is covered by the surface casing in accordance with 40 CFR 146.86(b)(2). According to the tables on Page G2, the surface casing is set to a depth of 500 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW in accordance with 40 CFR 146.86(b)(2). (Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.)

The applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of

the event. However, the applicant did not provide discussion regarding safety valves and automated shut-off devices in Attachment G2.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings).

Questions/Requests for the applicant:

- *Is Well 355-7R equipped with automatic shutoff systems connected to the real-time surface monitoring equipment and alarms, as required at 146.88(e)(2)? If so, please describe these systems in Attachment G2 and how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G2 to include these required components. Under "Alarms and Shut-off Devices" on page 5, the applicant states that real time monitoring and automated shut off controls will be added to the system. CTV is required to provide information for EPA to review before installing the equipment; these should be included on final as-built schematics of the well. CTV states that they do not plan to install down hole shut off systems due to the lack of risk factors (e.g., high temperatures and pressures or corrosive materials). Additional clarification on why these risk factors are considered low is required.*
- *Figure 1 of Attachment G2 is illegible. Please submit an updated, resolvable diagram for Well 355-7R that includes the following information:*
  - *All relevant formations (e.g., the injection and confining zones and the base of the USDW); These details were added to a wellbore diagram of the injection well in the confidential Appendix 1 - Monitoring Well Schematics and Plugging Details.*
  - *Surface casing that extends through the Base of the USDW, per 40 CFR 146.86(b)(2); Although the Construction, Operating and Plugging document (COP) states that surface casing is set and cemented within the USDW, according to the well schematic, the surface casing only extends to 500' which is above the bottom of the USDW at 840'. 40 CFR 146.86(b)(2) requires the surface casing must extend through the base of the lowermost USDW.*
- *For completeness, please include the description of testing of the deep monitoring wells (i.e., as described in Attachment G) in Attachment G2. The applicant states that these details will be incorporated into the pre-operational testing document, but did not include it. i*
- *Please explain how the injection well's design will mitigate potential shallow compression related to land subsidence while still complying with the requirement to cement to the surface. The applicant describes in the Casing section on pages 2 and 3 that there has been no historical occurrence of subsidence in the area. In addition, the COP states that well construction mimics other wells used in the area for injection with no operational issues related to structural strength. No evidence of this was provided, however.*

- *Please provide the most recent SAPT reports for the well. The most recent SAPT results from October 6, 2020, are provided on page 9 of the document, which shows the well maintaining pressure within the well annulus, demonstrating mechanical integrity. However, the SAPT was run for 30-40 minutes, and not the minimum of 60 minutes as described in the pre-injection testing in Appendix G2 submitted with the initial application materials. Because CTV will conduct an additional SAPT prior to injection, this response is acceptable at this point.*

Follow-up Requests for the Applicant

- ***Please clarify why the risk factors (temperature, pressure and corrosivity) are considered to be low and include further justification as to why the downhole shutoff system is not necessary.***
- ***Please confirm the base of the lowermost USDW. Please note the definition of USDW (40 CFR 146.3) below.***

  (USDW) means an aquifer or its portion:
  (1)(i) Which supplies any public water system; or (ii) Which contains a sufficient quantity of ground water to supply a public water system; and
  (A) Currently supplies drinking water for human consumption; or
  (B) Contains fewer than 10,000 mg/l total dissolved solids; and
  (2) Which is not an exempted aquifer.
- ***Please provide data or sources as evidence that lead to the determination that no subsidence has occurred in the area.***
- ***EPA requests that, for clarity, the conductor casing grade (which was reported as H-40 in the initial application) be included on Table 1. If this information was incorrect, please explain how the conductor casing is suitable for CO_2 injection.***
- ***Because the tubing grade was changed from 13CR-95 to L-80 CRA, please ensure that the coupons used in the corrosion monitoring section of the Testing and Monitoring Plan are revised accordingly.***
- ***Please update Attachment G2 to include the pre-operation testing plan for the deep monitoring wells.***
- ***Please provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.***

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 355-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in Narrative A2 and in Attachment G2. Attachment G2 identifies several tests that CTV indicates have been performed and were provided. These include deviation checks, a cement bond log, and open-hole well logs. CTV notes that mechanical integrity tests, including a temperature log and SAPT, were also acquired after the drilling of 355-7R; however, these were not provided. Attachment G2 also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2

Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed.

Questions/Requests for the applicant:

- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones. The applicant states that a full well CBL will be completed during pre-operational testing and tubing removal. The pre-operational testing plan submitted with the initial application in Appendix G2 includes a micro-seismogram log for cement evaluation, but not a CBL. If the purpose of this testing is to evaluate cement condition, the response is acceptable, although CTV should clarify the tests to be performed in their updated pre-operational testing plan. EPA will need to review and approve the results of the CBL prior to authorizing injection.*

Follow-up Requests for the Applicant

- ***Please provide an updated pre-operational testing plan that describes the tests identified in CTV's responses to questions in this document. For example, the plan should include: an SAPT of an appropriate test duration and MITs on monitoring wells 342-7R-RD1 and 327-7R-RD1.***

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
    - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
    - *Step-by-step procedures that would be employed during stimulation.*

The updated Attachment I (Stimulation Plan) states that stimulation is not anticipated and that a plan will be submitted for approval should stimulation be required; it contains no general description of stimulation procedures. EPA has communicated with CTV that a stimulation plan submitted after the permit is issued will necessitate a modification to the permit. CTV has chosen to not include a stimulation plan at this point.

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1? The applicant says they will address this within their pre-operational testing plan. MITs referenced in the original Attachment G include annulus pressure tests only. For existing wells that are proposed to be converted, an external MIT will be required.*
- *Please include information about MITs on the deep monitoring wells in Attachment G2 for completeness. The applicant says they will address within the pre-operational testing plan. MITs referenced in the original Attachment G include procedures for conducting annulus pressure tests on the deep monitoring wells.*

Follow-up Requests for the Applicant

- ***Please include an external MIT in the pre-operational testing plan for wells that are proposed to be converted to monitoring wells.***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions on the Proposed Emergency and Remedial Response Plan

In December 2021, EPA provided questions to CTV about the draft Emergency and Remedial Response Plan submitted as part of CTV's Class VI permit application (dated August 30, 2021). CTV provided an updated Emergency and Remedial Response Plan to EPA on March 2, 2022. EPA's May 2022 evaluation of how the updated plan addresses its questions is presented in red below. CTV submitted an updated Emergency and Remedial Response Plan (v3) to EPA on June 20, 2022. EPA's evaluation of how CTV's June 2022 update addresses its questions is presented in purple below. Requests for revisions and additional information are presented in ***purple, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Potential Risk Scenarios

The list of items in this section does not match the events and scenarios described in the following section.

- ***Please revise the list.*** The list was edited as requested.
    - ***Please remove earthquakes under "natural disaster" since these are addressed under the seismic events scenario.***

The list in this section also includes "CO_2 leakage to USDW or land surface," which appears to also be addressed under the "Potential Brine or CO_2 Leakage to a USDW" scenario.

- ***Please delete this item. This was edited as requested.***

Emergency Identification and Response Actions

EPA recommends some additions/revisions to the descriptions and response actions for the scenarios identified in the Emergency and Remedial Response Plan. These are presented in the table below:

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
1. All	a) EPA recommends that the Actionable Testing limits methods in Table 7 of the QASP be referenced in the Emergency and Remedial Response Plan.	a) This addition was not made. ***Please add to the introduction that the Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP.*** Edited as requested. ***Under the "Brine or CO_2 Leakage to USDW" scenario, please add other indicators of leakage including elevated pH levels in the Tulare Formation (e.g., 0.2) and pressure increases in the Etchegoin Formation of 0.001 psi detected by the pressure gauge.*** The information was added as requested; but there is a typo in the spelling of "Tulare."

		Please revise the text.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
2. Well Integrity Failure	a) A mechanical integrity (MI) failure of a monitoring well can also occur in the post-injection time frame; please update the "timing of the event" accordingly. b) The statement that CTV must notify the UIC Program Director is not an event that may signal loss of MI. Please make this a separate statement outside of the list on page 3. c) Consider including "Limit access to wellhead to authorized personnel only" to the response actions for major and minor emergencies. d) The response to a major or minor MI failure should also include necessary actions to identify the location/nature of the damage to the well or wellhead and confirm internal and external integrity prior to restarting injection (upon approval of the UIC Program Director).	***a) Please edit the timing of this event from "Injection/monitoring" to "injection/post-injection."*** Edited as requested. ***b)*** The requested change was made. No further questions. ***c)*** The requested change was made. No further questions. ***d)*** The requested changes were made. Note that there is a typo on page 5, "Preform a well log…". ***Please correct the typo.*** This edit was not made under major emergency***; please correct the text as requested.***
3. Well Integrity Failure – Major or Serious Emergency	a) Please clarify what would constitute a major or serious emergency (e.g., a verified loss or increase of pressure or fluid volumes and/or loss of mechanical integrity is discovered). b) Response to a major emergency may also include communicating with CTV personnel or other operators in the field and local authorities to initiate evacuation plans, as necessary.	a) The requested change was made. No further questions. b) The requested change was made. No further questions.
4. Well Integrity Failure – Minor Emergency	a) Please clarify what would constitute a minor emergency (e.g., downhole and surface sensor/monitoring equipment failure, procedural maintenance error or plant issue). b) Clarify that, if contamination is detected or a loss of integrity has occurred, then the situation becomes a major emergency and the actions under "Major or Serious Emergency" would be taken. c) "Initiate shutdown plan" is on the list of response actions twice.	a) The requested change was made. No further questions. b) The revised text is acceptable. No further questions. c) No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
5. Injection Well Monitoring Equipment Failure – Major or Serious Emergency	a) Please describe what constitutes a Major or Serious emergency (e.g., failure of sensors that will require shutdown of well to repair, extended repair time, and/or well reentry). b) Responses to a Major monitoring equipment failure emergency may also include: • Verifying whether any contamination has occurred (e.g., via handheld CO_2 monitors). • Communicating with CTV personnel/other operators in the field and local authorities to isolate the area or initiate evacuation plans, as necessary if contamination is detected. • Demonstrating internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director).	a) The requested change was made. No further questions. b) The requested changes were made. No further questions.
6. Injection Well Monitoring Equipment Failure – Minor Emergency	a) Please describe what constitutes a Minor emergency (e.g., sensor or monitoring failure that does not require shutdown of the well to repair). b) Potential response actions may also include actions to identify the location/nature of the damage and reset monitoring devices and/or confirm internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director). c) "Initiate shutdown plan" is on the list of response actions twice.	a) The requested change was made. No further questions. b) The requested changes were made. No further questions. c) The requested change was made. No further questions. ***Please remove reference to shutting in and restarting the well (in items 5 and 7) under the minor emergency scenario.***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
7. Potential Brine or CO_2 Leakage to USDW	a) EPA recommends that the introduction to this scenario be broadened to encompass any evidence of CO_2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address events associated with unanticipated fluid movement pathways, any potential USDW endangerment/unacceptable changes in water quality, and CO_2 leakage to the land surface. b) The severity of an event involving CO_2/brine leakage to a USDW would be serious, not low. c) Detection methods may also include pressure or water quality changes in the Etchegoin Formation monitoring well. d) The response actions should also address well integrity issues (e.g., by following responses under the MI failure scenario) or a risk to air quality (i.e., to isolate the nearby area and establish a perimeter using a hand-held air-quality monitors). e) The response equipment for this scenario should also include groundwater remediation equipment.	a) The response actions address CO_2 or fluid movement out of the injection zone (e.g., to the Etchegoin) or CO_2 detected by hand-held monitors at the surface. No further questions. b) The requested change was made. No further questions. c) The requested change was made. No further questions. d) The requested change was made. No further questions. e) The requested change was made. No further questions. ***EPA requests the following changes:*** • ***Please add performing MITs to the response actions, e.g., as part of the reference the MI failure scenario if a loss is detected.*** • ***Please revise all of the response actions to describe shut in of both injection wells, where mentioned.***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
8. Natural Disaster	a) The severity of these types of events could range up to serious or catastrophic. b) These types of events may occur in any of the project phases (e.g., construction and post-injection) not just the injection phase. c) For Major or Serious natural disasters, potential response actions may also include: • Initiating evacuation procedures; • Referencing the response actions described under the CO_2 leakage scenario if contamination or endangerment of a USDW is detected; or • Confirming mechanical integrity/taking appropriate steps if an injection/monitoring well has been damaged.	a) The requested change was made. No further questions. b) The requested change was made. No further questions. c) The requested changes were made. No further questions. ***EPA requests the following changes:*** ***a) Please remove mention of earthquakes from the introduction to this section (or reference the induced seismicity scenario).*** ***b) The severity of these types of events could range from minor to catastrophic.*** ***c) Please make the following revisions to potential response actions for Major or Serious natural disasters:*** • ***Revise the response actions to describe shut in of both injection wells (#3).*** • ***Edit item 5 to read, "If ~~there is~~ contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario."*** • ***Edit item 6 to read, "…initiate evacuation procedures (if necessary)."*** • ***Add "Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred."***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
9. Induced Seismic Event	a) This section and the title should refer to induced or naturally occurring seismic events since all seismic events have the potential to affect the injection wells and the necessary responses would be the same. b) It is unclear whether the area encompassed by "the AoR inclusive of a ¼ mile buffer," as described on page 8 is as large as a 2-mile radius of the injection wells, as described on Table 2. Please modify the introductory statement to reflect the area addressed in Table 2. c) The severity of seismic events could be major. d) Seismic events that may necessitate a response could occur during the injection or post injection phases. e) Please clarify what is meant by "seismic monitoring wells" as a detection method; EPA assumes this refers to the monitoring network that is described in the Testing and Monitoring Plan, and therefore recommends that similar terminology be used.	a) The requested change was made. No further questions. ***b)*** The introduction now refers to epicenters "within the AoR, inclusive of a two mile buffer" and Table 2 refers to "a two-mile radius of the injection well." ***Please revise the table to be consistent with the introduction.*** Edited as requested. c) The requested change was made. No further questions. d) The requested change was made. No further questions. e) The requested change was made. No further questions. ***EPA requests the following changes:*** • ***The severity of seismic events could range from minor to major; please revise this to be consistent with the table.*** • ***Please revise or delete the sentence on pg. 10, "An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase," as this contradicts reference to the injection and post-injection phases above.*** • ***Please clarify how California Geological Survey staff will be among response personnel.***
10. Induced Seismic Event—Table 2	a) Please modify the title to Table 2 to be consistent with the magnitude in the green response level (i.e., M 1.5). b) Please explain how the selected seismic thresholds (i.e., magnitude, distance from the project) are considered protective of USDWs.	a) The requested change was made. No further questions. b) The table has been revised to tie the magnitude-specific responses to USDW protection. No further questions.
11. Induced Seismic Event—Table 2, Green Level	a) Add the response action: Document the event in semiannual reports to EPA.	a) The requested change was made. No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
12. Induced Seismic Event—Table 2, Yellow Level	a) Potential response actions should also include: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Review seismic and operational data to determine the location and magnitude of seismic event. If the event falls within or near the extents of the plume, estimate potential impact to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. • Document the event in semiannual reports to EPA.	a) The requested changes were made. No further questions. ***Please revise Step 2 to reference shut down of both injection wells.***
13. Induced Seismic Event—Table 2, Orange Level	a) EPA recommends the following additions to the response actions: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Document the event in semiannual reports to EPA. • Expand Step 3 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).	a) The requested changes were made. No further questions. ***EPA requests the following changes:*** • ***Step 2: Please reference shut down of both injection wells.*** • ***Edit Step 5: "Report findings to the UIC Program Director and perform corrective actions."***
14. Induced Seismic Event—Table 2, Magenta Level	a) EPA recommends the following changes to the response actions: • Please describe the "rate reduction plan" in Step 1. Does this refer to gradual shutdown? • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event). • Add: Document the event in semiannual reports to EPA.	a) The rate reduction plan was not described***. Please describe this procedure or clarify in the E&RR Plan if it refers to gradual shutdown of the well.*** This term still is not consistent with the operating plan or other parts of Attachment F. ***Please revise Step 1 to read "Initiate gradual shutdown plan in both injection wells."*** ***EPA requests the following changes:*** • ***Edit Step 9: "If USDW contamination or endangerment is detected, or CO_2 leaked."*** • ***Edit Step 11: "Report findings to the UIC Program Director and perform corrective actions."***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
15. Induced Seismic Event—Table 2, Red Level	a) EPA recommends the following changes to the response actions: • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).	a) The requested changes were made. No further questions. ***EPA requests the following changes:*** • ***Step 1: Please reference shut down of both injection wells.*** • ***"Review seismic and operational data" is on the list twice (items 7 and 10).*** • ***Please add "Assess monitoring plans and, where necessary, intensify the monitoring plan to ensure containment" similar to the responses at the magenta level.*** • ***Edit Step 9: "If USDW contamination or endangerment is detected, or CO_2 leaked."*** • ***Edit Step 11: "Report findings to the UIC Program Director and perform corrective actions."***

Review of Carbon Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Proposed Testing and Monitoring Activities at the A1-A2 Class VI Project

In January 2022, EPA provided questions to CTV (*blue, italic text*) about proposed injection and post-injection monitoring activities submitted with CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated Testing and Monitoring Plan and PISC and Site Closure Plan to EPA on March 31, 2022. EPA's evaluation of how the updated plans address its questions is presented in red below. CTV responded to EPA's request on November 4, 2022. EPA's evaluation of the response is in green text. Requests for revisions and additional information are presented in ***green, bold, and italic*** below.

Carbon Dioxide Stream Analysis

To meet the requirements of 40 CFR 146.90(a), CTV plans to analyze the carbon dioxide (CO_2) stream quarterly for the constituents identified in Table 1 of the Testing and Monitoring Plan, which is replicated below.

Parameter	Analytical Method(s)
Oxygen	ASTM D1945
Nitrogen	ASTM D1945
Carbon Monoxide	ASTM D1945
Total hydrocarbons	ASTM D1945
Methane	ASTM D1945
Hydrogen Sulfide	ASTM D1945/D6228
CO_2 purity	ASTM D1945
Total Sulfur	ASTM 3246

There are no EPA-approved analytical methods for CO_2 injection streams, and the methods listed on Table 1 are not included among EPA-approved wastewater analytical methods in 40 CFR Part 136 (nor are they used in other Class VI CO_2 injection permits). Many of the analytes are to be analyzed using ASTM D1945, which is the Standard Test Method for Analysis of Natural Gas by Gas Chromatography. Based on the physical states of natural gas and CO_2, this test may be appropriate for CO_2 injectate analysis; however, no specific information or justification was provided in the application materials and there is no publicly available (free-of-charge) information available about these ASTM methods.

Table 4 of the Quality Assurance Surveillance Plan (QASP), Summary of Analytical Parameters for CO_2 Stream, also lists analysis of ethanol using method EPA 8260B. Although there is no EPA-approved analytical method for ethanol analysis in wastewater, this method is acceptable.

CTV is evaluating several sources of CO_2 as injectate for the project, and states that it will notify EPA prior to switching or adding CO_2 sources so that the sampling procedures can be reassessed. EPA will require that a sample be analyzed prior to initiation of injection.

CTV states that it will increase the sampling frequency if there is a significant change in the chemical or physical characteristics of the CO_2 injectate, a change in the CO_2 injectate source, or if the facility or injection well experiences a downtime over more than 30 days. Any change in the injection fluid would require advance notice and written approval from EPA.

Questions/Requests for the Applicant:

- *Please add analysis of ethanol using EPA method 8260B to Table 1 to be consistent with Table 4 of the QASP. Ethanol was added as an analyte as requested, using ISBT methods. However, Table 4 of the QASP references ASTM methods, and should reflect the methods described in the Testing and Monitoring Plan. (See the discussion of the updated QASP below.)*
- *CTV states that quarterly sampling will begin three months after the date of authorization of injection; please revise this timeline to begin three months after the commencement of injection so that the testing schedule is consistent with injection operations. The applicant made the requested edit in the first paragraph, but not in subsequent discussions under Sample Location and Frequency.*

Follow-up Questions for the Applicant:

- ***Please make global edits (e.g., under Sample Location and Frequency) to reflect that quarterly injectate sampling will begin three months after commencement of injection.*** *CTV made edits in the subsection, "Sampling Location and Frequency" and globally across Attachment C to clarify that quarterly sampling will begin three months after the commencement of injection. The response is acceptable.*

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *EPA will require a baseline injectate sample to be analyzed for the same parameters as in the Testing and Monitoring Plan prior to commencement of injection.*
- *If this sample or any updated information about injection formation fluids indicates that any injectate constituents may lead to geochemical reactions that could affect operations or change aquifer properties, additional analytical parameters for the injectate analysis may be requested.*

Injection Well Testing

The subsections below describe: the planned quarterly corrosion monitoring; continuous recording of injection pressure, rate, and volume to evaluate internal mechanical integrity; and annual external MITs that will meet the requirements at 40 CFR 146.90(b), (c), and (e). This portion of the testing and monitoring evaluation addresses both injection wells (Well 357-7R and Well 355-7R); however, CTV will need to provide a Testing and Monitoring Plan for each well, with unique well-specific testing (particularly for corrosion monitoring and continuous monitoring) that reflects each well's design.

Corrosion Monitoring

CTV proposes to conduct corrosion monitoring using the coupon method. The corrosion coupons will be in the pipeline that feeds CO_2 injectate to the injectors. Corrosion monitoring will occur between the compressor and wellhead, according to Table 1 of the QASP.

Samples of the materials used in the construction of the pipeline and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials will be weighed, measured, and photographed prior to installation. The coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The specific methods by which the samples will be handled are not described in the testing and monitoring plan; however, Table 5 of the QASP indicates that analytical methods include NACE TM0169/G31 and EPA 1110A SW846.

CTV says that, if the corrosion rate is greater than 0.3 mils/year, it will initiate consultation with regulatory agencies (but does not specify which agencies), and may run a casing inspection log to assess the thickness and quality of the casing.

The proposed coupons will be composed of the materials summarized in Attachment C, Table 3. The materials identified for corrosion monitoring were compared to the list of proposed construction materials for the injection well in Attachment G (Construction details) for Well 357-7R (submitted with the initial permit application on August 30, 2021) and Well 355-7R (submitted December 2, 2021). The first two columns of the table below are adapted from Table 3 of the Testing and Monitoring Plan (list of equipment coupon with material of construction), with review notes in the right-hand columns.

Coupon (Attachment C, Table 3)	**Construction Material (Attachment C, Table 3)**	**Review Notes based on Information in Attachment G**	
		Well 357-7R	**Well 355-7R**
Pipeline	CS A106B	Not identified	Not identified
Casing	N80 Steel	Intermediate and Long-string: N80 (pg. 2)	Intermediate and Long-string: N-80, K-55 (Table 5)
Tubing	13 CR-95	13 CR-95 (pg. 2)	L-80 (Table 6)
Wellhead	Stainless steel	Not identified	Not identified

The coupons proposed for corrosion monitoring of the casing and tubing match those described in Attachment G for injector 357-7R. However, it appears that Well 355-7R has different construction, and a corrosion testing program specific to the 355-7R injector is needed. Although the materials of construction for the pipelines and wellheads are not described in Attachment G, it is assumed that coupons would be selected to represent these materials.

Questions/Requests for the Applicant:

- *Please describe the corrosion coupons for a corrosion testing program specific to the 355-7R injector. Additional details were added to the sample description text regarding the coupon usage and application. CTV also provided additional details on Table 3 including N80 steel for*

casing and chrome alloy for the tubing; however, these do not match the materials described in the well construction descriptions.

- *For completeness, please include the details about the analytical methods for corrosion coupon monitoring that are described in Table 5 of the QASP into the Testing and Monitoring Plan. Attachment C references an ASTM method for prep/cleaning/evaluating corrosion test specimens. This differs from the QASP, which references NACE and EPA methods.*
- *Please provide the list of construction materials to be used for the pipeline and wellhead so that they can be compared to the proposed coupon materials for the corrosion testing program. Table 3 has been updated to include coupons made of carbon steel for the pipeline and chrome alloy for the wellhead; the response is acceptable at this point in the permit application review. EPA will need to verify that the corrosion coupons for the pipeline and wellhead are appropriate to the materials described in the well specifications when they are provided.*

Follow-up Questions for the Applicant:

- ***Please explain how using N80 steel coupons and chrome alloy are appropriate for monitoring the casing and tubing of each of the wells, as constructed.*** *CTV added text to Attachment C explaining that K-55 grade sections of the 7" casing will be above the packer and behind tubing and will not be directly exposed to the CO_2 injectate. The wellbore materials expected to come into contact with the CO_2 injectate include the N80 grade long string casing and the CRA tubing. Table 3 reflects this information (and is consistent with well construction information submitted by CTV in December 2022), and the response is acceptable.*
- ***Please modify the Testing and Monitoring Plan or the QASP so that the analytical methods for corrosion monitoring are consistent.*** *CTV edited the "Sample Handling and Measurement" section to reference NACE TM0169/G31 and EPA 1110A SW846. The response is acceptable.*

Continuous Monitoring to Evaluate Internal Mechanical Integrity

CTV will install and use continuous recording devices to monitor: injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Surface injection pressure will be set to a minimum of 1,200 psi, eventually reaching 2,000 psi at the cessation of injection operations, as noted in the discussion of "Operational Procedures" in the permit application narrative. For Well 357-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 3,800 psi (surface) and 6,100 psi (downhole) are not exceeded. For Well 355-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 2,900 psi (surface) and 6,108 psi (downhole) are not exceeded.

Additionally, a surface pressure gauge will be installed on the annulus to monitor the annular pressure and ensure the integrity of the packer and tubing. However, the annular pressure needed to signify a mechanical integrity issue is not indicated by CTV.

The maximum injection rate of 30 million standard cubic feet per day (mmscfpd) and average injection rate of 10-15 mmscfpd will be monitored by a surface flowmeter. The calculation of injection volumes will be calculated using the injection flow rate and CO_2 stream density and will be used to ensure the maximum expected injection volume does not exceed 10 million tonnes.

Temperature gauges will be employed at surface and downhole to monitor the temperature of the injectate and ensure it is consistent with the expected temperature of the CO_2 stream at a given depth.

Additional evaluation of the well monitoring equipment will be provided in the Well Construction reports for the injection wells.

Table 2 of Attachment C lists sampling devices, locations, and frequencies for continuous monitoring and is replicated below.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	30 seconds	30 seconds
Injection rate	Flowmeter	Surface	30 seconds	30 seconds
Injection volume	Calculated	Surface	30 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	30 seconds	30 seconds
CO_2 stream temperature	Temperature gauge	Surface and Downhole	30 seconds	30 seconds

Questions/Requests for the Applicant:

- *Please clarify the location/depths of the downhole temperature and pressure gauges listed on Table 2. These should also be depicted on the well schematics. Table 2 contains information regarding whether the gauges are at surface or downhole but does not include the actual depths. This information will need to be provided—and included on the well schematics—once the final well construction and equipment have been determined. CTV updated Table 2 to present the downhole depths of sampling devices for both injection wells. These depths match the Injection & Monitoring Well Schematics_v2 document added by reference to the Monitoring Devices, Location, and Frequency subsection. The response is acceptable.*
- *Please explicitly define the annular pressure deviation that would warrant a mechanical integrity investigation. CTV did not provide the requested information.*

Follow-up Questions/Requests for the Applicant:

- ***Please define the annular pressure deviation that would warrant a mechanical integrity investigation, as requested.*** *CTV expanded the Annular Pressure Monitoring subsection to explain the annular monitoring methodology and the pressure deviations that would warrant investigation. These deviations include a pressure decrease to 0 psi, pressure drops below 100 psi that cannot be stabilized after three attempts, and pressure increases above 1000 psi. The response is acceptable.*

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The maximum pressure thresholds identified for continuous monitoring and the annulus pressure in Attachment C may need to be adjusted to reflect the final permit conditions (e.g., if they change based on the results of pre-operational testing).*

External MITs

To verify external mechanical integrity as required at 40 CFR 146.89(c) and 146.90, CTV proposes to perform MITs annually. CTV also proposes to perform these same MITs prior to commencing injection.

Table 6 of Attachment C lists the MITs to be performed and is reproduced below.

Test Description	Location
Temperature Log	Along wellbore via wireline well log
Radioactive Tracer Survey (RTS)	Along wellbore via iodine

On page 9 of Attachment C, CTV only indicates that it will run a temperature log (and not a radioactive tracer log) and notes that if it elects to conduct an alternate MIT, it will request approval from EPA. (EPA notes that, if CTV opts to use an alternative MIT, the Class VI permit would need to be modified to incorporate this test.) CTV presents procedures for MIT temperature logging but does not describe the radioactive tracer logging procedures.

Questions/Requests for the Applicant:

- *Please revise the temperature logging procedure to include a minimum of 4 hours between runs. Additionally, please provide more extensive temperature logging procedures, e.g., in accordance with the document, "Appendix E – Temperature Logging Procedures – U.S.E.P.A. Region IX," which is available online at: https://archive.epa.gov/region9/water/archive/web/pdf/appendixetemplogreqs.pdf. The text has not been updated to incorporate the details about the temperature logging procedures that EPA requests, and some of the logging details that EPA requires have been left out.*
- *Please provide a detailed description of the MIT testing procedures for RTS. RTS appears to have been removed as a MIT testing procedure and was replaced with continuous distributed temperature sensing. This is acceptable as a secondary MIT, since temperature logs are an approved MIT method. However, consistent with 40 CFR 146.89, CTV must perform the temperature log on the injection well.*
- *The Emergency and Remedial Response Plan includes scenarios for monitoring well MI failures, however no MIT of the monitoring wells is described in the Testing and Monitoring Plan. Please provide procedures and plans for performing MITs in the deep monitoring wells. The revised plan indicates that CTV will use DTS (a fiber optic continuous temperature monitoring system) on the monitoring wells; while this is not an approved MIT method (i.e., that would meet the requirements on 146.89 for the injection well), it may be appropriate for monitoring well MITs, but additional information is required (see below).*
- *Please include MITs on the monitoring wells and the EOR wells to be used for deep monitoring as part of the Testing and Monitoring Plan. The text was updated to include DTS on the deep monitoring wells, no MITs are explicitly described for the EOR wells to be used for monitoring.*
- *Attachment G describes Annulus Pressure Testing Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1. Please also include internal and external MITs during the injection and post-injection phases and describe these in Attachments C and E. This was not included in the updated attachments.*

Follow-up Questions/Requests for the Applicant:

- ***Please explicitly state in the introduction to this section of the Testing and Monitoring Plan***

that CTV will, at a minimum, perform a temperature log on the injection well (i.e., not that it will perform "one of two methods in Table 6"). *CTV added the requested statement to the new External Mechanical Integrity Testing section, indicating that, at a minimum, CTV will perform a temperature log on the injection wells. The response is acceptable.*

- ***Please provide additional detail about the temperature logging procedures or indicate in the plan that CTV plans to perform temperature logging exactly as described in the EPA guidance.*** *CTV added the subsection "Description of Temperature Logging with Wireline" to provide the requested level of detail about the temperature logging procedures. The subsection now includes specific procedures that are consistent with EPA guidelines, and the response is acceptable.*

- ***Please provide additional information on the DTS and its suitability as a secondary MIT method.*** *CTV added the subsections "Description of Temperature Logging using Distributed Temperature Sensing (DTS)" and "Description of Passive Temperature Logging using DTS" to justify the use of DTS as a MIT method for the monitoring wells. CTV clarified that DTS will not be installed on the Monterey Formation A3-A11 wells, though DTS will be installed on other monitoring wells for passive external MI monitoring. The response is acceptable given that CTV DTS is used in addition to performing temperature logging, as required at 40 CFR 146.89.*

- ***Will DTS be employed in the EOR wells that CTV plans to use for monitoring? If so, please state this in the plan.*** *CTV clarified that DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above confining zone monitoring wells. CTV added a subsection on Internal MIT for Monterey Formation A3-A11 Monitoring Wells to explain that the A3-A11 monitoring wells are not configured with tubing and packer that would allow SAPT or annulus monitoring; therefore, they plan to perform fluid sampling for CO_2 which will serve as a proxy for internal MI of the A3-A11 wells. The presence of CO_2 in the wellbore would indicate leakage, in which case they would notify EPA. Specific testing details and parameters for fluid sampling in wells A3-A11 are given in Tables 8 and 9, respectively. The response is acceptable. However, based on Table 4 of the PISC and Site Closure Plan, it does not appear that CTV plans to perform fluid sampling in the deep monitoring wells in the post-injection phase.*

- ***Please include internal and external MITs for Monitoring Well 327-7R-RD1 & 342-7R-RD1 during the injection and post-injection phases and describe these in Attachments C and E as requested.*** *CTV stated in their response document that Well 342-7R-RD1 is not a monitoring well in the project, and it appears to have been removed throughout the permit application. Only Monitoring Well 327-7R-RD1 is planned for use in the Etchegoin Formation. The updated Attachment C now has two separate subsections for internal and external MITs. Table 6 describes internal MITs that will be performed on Well 327-7R-RD1 and includes testing frequencies for the injection and post-injection phases. Table 7 gives potential external MIT methods that may be performed on monitoring wells; however, external MITs for monitoring wells are not explicitly identified. CTV states that they will utilize an approved method under 40 CFR 146.89(c), and CTV may seek future EPA approval for use of DTS.*

Additional Follow-up Questions/Requests for the Applicant:

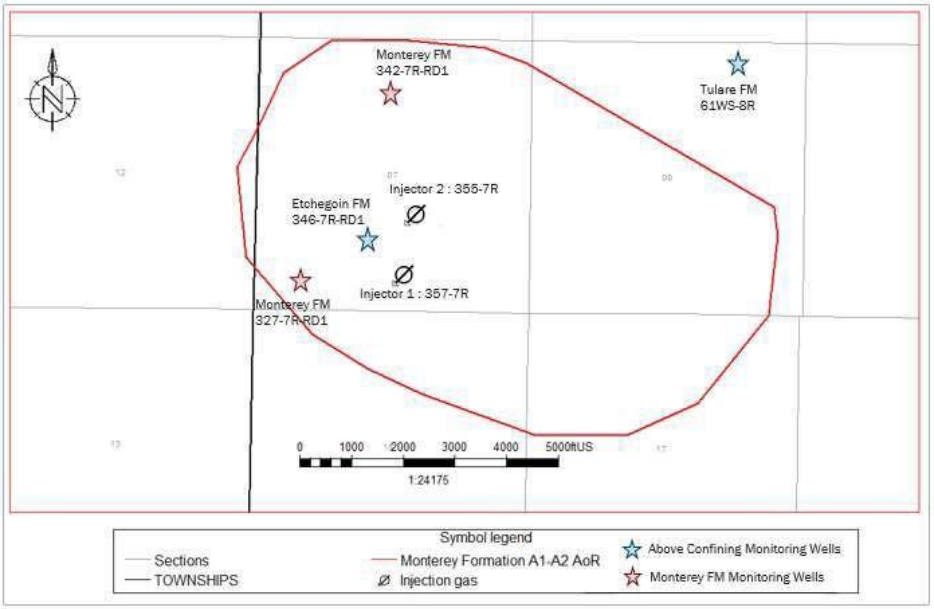
- ***Please confirm that at least one external MIT will be performed on the monitoring wells.***
- ***Please include quarterly sampling in the A3-A11 wells on Table 4 of the PISC and Site Closure Plan to provide consistency/continuity of injection-phase monitoring.***

Groundwater Quality Monitoring

CTV proposes to monitor groundwater quality in existing wells above the confining zone using direct and indirect methods. To meet the requirements of 40 CFR 146.90(d), CTV proposes to perform the following monitoring above the confining zone:

- Annual injection-phase water quality monitoring and continuous pressure and temperature monitoring via one well located outside of, and to the northeast of, the delineated AoR in the Upper Tulare Formation (the lowermost USDW) and the Lower Tulare Formation. Post-injection water quality sampling will continue annually and continuous pressure monitoring in the USDW is proposed.
- Continuous monitoring of pressure and temperature in the Etchegoin Formation within a monitoring well located to the west of the injection wells.

Attachment E does not describe any monitoring in the Etchegoin or the Monterey Formation A3-A11 Sands after cessation of injection. However, EPA will likely require that post injection phase monitoring



be an extension of injection phase monitoring to confirm continued demonstration that USDWs are not endangered and to inform the non-endangerment demonstration required at 40 CFR 146.93(b)(3).

Figure 2 of the QASP shows the locations of all monitoring wells associated with the project and is reproduced below.

The Etchegoin Formation monitoring well appears to be situated within the AoR and in the anticipated path of the CO_2 plume and pressure front (based on information in Attachment B). The Upper/Lower Tulare Formation monitoring well is outside of the delineated AoR to the northeast of the injection wells, and down plume. Given that the Tulare Formation does not hold much water within the AoR, this

location, while not in the same direction as the deeper monitoring wells may be most appropriate to allow geochemical sampling, although it is unlikely that CO_2 will travel that far down the limb of the anticline. CTV states that additional Upper Tulare monitoring wells will be drilled if increased pressure is observed in the Etchegoin Formation monitoring well or water quality changes in the Tulare Formation that is due to Monterey Formation A1-A2 CO_2 injection. However, it is unclear how a linkage of water quality/pressure changes to CO_2 injection (and not other activities) would be made.

The applicant proposes to monitor water quality in the Upper/Lower Tulare Formation and the Monterey Formation during the injection and post-injection phases. The analytical and field parameters and methods described in Tables 5 and 8 of Attachment C (injection-phase monitoring of the Tulare and Monterey Formations, respectively) are nearly the same as those in Tables 2 and 5 of Attachment E. Additional information about monitoring in the Monterey Formation is described under "CO_2 Plume Tracking" below. CTV also proposes to perform a baseline water analysis in the Etchegoin Formation monitoring zone and in the Tulare Formation monitoring well.

Table 5 of Attachment C (Injection-phase Tulare Formation monitoring) is reproduced in the first two columns of the table on the next page. Because consistency of monitoring parameters above and within the injection zone is appropriate for detecting leakage of the CO_2 plume, EPA evaluated proposed injection and post injection monitoring in the Tulare and Monterey Formations together. EPA's notes and recommendations are provided in the right-hand column; see also the discussion of "Quality Assurance Procedures" below for additional comments on the parameters to be monitored.

The parameters appear to be generally appropriate for groundwater quality monitoring needs for GS projects, and are consistent with other Class VI monitoring programs, except as noted below. As the permit application narrative describes (pg. 39), the Monterey A1-A2 Sands are dominated by quartz and feldspar, which are stable in the presence of CO_2 and carbonic acid. Note that, as additional information is gathered based on the reviews of other parts of the permit application or pre-operational data collection, recommendations or requirements for additional analytical parameters may be provided.

Parameters	Analytical Methods	Evaluation Notes/Recommendations
Tulare Formation		
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B	200.7 and 6010B are both ICP-AES methods, not ICP-OEC. Please explain what ICP-OEC is or revise the table. These were changed to ICP-MS and EPA Method 6020. In Table 17 of the QASP, the final cation is Ti, not Tl as in Attachment C. Please clarify/be consistent. Also, this is "T1" in the tables of Attachment E; please correct the typographical error. Not addressed. Standardized to Ti in the QASP, Attachment C, and Attachment E. Cations of Sb are also mentioned in Table 17 of the QASP; please add this to the ground water monitoring parameters in Attachments C and E. Not addressed. Sb added to Attachment C and Attachment E. 200.7 is an EPA-approved wastewater analytical method, while 6010B is not. EPA requests that Method 200.7, Rev 4.4 (1994) be specified. These were changed to ICP-MS and EPA Method 6020.
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B	See above. These were changed to ICP-OES and EPA Method 6010B.
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	Attachment E and Table 17 of the QASP also include anions of Cl; please add this to Attachment C for consistency and completeness. Added. Tables 2 and 5 of Attachment E reference EPA Method 300; please revise the method to be consistent with Attachment C (i.e., Method 300.0). Also, please specify that EPA Method 300.0, Rev. 2.1, Part A (1993) will be used. Addressed.
Dissolved CO_2	SM 4500-CO2-C	No comments.
Total Dissolved Solids	SM 2540 C	Attachment E refers to SM 4500 C for TDS; EPA requests the use of SM 2540 C for consistency. Addressed.
Alkalinity	SM 2320 B	Attachment E refers to SM 2510, which is for conductivity, not alkalinity. EPA requests that CTV revise Attachment E to reference SM 2320 B for consistency. (SM 2320 B is an approved wastewater method.) Addressed.
pH (field)	EPA 150.1 / SM4500-H+B	No comments.
Specific Conductance (field)	SM 2510 B	SM 2510 B is named by SM as a laboratory method, and it is not clear whether SM 2510 B can be conducted in the field. EPA Method 120.1 may be more amenable to field screening if SM 2510 B is not. Please clarify if field use of SM 2510 B is possible or revise the table (i.e., field vs. lab designation) or the method. Not addressed. Changed to APHA 2510.
Temperature (field)	Thermocouple	No comments.
Dissolved Methane	RSK-175/Gas Chromatography	This method was developed by EPA but is not an EPA approved method for wastewater analysis. Please provide information to support the use of this method for dissolved methane analysis. Alternatively, consider using EPA-approved method SM 6211 B and/or 6211 C. Parameter was removed. Change not made.

EPA recommends in Class VI guidance that monitoring well construction and planned plugging procedures for monitoring wells be reviewed as part of the permit application evaluation to confirm that

these wells will not provide conduits for fluid movement that could endanger USDWs. No monitoring well construction or plugging information was provided in the permit application materials.

CTV should note that the Central Valley Water Board indicated in its consultations with EPA on a prior Class VI project that any newly drilled monitoring wells must be approved by the Water Board and, while existing wells would not need to be approved, the Water Board expressed interest in any plans to use existing wells as monitoring wells.

Attachment C also describes the water quality sampling procedures, the laboratory to be used, and chain of custody procedures. This information is detailed in the QASP as well.

Questions/Requests for the Applicant:

- *Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E as noted in the table above. Further, the same analytes and methods should be used for monitoring of all formations - to provide consistent data to support modeling reviews and a non-endangerment demonstration. Tables 5 and 8 have been updated; however, some additional changes are needed, as noted above.*

- *In addition, please include additional ground water quality parameters to support a robust monitoring program, as follows:*
    - *δ13C, which is mentioned in the QASP, but not in Attachments C and E. This was added to Table 8; the response is acceptable.*
    - *Water density (which is referenced in the Testing and Monitoring Plan as an expected water quality change due to plume movement on pg. 12). This was not included.*
    - *Dissolved O_2 and H_2S. Dissolved O_2 is a primary indicator of water quality. H_2S occurs in the subsurface, may be common in oil fields, and has the potential to be mobilized, and, is listed as a toxic substance by the CDC. H_2S was added to the parameters in Tables 5 and 8; dissolved O_2 was not added as a parameter but is listed under field measurements where it should be measured. The response is acceptable.*

- *Please include the groundwater monitoring well 61WS-8R in Figure 4 of the PISC and Site Closure Plan. This was not added to Figure 4 as requested.*

Follow-up Questions for the Applicant:

- ***Please provide monitoring well construction and plugging plans to confirm that these wells will not provide conduits for fluid movement that could endanger USDWs.*** *CTV provided Monitoring Well Construction and Plugging Plans for monitoring wells 327-7R-RD1, 335X-7R, and 353A-7R (Attachment G). The plans are consistent with EPA templates for well construction and plugging. However, it is noted that there are some discrepancies between the data tables in the Monitoring Well Construction and Plugging plans and similar data tables within the well schematics that CTV submitted in May 2022. Additionally, the plans state that the cement type used for plugging will be API Spec 10A. The tables within the well schematics, and within the plans, indicate Class G type cement will be used. Although equivalent to each other, the schematics should reference the same type as described in the plans (API Spec 10A).*

- ***Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E to incorporate the notes above, i.e., add specific conductance (field), Sb, and water density and revise the chemical symbol for titanium.*** *CTV made some of the requested changes and*

revisions to Table 5 and 9 (formerly Table 8) of Attachment C and Tables 2 and 5 of Attachment E (as noted above).

- ***For clarity, please also include the depths of pressure/temperature monitoring gauges on Tables 4, 7, and 9 (only the fluid sampling depths are shown, and a separate depth row for the pressure/temperature gauges would clarify this monitoring).*** *CTV updated the relevant tables (now Tables 4, 8, and 10) to include depths for pressure and temperature monitoring, with separate rows for each measurement; pressure and temperature monitoring will occur at the same depths. The response is acceptable.*

- ***Please update the USDW fluid sampling depth for the Tulare Formation well in Attachment E Table 1 to 940 – 960 feet to be consistent with Attachment C.*** *CTV updated Table 1 of Attachment E to be consistent with Table 4 of Attachment C. The response is acceptable.*

- ***Why was dissolved methane removed as a ground water analytical parameter?*** *CTV states in their response document that dissolved methane is not considered a necessary component to understanding leakage from the CO_2 reservoir into the USDW. However monitoring for methane would be consistent with other Class VI projects and is recommended in the UIC Class VI Testing Guidance document.*

- ***Please include well 61WS-8R in Figure 4 of the PISC and Site Closure Plan.*** *CTV clarified in their response document that the 61WS-8R monitoring well is not being considered for the project. The USDW monitoring well planned for the project is shown on Figure 1 of Attachment C, Figure 3 of Attachment E, and Figure 2 of the QASP. The response is acceptable.*

Additional Follow-up Questions/Requests for the Applicant:

- ***Please update the groundwater analytical parameters to include testing for dissolved methane with an EPA approved method.***
- ***Please update the monitoring well schematics data tables to address the inconsistencies with the plugging plans in Attachment G.***
- ***APHA 2510 is a laboratory (not a field) method. Please revise the Tables 5 and 9 and/or the Sampling Methods section on pg. 10 to state that this test is planned for a laboratory setting and not the field, or, specify a new testing method for field use.***
- ***Please add water density as a testing parameter to Tables 5 and 9 of Attachment C, Tables 2 and 5 of Attachment E, and Table 3 of the QASP.***
- ***CTV stated in their response to questions about MITs (see above) that Well 342-7R-RD1 is not a monitoring well in the project. Therefore, there is only one Etchegoin monitoring well, to the southwest of the injectors. Please include a description of how CTV will monitor for water quality changes above the confining zone in the northwestern portion of the plume.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of groundwater quality analytical parameters may need to be updated to ensure that all applicable parameters are included.*

CO_2 Plume and Pressure Front Tracking

The applicant describes proposals for CO_2 plume and pressure front tracking that include: (1) the use of direct and indirect methods for tracking the pressure front within the injection zone [40 CFR 146.90(g)(1)]; and, (2) direct pressure front monitoring in two monitoring wells and seismic monitoring to indirectly track the extent of the CO_2 plume [40 CFR 146.90(g)(2)].

For post-injection site care, CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. In Attachment E, Table 4 details the methods that will be used to monitor the CO_2 plume post-injection, and Table 6 details the methods that will be used to monitor the associated pressure front. Injection reservoir pressure monitoring will occur to ensure confinement of the reservoir and consistency with computational modeling results. As seen in Table 6 of Attachment E, seismicity monitoring will also occur via surface and shallow borehole seismometers. Table 5 of Attachment E lists the analytical methods that will be used for the injection zone fluid monitoring and analysis.

CO_2 Plume Monitoring

CTV proposes to monitor the plume via direct and indirect monitoring in the Monterey Formation:

Direct plume tracking methods include:

- Annual fluid sampling during the injection and post-injection phases in Monterey Formation A1-A2 Sands via two monitoring wells (327-7R-RD1 and 342-7R-RD1, located to the southwest and the northwest of the injection wells, respectively).

- Quarterly fluid sampling during the injection phase in EOR producers in the Monterey A3-A11 Sands. The location of the EOR wells is not described.

Indirect plume monitoring includes:

- Pulse neutron logging in the Monterey Formation A1-A2 Sands via the same monitoring wells. This logging will be conducted every two years during the injection phase and every 5 years during the post-injection phase.

The parameters and associated analytical methods are presented in Table 8 of Attachment C. They are identical to those proposed for Tulare Formation water quality monitoring described under "Ground Water Monitoring" above. Deep and shallow water quality monitoring should be for the same parameters to provide consistent data on which to evaluate potential fluid movement out of the confining zone.

Figure 2 of the QASP (reproduced under "Groundwater Monitoring" above) shows the location of the monitoring wells in the Monterey Formation A1-A2 Sands. CTV asserts that modeling indicates that the CO_2 plume will reach each of these monitoring wells by the second year of injection.

Pressure Front Monitoring

CTV plans to conduct **direct pressure front monitoring** by continuously monitoring pressure and temperature during the injection and post-injection phases within the Monterey Formation A1-A2 Sands via pressure gauges in monitoring wells 327-7R-RD1 and 342-7R-RD1.

Indirect pressure front monitoring will be accomplished via seismic monitoring throughout the AoR. CTV states that it will monitor seismicity with surface and shallow borehole seismometers it plans to install, as well as monitor seismic data from the Southern California Earthquake Data Center (SCEDC) network. This continuous monitoring will continue throughout the injection and post-injection phases.

Pressure-front monitoring activities are summarized in Table 9 of Attachment C and Table 6 of Attachment E.

Questions/Requests for the Applicant:

- *Please refer to EPA's questions and recommendations under "Groundwater Monitoring" above regarding water quality analysis and revise Table 8 of Attachment C and Table 5 of Attachment E accordingly. Additional revisions are needed, as described in the comments above.*

- *Please elaborate on the monitoring in the Monterey Formation A3-A11 Sands as described on page 12 of Attachment C. Specifically, where are the EOR producers from which CTV plans to sample the Monterey Formation A3-A11 Sands? At what depths will sampling be performed, and what parameters will be analyzed for? (The analytical parameters should be consistent with other monitoring.) Please describe who owns these wells, and whether they will be operational throughout the injection and post-injection periods? Please include the locations of these wells on the relevant figures in Attachments C and E and the QASP. The applicant provided a new Figure 3 that shows the locations of these wells, and their depths are presented in Table 7. The updated plan indicates that the same analytes will be monitored as shown in Table 8. The response is acceptable (pending requested updates to Table 8).*

- *Please describe the seismic monitoring network discussed on pg. 16 of Attachment C, including the number and location of the seismometers that CTV proposes to install. The requested information was not provided.*

- *Please explain the timeframe for which a seismicity baseline will be established, and if historical seismicity will be incorporated into this baseline. CTV says that historical seismicity within the area will be accounted for in the baseline assessment, but does not explain how.*

- *Page 15 of Attachment C says that CTV plans to perform direct pressure monitoring in the Monterey Formation A1-A2 Sands, and Table 9 indicates that pressure and temperature monitoring will be performed. Please revise the statement on pg. 15 to be consistent with the table – to include temperature as well as pressure. The revision has not been made to mention temperature monitoring as detailed in Table 9.*

- *EPA recommends that the sampling/measurement depths be included in Tables 7 and 9 of Attachment C and Tables 4 and 6 of Attachment E for clarity and completeness. Depths were added as requested to Attachment C Table 7; but were not added to Table 9 of Appendix C or Tables 4 and 6 of Attachment E. Note also that, in the updated attachment, CTV identified different injection zone monitoring wells (i.e., 353A-7R and 335X-7R); these wells are located close to the wells identified in maps in the initial plan.*

- *Please make the following changes to the proposed plume and pressure front tracking in Attachments C and E:*
    - *Perform frequent sampling and logging (e.g., quarterly, or semi-annually) early in the injection phase (i.e., at least until the CO_2 plume passes the monitoring well locations).*

This would allow the acquisition of additional data to validate the modeling, provide early warning of unanticipated fluid movement, and be consistent with other Class VI projects. The requested change was not made.

- *Conduct a 3D seismic survey or a vertical seismic profile during injection operations for comparison to the 2019 3D seismic survey described in the application narrative. The requested change was not made.*
- *Conduct quarterly water quality sampling in the A1-A2 Sands for plume tracking to be consistent with the A3-A11 monitoring activities as well as provide additional data points to validate modeled predictions, and to eventually support the demonstration of non-endangerment. CTV updated Table 7 to align sampling frequencies in the Monterey Formation A1-A2 and A3-A11.*

Follow-up Questions/Requests for the Applicant:

- ***Please revise Table 8 of Attachment C and Table 5 of Attachment E to address EPA's comments under groundwater quality monitoring above.*** *CTV made some of the requested revisions. See EPA's evaluation and Follow-up Questions for the Applicant in Groundwater Monitoring above.*
- ***Please describe the seismic monitoring network and explain how historic seismicity within the area will be accounted for in the baseline assessment.*** *CTV expanded the subsection "Induced Seismicity and Fault Monitoring" to describe the proposed seismic network and explain the seismic analysis, which includes a baseline study and continuous monitoring. CTV specified that 7 borehole and near-surface seismic sensor locations will make up the seismic network. Seismic data will be collected for at least 12 months from the seismic network prior to injection to establish baseline seismicity. Historical seismic data will be obtained from the Southern California Seismic Network and reviewed to assist in establishing the baseline. The response is acceptable.*
- ***Please revise the statement on pg. 15 to describe temperature and pressure monitoring as described above.*** *CTV updated the text to clarify that both pressure and temperature of the plume will be monitored. The response is acceptable.*
- ***Please add sampling/measurement depths to Table 9 of Appendix C and Tables 4 and 6 of Attachment E as described above.*** *CTV added a depth column to Table 10 (formerly Table 9) of Attachment C and Tables 4 and 6 of Attachment E. The response is acceptable.*
- ***Please update the plume and pressure front tracking discussion to include the requested frequent sampling and logging early in the injection phase and a 3D seismic survey or a vertical seismic profile as described above.*** *CTV updated Table 4 of Attachment E to reflect quarterly fluid sampling for direct plume monitoring but did not include a 3D seismic survey or a vertical seismic profile.*

Additional Follow-up Questions/Requests for the Applicant:

- ***Please include a map of the 7 seismic monitoring locations in Attachment C.***
- ***Please update the plume and pressure front tracking discussion to include a 3D seismic survey or a vertical seismic profile.***

Air/Soil or Other Testing and Monitoring

Based on the currently available information about the geologic setting (i.e., the depth of the injection formations and the lack of evidence for the presence of transmissive faults of fractures), surface air

and/or soil gas monitoring are not needed to detect movement of fluid that could endanger USDWs within the AoR.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If, based on the results of planned pre-operational testing, uncertainties about the geologic setting are identified, the need for air and/or soil gas monitoring or other monitoring will be reconsidered.*

Quality Assurance Procedures

The review team evaluated the QASP submitted with the permit application to verify that all the testing activities, analytes, etc., included in the QASP are consistent with proposed injection and post-injection phase testing and monitoring. All the injection and post-injection testing and monitoring activities (except for pressure falloff testing) are addressed in the QASP and the QASP covers activities recommended by EPA. EPA noted a few discrepancies between the tables in the QASP and the activities described in Attachments C and E. These are summarized in the table below:

QASP Table	EPA comments
Table 1. Summary of testing and monitoring.	Cement bond logs and standard annulus pressure tests of the injection wells are listed in the QASP, but these tests are not described in Attachment C. Please clarify if these tests are planned to be performed, either as part of pre-operational or injection-phase testing, or revise the QASP accordingly. Cement evaluation was removed from the updated QASP. Please add PFOT and RTS to Table 1. PFOT was added to Table 1 (RTS is no longer planned).
Table 2. Monitoring Well Summary.	Monitoring the A3-A11 Sands via the EOR wells is not included on Table 2 of the QASP; please include this for consistency. Table 2 was updated as requested.
Table 3. Summary of analytical and field parameters for ground water samples.	Please update the placeholders for specific cations and anions in Table 3 to reflect Table 17 of the QASP. Zinc needs to be added to Table 17. Zinc was added to Table 17 as requested. This table should address sampling in formations other than the Tulare Formation (per recommendations above). Table 3 was updated as requested. There is a typo in the pH (field): the method “SPA 150.1” should be “EPA 150.1” This has been corrected.
Table 5. Summary of Analytical Parameters for Corrosion Coupons.	Please include the QC Requirements on Table 5. This has been added as requested.

Table 17. Summary of sample containers, preservation treatments, and holding times for ground water samples.	There are a few discrepancies between the analytical parameters mentioned on Table 17 of the QASP and in Attachments C and E. EPA recommends the following changes for consistency: • Please revise the parameter NO_2 in Table 17 of the QASP to be consistent with NO_3, which is a planned analyte, per Attachments C and E. This has been corrected. • Add cations of K (in Tables 5 and of Attachment C and Tables 2 and 5 of Attachment E) to Table 17. This has been added as requested. • Please also make other necessary revisions to Table 17 of the QASP to address EPA's requests related to analytical parameters under "Ground Water Monitoring" above. See comments related to Table 17 edits under Groundwater Quality Monitoring.
Other	Please fix the formatting of the Table of Contents for Section B.1. a. This has been corrected.

Follow-up Questions/Requests for the Applicant:

- ***Please update Table 4 of the QASP to reflect use of ISBT methods for injectate analysis.*** *CTV updated Table 4 to use equivalent ISBT methods described in Table 1 of Attachment C. The response is acceptable.*
- ***Please revise Table 17 of the QASP to include zinc and Ti (not Tl) to be consistent with Attachment C.*** *CTV included Zn and corrected Ti. The response is acceptable.*

Additional Follow-up Questions/Requests for the Applicant:

- ***Please update Table 3 of the QASP to indicate that APHA 2510 is a laboratory (not a field) method.***

Review of Carbon TerraVault (CTV) Responses to EPA's Site Characterization Questions about the Class VI A1-A2 Permit Application

In December 2021, EPA provided questions presented in ***blue, bold, and italic text*** to CTV about the geologic narrative submitted as part of CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated narrative and a table summarizing their responses to EPA on March 2, 2022. EPA's May 2022 evaluation of how the narrative addressed its questions is presented in ***red, bold and italic*** text. CTV submitted an updated narrative (Attachment A Site Evaluation v3) to EPA on June 20, 2022. This document evaluates how the updated narrative addresses EPA's May 5, 2022 questions (in purple text). Requests for revisions and additional information are presented in ***purple, bold and italic*** text. Previous responses that require no further information are not included in this enclosure.

Regional Geology and Geologic Structure

The Elk Hills Oil Field (EHOF) is in Kern County, California, in the southern San Joaquin Basin (Figures 1 and 2) CTV plans to inject CO_2 at the EHOF into the Monterey Formation via 2 injection wells, 355-7R and 357-7R, over a period of 15 years. The 2 injection wells are 1,250 feet apart and will inject into the Monterey Formation A1-A2 reservoir (Monterey A1-A2) at the Northwest Stevens Anticline at ~8,500 ft depth (Figure 8 and pg. 4).

The Monterey Formation at the EHOF also contains the Miocene Reef Ridge Shale (the primary confining zone), which directly overlies the Monterey A1-A2 and has been an effective seal for 40+ years of oil and gas operations (pg. 9). Figures 4 and 5 show the spatial distribution of wells in the EHOF and data available for use in characterizing the injection zone.

The Monterey A1-A2 consists of turbidite sands bounded above and below by siliceous shale (pg. 9). The application asserts that this depositional history has resulted in minimal lateral communication of the Monterey A1-A2 outside the EHOF (Cross Section Figure 3, pg. 4; pg. 9). The reservoir is continuous across the area of review (AoR), with pinch-outs on the channel edges (pg. 9).

The Upper Tulare Formation is the lowermost underground source of drinking water (USDW). The Tulare Formation consists of poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley (pg. 7). It is divided into the Upper Tulare and the Lower Tulare by the Amnicola Clay (a low permeability claystone). An aquifer exemption was approved for the Lower Tulare Formation in 2018, making the Upper Tulare Formation the lowermost USDW.

In addition to the Reef Ridge Shale, the Monterey A1-A2 Sands are separated from the lowermost USDW in the Upper Tulare Formation by the Amnicola Clay (pg. 31), the Lower Tulare Formation, the San Joaquin Formation, a depleted gas reservoir directly underlying the Tulare Formation, and the Etchegoin Formation (pg. 8). The Monterey A1-A2 Sands are separated from the underlying Monterey A3-A11 reservoir by a laterally continuous 20-foot shale known as the A2 Shale (Figure 9). The application asserts that they are not in communication, as evidenced by a pressure differential (of 200-300 psi in the A1-A2 and ~1,700 psi in the A3-A11), and the need for separate pressure maintenance strategies (pg. 10). The A3-A6 reservoir is also considered a viable target for future CO_2-EOR based on its existing

waterflood injector infrastructure and high reservoir pressure (pg. 11).[1]

Tests and logs performed during drilling and prior to completion of the 357-7R injection well and the 342-7R-RD1 and 327-7R-RD1 monitoring wells (which are completed in the Monterey Formation and are located to the west and northwest of the injectors) include Array Compensated True Resistivity, SP logs, caliper logs, compensated spectral natural gamma log, spectral density dual spaced neutron log, and mud logs (Attachment G pg. 4-5). Cement bond logs and MIT tests (temperature log and SAPT) were also performed on the 357-7R injection well.

- ***Please provide pressure build-up test results for the 357-7R injection well. CTV requested technical discussion prior to inclusion in the pre-operational testing plan. The response is acceptable at this stage of the permit application review. EPA will schedule a technical discussion.***

Objectives for Pre-Operational Testing:

- ***Confirm hydraulic separation of the Monterey A1-A2 Sands and the Monterey Formation A3-A11 reservoir.***
- ***If no pressure build-up test results exist for the 357-7R injection well, perform pressure build-up testing as part of the Pre-Operational Testing Plan.***

Geochemistry/Geochemical Data

Limited baseline geochemical data for the Upper Tulare Formation (USDW) and Monterey Formation (injection zone) are provided in the application.

Figure 30 shows the results of water analysis performed on waters from the Upper and Lower Tulare Formations. The produced fluid has been collected during previous operations to establish a baseline and characterize the region. Hydrocarbon content in the injection zone was determined through fractional distillation and chromatography (pg. 37). Figure 30 is difficult to read, but it appears that the analysis is from 1995, and the analytes include some, but not all, of those planned as part of injection and post-injection phase monitoring. The TDS values of the Upper Tulare Formation appear to be 4,800-4,900 mg/L.

The application states that water sampling was not performed in the Monterey A1-A2 Sands because reservoir depletion has now reduced water saturation to residual levels. However, geochemical analysis was performed using fluid produced during oil and gas operations (pg.37). CTV provides an example of the water geochemistry analysis taken from well 381-17R from a sand underlying the Monterey A1-A2 Sands (Figure 31). Figure 33 presents a 2021 analysis from nearby Well 353-7R. The figure is difficult to read, so it is unclear what analytes were measured, and if all the analytes planned during operational testing are addressed. It appears that the TDS of the Monterey A1-A2 Sands is about 24,000 mg/L.

CTV's Testing and Monitoring Plan (Attachment C) includes monitoring the overlying Etchegoin/San Joaquin Formations and the Tulare Formation for groundwater quality and geochemical changes and the Monterey Formation as part of direct plume tracking activities. Water quality will need to be established in each of these formations prior to injection operations to provide a baseline for comparison to future

[1] Note: CA SB905 now prohibits enhanced oil recovery with CO2.

monitoring results.

Questions/Requests for the Applicant:

- ***Please provide clear/legible versions of the sample analyses in Figures 30 and 31 to allow a review of the sampling performed.*** The revised figures (now Figures 33 and 34) are legible. The TDS of the four samples in the Upper Tulare Formation ranges from 4,800 to 4,900 mg/L. EPA has no further questions.
- ***Where is Well 381-17R***? CTV referenced page 40; however a revised Figure 34 on page 39 shows the well, which is just outside the eastern edge of the AoR. EPA has no further questions.
- ***What is the total dissolved solids (TDS) content of the Monterey Formation? Please indicate how many data points or measurements are available to support this measurement (i.e., based on past field operations) and, if they are not from throughout the AoR, please provide information to support a determination that the Monterey Formation is not a USDW.*** CTV referenced page 40; however Figure 34 on page 39 shows the requested water quality information. EPA has no further questions.
- ***Is any water quality data available for the Etchegoin Formation? If so, please provide this.*** CTV responded that this is included in the pre-operational testing plan. It is assumed that no current water quality data exist. The response is acceptable at this point in the permit application review. No further questions.
- ***In the Testing and Monitoring Plan, CTV states that they obtained a baseline analysis for the 61WS-8R well (apparently for the Tulare Formation). Please provide this analysis if it is not the same as is provided in Figure 30.*** CTV responded that it will drill a new monitoring well and baseline results will be included in pre-operational testing. However, they did not provide any specific information about the location or construction of the well (which has ramifications for the testing and monitoring and financial responsibility evaluations).

Follow-up Questions/Requests for the Applicant:

- ***Where will the new Tulare Formation monitoring well that CTV references above be located?*** CTV responded that the USDW monitoring well will be located on the pad for 61WS-8R (it is shown on Figure 1 of the Testing and Monitoring Plan and its construction is shown in Appendix 1_TM Monitoring Well Schematics). Data will be gathered on the new USDW monitoring well and provided as part of pre-operational testing. No further questions in the context of the geology evaluation.
    - ***Is this well in addition to the existing well 61WS-8R?*** CTV responded that it reviewed the 61WS-8R well and determined that it was not an adequate monitoring well; therefore, the new well will replace that well.
    - ***CTV should provide specific information about the construction of this well and include this well in the Testing and Monitoring Plan and PISC and Site Closure Plan, and address it in the financial responsibility cost estimates.*** CTV responded that it will update the Testing and Monitoring Plan, PISC and Site Closure Plan, provide well construction details, and address this in the financial responsibility cost estimates.
        - ***Please update the modules listed above to reflet the construction of the new monitoring well.***

Objectives for Pre-Operational Testing:

- ***Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan.***

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

January 11, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the area of review (AOR) delineation, testing and monitoring activities, and operating procedures for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the three Enclosures.

Please submit the information requested in the Enclosures by February 25, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Michele Dermer at (415) 972-3417.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.01.11 10:58:13 -08'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: AOR Delineation Modeling Approach
Testing and Monitoring Activities
Operating Procedures

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

February 3, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit Nos. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3; Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Construction and Plugging Procedures for the two proposed injection wells for the subject permit application – Well 355-7R and Well 357-7R. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the two Enclosures.

Please submit the information requested in the Enclosures, by March 31, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or call Michele Dermer at (415) 972-3417.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.02.03 06:55:57 -08'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: Construction and Plugging Procedures for Injection Well 355-7R
Construction and Plugging Procedures for Injection Well 357-7R

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

December 15, 2021 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the site characterization, financial responsibility, and emergency and remedial response plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below, and in the three Enclosures.

Considerations of Specific Federal Laws

40 CFR §144.4 requires that EPA consider the potential applicability of several specific Federal Laws, including the Wild and Scenic Rivers Act (WSRA), National Historic Preservation Act (NHPA), Endangered Species Act (ESA), Coastal Zone Management Act (CZMA), and the Fish and Wildlife Conservation Act (FWCA). To expedite our consideration of these laws, please describe how the proposed project will satisfy applicable requirements under those Federal Laws. For the ESA and NHPA,we have included some guidance below to assist you with obtaining the required information.

Endangered Species Act (ESA)

The ESA requires EPA to ensure, in consultation with the U.S. Fish and Wildlife Services (FWS), that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or adversely affect its critical habitat. We recommend that you use FWS's project planning tool to map out your project area and do a search for potential endangered species within the project area. The tool can be accessed here: https://ecos.fws.gov/ipac/.

Based on the results of your search, you may need to hire a Wildlife Consultant to provide additional analysis or otherwise show how your project will not cause harm to endangered species with habitat located near the CTV A1-A2 project area. Please provide a report depicting the results of the FWS project planning tool, including a map of the project area and any listed endangered or threatened species habitat near the site. Please include any comments or reports made by a Wildlife Consultant, if applicable.

National Historic Preservation Act (NHPA)

NHPA §106 requires a federal agency to take certain steps before it commits to any "undertaking," including the issuance of a permit or license, that has the potential to adversely affect property that is listed, or eligible for listing, in the National Register for Historic Places. The NHPA requires EPA, before issuing a permit, to adopt measures when feasible to mitigate potential adverse effects of the permitted activity and properties listed or eligible for listing in the National Register of Historic Places. The Act's requirements are to be implemented in cooperation with State Historic Preservation Officer and upon notice to, and when appropriate, in consultation with the Advisory Council on Historic Preservation.

To facilitate EPA's consideration of NHPA compliance for CTV's proposed project, we request that you identify the Historic Places designated in the National Register for Historic Places (https://www.nps.gov/subjects/nationalregister/database- research.htm) in close proximity to the CTV A1-A2 project site. Based on the results of your review of the National Register of Historic Places listings in Kern County, you may need to hire an archaeologist to provide additional analysis or otherwise show how your project will not adversely affect the identified historic places located near the CTV A1-A2 project site. Please provide a list of the Historic Places near the site. Please include any comments or reports made by an archaeologist, if applicable.

Please submit the information requested in the Enclosures, and regarding compliance with the above referenced Federal Laws by January 21, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Michele Dermer at (415) 972-3417.

Sincerely,

DAVID ALBRIGHT

Digitally signed by DAVID ALBRIGHT
Date: 2021.12.15 15:52:18 -08'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Site Characterization
Financial Responsibility
Emergency and Remedial Response Plan

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

May 5, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Site Characterization and Emergency and Remedial Response Plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. Our comments are included in the two Enclosures.

Please submit the information requested in the Enclosures by June 6, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.05.05 16:13:52 -07'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: Site Characterization Evaluation
Emergency and Remedial Response Plan Evaluation

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Review of Carbon TerraVault (CTV) Responses to EPA's Site Characterization Questions about the Class VI A1-A2 Permit Application

In December 2021, EPA provided questions presented in ***blue, bold, and italic text*** to CTV about the geologic narrative submitted as part of CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated narrative and a table summarizing their responses to EPA on March 2, 2022. EPA's evaluation of how the narrative addresses its questions is presented in red. Requests for revisions and additional information are presented in ***red, bold, and italic*** text.

The Elk Hills Oil Field (EHOF) is in Kern County, California, in the southern San Joaquin Basin (Figures 1 and 2) CTV plans to inject CO_2 at the EHOF into the Monterey Formation via 2 injection wells, 355-7R and 357-7R, over a period of 15 years. The 2 injection wells are 1,250 feet apart and will inject into the Monterey Formation A1-A2 reservoir (Monterey A1-A2) at the Northwest Stevens Anticline at ~8,500 ft depth (Figure 8 and pg. 4).

The Monterey Formation at the EHOF also contains the Miocene Reef Ridge Shale (the primary confining zone), which directly overlies the Monterey A1-A2 and has been an effective seal for 40+ years of oil and gas operations (pg. 9). Figures 4 and 5 show the spatial distribution of wells in the EHOF and data available for use in characterizing the injection zone.

The Monterey A1-A2 consists of turbidite sands bounded above and below by siliceous shale (pg. 9). The application asserts that this depositional history has resulted in minimal lateral communication of the Monterey A1-A2 outside the EHOF (Cross Section Figure 3, pg. 4; pg. 9). The reservoir is continuous across the area of review (AoR), with pinch-outs on the channel edges (pg. 9).

The Upper Tulare Formation is the lowermost underground source of drinking water (USDW). The Tulare Formation consists of poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley (pg. 7). It is divided into the Upper Tulare and the Lower Tulare by the Amnicola Clay (a low permeability claystone). An aquifer exemption was approved for the Lower Tulare Formation in 2018, making the Upper Tulare Formation the lowermost USDW.

In addition to the Reef Ridge Shale, the Monterey A1-A2 Sands are separated from the lowermost USDW in the Upper Tulare Formation by the Amnicola Clay (pg. 31), the Lower Tulare Formation, the San Joaquin Formation, a depleted gas reservoir directly underlying the Tulare Formation, and the Etchegoin Formation (pg. 8). The Monterey A1-A2 Sands are separated from the underlying Monterey A3-A11 reservoir by a laterally continuous 20-foot shale known as the A2 Shale (Figure 9). The application asserts that they are not in communication, as evidenced by a pressure differential (of 200-300 psi in the A1-A2 and ~1,700 psi in the A3-A11), and the need for separate pressure maintenance strategies (pg. 10). The A3-A6 reservoir is also considered a viable target for future CO_2-EOR based on its existing waterflood injector infrastructure and high reservoir pressure (pg. 11).

Tests and logs performed during drilling and prior to completion of the 357-7R injection well and the 342-7R-RD1 and 327-7R-RD1 monitoring wells (which are completed in the Monterey Formation and are located to the west and northwest of the injectors) include Array Compensated True Resistivity, SP logs, caliper logs, compensated spectral natural gamma log, spectral density dual spaced neutron log, and

mud logs (Attachment G pg. 4-5). Cement bond logs and MIT tests (temperature log and SAPT) were also performed on the 357-7R injection well.

Questions/Requests for the Applicant:

- ***Please label the injection wells or the injection well site on Figure 2***. The labels were added, and the response is acceptable. No further questions.

- ***Was any data collected or testing performed during drilling of the 355-7R injection well? If so, please characterize this data.*** CTV responded that, during the drilling of well 355-7R in 1973, the following characterizing logging measurements were obtained: Gamma Ray (GR), Spontaneous potential (SP), Resistivity (Dual induction laterlog), Density, Neutron Porosity and formation dip from 10,509' to 3,393', covering the Etchegoin, Reef Ridge, and Monterey formations. In addition, CTV states that 28 sidewall core samples were obtained over the same interval, but no detailed analysis of the core samples was performed at the time. The log data supports the applicant's characterization of the injection zone and the confining zone at the well site, and the response is acceptable***. Please include this information in the narrative to provide further evidence to support the descriptions of the injection and confining zones.***

- ***The AoR and Corrective Action Plan (on pg. 3) states that, the "Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation." Please clarify the difference between the A2 Shale and the Lower Antelope Shale.*** CTV responded that the A2 Shale lies directly beneath the Monterey Formation A1-A2 reservoir and provides hydraulic separation with the Monterey Formation A3-A11 reservoir. The Lower Antelope Shale is at the base of the Monterey Formation. The response is acceptable. No further questions.

- ***Does the Antelope Shale provide confinement? If so, please provide additional discussion of the confining properties.*** CTV responded that the Lower Antelope Shale does not provide confinement for the Monterey Formation A1-A2 reservoir. The response is acceptable, as the application does not rely on lower confinement to contain the CO_2. No Further questions.

- ***What is the source of the statement about the pressure differential between the Monterey A1-A2 Sands and the Monterey A3-A11 Sands described on pg. 10?*** CTV referenced a new Figure 10, which shows pressure data from 2014 in the A1-A2 sands and the A3-11 sands from two wells in the AoR. In both wells, pressures in the A1-A2 sands are below 500 psi, and pressures in the A3-11 sands are above 1,500 psi, supporting the statement. Added text on page 9 describes pressure data obtained using Repeat Formation Testers (RFT) during the drilling of oil and gas wells in the project area. The response is acceptable. No further questions.

- ***Please provide pressure build-up test results for the 357-7R injection well. CTV requested technical discussion prior to inclusion in the pre-operational testing plan. The response is acceptable at this stage of the permit application review. EPA will schedule a technical discussion.***

- ***Several of the figures in the narrative that contain data are difficult to read (e.g., Figures 14 and 15); please provide higher resolution versions of this information.*** CTV provided high resolution versions of all of the figures. The response is acceptable. No further questions.
- ***Please provide a map of the Elk Hills Oil Field that shows the 355-7R and 357-7R injection wells, along with the wells planned for the Elk Hills 26R Storage Project (with a scale that shows distances).*** CTV provided an updated Figure 8 that shows the requested information. The response is acceptable.

Follow-up Questions/Requests for the Applicant:

- ***When the narrative is next updated, please describe the testing performed during the drilling of well 355-7R to support the descriptions of the injection and confining zones.***
- ***EPA also recommends describing the Lower Antelope Shale in the updated narrative to provide a more complete stratigraphic context.***

Objectives for Pre-Operational Testing:

- ***Confirm hydraulic separation of the Monterey A1-A2 Sands and the Monterey Formation A3-A11 reservoir.***
- ***If no pressure build-up test results exist for the 357-7R injection well, perform pressure build-up testing as part of the Pre-Operational Testing Plan.***

Faults and Fractures

The 31S and Northwest Stevens (NWS) anticlines in the EHOF are separated by mid-Miocene thrust faults (pg. 12). The application states that the Reef Ridge Shale and Monterey Formation are well resolved based on seismic data, and there is no evidence of faults penetrating the Reef Ridge Shale or transecting the Monterey Formation (pg. 13). Figure 10 shows reverse faults in seismic profiles, however the resolution is too low to discern formation labels (pg.12). These reverse faults, oriented NW-SE, offset the NWS anticline (pg. 12).

Evidence for confinement includes 3D seismic and well data confirming the absence of faults penetrating the Reef Ridge Shale, 40+ years of previous waterflooding and gas injection operation, pressure differentials across formations (i.e., 230 psi in the Monterey A1-A2 Sands and 1,500 psi in the Etchegoin Formation for a 0.43 psi/ft pressure gradient at 3,600 ft depth), and geochemical analysis of 66 oil samples (Zumberge, 2005; Figure 12).

Questions/Requests for the Applicant:

- ***Please update Figure 10 to clearly label the formations in which the thrust faults terminate.*** The updated figure is acceptable; this is now Figure 11. No further questions.

- ***Where were the 66 oil samples collected within the EHOF described on pp 13-14, relative to faults within the field?*** CTV referenced Figure 2, which appears to show about 10 wells that were sampled in the Monterey Formation throughout the Northwest Stevens Anticline. While the response is not specific as to which wells were sampled, it is assumed the referenced study by Zumberge represents the entire AoR. The response is acceptable. No further questions.

Depth, Areal Extent, and Thickness of the Injection and Confining Zones

At the site of the injection wells, the stratigraphic sequence from top to bottom consists of the Tulare Formation, the San Joaquin and Etchegoin Formations, the Reef Ridge Shale confining zone, and the Monterey Formation injection zone (pg. 4, 7). The depths and thicknesses of the injection and confining zones were determined based on wireline logs and 3D seismic data and are presented in Table 1 of the application narrative. In the AoR, the Reef Ridge Shale thickness is controlled by the Monterey Formation deposition patterns and minimum thickness corresponds to a highpoint in the Monterey Formation Sand thickness (pg. 15).

The table below summarizes the depth and thickness of the formations of interest according to available data in the permit application narrative. Some depth/thickness information for the San Joaquin or Etchegoin Formations was not provided; however, this is not critical for the purposes of the application evaluation. Porosity and permeability data are presented as well; additional discussion of these characteristics is provided under "Geomechanical and Petrophysical Characterization."

Unit	**Average Depth within the AoR**	**Thickness Across the AoR**	**Porosity**	**Permeability**
Tulare Formation	600-2,500 ft (pg. 31)	1,200-1,500 ft (pg. 31)	34-40% (pg. 7)	1,410-8,150 mD (pg. 7)
San Joaquin Formation	Not given	Not Given	28%-45% (pg. 8)	64-6,810 mD (pg. 8)
Etchegoin Formation	1,500-4,000 ft (pg. 8)	Not Given	29-37% (pg. 9)	32-826 mD (pg. 9)
Reef Ridge Shale (Confining Zone)	6,929 ft-7,962 ft TVD (Table 1, Figure 13)	1,122-1,892 ft (Table 1, Figure 13)	7.7% (pg. 6); 7% (pg.9); 4 to 14% (Table 2)	0.01 mD (pg. 9); 0.00003 to 0.0917 mD (Table 2)
Monterey Formation A1-A2 Sands (Injection Zone)	8,403 ft – 9,598 ft TVD (Table 1, Figure 13)	27-548 ft (Table 1, Figure 13)	11%-27% (Figures 16 and 17); 16% (pg. 9)	0.1-1,300 mD (Figures 16 and 17); 60 mD (pg. 9)

Questions/Requests for the Applicant:

- ***The depths listed in Table 1 for the Monterey A1-A2 Sands are inconsistent with the logs in Figure 9. It appears, based on the log, that the depth to the Monterey A1-A2 Sands is ~8,500 feet MD or ~7,700 feet TVD at the 357-7R injection well, not 8,403 feet TVD as stated in Table 1. The mean depth to the Monterey Formation is also listed as 5,907 ft when the low and high depths are listed as 8,403 ft and 9,589 ft respectively. Please clarify the discrepancy or revise Table 1.*** CTV responded that Table 1 depths represents the distribution over the AoR and are in true vertical depth. The logs in Figure 9 are annotated with measured depth and sub-sea true vertical depth (this is now clarified in the figure title). CTV also fixed the 5,907 foot value in Table 1. The response is acceptable. No further questions.
- ***There is a typo on Figure 16, "Capitally" for Mercury Injection Capillary Pressure. Please fix this when the application is updated.*** CTV fixed the typo; this is now Figure 19. EPA has no further questions.

- ***Please characterize, name, and provide depth and permeability data for the underlying confining unit, if one exists.*** CTV provided a reference to page 10,which is unclear. However, CTV states in a response above that there is no lower confining zone. EPA has no further questions.

Hydrologic and Hydrogeologic Information

The Lower Tulare Formation, which conformably overlies the shallow marine deposits of the San Joaquin Formation, was approved as an exempt aquifer in 2018. The Upper Tulare Formation is the only USDW in the AoR (pg. 7). The regional extent of the exempted portions of the Lower Tulare Formation is shown in Figures 7, 26, and 29. It extends well beyond the AoR in the southern direction but closely borders the AoR to the north. The depth to the lowest USDW in the Upper Tulare is shown in Figure 28; however, the figure is difficult to read.

The San Joaquin Basin has no appreciable surface or subsurface outflow (pg. 35). The primary source of surface water and fresh groundwater is the Kern River, which drains to the southeast and terminates near the EHOF (pg. 35). Low precipitation rates and high evaporation rates result in almost no groundwater recharge from precipitation, leading to high salinity and TDS concentrations (pg. 35). CTV did not find any water supply wells within the AoR after a search of CALGEM, USGS, Kern County Water Agency (KCWA), West Kern Water District, and the GeoTracker Groundwater Ambient Monitoring and Assessment online database (pg. 36). CTV owns the surface area of the EHOF (pg.35).

Questions/Requests for the Applicant:

- ***It appears that Figure 26 provides information on the depth and regional extent of the area shown in cross section with wireline logs for TDS content, however the resolution is low (pg. 31). Please provide a higher resolution version of Figure 26.*** CTV provided a higher resolution version of Figure 29. While the text is small, the calculated TDS is 24,877 mg/L. The response is acceptable. No further questions.
- ***What is the depth of the Upper Tulare Formation and the separation of this lowermost USDW from the injection zone and the confining zone within the AoR?*** CTV referenced page 34, which includes an added discussion of the depth and separation between the injection zone and USDWs. Figure 31 shows the Upper Tulare USDW overlain by the Upper Tulare air sands. The narrative now describes that the Upper Tulare is 850 feet in depth and is separated from the underlying Reef Ridge Shale confining layer by 6,450 feet and the Monterey Formation A1-A2 sequestration reservoir by 7,650 feet. This information is approximately consistent with other depth values reported in the narrative. The response is acceptable. No further questions.
- ***Is the Upper Tulare USDW present within the modeled AoR of the injection wells?*** CTV referenced pages 34 and 35, where the depths of the Upper Tulare Formation and Monterey Formation are provided. In addition, the higher resolution version of Figure 29 shows the Upper Tulare within the Northwest Stevens Anticline. A type log in Figure 31 is from a well that is within the AoR. This appears to provide evidence that the Upper Tulare Formation is present within the AoR. The response is acceptable. No further questions.

Geochemistry/Geochemical Data

Limited baseline geochemical data for the Upper Tulare Formation (USDW) and Monterey Formation (injection zone) are provided in the application.

Figure 30 shows the results of water analysis performed on waters from the Upper and Lower Tulare Formations. The produced fluid has been collected during previous operations to establish a baseline and characterize the region. Hydrocarbon content in the injection zone was determined through fractional distillation and chromatography (pg. 37). Figure 30 is difficult to read, but it appears that the analysis is from 1995, and the analytes include some, but not all, of those planned as part of injection and post-injection phase monitoring. The TDS values of the Upper Tulare Formation appear to be 4,800-4,900 mg/L.

The application states that water sampling was not performed in the Monterey A1-A2 Sands because reservoir depletion has reduced water saturation to residual levels. However, geochemical analysis was performed using fluid produced during oil and gas operations (pg.37). CTV provides an example of the water geochemistry analysis taken from well 381-17R from a sand underlying the Monterey A1-A2 Sands (Figure 31). Figure 33 presents a 2021 analysis from nearby Well 353-7R. The figure is difficult to read, so it is unclear what analytes were measured, and if all the analytes planned during operational testing are addressed. It appears that the TDS of the Monterey A1-A2 Sands is about 24,000 mg/L.

CTV's Testing and Monitoring Plan (Attachment C) includes monitoring the overlying Etchegoin/San Joaquin Formations and the Tulare Formation for groundwater quality and geochemical changes and the Monterey Formation as part of direct plume tracking activities. Water quality will need to be established in each of these formations prior to injection operations to provide a baseline for comparison to future monitoring results.

Questions/Requests for the Applicant:

- ***Please provide clear/legible versions of the sample analyses in Figures 30 and 31 to allow a review of the sampling performed.*** The revised figures (now Figures 33 and 34) are legible. The TDS of the four samples in the Upper Tulare Formation ranges from 4,800 to 4,900 mg/L. EPA has no further questions.
- ***Where is Well 381-17R***? CTV referenced page 40; however a revised Figure 34 on page 39 shows the well, which is just outside the eastern edge of the AoR. EPA has no further questions.
- ***What is the total dissolved solids (TDS) content of the Monterey Formation? Please indicate how many data points or measurements are available to support this measurement (i.e., based on past field operations) and, if they are not from throughout the AoR, please provide information to support a determination that the Monterey Formation is not a USDW.*** CTV referenced page 40; however Figure 34 on page 39 shows the requested water quality information. EPA has no further questions.
- ***Is any water quality data available for the Etchegoin Formation? If so, please provide this.*** CTV responded that this is included in the pre-operational testing plan. It is assumed that no current water quality data exist. The response is acceptable at this point in the permit application review. No further questions.

- ***In the Testing and Monitoring Plan, CTV states that they obtained a baseline analysis for the 61WS-8R well (apparently for the Tulare Formation). Please provide this analysis if it is not the same as is provided in Figure 30.*** CTV responded that it will drill a new monitoring well and baseline results will be included in pre-operational testing. However, they did not provide any specific information about the location or construction of the well (which has ramifications for the testing and monitoring and financial responsibility evaluations).

Follow-up Questions/Requests for the Applicant:

- ***Where will the new Tulare Formation monitoring well that CTV references above be located?***
  - ***Is this well in addition to the existing well 61WS-8R?***
  - ***CTV should provide specific information about the construction of this well prior to issuance of a Class VI permit, include this well in the Testing and Monitoring Plan and PISC and Site Closure Plan, and address it in the financial responsibility cost estimates.***
- ***There is a typo on page 40 in the numbering of Figure 36; please fix this when the narrative is updated.***

Objectives for Pre-Operational Testing:

- ***Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan.***

Geomechanical and Petrophysical Characterization

Capillary pressure was determined using mercury injection capillary pressure analysis from 18 wells. The average rock strength of the confining zone is 2,452 psi according to brittleness calculations and the average ductility of the confining zone is 1.24 as derived from compressional sonic data from 18 wells with 59,214 data points using a calculation methodology from Ingram and Urai (1999) and Ingram et al. (1997) (pg.23). The applicant concludes that brittleness of less than 2 is evidence that the confining layer is sufficiently ductile to "anneal" discontinuities and that there are no fractures for fluid migration (Figure 19). The application states that this conclusion is further supported by historical water and gas injection data at the site in addition to millions of years of confinement of oil and gas in the Monterey Formation by the Reef Ridge Shale (pg. 23).

In the EHOF, the maximum principal stress direction is northeast-southwest as determined by a study of EHOF fracture gradients and borehole breakout (Castillo, 1997; Figure 21) Table 3 of the application narrative is reproduced below.

Stress	Reef Ridge Shale Confining Layer (Well: 374A-7R-RD1)	Monterey Formation A1-A2 Reservoir (Well: 372-7R-RD1)
Pore Pressure Gradient (psi/foot)	0.433	0.2
Overburden Gradient (psi/foot)	0.93	0.94
Minimum Horizontal Stress Gradient (psi/foot)	0.73	0.97

The GEOMECH geomechanical model, along with the GEM equation of state compositional reservoir simulator, were used to determine failure pressures under a base case and three additional scenarios;

this modeling is described on pages 25-28 of the application narrative. Descriptions of variations from the base case for other scenarios are given below:

- Reduced Young's Modulus: to model uncertainty in the cap rock Young's Modulus, a second case was run with a value of 8E05 psi.
- Reduced Injection Rate: sensitivity to injection rate was studied by reducing the injection rate to 20 million cbf per day.
- Thinner cap rock: the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet.

Table 4 of the application narrative, which presents the results of the modeling, is reproduced below:

Geomechanical Scenario Results	
Scenario	**Failure pressure (psi)**
Base Case	8,306
Reduced Young's Modulus	8,388
Reduced Injection Rate	8,340
Thinner Cap Rock	7,600

Figure 23 shows the change in normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. See also the evaluation of the AoR CA (Attachment B) for additional information.

Porosity and Permeability

As shown in the table under "Depth, Areal Extent, and Thickness of the Injection and Confining Zones," above, porosity values for the Reef Ridge Shale are approximately 7-14% and reported porosities of the Monterey A1-A2 Sands range from 11%-27%. The permeability of the Reef Ridge Shale is about 0.01 mD, and Monterey Formation permeability ranges from 0.1-1,300 mD. Permeability and porosity for the Reef Ridge Shale in the 355X-30R well are presented in Table 2 of the application.

Formation porosity and permeability used as inputs for the geomodel were determined using wireline log data, including SP logs, gamma ray, borehole caliper, resistivity, neutron porosity, and bulk density (pg. 17). Porosity is determined from bulk density using a 2.65 matrix density calibrated from particle density (Figure 15) and porosity data. Clay volume is determined from neutron-density separation and is calibrated to core data. A permeability function was calculated using mercury injection capillary pressure porosity and clay values (Figure 16). The application states (on pg. 17) that core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. However, it is unclear which wells are the source of this data.

Questions/Requests for the Applicant:

- ***Please update Figure 23 to include base case pressure.*** CTV responded that base case pressure is in the red line that is covered by the reduced Young's Modulus case. The response is acceptable. No further questions.

- ***Please discuss the selection of the base case parameter values (i.e., Young's Modulus, thickness, etc.) in the geomechanical modeling.*** CTV referenced added text on pages 28 and 29,

which describes the ranges of inputs for thickness, Poisson's ratio, and Young's modulus that were incorporated into the geomechanical modeling. The response is acceptable. No further questions.

- ***Please explain what is meant by "anneal discontinuities" in the discussion on page 23***. CTV responded that this refers to uncompacted, low-density shales that are extremely ductile and can thus accommodate large amounts of strain without undergoing brittle failure and loss of top seal integrity. The response is acceptable and EPA has no further questions.

- ***The application references core data from 13 wells on page 17.*** CTV referenced updated Figure 22, which describes calculations for well 354X-7R, but the index map includes several other wells. It is unclear if these are the 13 wells and if well 354X-7R is a representative example.
    - **To which wells does this refer and where are they located?**
    - **If they are not distributed throughout the AoR, please describe how they are representative of the entire area that will be affected by injection.**

- ***Where are the 18 wells that are the source of ductility data referred to on pg. 23 located?*** CTV referenced Figure 19, which includes an index map of the wells from throughout the EHOF, and only one of them is in the AoR. The narrative states that the distribution of wells and data points covers Monterey Formation sands in the Elk Hills Oil Field and ensures coverage of the storage reservoir. The response is acceptable, pending the results of the pre-operational testing. No further questions.

- ***The application states that, "The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of .8 psi/foot," and that, "the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI" (pg. 46). Please clarify the sources of data used to determine failure pressure, fracture pressure, and fracture gradient.*** CTV responded that the tensile failure for the Reef Ridge Shale is 7,500 psi based on geomechanical modeling, and that the Reef Ridge Shale confining layer fracture pressure will be addressed in pre-operational testing. The Monterey Formation fracture gradient is 0.82 based on a test in 327-7R- RD1. Table 3 includes a map with the location of well 327-7R- RD1, which is inside of the AoR. Added text on pages 28 and 29 describes the ranges of inputs for thickness, Poisson's ratio, and Young's modulus that were incorporated into the geomechanical modeling. The response is acceptable pending the results of the pre-operational testing.

Follow-up Questions/Requests for the Applicant:

- ***On Figure 22, are the wells in the index map the 13 wells with core data?***
- ***Please edit the title to Figure 22, which appears to have cut off a few words.***

Mineralogy of the Injection and Confining Zones

X-ray diffraction (XRD) data from 108 data points in 9 wells was analyzed to determine injection zone mineralogy. Fourier Transform Infrared Spectroscopy from 36 points in 1 well located outside the AoR but within the EHOF was used to characterize confining zone mineralogy (pg. 16-17). Figure 14 presents an example XRD analysis from well 367-7R located within the AoR. The applicant addresses the use of a single well for characterizing the mineralogy of the confining zone, citing that it is representative of the formation because of depositional continuity and consistency of facies and properties within the EHOF (Figure 15).

The Monterey A1-A2 Sand intervals consist of 43% quartz, 38% potassium feldspar, albite, and oligoclase as well as 7% total clay. The Reef Ridge Shale consists of 47.1% silica polymorphs (Opal-CT, chert, and cristobalite), 29.5% total clay, 14.5% potassium feldspar, albite, and oligoclase, and 3.7% quartz (pg.16).

Questions/Requests for the Applicant:

- ***Please provide a map of the 9 well locations used for XRD described on pages 16-17***. CTV referenced Figure 17, which includes the locations of wells throughout the Elk Hills Oil Field, and one of the wells is within the AoR. A table in the figure presents sand mineralogy from the well (367-7R) in the AoR. The response is acceptable. No further questions.

- ***What evidence is there for depositional continuity and facies consistency within the EHOF, as described on page 17?*** CTV referenced Figure 16, which shows the wells throughout the AoR that were used to define the Monterey Formation A1-A2 injection reservoir and confining zone. The updated narrative states that these wells have open-hole log data that is used to establish, clay volume, porosity, permeability, and facies (sand and shale) which are used in the static geological model (although no data were provided). ***Please provide the open-hole log data for 3 – 5 wells that are in the AoR and are representative of all wells data was collected from, for EPA to verify the results.***

Seismic History and Seismic Risk

The application notes that the "EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997)" (pg.29). Seismic activity in the region stems from the San Andreas Fault (12 miles west of the project site) and the White Wolf fault (25 miles southeast of the site) (pg. 29). Regional seismic data dating back to 1932 was gathered from the Southern California Earthquake Data Center (SCEDC) and USGS databases (Pg.29).

Figure 24 shows the eight (8) magnitude 5.0 or greater earthquakes that have occurred within a 30-mile radius of the EHOF. These earthquakes have an average depth of 6.3 miles, well below the Monterey Formation (pg.29). It is stated that there have been no earthquakes within the EHOF greater than magnitude 3.0. Site characteristics, including low factor amplification due to thin sediment, high density soil, and soft rock, based on shear-wave velocity (V_S) are asserted to further reduce seismic risk. The largest known earthquake in the region was a 7.5 magnitude 1952 earthquake in nearby Kern County which did not affect reservoir containment (pg. 30).

CTV will install borehole and surface seismometers to establish a baseline and assess natural and induced seismicity (pg. 29).

The evaluation of seismic risk also reflects other elements of the comprehensive permit application review (described elsewhere in this report), including porosity and permeability of the injection and confining zones; regional structural features; information on faults in the vicinity of the project site; formation pressure; and the geomechanical properties of the injection and confining zones.

Seismic risk and risk mitigation will also be considered in the review of the following aspects of the permit application:

- Predictions of plume and pressure front behavior over time, including pressure build-up over time, and pressure dissipation following cessation of injection.
- The ability of the injection well to maintain mechanical integrity under stress.
- Wells within the project area and the status of well corrective action.
- Planned injection pressures.
- Seismic monitoring and emergency and remedial response planning.

Questions/Requests for the Applicant:

- ***Please include all earthquakes of magnitude 3.0 and above in Figure 24.*** CTV updated the figure, which is now Figure 27 and includes more seismic events. However, the added discussion of seismic risk and other information does not present an added concern about induced seismicity. The response is acceptable. No further questions.

- ***To inform an evaluation and documentation that there is no significant seismic risk, EPA recommends that CTV describe how the project:***
  - ***has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected.***
  - ***will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;***
  - ***will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and***
  - ***poses a low risk of inducing a felt seismic event.***

  CTV referenced a new discussion on pages 31 and 32 of the narrative that addresses the requested information. It describes the evaluation of faults and fractures described elsewhere in the application (and previously evaluated) and knowledge gained from historical operations (including injection pressure limits and seismic and pressure monitoring). The response documents the evaluation and is acceptable. No further questions.

Objectives for Pre-Operational Testing:

- ***Establish baseline seismicity after borehole and surface seismometers are installed.***

Surface Air and/or Soil Gas Monitoring Data

No soil gas or surface air data were submitted with the permit application. At this point, we do not believe this will be necessary; however, if the results of future reviews necessitate surface air and/or soil gas monitoring, we would request baseline data.

Facies Changes in the Injection or Confining Zones

Depths to the confining and injection zones are presented on structural and isopach maps based on 3D seismic and wireline log data (Figure 13). However, the locations and number of wells used to characterize formation depths was not provided.

Figure 3 of the application shows a cross section of formations across the San Joaquin Basin and Figure 6 shows a stratigraphic cross section with well types for the Northwest Stevens anticline. Figure 12 shows a stratigraphic column with oil samples grouped into families. There appear to be logs on the figure used to correlate formations laterally, but they could not be distinguished.

Page 41 of the application describes the development of a geo-cellular model as part of the A1-A2 reservoir characterization and plume modeling. This is supported by cross sections in Figures 34 and 35 (which appear to be outputs of the AoR delineation model) that the applicant asserts also demonstrate the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers also supports predictable plume development. The application states that the modeled plume migration (Figures 34 and 35) is consistent with the structure of the anticline.

Figure 4 identifies “data coverage” for the Reef Ridge Shale and per Figures 5 and 8, several wells have core data in the Reef Ridge Shale and the Monterey Formation; however, it is unclear what information is available from the wells on the map and how it informed the application.

On page 11, the application concludes that the Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core data, as well as 3D seismic data. Discussion and questions for the applicant regarding lateral continuity of the Confining Zone are discussed above in the section on “Mineralogy of the Injection and Confining Zones.”

Questions/Requests for the Applicant:

- ***Please clarify what data sources were used to determine inputs for the geomodel where applicable, e.g., the inputs for sand vs. shale facies as discussed on pg. 40.*** CTV referenced Figure 16, which shows the wells (which are throughout the AoR) that were used to define the Monterey Formation A1-A2 injection reservoir and confining zone. The application states that these wells have open-hole log data that is used to establish clay volume, porosity, permeability, and facies (sand and shale), and that data from 255 wells were used to define stratigraphy, lithology/facies and reservoir properties for the static geological model. CTV asserts that this quantity and spacing of data is more than sufficient to generate a data driven static model that defines facies changes in the reservoir and confining zone, and support a conclusion that there are no facies changes that will impact injection operations or confinement. The response is acceptable. No further questions.

- ***Please also discuss how a sufficient number and distribution of formation characterization data are available to demonstrate a lack of local heterogeneities that could affect storage or confinement of CO_2.*** CTV referenced Figure 16 and page 17 text, and asserts that the total of 255 wells and spacing of 400-800 feet provide sufficient quantity and spacing of data to generate the geological model. The response is acceptable. No further questions.

- ***Please specify the names, number, and locations of wells used to characterize formation thicknesses for the maps in Figure 13.*** CTV referenced Figure 16, which shows the wells throughout the AoR. The response is acceptable. No further questions.

Objectives for Pre-Operational Testing:

- ***Determine if there are any heterogeneities within the Monterey A1-A2 Sands that could affect its suitability for injection, including facies changes that could facilitate preferential flow.***

Structure of the Injection and Confining Zones

Regional structure of the injection and confining zones is controlled by San Andreas Fault development resulting in mid-Miocene anticlines (pg. 3). The application describes the anticlines that form the Elk Hills Oil Field, which CTV asserts will contribute to confinement. See the discussions of "Regional Geology and Geologic Structure" and "Faults and Fractures," above.

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

The proposed injectate will consist of at least 95% CO_2 with mixtures of water and oxygen that will be controlled for corrosion mitigation (pg. 46). The applicant states that corrosiveness of the stream will be "very low as long as the entrained water is kept in solution with the CO_2" which will be accomplished by limiting its water content (pg. 46).

Existing subsurface fluid information is based on extensive and ongoing CO_2 injection activity in the EHOF region. CTV has injected 6.3 billion cubic feet of gas containing up to 44% CO_2 into the Monterey A1-A2 Sands since 2011 without any changes to injectivity (pg. 38-39). A 2021 analysis from an oil

sample in the 353-7R well showed a 6.5 mole % CO_2 content (pg. 38). The applicant states that low water volume in the formation (15% saturation in the gas cap and 85% in the thin oil band) and low residual oil saturation (15%) will also dissolve only a small amount of CO_2. Furthermore, the Monterey A1-A2 Sands is dominated by quartz and feldspar which are stable in the presence of CO_2 and carbonic acid (pg. 39).

There is no geochemical analysis of water samples from the Reef Ridge Shale because the shale will only provide fluid for analysis if stimulated (pg. 39). The CO_2 composition used for the geomodel and its interaction/solubility is established by the Peng-Robinson Equation of State (AoR and CA Plan, pg. 2).

Questions/Requests for the Applicant:

- ***Please provide evidence for the statement in the Application on page 39 that the quartz and feldspar in the Monterey A1-A2 Sands are stable in the presence of CO_2 and carbonic acid?*** CTV responded that this will be included in its pre-operational testing plan. The response is acceptable; this is added to the testing objectives below for completeness.

- ***Please elaborate on why use of the Peng-Robinson Equation of State supports compatibility of the CO_2 with any fluid which may be contained within the Reef Ridge Shale.*** CTV responded that, due to the extremely low permeability of the Reef Ridge Shale (< 0.01 mD) and the high capillary entry pressure (4,220 psi), the Peng Robinson Equation of State based simulation is valid to model the project over the expected reservoir pressure range of 250 – 4,000 psi as there should be no entry of the CO_2 injectate into the Reef Ridge. The response is acceptable. No further questions.

Objectives for Pre-Operational Testing:

- ***Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and provide verification that it will not react with the formation matrix.***
- ***Characterize the mineralogy of the Monterey A1-A2 Sands to confirm its stability in the presence of CO_2 and carbonic acid.***

Injection Zone Storage Capacity

Modeled storage capacity of the Monterey Formation A1-A2 reservoir was 8-10 million tons of CO_2 (pg. 41). The forecasted/proposed injection rate is 0.25 - 0.75 million tons per year for 15 years; according to Table 8 (Proposed operational procedures); an average estimate of 8 million tonnes and a maximum of 10 million tonnes will be injected.

Injection zone storage capacity is discussed in the Evaluation of the AoR CA and above in the “Structure of the Injection Zone and Confining Zone” section. Any additional follow up questions/requests for the applicant will be provided in the AoR modeling evaluation.

Confining Zone Integrity

Fluid confinement is supported by 3D seismic data (pg. 12) and historic operating experience in addition to core data (pg. 20) and geochemical analysis (pg. 13). The capillary entry pressure of the Reef Ridge Shale is 4,220 psi in a CO_2-brine system, reducing the likelihood of deformation (pg. 20). There are no

faults extending into the Reef Ridge Shale. See additional discussion and questions for the applicant above.

Questions/Requests for the Applicant:

- ***Were any other tests performed to corroborate pressure measurements in the Reef Ridge Shale?*** CTV referenced the pre-operational testing plan. It is assumed that no other current pressure data exist. On page 25, the narrative includes new text that there is no site specific Reef Ridge Shale fracture pressure or fracture gradient measurements within the AoR, and that a Reef Ridge Shale step rate test will be conducted as per the pre-operational testing plan. The response is acceptable at this point in the permit application review.
- ***The application, on pg. 14, states that there is a pressure differential of 1,300 psi between the overlying Etchegoin Formation and Monterey Formation due to the sealing nature of the Reef Ridge Shale. What is the source of the pressure data for this statement?*** CTV referenced a new Figure 13, which shows data from a well that is located just outside of the AoR to the east. Based on the figure, it appears that pressures in the Etchegoin Formation are about 1,800 psi and in the Monterey Formation are about 400-500 psi. CTV also updated the narrative to explain that the figure shows an example of RFT pressure data collected in 2004 during the drilling of an oil and gas well near the project area. CTV asserts that the RFT data shows that the Etchegoin is hydraulically separated from the deeper Monterey Formation and at a much higher pressure. The response is acceptable**.**

Objectives for Pre-Operational Testing:

- ***Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate via laboratory experiments.***
- ***A step rate test should be performed to establish the fracture pressure of the confining zone.***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions on the Proposed Emergency and Remedial Response Plan

In December 2021, EPA provided questions to CTV about the draft Emergency and Remedial Response Plan submitted as part of CTV's Class VI permit application (dated August 30, 2021). CTV provided an updated Emergency and Remedial Response Plan to EPA on March 2, 2022. EPA's evaluation of how the updated plan addresses its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below.

Potential Risk Scenarios

The list of items in this section does not match the events and scenarios described in the following section.

- ***Please revise the list.***

The list in this section also includes "CO_2 leakage to USDW or land surface," which appears to also be addressed under the "Potential Brine or CO_2 Leakage to a USDW" scenario.

- ***Please delete this item.***

Emergency Identification and Response Actions

EPA recommends some additions/revisions to the descriptions and response actions for the scenarios identified in the Emergency and Remedial Response Plan. These are presented in the table below:

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
1. All	a) EPA recommends that the Actionable Testing limits methods in Table 7 of the QASP be referenced in the Emergency and Remedial Response Plan.	a) This addition was not made. ***Please add to the introduction that the Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP.*** ***Under the "Brine or CO_2 Leakage to USDW" scenario, please add other indicators of leakage including elevated pH levels in the Tulare Formation (e.g., 0.2) and pressure increases in the Etchegoin Formation of 0.001 psi detected by the pressure gauge.***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
2. Well Integrity Failure	a) A mechanical integrity (MI) failure of a monitoring well can also occur in the post-injection time frame; please update the "timing of the event" accordingly. b) The statement that CTV must notify the UIC Program Director is not an event that may signal loss of MI. Please make this a separate statement outside of the list on page 3. c) Consider including "Limit access to wellhead to authorized personnel only" to the response actions for major and minor emergencies. d) The response to a major or minor MI failure should also include necessary actions to identify the location/nature of the damage to the well or wellhead and confirm internal and external integrity prior to restarting injection (upon approval of the UIC Program Director).	***a) Please edit the timing of this event from "Injection/monitoring" to "injection/post-injection."*** b) The requested change was made. No further questions. c) The requested change was made. No further questions. d) The requested changes were made. Note that there is a typo on page 5, "Preform a well log…". ***Please correct the typo.***
3. Well Integrity Failure – Major or Serious Emergency	a) Please clarify what would constitute a major or serious emergency (e.g., a verified loss or increase of pressure or fluid volumes and/or loss of mechanical integrity is discovered). b) Response to a major emergency may also include communicating with CTV personnel or other operators in the field and local authorities to initiate evacuation plans, as necessary.	a) The requested change was made. No further questions. b) The requested change was made. No further questions.
4. Well Integrity Failure – Minor Emergency	a) Please clarify what would constitute a minor emergency (e.g., downhole and surface sensor/monitoring equipment failure, procedural maintenance error or plant issue). b) Clarify that, if contamination is detected or a loss of integrity has occurred, then the situation becomes a major emergency and the actions under "Major or Serious Emergency" would be taken. c) "Initiate shutdown plan" is on the list of response actions twice.	a) The requested change was made. No further questions. b) The revised text is acceptable. No further questions. c) No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
5. Injection Well Monitoring Equipment Failure – Major or Serious Emergency	a) Please describe what constitutes a Major or Serious emergency (e.g., failure of sensors that will require shutdown of well to repair, extended repair time, and/or well reentry). b) Responses to a Major monitoring equipment failure emergency may also include: • Verifying whether any contamination has occurred (e.g., via handheld CO_2 monitors). • Communicating with CTV personnel/other operators in the field and local authorities to isolate the area or initiate evacuation plans, as necessary if contamination is detected. • Demonstrating internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director).	a) The requested change was made. No further questions. b) The requested changes were made. No further questions.
6. Injection Well Monitoring Equipment Failure – Minor Emergency	a) Please describe what constitutes a Minor emergency (e.g., sensor or monitoring failure that does not require shutdown of the well to repair). b) Potential response actions may also include actions to identify the location/nature of the damage and reset monitoring devices and/or confirm internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director). c) "Initiate shutdown plan" is on the list of response actions twice.	a) The requested change was made. No further questions. b) The requested changes were made. No further questions. c) The requested change was made. No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
7. Potential Brine or CO_2 Leakage to USDW	a) EPA recommends that the introduction to this scenario be broadened to encompass any evidence of CO_2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address events associated with unanticipated fluid movement pathways, any potential USDW endangerment/unacceptable changes in water quality, and CO_2 leakage to the land surface. b) The severity of an event involving CO_2/brine leakage to a USDW would be serious, not low. c) Detection methods may also include pressure or water quality changes in the Etchegoin Formation monitoring well. d) The response actions should also address well integrity issues (e.g., by following responses under the MI failure scenario) or a risk to air quality (i.e., to isolate the nearby area and establish a perimeter using a hand-held air-quality monitors). e) The response equipment for this scenario should also include groundwater remediation equipment.	a) The response actions address CO_2 or fluid movement out of the injection zone (e.g., to the Etchegoin) or CO_2 detected by hand-held monitors at the surface. No further questions. b) The requested change was made. No further questions. c) The requested change was made. No further questions. d) The requested change was made. No further questions. e) The requested change was made. No further questions.
8. Natural Disaster	a) The severity of these types of events could range up to serious or catastrophic. b) These types of events may occur in any of the project phases (e.g., construction and post-injection) not just the injection phase. c) For Major or Serious natural disasters, potential response actions may also include: • Initiating evacuation procedures; • Referencing the response actions described under the CO_2 leakage scenario if contamination or endangerment of a USDW is detected; or • Confirming mechanical integrity/taking appropriate steps if an injection/monitoring well has been damaged.	a) The requested change was made. No further questions. b) The requested change was made. No further questions. c) The requested changes were made. No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
9. Induced Seismic Event	a) This section and the title should refer to induced or naturally occurring seismic events since all seismic events have the potential to affect the injection wells and the necessary responses would be the same. b) It is unclear whether the area encompassed by "the AoR inclusive of a ¼ mile buffer," as described on page 8 is as large as a 2-mile radius of the injection wells, as described on Table 2. Please modify the introductory statement to reflect the area addressed in Table 2. c) The severity of seismic events could be major. d) Seismic events that may necessitate a response could occur during the injection or post injection phases. e) Please clarify what is meant by "seismic monitoring wells" as a detection method; EPA assumes this refers to the monitoring network that is described in the Testing and Monitoring Plan, and therefore recommends that similar terminology be used.	a) The requested change was made. No further questions. ***b)*** The introduction now refers to epicenters "within the AoR, inclusive of a two mile buffer" and Table 2 refers to "a two-mile radius of the injection well." ***Please revise the table to be consistent with the introduction.*** c) The requested change was made. No further questions. d) The requested change was made. No further questions. e) The requested change was made. No further questions.
10. Induced Seismic Event—Table 2	a) Please modify the title to Table 2 to be consistent with the magnitude in the green response level (i.e., M 1.5). b) Please explain how the selected seismic thresholds (i.e., magnitude, distance from the project) are considered protective of USDWs.	a) The requested change was made. No further questions. b) The table has been revised to tie the magnitude-specific responses to USDW protection. No further questions.
11. Induced Seismic Event—Table 2, Green Level	a) Add the response action: Document the event in semiannual reports to EPA.	a) The requested change was made. No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
11. Induced Seismic Event—Table 2, Yellow Level	a) Potential response actions should also include: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Review seismic and operational data to determine the location and magnitude of seismic event. If the event falls within or near the extents of the plume, estimate potential impact to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. • Document the event in semiannual reports to EPA.	a) The requested changes were made. No further questions.
12. Induced Seismic Event—Table 2, Orange Level	a) EPA recommends the following additions to the response actions: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Document the event in semiannual reports to EPA. • Expand Step 3 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).	a) The requested changes were made. No further questions.
13. Induced Seismic Event—Table 2, Magenta Level	a) EPA recommends the following changes to the response actions: • Please describe the "rate reduction plan" in Step 1. Does this refer to gradual shutdown? • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event). • Add: Document the event in semiannual reports to EPA.	a) The rate reduction plan was not described. ***Please describe this procedure or clarify in the E&RR Plan if it refers to gradual shutdown of the well.***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
14. Induced Seismic Event—Table 2, Red Level	a) EPA recommends the following changes to the response actions: • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).	a) The requested changes were made. No further questions.

Response Personnel and Equipment

a) Are any of the personnel to be notified a 24-hour contact, such as a 24-hour emergency coordinator in the control room? If so, please include this in the plan. The requested change was made; EPA has no further questions.

b) In Table 3, EPA recommends the following additions/changes: The requested changes below were made. ***Please fix the typo, "EOA Region 9."***

- The UIC Program Director will be an EPA Region 9 staff person (David Albright albright.david@epa.gov.
- Consider also including: the local/community medical center, Poison Control Center, California Office of Emergency Services, and the State Water Quality Control Board.

Staff Training and Exercise Procedures

There are several typos in this section; please revise.

- Several typos remain, e.g., mis-spelling of facilities, maintenance, monitors, hazards, exercise. ***Please fix these.***

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

July 20, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the AoR Modeling, Operating Procedures, and Testing and Monitoring Plans for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below, and in the three Enclosures.

Please submit the information requested in the Enclosures by August 19, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2022.07.20 16:33:53 -07'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Operating Procedures Evaluation
Proposed Testing and Monitoring Evaluation
AoR Modeling Evaluation

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Review of Carbon Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Proposed Testing and Monitoring Activities at the A1-A2 Class VI Project

In January 2022, EPA provided questions to CTV (*blue, italic text*) about proposed injection and post-injection monitoring activities submitted with CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated Testing and Monitoring Plan and PISC and Site Closure Plan to EPA on March 31, 2022. EPA's evaluation of how the updated plans address its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Carbon Dioxide Stream Analysis

To meet the requirements of 40 CFR 146.90(a), CTV plans to analyze the carbon dioxide (CO_2) stream quarterly for the constituents identified in Table 1 of the Testing and Monitoring Plan, which is replicated below.

Parameter	Analytical Method(s)
Oxygen	ASTM D1945
Nitrogen	ASTM D1945
Carbon Monoxide	ASTM D1945
Total hydrocarbons	ASTM D1945
Methane	ASTM D1945
Hydrogen Sulfide	ASTM D1945/D6228
CO_2 purity	ASTM D1945
Total Sulfur	ASTM 3246

There are no EPA-approved analytical methods for CO_2 injection streams, and the methods listed on Table 1 are not included among EPA-approved wastewater analytical methods in 40 CFR Part 136 (nor are they used in other Class VI CO_2 injection permits). Many of the analytes are to be analyzed using ASTM D1945, which is the Standard Test Method for Analysis of Natural Gas by Gas Chromatography. Based on the physical states of natural gas and CO_2, this test may be appropriate for CO_2 injectate analysis; however, no specific information or justification was provided in the application materials and there is no publicly available (free-of-charge) information available about these ASTM methods.

Table 4 of the Quality Assurance Surveillance Plan (QASP), Summary of Analytical Parameters for CO_2 Stream, also lists analysis of ethanol using method EPA 8260B. Although there is no EPA-approved analytical method for ethanol analysis in wastewater, this method is acceptable.

CTV is evaluating several sources of CO_2 as injectate for the project, and states that it will notify EPA prior to switching or adding CO_2 sources so that the sampling procedures can be reassessed. EPA will require that a sample be analyzed prior to initiation of injection.

CTV states that it will increase the sampling frequency if there is a significant change in the chemical or physical characteristics of the CO_2 injectate, a change in the CO_2 injectate source, or if the facility or injection well experiences a downtime over more than 30 days. Any change in the injection fluid would require advance notice and written approval from EPA.

Questions/Requests for the Applicant:

- *Please add analysis of ethanol using EPA method 8260B to Table 1 to be consistent with Table 4 of the QASP. Ethanol was added as an analyte as requested, using ISBT methods. However, Table 4 of the QASP references ASTM methods, and should reflect the methods described in the Testing and Monitoring Plan. (See the discussion of the updated QASP below.)*
- *CTV states that quarterly sampling will begin three months after the date of authorization of injection; please revise this timeline to begin three months after the commencement of injection so that the testing schedule is consistent with injection operations. The applicant made the requested edit in the first paragraph, but not in subsequent discussions under Sample Location and Frequency.*

Follow-up Questions for the Applicant:

- ***Please make global edits (e.g., under Sample Location and Frequency) to reflect that quarterly injectate sampling will begin three months after commencement of injection.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *EPA will require a baseline injectate sample to be analyzed for the same parameters as in the Testing and Monitoring Plan prior to commencement of injection.*
- *If this sample or any updated information about injection formation fluids indicates that any injectate constituents may lead to geochemical reactions that could affect operations or change aquifer properties, additional analytical parameters for the injectate analysis may be requested.*

Injection Well Testing

The subsections below describe: the planned quarterly corrosion monitoring; continuous recording of injection pressure, rate, and volume to evaluate internal mechanical integrity; and annual external MITs that will meet the requirements at 40 CFR 146.90(b), (c), and (e). This portion of the testing and monitoring evaluation addresses both injection wells (Well 357-7R and Well 355-7R); however, CTV will need to provide a Testing and Monitoring Plan for each well, with unique well-specific testing (particularly for corrosion monitoring and continuous monitoring) that reflects each well's design.

Corrosion Monitoring

CTV proposes to conduct corrosion monitoring using the coupon method. The corrosion coupons will be in the pipeline that feeds CO_2 injectate to the injectors. Corrosion monitoring will occur between the compressor and wellhead, according to Table 1 of the QASP.

Samples of the materials used in the construction of the pipeline and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials will be weighed, measured, and photographed prior to installation. The coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The specific methods by which the samples will be handled are not described in the testing and monitoring plan; however, Table 5 of the QASP indicates that analytical methods include NACE TM0169/G31 and EPA 1110A SW846.

CTV says that, if the corrosion rate is greater than 0.3 mils/year, it will initiate consultation with regulatory agencies (but does not specify which agencies), and may run a casing inspection log to assess the thickness and quality of the casing.

The proposed coupons will be composed of the materials summarized in Attachment C, Table 3. The materials identified for corrosion monitoring were compared to the list of proposed construction materials for the injection well in Attachment G (Construction details) for Well 357-7R (submitted with the initial permit application on August 30, 2021) and Well 355-7R (submitted December 2, 2021). The first two columns of the table below are adapted from Table 3 of the Testing and Monitoring Plan (list of equipment coupon with material of construction), with review notes in the right-hand columns.

Coupon (Attachment C, Table 3)	**Construction Material (Attachment C, Table 3)**	**Review Notes based on Information in Attachment G**	
		Well 357-7R	**Well 355-7R**
Pipeline	CS A106B	Not identified	Not identified
Casing	N80 Steel	Intermediate and Long-string: N80 (pg. 2)	Intermediate and Long-string: N-80, K-55 (Table 5)
Tubing	13 CR-95	13 CR-95 (pg. 2)	L-80 (Table 6)
Wellhead	Stainless steel	Not identified	Not identified

The coupons proposed for corrosion monitoring of the casing and tubing match those described in Attachment G for injector 357-7R. However, it appears that Well 355-7R has different construction, and a corrosion testing program specific to the 355-7R injector is needed. Although the materials of construction for the pipelines and wellheads are not described in Attachment G, it is assumed that coupons would be selected to represent these materials.

Questions/Requests for the Applicant:

- *Please describe the corrosion coupons for a corrosion testing program specific to the 355-7R injector. Additional details were added to the sample description text regarding the coupon usage and application. CTV also provided additional details on Table 3 including N80 steel for*

casing and chrome alloy for the tubing; however, these do not match the materials described in the well construction descriptions.

- *For completeness, please include the details about the analytical methods for corrosion coupon monitoring that are described in Table 5 of the QASP into the Testing and Monitoring Plan. Attachment C references an ASTM method for prep/cleaning/evaluating corrosion test specimens. This differs from the QASP, which references NACE and EPA methods.*
- *Please provide the list of construction materials to be used for the pipeline and wellhead so that they can be compared to the proposed coupon materials for the corrosion testing program. Table 3 has been updated to include coupons made of carbon steel for the pipeline and chrome alloy for the wellhead; the response is acceptable at this point in the permit application review. EPA will need to verify that the corrosion coupons for the pipeline and wellhead are appropriate to the materials described in the well specifications when they are provided.*

Follow-up Questions for the Applicant:

- ***Please explain how using N80 steel coupons and chrome alloy are appropriate for monitoring the casing and tubing of each of the wells, as constructed.***
- ***Please modify the Testing and Monitoring Plan or the QASP so that the analytical methods for corrosion monitoring are consistent.***

Continuous Monitoring to Evaluate Internal Mechanical Integrity

CTV will install and use continuous recording devices to monitor: injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Surface injection pressure will be set to a minimum of 1,200 psi, eventually reaching 2,000 psi at the cessation of injection operations, as noted in the discussion of "Operational Procedures" in the permit application narrative. For Well 357-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 3,800 psi (surface) and 6,100 psi (downhole) are not exceeded. For Well 355-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 2,900 psi (surface) and 6,108 psi (downhole) are not exceeded.

Additionally, a surface pressure gauge will be installed on the annulus to monitor the annular pressure and ensure the integrity of the packer and tubing. However, the annular pressure needed to signify a mechanical integrity issue is not indicated by CTV.

The maximum injection rate of 30 million standard cubic feet per day (mmscfpd) and average injection rate of 10-15 mmscfpd will be monitored by a surface flowmeter. The calculation of injection volumes will be calculated using the injection flow rate and CO_2 stream density and will be used to ensure the maximum expected injection volume does not exceed 10 million tonnes.

Temperature gauges will be employed at surface and downhole to monitor the temperature of the injectate and ensure it is consistent with the expected temperature of the CO_2 stream at a given depth.

Additional evaluation of the well monitoring equipment will be provided in the Well Construction reports for the injection wells.

Table 2 of Attachment C lists sampling devices, locations, and frequencies for continuous monitoring and is replicated below.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	30 seconds	30 seconds
Injection rate	Flowmeter	Surface	30 seconds	30 seconds
Injection volume	Calculated	Surface	30 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	30 seconds	30 seconds
CO_2 stream temperature	Temperature gauge	Surface and Downhole	30 seconds	30 seconds

Questions/Requests for the Applicant:

- *Please clarify the location/depths of the downhole temperature and pressure gauges listed on Table 2. These should also be depicted on the well schematics. Table 2 contains information regarding whether the gauges are at surface or downhole but does not include the actual depths. This information will need to be provided—and included on the well schematics—once the final well construction and equipment have been determined.*
- *Please explicitly define the annular pressure deviation that would warrant a mechanical integrity investigation. CTV did not provide the requested information.*

Follow-up Questions for the Applicant:

- ***Please define the annular pressure deviation that would warrant a mechanical integrity investigation, as requested.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The maximum pressure thresholds identified for continuous monitoring and the annulus pressure in Attachment C may need to be adjusted to reflect the final permit conditions (e.g., if they change based on the results of pre-operational testing).*

External MITs

To verify external mechanical integrity as required at 40 CFR 146.89(c) and 146.90, CTV proposes to perform MITs annually. CTV also proposes to perform these same MITs prior to commencing injection.

Table 6 of Attachment C lists the MITs to be performed and is reproduced below.

Test Description	Location
Temperature Log	Along wellbore via wireline well log
Radioactive Tracer Survey (RTS)	Along wellbore via iodine

On page 9 of Attachment C, CTV only indicates that it will run a temperature log (and not a radioactive tracer log) and notes that if it elects to conduct an alternate MIT, it will request approval from EPA. (EPA notes that, if CTV opts to use an alternative MIT, the Class VI permit would need to be modified to incorporate this test.) CTV presents procedures for MIT temperature logging but does not describe the radioactive tracer logging procedures.

Questions/Requests for the Applicant:

- *Please revise the temperature logging procedure to include a minimum of 4 hours between runs. Additionally, please provide more extensive temperature logging procedures, e.g., in accordance with the document, "Appendix E – Temperature Logging Procedures – U.S.E.P.A. Region IX," which is available online at: https://archive.epa.gov/region9/water/archive/web/pdf/appendixetemplogreqs.pdf. The text has not been updated to incorporate the details about the temperature logging procedures that EPA requests, and some of the logging details that EPA requires have been left out.*
- *Please provide a detailed description of the MIT testing procedures for RTS. RTS appears to have been removed as a MIT testing procedure and was replaced with continuous distributed temperature sensing. This is acceptable as a secondary MIT, since temperature logs are an approved MIT method. However, consistent with 40 CFR 146.89, CTV must perform the temperature log on the injection well.*
- *The Emergency and Remedial Response Plan includes scenarios for monitoring well MI failures, however no MIT of the monitoring wells is described in the Testing and Monitoring Plan. Please provide procedures and plans for performing MITs in the deep monitoring wells. The revised plan indicates that CTV will use DTS (a fiber optic continuous temperature monitoring system) on the monitoring wells; while this is not an approved MIT method (i.e., that would meet the requirements on 146.89 for the injection well), it may be appropriate for monitoring well MITs, but additional information is required (see below).*
- *Please include MITs on the monitoring wells and the EOR wells to be used for deep monitoring as part of the Testing and Monitoring Plan. The text was updated to include DTS on the deep monitoring wells, no MITs are explicitly described for the EOR wells to be used for monitoring.*
- *Attachment G describes Annulus Pressure Testing Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1. Please also include internal and external MITs during the injection and post-injection phases and describe these in Attachments C and E. This was not included in the updated attachments.*

Follow-up Questions for the Applicant:

- ***Please explicitly state in the introduction to this section of the Testing and Monitoring Plan that CTV will, at a minimum, perform a temperature log on the injection well (i.e., not that it will perform "one of two methods in Table 6").***
- ***Please provide additional detail about the temperature logging procedures or indicate in the plan that CTV plans to perform temperature logging exactly as described in the EPA guidance.***
- ***Please provide additional information on the DTS and its suitability as a secondary MIT method.***
- ***Will DTS be employed in the EOR wells that CTV plans to use for monitoring? If so, please state this in the plan.***

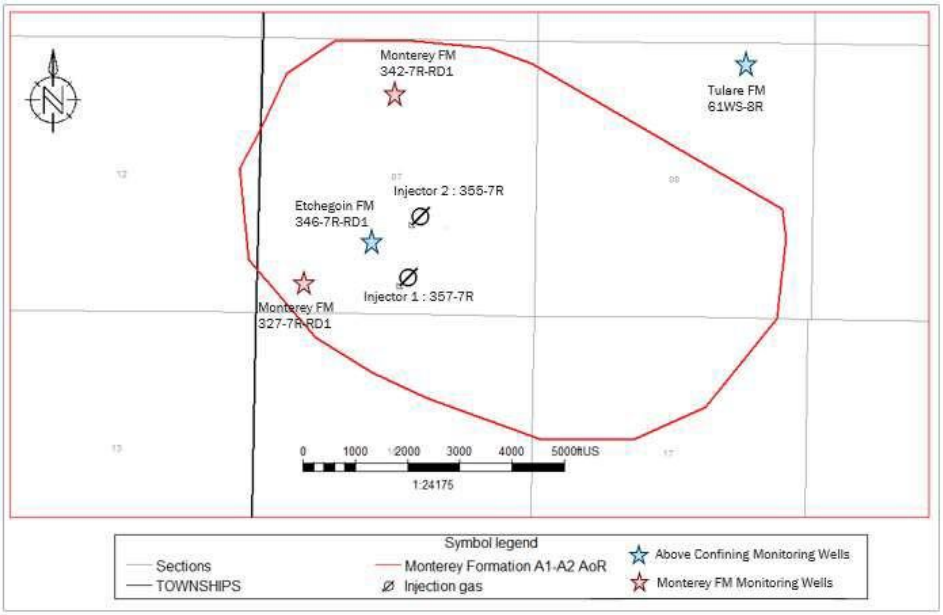
- ***Please include internal and external MITs for Monitoring Well 327-7R-RD1 & 342-7R-RD1 during the injection and post-injection phases and describe these in Attachments C and E as requested.***

Groundwater Quality Monitoring

CTV proposes to monitor groundwater quality in existing wells above the confining zone using direct and indirect methods. To meet the requirements of 40 CFR 146.90(d), CTV proposes to perform the following monitoring above the confining zone:

- Annual injection-phase water quality monitoring and continuous pressure and temperature monitoring via one well located outside of, and to the northeast of, the delineated AoR in the Upper Tulare Formation (the lowermost USDW) and the Lower Tulare Formation. Post-injection water quality sampling will continue annually and continuous pressure monitoring in the USDW is proposed.
- Continuous monitoring of pressure and temperature in the Etchegoin Formation within a monitoring well located to the west of the injection wells.

Attachment E does not describe any monitoring in the Etchegoin or the Monterey Formation A3-A11 Sands after cessation of injection. However, EPA will likely require that post injection phase monitoring



be an extension of injection phase monitoring to confirm continued demonstration that USDWs are not endangered and to inform the non-endangerment demonstration required at 40 CFR 146.93(b)(3).

Figure 2 of the QASP shows the locations of all monitoring wells associated with the project and is reproduced below.

The Etchegoin Formation monitoring well appears to be situated within the AoR and in the anticipated path of the CO_2 plume and pressure front (based on information in Attachment B). The Upper/Lower Tulare Formation monitoring well is outside of the delineated AoR to the northeast of the injection

wells, and down plume. Given that the Tulare Formation does not hold much water within the AoR, this location, while not in the same direction as the deeper monitoring wells may be most appropriate to allow geochemical sampling, although it is unlikely that CO_2 will travel that far down the limb of the anticline. CTV states that additional Upper Tulare monitoring wells will be drilled if increased pressure is observed in the Etchegoin Formation monitoring well or water quality changes in the Tulare Formation that is due to Monterey Formation A1-A2 CO_2 injection. However, it is unclear how a linkage of water quality/pressure changes to CO_2 injection (and not other activities) would be made.

The applicant proposes to monitor water quality in the Upper/Lower Tulare Formation and the Monterey Formation during the injection and post-injection phases. The analytical and field parameters and methods described in Tables 5 and 8 of Attachment C (injection-phase monitoring of the Tulare and Monterey Formations, respectively) are nearly the same as those in Tables 2 and 5 of Attachment E. Additional information about monitoring in the Monterey Formation is described under "CO_2 Plume Tracking" below. CTV also proposes to perform a baseline water analysis in the Etchegoin Formation monitoring zone and in the Tulare Formation monitoring well.

Table 5 of Attachment C (Injection-phase Tulare Formation monitoring) is reproduced in the first two columns of the table on the next page. Because consistency of monitoring parameters above and within the injection zone is appropriate for detecting leakage of the CO_2 plume, EPA evaluated proposed injection and post injection monitoring in the Tulare and Monterey Formations together. EPA's notes and recommendations are provided in the right-hand column; see also the discussion of "Quality Assurance Procedures" below for additional comments on the parameters to be monitored.

The parameters appear to be generally appropriate for groundwater quality monitoring needs for GS projects, and are consistent with other Class VI monitoring programs, except as noted below. As the permit application narrative describes (pg. 39), the Monterey A1-A2 Sands are dominated by quartz and feldspar, which are stable in the presence of CO_2 and carbonic acid. Note that, as additional information is gathered based on the reviews of other parts of the permit application or pre-operational data collection, recommendations or requirements for additional analytical parameters may be provided.

Parameters	Analytical Methods	Evaluation Notes/Recommendations
Tulare Formation		
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B	200.7 and 6010B are both ICP-AES methods, not ICP-OEC. Please explain what ICP-OEC is or revise the table. These were changed to ICP-MS and EPA Method 6020. In Table 17 of the QASP, the final cation is Ti, not Tl as in Attachment C. Please clarify/be consistent. Also, this is "T1" in the tables of Attachment E; please correct the typographical error. Not addressed. Cations of Sb are also mentioned in Table 17 of the QASP; please add this to the ground water monitoring parameters in Attachments C and E. Not addressed. 200.7 is an EPA-approved wastewater analytical method, while 6010B is not. EPA requests that Method 200.7, Rev 4.4 (1994) be specified. These were changed to ICP-MS and EPA Method 6020.
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B	See above. These were changed to ICP-OES and EPA Method 6010B.
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	Attachment E and Table 17 of the QASP also include anions of Cl; please add this to Attachment C for consistency and completeness. Added. Tables 2 and 5 of Attachment E reference EPA Method 300; please revise the method to be consistent with Attachment C (i.e., Method 300.0). Also, please specify that EPA Method 300.0, Rev. 2.1, Part A (1993) will be used. Addressed.
Dissolved CO_2	SM 4500-CO2-C	No comments.
Total Dissolved Solids	SM 2540 C	Attachment E refers to SM 4500 C for TDS; EPA requests the use of SM 2540 C for consistency. Addressed.
Alkalinity	SM 2320 B	Attachment E refers to SM 2510, which is for conductivity, not alkalinity. EPA requests that CTV revise Attachment E to reference SM 2320 B for consistency. (SM 2320 B is an approved wastewater method.) Addressed.
pH (field)	EPA 150.1 / SM4500-H+B	No comments.
Specific Conductance (field)	SM 2510 B	SM 2510 B is named by SM as a laboratory method, and it is not clear whether SM 2510 B can be conducted in the field. EPA Method 120.1 may be more amenable to field screening if SM 2510 B is not. Please clarify if field use of SM 2510 B is possible or revise the table (i.e., field vs. lab designation) or the method. Not addressed.
Temperature (field)	Thermocouple	No comments.
Dissolved Methane	RSK-175/Gas Chromatography	This method was developed by EPA but is not an EPA approved method for wastewater analysis. Please provide information to support the use of this method for dissolved methane analysis. Alternatively, consider using EPA-approved method SM 6211 B and/or 6211 C. Parameter was removed.

EPA recommends in Class VI guidance that monitoring well construction and planned plugging procedures for monitoring wells be reviewed as part of the permit application evaluation to confirm that

these wells will not provide conduits for fluid movement that could endanger USDWs. No monitoring well construction or plugging information was provided in the permit application materials.

CTV should note that the Central Valley Water Board indicated in its consultations with EPA on a prior Class VI project that any newly drilled monitoring wells must be approved by the Water Board and, while existing wells would not need to be approved, the Water Board expressed interest in any plans to use existing wells as monitoring wells.

Attachment C also describes the water quality sampling procedures, the laboratory to be used, and chain of custody procedures. This information is detailed in the QASP as well.

Questions/Requests for the Applicant:

- *Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E as noted in the table above. Further, the same analytes and methods should be used for monitoring of all formations - to provide consistent data to support modeling reviews and a non-endangerment demonstration. Tables 5 and 8 have been updated; however, some additional changes are needed, as noted above.*
- *In addition, please include additional ground water quality parameters to support a robust monitoring program, as follows:*
    - *δ13C, which is mentioned in the QASP, but not in Attachments C and E. This was added to Table 8; the response is acceptable.*
    - *Water density (which is referenced in the Testing and Monitoring Plan as an expected water quality change due to plume movement on pg. 12). This was not included.*
    - *Dissolved O_2 and H_2S. Dissolved O_2 is a primary indicator of water quality. H_2S occurs in the subsurface, may be common in oil fields, and has the potential to be mobilized, and, is listed as a toxic substance by the CDC. H_2S was added to the parameters in Tables 5 and 8; dissolved O_2 was not added as a parameter but is listed under field measurements where it should be measured. The response is acceptable.*
- *Please include the groundwater monitoring well 61WS-8R in Figure 4 of the PISC and Site Closure Plan. This was not added to Figure 4 as requested.*

Follow-up Questions for the Applicant:

- ***Please provide monitoring well construction and plugging plans to confirm that these wells will not provide conduits for fluid movement that could endanger USDWs.***
- ***Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E to incorporate the notes above, i.e., add specific conductance (field), Sb, and water density and revise the chemical symbol for titanium.***
- ***For clarity, please also include the depths of pressure/temperature monitoring gauges on Tables 4, 7, and 9 (only the fluid sampling depths are shown, and a separate depth row for the pressure/temperature gauges would clarify this monitoring).***
- ***Please update the USDW fluid sampling depth for the Tulare Formation well in Attachment E Table 1 to 940 – 960 feet to be consistent with Attachment C.***

- ***Why was dissolved methane removed as a ground water analytical parameter?***
- ***Please include well 61WS-8R in Figure 4 of the PISC and Site Closure Plan.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of groundwater quality analytical parameters may need to be updated to ensure that all applicable parameters are included.*

CO_2 Plume and Pressure Front Tracking

The applicant describes proposals for CO_2 plume and pressure front tracking that include: (1) the use of direct and indirect methods for tracking the pressure front within the injection zone [40 CFR 146.90(g)(1)]; and, (2) direct pressure front monitoring in two monitoring wells and seismic monitoring to indirectly track the extent of the CO_2 plume [40 CFR 146.90(g)(2)].

For post-injection site care, CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. In Attachment E, Table 4 details the methods that will be used to monitor the CO_2 plume post-injection, and Table 6 details the methods that will be used to monitor the associated pressure front. Injection reservoir pressure monitoring will occur to ensure confinement of the reservoir and consistency with computational modeling results. As seen in Table 6 of Attachment E, seismicity monitoring will also occur via surface and shallow borehole seismometers. Table 5 of Attachment E lists the analytical methods that will be used for the injection zone fluid monitoring and analysis.

CO_2 Plume Monitoring

CTV proposes to monitor the plume via direct and indirect monitoring in the Monterey Formation:

Direct plume tracking methods include:

- Annual fluid sampling during the injection and post-injection phases in Monterey Formation A1-A2 Sands via two monitoring wells (327-7R-RD1 and 342-7R-RD1, located to the southwest and the northwest of the injection wells, respectively).

- Quarterly fluid sampling during the injection phase in EOR producers in the Monterey A3-A11 Sands. The location of the EOR wells is not described.

Indirect plume monitoring includes:

- Pulse neutron logging in the Monterey Formation A1-A2 Sands via the same monitoring wells. This logging will be conducted every two years during the injection phase and every 5 years during the post-injection phase.

The parameters and associated analytical methods are presented in Table 8 of Attachment C. They are identical to those proposed for Tulare Formation water quality monitoring described under "Ground Water Monitoring" above. Deep and shallow water quality monitoring should be for the same parameters to provide consistent data on which to evaluate potential fluid movement out of the confining zone.

Figure 2 of the QASP (reproduced under "Groundwater Monitoring" above) shows the location of the monitoring wells in the Monterey Formation A1-A2 Sands. CTV asserts that modeling indicates that the CO_2 plume will reach each of these monitoring wells by the second year of injection.

Pressure Front Monitoring

CTV plans to conduct **direct pressure front monitoring** by continuously monitoring pressure and temperature during the injection and post-injection phases within the Monterey Formation A1-A2 Sands via pressure gauges in monitoring wells 327-7R-RD1 and 342-7R-RD1.

Indirect pressure front monitoring will be accomplished via seismic monitoring throughout the AoR. CTV states that it will monitor seismicity with surface and shallow borehole seismometers it plans to install, as well as monitor seismic data from the Southern California Earthquake Data Center (SCEDC) network. This continuous monitoring will continue throughout the injection and post-injection phases.

Pressure-front monitoring activities are summarized in Table 9 of Attachment C and Table 6 of Attachment E.

Questions/Requests for the Applicant:

- *Please refer to EPA's questions and recommendations under "Groundwater Monitoring" above regarding water quality analysis and revise Table 8 of Attachment C and Table 5 of Attachment E accordingly. Additional revisions are needed, as described in the comments above.*
- *Please elaborate on the monitoring in the Monterey Formation A3-A11 Sands as described on page 12 of Attachment C. Specifically, where are the EOR producers from which CTV plans to sample the Monterey Formation A3-A11 Sands? At what depths will sampling be performed, and what parameters will be analyzed for? (The analytical parameters should be consistent with other monitoring.) Please describe who owns these wells, and whether they will be operational throughout the injection and post-injection periods? Please include the locations of these wells on the relevant figures in Attachments C and E and the QASP. The applicant provided a new Figure 3 that shows the locations of these wells, and their depths are presented in Table 7. The updated plan indicates that the same analytes will be monitored as shown in Table 8. The response is acceptable (pending requested updates to Table 8).*
- *Please describe the seismic monitoring network discussed on pg. 16 of Attachment C, including the number and location of the seismometers that CTV proposes to install. The requested information was not provided.*
- *Please explain the timeframe for which a seismicity baseline will be established, and if historical seismicity will be incorporated into this baseline. CTV says that historical seismicity within the area will be accounted for in the baseline assessment, but does not explain how.*

- *Page 15 of Attachment C says that CTV plans to perform direct pressure monitoring in the Monterey Formation A1-A2 Sands, and Table 9 indicates that pressure and temperature monitoring will be performed. Please revise the statement on pg. 15 to be consistent with the table – to include temperature as well as pressure. The revision has not been made to mention temperature monitoring as detailed in Table 9.*
- *EPA recommends that the sampling/measurement depths be included in Tables 7 and 9 of Attachment C and Tables 4 and 6 of Attachment E for clarity and completeness. Depths were added as requested to Attachment C Table 7; but were not added to Table 9 of Appendix C or Tables 4 and 6 of Attachment E. Note also that, in the updated attachment, CTV identified different injection zone monitoring wells (i.e., 353A-7R and 335X-7R); these wells are located close to the wells identified in maps in the initial plan.*
- *Please make the following changes to the proposed plume and pressure front tracking in Attachments C and E:*
    - *Perform frequent sampling and logging (e.g., quarterly, or semi-annually) early in the injection phase (i.e., at least until the CO_2 plume passes the monitoring well locations). This would allow the acquisition of additional data to validate the modeling, provide early warning of unanticipated fluid movement, and be consistent with other Class VI projects. The requested change was not made.*
    - *Conduct a 3D seismic survey or a vertical seismic profile during injection operations for comparison to the 2019 3D seismic survey described in the application narrative. The requested change was not made.*
    - *Conduct quarterly water quality sampling in the A1-A2 Sands for plume tracking to be consistent with the A3-A11 monitoring activities as well as provide additional data points to validate modeled predictions, and to eventually support the demonstration of non-endangerment. CTV updated Table 7 to align sampling frequencies in the Monterey Formation A1-A2 and A3-A11.*

Follow-up Questions for the Applicant:

- ***Please revise Table 8 of Attachment C and Table 5 of Attachment E to address EPA's comments under groundwater quality monitoring above.***
- ***Please describe the seismic monitoring network and explain how historic seismicity within the area will be accounted for in the baseline assessment.***
- ***Please revise the statement on pg. 15 to describe temperature and pressure monitoring as described above.***
- ***Please add sampling/measurement depths to Table 9 of Appendix C and Tables 4 and 6 of Attachment E as described above.***

- ***Please update the plume and pressure front tracking discussion to include the requested frequent sampling and logging early in the injection phase and a 3D seismic survey or a vertical seismic profile as described above.***

Air/Soil or Other Testing and Monitoring

Based on the currently available information about the geologic setting (i.e., the depth of the injection formations and the lack of evidence for the presence of transmissive faults of fractures), surface air and/or soil gas monitoring are not needed to detect movement of fluid that could endanger USDWs within the AoR.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If, based on the results of planned pre-operational testing, uncertainties about the geologic setting are identified, the need for air and/or soil gas monitoring or other monitoring will be reconsidered.*

Quality Assurance Procedures

The review team evaluated the QASP submitted with the permit application to verify that all the testing activities, analytes, etc., included in the QASP are consistent with proposed injection and post-injection phase testing and monitoring. All the injection and post-injection testing and monitoring activities (except for pressure falloff testing) are addressed in the QASP and the QASP covers activities recommended by EPA. EPA noted a few discrepancies between the tables in the QASP and the activities described in Attachments C and E. These are summarized in the table below:

QASP Table	**EPA comments**
Table 1. Summary of testing and monitoring.	Cement bond logs and standard annulus pressure tests of the injection wells are listed in the QASP, but these tests are not described in Attachment C. Please clarify if these tests are planned to be performed, either as part of pre-operational or injection-phase testing, or revise the QASP accordingly. Cement evaluation was removed from the updated QASP. Please add PFOT and RTS to Table 1. PFOT was added to Table 1 (RTS is no longer planned).
Table 2. Monitoring Well Summary.	Monitoring the A3-A11 Sands via the EOR wells is not included on Table 2 of the QASP; please include this for consistency. Table 2 was updated as requested.
Table 3. Summary of analytical and field parameters for ground water samples.	Please update the placeholders for specific cations and anions in Table 3 to reflect Table 17 of the QASP. Zinc needs to be added to Table 17. This table should address sampling in formations other than the Tulare Formation (per recommendations above). Table 3 was updated as requested. There is a typo in the pH (field): the method “SPA 150.1” should be “EPA 150.1” This has been corrected.

QASP Table	EPA comments
Table 5. Summary of Analytical Parameters for Corrosion Coupons.	Please include the QC Requirements on Table 5. This has been added as requested.
Table 17. Summary of sample containers, preservation treatments, and holding times for ground water samples.	There are a few discrepancies between the analytical parameters mentioned on Table 17 of the QASP and in Attachments C and E. EPA recommends the following changes for consistency: • Please revise the parameter NO_2 in Table 17 of the QASP to be consistent with NO_3, which is a planned analyte, per Attachments C and E. This has been corrected. • Add cations of K (in Tables 5 and of Attachment C and Tables 2 and 5 of Attachment E) to Table 17. This has been added as requested. • Please also make other necessary revisions to Table 17 of the QASP to address EPA's requests related to analytical parameters under "Ground Water Monitoring" above. See comments related to table 17 edits under Groundwater Quality Monitoring.
Other	Please fix the formatting of the Table of Contents for Section B.1. a. This has been corrected.

Follow-up Questions for the Applicant:

- ***Please update Table 4 of the QASP to reflect use of ISBT methods for injectate analysis.***
- ***Please revise Table 17 of the QASP to include zinc and Ti (not Tl) to be consistent with Attachment C.***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Operating Procedures for the A1-A2 Project

In January 2022, EPA provided questions to CTV (*blue, italic text*) about the proposed operating procedures for injection wells 355-7R and 357-7R submitted as part of CTV's Class VI permit application (dated August 30, 2021 and December 2, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided updated operating procedures for the two wells to EPA on March 31, 2022. EPA's evaluation of how the update addresses its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

The proposed operational procedures (which appear to be specific to Well 357-7R) are described on page 47 of the initial Narrative and summarized in Table 8, which is replicated below:

Table 8 of initial Narrative (for Well 357-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	3,800	Psig
Downhole	6,100	Psig
Average Injection Pressure		
Surface	1,600	Psig
Downhole	4,100	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,730 @ packer	Psig
Annulus Pressure/Tubing Differential	370@packer @ average injection condition	Psig

The proposed operational procedures for Well 355-7R are described in the amended Narrative (Attachment A2) and summarized in a revised Table 8, which is replicated below:

Table 8 of updated Narrative (for Well 355-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	2,900	Psig
Downhole	6,108	Psig
Injection Pressure		
Surface Average / Maximum	1,400/1,600	Psig
Downhole Average / Maximum	4,300 / 4,516	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,720 @ packer	Psig
Annulus Pressure/Tubing Differential	578@packer @ average injection condition	Psig

Injection Pressure

The basis for the proposed maximum injection pressure (MAIP) is described in Attachment B – the AoR and Corrective Action Plan (AoR CA). CTV states that the MAIP will be below 90% of the fracture pressure of the Monterey Formation at the base of the Reef Ridge Shale confining zone, and is calculated as follows:

$$8{,}150 psi \times 0.9 psi/ft = 7{,}335\ psi$$

Where:

Fracture pressure (Fp) at base of confining zone = 8,150psi

Safety factor = 0.9 (90%)

Tables 6 and 7 of the AoR CA provide fracture gradients and fracture pressures for the Monterey Formation A1-A2 reservoir, and are replicated below:

Table 6		
Interval	**Fracture Gradient psi/ft**	**Fracture Pressure (psi) at base of Reef Ridge Shale (8,403 ft)**
Monterey Formation A1-A2	0.97	8,150

Table 7		
Injection Pressure Details	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Fracture gradient (psi/ft)	0.97	0.97
Maximum injection pressure (90% of fracture pressure) (psi)	7,335	7,335
Elevation corresponding to maximum injection pressure (ft MSL)	8,403	8,403
Elevation at the top of the perforated interval (ft MSL)	8,485	8,462
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,407	7,387
Planned maximum injection pressure / gradient (top of perforations)	4,500 / 0.53	4,500 / 0.53

The maximum injection pressure listed in Table 7 of the AoR CA for injection wells 357-7R and 355-7R does not correspond to the maximum injection pressure in Table 8 of the Narrative or the amended Narrative. Additionally, the proposed injection pressures of 4,500 psi in Table 7 of the AoR CA exceed the proposed average injection pressures of 4,100 psi, listed in Table 8 of the Narrative. It appears that, regardless of the discrepancy in maximum injection pressures, CTV proposes to operate at an injection pressure of 4,100 – 4,500 psi, well below 90% of the injection zone fracture pressure. However, the proposed injection pressures will need to be confirmed as being below 90% of the fracture pressure at the top of the perforations (i.e., within the Monterey Formation injection zone), and the discrepancy in maximum injection pressures will need to be resolved.

CTV states in the AoR CA that their current Class II UIC permit mandates a maximum operating pressure gradient of 0.80 psi/ft unless additional testing indicates a higher gradient. It appears that CTV conducted a test(s) to obtain a higher fracture gradient, 0.9 psi/ft, as seen in Table 6 of the AoR CA, above. However, these tests are not described in the application and will need to be provided for validation of the fracture pressure of the injection and confining zones and the corresponding maximum injection pressures. A question for the applicant regarding this topic is included in the AoR CA Evaluation.

Questions/Requests for the applicant:

- *Please provide separate stand-alone versions of Attachment A for Well 357-7R and Well 355-7R that describe operating conditions. The attachments should include the following: injection well operating conditions (e.g., a tabular description of surface and bottomhole maximum injection pressures, annulus pressure, annulus pressure/tubing differential, and the maximum CO_2 injection rate); how the maximum injection pressure was determined; a description of routine shutdown procedures; and tables summarizing reporting of well and project-related monitoring. The applicant provided stand-alone versions of the operating conditions for Wells 357-7R and 355-7R. Each attachment contains a tabular description of surface and downhole minimum and maximum injection pressures, annulus pressure, and the maximum CO_2 injection rate. The*

annulus pressure/tubing differential was not included on the tables, but CTV referenced the pressure differential will meet the requirements of 40 CFR 146.88 (c) in the Annulus Pressure. EPA recommends that this information be included on the table. CTV also described the routine well shutdown procedures, but did not describe the reporting of monitoring data.

Follow-up Requests for the Applicant:

- ***Please include tables summarizing reporting of well and project-related monitoring. A template with this information, called "Summary of Requirements Template," is available at https://www.epa.gov/uic/class-vi-permit-application-templates.***
- ***Please include the annulus pressure/tubing differential on Table 1 for each well.***

Maximum CO_2 Injection Rate

The applicant proposes a daily CO_2 injection rate of 648 to 1,917 tons per day, which equates to 236,520 to 699,705 tons/year (or 3.5 – 10.5 million tons over the planned 15-year injection phase of the project) as seen in Table 5 of the AoR CA and excerpted below. However, the applicant notes in the Narrative that the storage capacity of the Monterey Formation A1-A2 reservoir is approximately 8 – 10 million tonnes of CO_2 based on computational modeling results. The maximum storage capacity of 10 million tonnes of CO_2 is slightly less than the projected maximum volume of 10.5 million tonnes of CO_2 based on daily injection rates as seen in Table 5 below (assuming injection activities will occur 365 days per year). Based on an evaluation of the AoR delineation modeling and geologic site characterization, it appears that the injection and confining zones are appropriately characterized; however, the range of proposed daily injection rates allow for the exceedance of the modeled storage capacity. The applicant should reconcile this inconsistency and provide an updated range of daily CO_2 injection rates that satisfies the modeled CO_2 storage capacity. See the AoR CA evaluation report for additional discussion.

Table 5. Operating details.

Operating Information	Injection Well 1 357-7R	Injection Well 2 355-7R
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft MSL) Z top Z bottom	 7,728 8,010	 7,774 7,949
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15

Injection rate (t/day)*	648 – 1,917	648 – 1,917

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

In the Testing and Monitoring Plan (pg. 5), CTV states that the volume of CO_2 injected into the Monterey Formation A1-A2 Sands will be calculated from the injection flow rate and CO_2 density, and that density will be determined from the Massachusetts Institute of Technology's CO_2 Thermophysical Calculator (https://sequestration.mit.edu/tools/index.html). However, upon investigation of the online calculator, it appears to no longer be operational. The applicant should provide another method by which the CO_2 density will be calculated.

Questions/Requests for the applicant:

- *Please include a description of standard operating procedures to ensure that the maximum daily injection rate will not be exceeded.*
  CTV updated the Operating Procedures for Wells 355-7R and 357-7R to discuss standard operating procedures to ensure that the maximum daily injection rate will not be exceeded. CTV explained that a threshold of 10% over these values will be used to configure the automation and alarms, which equates to 16.5 million cubic feet per day and 4,300 psi. If either threshold is achieved or exceeded, alarms will indicate there is an issue and a response appropriate to the event will be taken. It is unclear how setting the alarm threshold at 10% above the permit limit will avoid a violation of the permit or potential USDW endangerment.
- *Please update the daily CO_2 injection volumes in Table 5 of the AoR CA to ensure they are consistent with the modeled cumulative injection volumes of 8 – 10 million tonnes of CO_2 over 15 years.*
  CTV changed the daily CO_2 injection rate of 648 – 1,917 tonnes/day on Table 5 of the AOR CA to 530 – 794 tonnes/day. This reflects the cumulative injection volume between 8 – 10 million tonnes of CO_2 over 15 years. This response is acceptable, pending resolution of the injection duration (in EPA's follow up questions on the AOR CA).

Follow-up Requests for the Applicant:

- ***The alarm threshold should be set at 90% of the permit's injection pressure limit to avoid a violation of the permit and to ensure protection of USDWs. Please revise the threshold limit.***

Automated Shutdown System

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the automatic shutdown devices are activated if wellhead pressure exceeds the specified shutdown pressure listed in the permit, or if the annulus pressure indicates a loss of external or internal well containment. However, standard operating procedures that support the automated shutdown system are not provided.

Questions/Requests for the applicant:

- *Please include standard operating procedures to support the automated shutdown system. CTV updated the Operating Procedures for Wells 355-7R and 357-7R to include a subsection on the Automated Shutdown System. CTV discusses that data will be collected in an automated system and monitored by a control system, and if an established operating threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented. As CTV describes, they will share information about the monitoring system with EPA when it is established (it is expected that these will be included in well specifications provided later in the permitting process). This update addresses the comment and is acceptable at this point.*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

August 17, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Construction and Plugging Plans for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below in the two Enclosures.

Please submit the information requested in the Enclosures by September 19, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2022.08.17 09:54:33 -07'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Construction and Plugging Plan Evaluation 355-7R
Construction and Plugging Plan Evaluation 357-7R

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Construction and Plugging Procedures for Injection Well 355-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

In February 2022, EPA provided questions to CTV (*blue, italic text*) about the construction and plugging of the 355-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands, submitted as part of CTV's Class VI permit application (dated August 30, 2021 and December 2, 2021) for the proposed CTV-Elk Hills Class VI geologic sequestration (GS) project. CTV provided updated operating procedures for the two wells to EPA on May 16, 2022. EPA's evaluation of how the update addresses its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Injection Well Construction

Narrative A2 and Attachment G2 describe the construction design for Well 355-7R. Well 355–7R is an existing Class II pressure maintenance well, approved by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 355–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2. Well 355-7R was drilled in 1973; Narrative A2 contains construction details regarding Well 355-7R.

Table 5 of the Narrative A2, matches the casing specifications listed in Attachment G2 for Well 355-7R (see below). Attachment G2 also includes tubing and packer specifications for Well 355-7R, which are excerpted below. The tubing and packer specifications in Attachment G2 mostly correspond to Table 7 of the Narrative A2, however there appear to be typos regarding: tubing outside diameter and weight (in the Narrative A2) and regarding packer tensile rating (in Attachment G2).

Injection Well 355-7R Construction Details (from Attachment G2)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)

Injection tubing	8,398	4.500	3.920	13.5	L-80	Long	9,020	8,540

Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

CTV states that all the well materials and the stainless-steel wellhead are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. The Applicant notes that the Class G Portland cement used to complete well 355-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor and long string (injection string), had cement returns to surface according to Narrative A2. A CBL indicated that the top of cement in the injection string annulus is above 5,200 ft, which is above the Reef Ridge Shale upper confining layer, reported as 6,929 ft-7,962 ft true vertical depth (TVD), per Table 1 of the Narrative A2.

The cement integrity is supported by information from existing wells and a CBL in Well 355-7R. California Resources Corporation (CRC) has conducted standard annulus pressure tests (SAPTs) historically to ensure continued internal mechanical integrity of the well. No SAPT results were provided in the permit application materials, however. These tests will also be conducted prior to injection and every five years thereafter and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1 of Attachment G2 is illegible, so information such as geologic formation tops (for the injection and confining zones and the Base of the USDW), perforation depths, and casing depths, cannot be evaluated. The applicant will need to resubmit an updated, resolvable casing diagram for Well 355-7R that demonstrates proper construction, including that the Base of the lowermost USDW is covered by the surface casing in accordance with 40 CFR 146.86(b)(2). According to the tables on Page G2, the surface casing is set to a depth of 500 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW in accordance with 40 CFR 146.86(b)(2). (Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.)

The applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of

the event. However, the applicant did not provide discussion regarding safety valves and automated shut-off devices in Attachment G2.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings).

Questions/Requests for the applicant:

- *Is Well 355-7R equipped with automatic shutoff systems connected to the real-time surface monitoring equipment and alarms, as required at 146.88(e)(2)? If so, please describe these systems in Attachment G2 and how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G2 to include these required components. Under "Alarms and Shut-off Devices" on page 5, the applicant states that real time monitoring and automated shut off controls will be added to the system. CTV is required to provide information for EPA to review before installing the equipment; these should be included on final as-built schematics of the well. CTV states that they do not plan to install down hole shut off systems due to the lack of risk factors (e.g., high temperatures and pressures or corrosive materials). Additional clarification on why these risk factors are considered low is required.*
- *Figure 1 of Attachment G2 is illegible. Please submit an updated, resolvable diagram for Well 355-7R that includes the following information:*
  - *All relevant formations (e.g., the injection and confining zones and the base of the USDW); These details were added to a wellbore diagram of the injection well in the confidential Appendix 1 - Monitoring Well Schematics and Plugging Details.*
  - *Surface casing that extends through the Base of the USDW, per 40 CFR 146.86(b)(2); Although the Construction, Operating and Plugging document (COP) states that surface casing is set and cemented within the USDW, according to the well schematic, the surface casing only extends to 500' which is above the bottom of the USDW at 840'. 40 CFR 146.86(b)(2) requires the surface casing must extend through the base of the lowermost USDW.*
- *For completeness, please include the description of testing of the deep monitoring wells (i.e., as described in Attachment G) in Attachment G2. The applicant states that these details will be incorporated into the pre-operational testing document, but did not include it. i*
- *Please explain how the injection well's design will mitigate potential shallow compression related to land subsidence while still complying with the requirement to cement to the surface. The applicant describes in the Casing section on pages 2 and 3 that there has been no historical occurrence of subsidence in the area. In addition, the COP states that well construction mimics other wells used in the area for injection with no operational issues related to structural strength. No evidence of this was provided, however.*

- *Please provide the most recent SAPT reports for the well. The most recent SAPT results from October 6, 2020, are provided on page 9 of the document, which shows the well maintaining pressure within the well annulus, demonstrating mechanical integrity. However, the SAPT was run for 30-40 minutes, and not the minimum of 60 minutes as described in the pre-injection testing in Appendix G2 submitted with the initial application materials. Because CTV will conduct an additional SAPT prior to injection, this response is acceptable at this point.*

Follow-up Requests for the Applicant

- ***Please clarify why the risk factors (temperature, pressure and corrosivity) are considered to be low and include further justification as to why the downhole shutoff system is not necessary.***
- ***Please confirm the base of the lowermost USDW. Please note the definition of USDW (40 CFR 146.3) below.***

  (USDW) means an aquifer or its portion:
  (1)(i) Which supplies any public water system; or (ii) Which contains a sufficient quantity of ground water to supply a public water system; and
  (A) Currently supplies drinking water for human consumption; or
  (B) Contains fewer than 10,000 mg/l total dissolved solids; and
  (2) Which is not an exempted aquifer.
- ***Please provide data or sources as evidence that lead to the determination that no subsidence has occurred in the area.***
- ***EPA requests that, for clarity, the conductor casing grade (which was reported as H-40 in the initial application) be included on Table 1. If this information was incorrect, please explain how the conductor casing is suitable for CO_2 injection.***
- ***Because the tubing grade was changed from 13CR-95 to L-80 CRA, please ensure that the coupons used in the corrosion monitoring section of the Testing and Monitoring Plan are revised accordingly.***
- ***Please update Attachment G2 to include the pre-operation testing plan for the deep monitoring wells.***
- ***Please provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.***

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 355-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in Narrative A2 and in Attachment G2. Attachment G2 identifies several tests that CTV indicates have been performed and were provided. These include deviation checks, a cement bond log, and open-hole well logs. CTV notes that mechanical integrity tests, including a temperature log and SAPT, were also acquired after the drilling of 355-7R; however, these were not provided. Attachment G2 also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2

Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed.

Questions/Requests for the applicant:

- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones. The applicant states that a full well CBL will be completed during pre-operational testing and tubing removal. The pre-operational testing plan submitted with the initial application in Appendix G2 includes a micro-seismogram log for cement evaluation, but not a CBL. If the purpose of this testing is to evaluate cement condition, the response is acceptable, although CTV should clarify the tests to be performed in their updated pre-operational testing plan. EPA will need to review and approve the results of the CBL prior to authorizing injection.*

Follow-up Requests for the Applicant

- ***Please provide an updated pre-operational testing plan that describes the tests identified in CTV's responses to questions in this document. For example, the plan should include: an SAPT of an appropriate test duration and MITs on monitoring wells 342-7R-RD1 and 327-7R-RD1.***

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
    - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
    - *Step-by-step procedures that would be employed during stimulation.*

The updated Attachment I (Stimulation Plan) states that stimulation is not anticipated and that a plan will be submitted for approval should stimulation be required; it contains no general description of stimulation procedures. EPA has communicated with CTV that a stimulation plan submitted after the permit is issued will necessitate a modification to the permit. CTV has chosen to not include a stimulation plan at this point.

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1? The applicant says they will address this within their pre-operational testing plan. MITs referenced in the original Attachment G include annulus pressure tests only. For existing wells that are proposed to be converted, an external MIT will be required.*
- *Please include information about MITs on the deep monitoring wells in Attachment G2 for completeness. The applicant says they will address within the pre-operational testing plan. MITs referenced in the original Attachment G include procedures for conducting annulus pressure tests on the deep monitoring wells.*

Follow-up Requests for the Applicant

- ***Please include an external MIT in the pre-operational testing plan for wells that are proposed to be converted to monitoring wells.***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Construction and Plugging Procedures for Injection Well 357-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

In February 2022, EPA provided questions to CTV (*blue, italic text*) about the construction and plugging of the 357-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands, submitted as part of CTV's Class VI permit application (dated August 30, 2021 and December 2, 2021) for the proposed CTV-Elk Hills Class VI geologic sequestration (GS) project. CTV provided updated operating procedures for the two wells to EPA on May 16, 2022. EPA's evaluation of how the update addresses its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Injection Well Construction

Attachment A--Narrative (referred to as The Narrative herein) and Attachment G describe the well construction design for Well 357-7R. Well 357-7R is an existing Class II pressure maintenance well that is currently permitted by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 357–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2. Well 357-7R was drilled in 1980; the Narrative A2 contains construction details regarding Well 357-7R.

Table 5 of the Narrative, corresponds to the casing specifications listed in Attachment G for Well 357-7R, pictured below. Attachment G also includes tubing and packer specifications for Well 357-7R, which are excerpted below. The tubing and packer specifications in Attachment G mostly correspond to Table 7 of the Narrative, however the packer burst strength (psi) and collapse rating (psi) differ between the documents.

Injection Well 357-7R Construction Details (Attachment G)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,447	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

All well materials noted in the tables above, in addition to the stainless-steel wellhead, are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are mostly consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. However, the surface pressure field gauges listed in Tables 10, 11, 12, and 14 of the QASP show a maximum calibrated working pressure of 3,000 psi, which is lower than the maximum surface injection pressure of 3,800 psi. The Applicant notes that the Class G Portland cement used to complete Well 357-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor, had cement returns to surface according to Figure 1 of Attachment G (reproduced below). The cement integrity is supported by data from existing wells and a cement bond log (CBL) in Well 357-7R. California Resources Corporation (CRC) has conducted MITs and standard annulus pressure test (SAPTs) every five years (no SAPT results were provided with the application materials, however). These tests will also be conducted prior to injection and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Relevant geologic formation tops were noted in Figure 1 of Attachment G. The figure shows that the Base of the USDW is approximately 806 ft. TVD (true vertical depth), which is behind both the long string and intermediate casing. The surface casing is set to a depth of 501 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW in accordance with 40 CFR 146.86(b)(2). (Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.)

The perforations for Well 357-7R are shown at depths of 8,782 to 8,830 feet. The perforations are also described in the AoR and Corrective Action Plan; however, they are presented in depth relative to mean sea level, so confirmation that the depths are consistent is not possible.

According to Table 1 in *Attachment C – Testing and Monitoring Plan,* CTV will analyze the following CO_2 stream constituents based on established ASTM methods: O_2, N_2, CO, CH_4, H_2S, total hydrocarbons, total Sulfur, and CO_2 purity. It appears that H_2O was excluded from the CO_2 stream constituent analysis and will need to be included (a request was provided with the testing and monitoring evaluation). Additionally, the applicant does not state if the compatibility of the CO_2 stream and well construction components will be determined prior to well operation. Following the pre-construction measurement of

the composition, properties, and corrosiveness of the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.

Figure 1 of Attachment G, excerpted below, demonstrates the casing design for Well 357-7R. The well construction and cementing criteria described in the Narrative and Attachment G appear to be acceptable, except as noted in the questions below. However, the applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. However, the applicant did not describe safety valves and automated shut-off devices in Attachment G.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings). Any design modifications to address the subsidence concern will need to meet the requirement that Class VI wells have cementing of the surface casing that extends to the surface.

Questions/requests for the applicant:

- *There are several discrepancies in the descriptions of Well 357-7R between tables 5, 6, and 7 of Attachment A and the tables on pages G2 and G3 of Attachment G. Please make the tables and the well bore diagram in Attachment G (if needed) consistent.*
  - *Attachment A, Table 5, and the Table on page G2 indicate that the intermediate casing in Well 357-7R is to a depth of 3,517 ft; on Table 6, this depth is 3,516 ft. The applicant removed this table from Attachment A and corrected the depth to 3,517 ft. The response is acceptable.*
  - *The conductor casing material is H-40 in Attachment A, Table 5 and Attachment G, and it is J-55 in Table 6. CTV removed the conductor casing grade from Table 1 and states that the conductor grade is not specified or relevant, but they did not explain why.*
  - *The surface casing material is H-40 in Table 5 and in Attachment G, pg. 2, and it is H-80 in Table 6. CTV changed the surface casing grade to H-40. The response is acceptable.*
- *Please confirm that the surface casing extends through the base of the lowermost USDW, as required per 40 CFR 146.86(b)(2). If it does not, please explain how the well will meet the requirements of 40 CFR 146.86(b)(2). A new Protection of USDW section on pg. 3 states that the surface casing is set and cemented within the USDW, not through the base of the USDW, and describes additional ways in which the surface casing is designed to protect the USDW. The applicant states that the intermediate string is set across the base of the USDW, and the annular cement will provide additional isolation. Cement bond logs in the 7" casing string indicate annular cement within and above the injection and confining zones.*
- *Is Well 357-7R equipped with real-time surface monitoring equipment and alarms and, if so, are these connected to automatic shutoff systems, as required at 146.88(e)(2)? If so, please describe*

these in Attachment G and describe how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G to include these required components. Under "Alarms and Shut-off Devices" on page 5, the applicant states that real time monitoring and automated shut off controls will be added to the system. CTV is required to provide information for EPA to review before installing the equipment; these should be included on final as-built schematics of the well ; these should be included on final as-built schematics of the well. CTV states that they do not plan to install down hole shut off systems due to the lack of risk factors (e.g., high temperatures and pressures or corrosive materials). Additional clarification on why these risk factors are considered low is required.

- *Please explain how the injection well's design will mitigate potential shallow compression resulting from land subsidence and comply with the requirement to cement to the surface. CTV describes in the Casing section on pages 2 and 3 that the well construction mimics other wells used in the area for injection with no operational issues related to structural strength. Additionally, the Construction, Operating and Plugging document (COP) states that subsidence has not been observed historically, and shallow compression is not anticipated as a concern. No evidence of this was provided, however.*
- *Please include alternative pressure monitoring devices to those listed in Tables 10, 11, 12, and 14 of the QASP with pressure field gauges with higher pressure ratings to function at the maximum surface injection pressure of 3,800 psi safely and reliably. CTV stated that the QASP will be updated to show equipment with pressure ratings of 5,000 psi. However, this change was not included in an updated QASP that CTV submitted on March 31.*
- *Please provide the most recent SAPT reports for the well. The most recent SAPT results from October 6, 2020, are provided on page 9 of the document, which shows the well maintaining pressure within the well annulus, demonstrating mechanical integrity. However, the SAPT was run for 20-30 minutes, and not the minimum of 60 minutes as described in the pre-injection testing in Appendix G2 submitted with the initial application materials. Because CTV will conduct an additional SAPT prior to injection, this response is acceptable at this point.*

Follow-up Questions for the Applicant:

- ***Please clarify why the risk factors (temperature, pressure and corrosivity) are considered to be low and include further justification as to why the downhole shutoff system is not necessary.***
- ***Please confirm the base of the lowermost USDW. Please note the definition of USDW (40 CFR 146.3) below.***

  (USDW) means an aquifer or its portion:
  (1)(i) Which supplies any public water system; or (ii) Which contains a sufficient quantity of ground water to supply a public water system; and
  (A) Currently supplies drinking water for human consumption; or
  (B) Contains fewer than 10,000 mg/l total dissolved solids; and
  (2) Which is not an exempted aquifer.
- ***Please provide data or sources as evidence that lead to the determination that no subsidence has occurred in the area.***

- ***EPA requests that, for clarity, the conductor casing grade (which was reported as H-40 in the initial application) be included on Table 1. If this information was incorrect, please explain how the conductor casing is suitable for CO_2 injection.***
- ***Because the tubing grade was changed from 13CR-95 to L-80 CRA, please ensure that the coupons used in the corrosion monitoring section of the Testing and Monitoring Plan are revised accordingly.***
- ***Please update the QASP to show equipment with pressure ratings of 5,000 psi.***
- ***Please update Attachment G2 to include the pre-operation testing plan for the deep monitoring wells.***
- ***Please provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.***

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 357-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in the Narrative and in Attachment G. Table 1 of the Pre-Operational Testing Plan for Well 357-7R identifies several tests that CTV indicates have been performed, and that these were provided. These include deviation checks, cement bond log, open-hole well logs, mechanical integrity test, SAPT, injection zone and confining layer core, reservoir conditions and fluid, injection zone and confining layer fracture gradients, and pressure testing. Attachment G also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2 Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed.

Questions/Requests for the applicant:

- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones. The applicant states that a full-well CBL will be completed during pre-operational testing and tubing removal. Please note that EPA will need to review and approve the results of the CBL prior to authorizing injection. Response is acceptable at this point.*

Follow-up Questions for the Applicant:

- ***Please provide an updated pre-operational testing plan that describes the tests identified in CTV's responses to questions in this document. For example, the plan should include: testing to confirm the plugback depth; a CBL along the full length of the well; an SAPT of an appropriate test duration; and MITs on monitoring wells 342-7R-RD1 and 327-7R-RD1.***

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
  - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
  - *Step-by-step procedures that would be employed during stimulation.*

The updated Attachment I (Stimulation Plan) states that stimulation is not anticipated and that a plan will be submitted for approval should stimulation be required; it contains no general description of stimulation procedures. EPA has communicated with CTV that a stimulation plan submitted after the permit is issued will necessitate a modification to the permit. CTV has chosen to not include a stimulation plan at this point.

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1? The applicant says that they will address this in their pre-operational testing plan. MITs referenced in the original Attachment G include annulus pressure tests only. For existing wells that are proposed to be converted, an external MIT will be required.*

Follow-up Requests for the Applicant

- ***Please include an external MIT in the pre-operational testing plan for wells that are proposed to be converted to monitoring wells***

Review of Carbon Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Proposed Testing and Monitoring Activities at the A1-A2 Class VI Project

In January 2022, EPA provided questions to CTV (*blue, italic text*) about proposed injection and post-injection monitoring activities submitted with CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated Testing and Monitoring Plan and PISC and Site Closure Plan to EPA on March 31, 2022. EPA's evaluation of how the updated plans address its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Carbon Dioxide Stream Analysis

To meet the requirements of 40 CFR 146.90(a), CTV plans to analyze the carbon dioxide (CO_2) stream quarterly for the constituents identified in Table 1 of the Testing and Monitoring Plan, which is replicated below.

Parameter	Analytical Method(s)
Oxygen	ASTM D1945
Nitrogen	ASTM D1945
Carbon Monoxide	ASTM D1945
Total hydrocarbons	ASTM D1945
Methane	ASTM D1945
Hydrogen Sulfide	ASTM D1945/D6228
CO_2 purity	ASTM D1945
Total Sulfur	ASTM 3246

There are no EPA-approved analytical methods for CO_2 injection streams, and the methods listed on Table 1 are not included among EPA-approved wastewater analytical methods in 40 CFR Part 136 (nor are they used in other Class VI CO_2 injection permits). Many of the analytes are to be analyzed using ASTM D1945, which is the Standard Test Method for Analysis of Natural Gas by Gas Chromatography. Based on the physical states of natural gas and CO_2, this test may be appropriate for CO_2 injectate analysis; however, no specific information or justification was provided in the application materials and there is no publicly available (free-of-charge) information available about these ASTM methods.

Table 4 of the Quality Assurance Surveillance Plan (QASP), Summary of Analytical Parameters for CO_2 Stream, also lists analysis of ethanol using method EPA 8260B. Although there is no EPA-approved analytical method for ethanol analysis in wastewater, this method is acceptable.

CTV is evaluating several sources of CO_2 as injectate for the project, and states that it will notify EPA prior to switching or adding CO_2 sources so that the sampling procedures can be reassessed. EPA will require that a sample be analyzed prior to initiation of injection.

CTV states that it will increase the sampling frequency if there is a significant change in the chemical or physical characteristics of the CO_2 injectate, a change in the CO_2 injectate source, or if the facility or injection well experiences a downtime over more than 30 days. Any change in the injection fluid would require advance notice and written approval from EPA.

Questions/Requests for the Applicant:

- *Please add analysis of ethanol using EPA method 8260B to Table 1 to be consistent with Table 4 of the QASP. Ethanol was added as an analyte as requested, using ISBT methods. However, Table 4 of the QASP references ASTM methods, and should reflect the methods described in the Testing and Monitoring Plan. (See the discussion of the updated QASP below.)*
- *CTV states that quarterly sampling will begin three months after the date of authorization of injection; please revise this timeline to begin three months after the commencement of injection so that the testing schedule is consistent with injection operations. The applicant made the requested edit in the first paragraph, but not in subsequent discussions under Sample Location and Frequency.*

Follow-up Questions for the Applicant:

- ***Please make global edits (e.g., under Sample Location and Frequency) to reflect that quarterly injectate sampling will begin three months after commencement of injection.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *EPA will require a baseline injectate sample to be analyzed for the same parameters as in the Testing and Monitoring Plan prior to commencement of injection.*
- *If this sample or any updated information about injection formation fluids indicates that any injectate constituents may lead to geochemical reactions that could affect operations or change aquifer properties, additional analytical parameters for the injectate analysis may be requested.*

Injection Well Testing

The subsections below describe: the planned quarterly corrosion monitoring; continuous recording of injection pressure, rate, and volume to evaluate internal mechanical integrity; and annual external MITs that will meet the requirements at 40 CFR 146.90(b), (c), and (e). This portion of the testing and monitoring evaluation addresses both injection wells (Well 357-7R and Well 355-7R); however, CTV will need to provide a Testing and Monitoring Plan for each well, with unique well-specific testing (particularly for corrosion monitoring and continuous monitoring) that reflects each well's design.

Corrosion Monitoring

CTV proposes to conduct corrosion monitoring using the coupon method. The corrosion coupons will be in the pipeline that feeds CO_2 injectate to the injectors. Corrosion monitoring will occur between the compressor and wellhead, according to Table 1 of the QASP.

Samples of the materials used in the construction of the pipeline and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials will be weighed, measured, and photographed prior to installation. The coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The specific methods by which the samples will be handled are not described in the testing and monitoring plan; however, Table 5 of the QASP indicates that analytical methods include NACE TM0169/G31 and EPA 1110A SW846.

CTV says that, if the corrosion rate is greater than 0.3 mils/year, it will initiate consultation with regulatory agencies (but does not specify which agencies), and may run a casing inspection log to assess the thickness and quality of the casing.

The proposed coupons will be composed of the materials summarized in Attachment C, Table 3. The materials identified for corrosion monitoring were compared to the list of proposed construction materials for the injection well in Attachment G (Construction details) for Well 357-7R (submitted with the initial permit application on August 30, 2021) and Well 355-7R (submitted December 2, 2021). The first two columns of the table below are adapted from Table 3 of the Testing and Monitoring Plan (list of equipment coupon with material of construction), with review notes in the right-hand columns.

Coupon (Attachment C, Table 3)	**Construction Material (Attachment C, Table 3)**	**Review Notes based on Information in Attachment G**	
		Well 357-7R	**Well 355-7R**
Pipeline	CS A106B	Not identified	Not identified
Casing	N80 Steel	Intermediate and Long-string: N80 (pg. 2)	Intermediate and Long-string: N-80, K-55 (Table 5)
Tubing	13 CR-95	13 CR-95 (pg. 2)	L-80 (Table 6)
Wellhead	Stainless steel	Not identified	Not identified

The coupons proposed for corrosion monitoring of the casing and tubing match those described in Attachment G for injector 357-7R. However, it appears that Well 355-7R has different construction, and a corrosion testing program specific to the 355-7R injector is needed. Although the materials of construction for the pipelines and wellheads are not described in Attachment G, it is assumed that coupons would be selected to represent these materials.

Questions/Requests for the Applicant:

- *Please describe the corrosion coupons for a corrosion testing program specific to the 355-7R injector. Additional details were added to the sample description text regarding the coupon usage and application. CTV also provided additional details on Table 3 including N80 steel for*

casing and chrome alloy for the tubing; however, these do not match the materials described in the well construction descriptions.

- *For completeness, please include the details about the analytical methods for corrosion coupon monitoring that are described in Table 5 of the QASP into the Testing and Monitoring Plan. Attachment C references an ASTM method for prep/cleaning/evaluating corrosion test specimens. This differs from the QASP, which references NACE and EPA methods.*
- *Please provide the list of construction materials to be used for the pipeline and wellhead so that they can be compared to the proposed coupon materials for the corrosion testing program. Table 3 has been updated to include coupons made of carbon steel for the pipeline and chrome alloy for the wellhead; the response is acceptable at this point in the permit application review. EPA will need to verify that the corrosion coupons for the pipeline and wellhead are appropriate to the materials described in the well specifications when they are provided.*

Follow-up Questions for the Applicant:

- ***Please explain how using N80 steel coupons and chrome alloy are appropriate for monitoring the casing and tubing of each of the wells, as constructed.***
- ***Please modify the Testing and Monitoring Plan or the QASP so that the analytical methods for corrosion monitoring are consistent.***

Continuous Monitoring to Evaluate Internal Mechanical Integrity

CTV will install and use continuous recording devices to monitor: injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Surface injection pressure will be set to a minimum of 1,200 psi, eventually reaching 2,000 psi at the cessation of injection operations, as noted in the discussion of "Operational Procedures" in the permit application narrative. For Well 357-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 3,800 psi (surface) and 6,100 psi (downhole) are not exceeded. For Well 355-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 2,900 psi (surface) and 6,108 psi (downhole) are not exceeded.

Additionally, a surface pressure gauge will be installed on the annulus to monitor the annular pressure and ensure the integrity of the packer and tubing. However, the annular pressure needed to signify a mechanical integrity issue is not indicated by CTV.

The maximum injection rate of 30 million standard cubic feet per day (mmscfpd) and average injection rate of 10-15 mmscfpd will be monitored by a surface flowmeter. The calculation of injection volumes will be calculated using the injection flow rate and CO_2 stream density and will be used to ensure the maximum expected injection volume does not exceed 10 million tonnes.

Temperature gauges will be employed at surface and downhole to monitor the temperature of the injectate and ensure it is consistent with the expected temperature of the CO_2 stream at a given depth.

Additional evaluation of the well monitoring equipment will be provided in the Well Construction reports for the injection wells.

Table 2 of Attachment C lists sampling devices, locations, and frequencies for continuous monitoring and is replicated below.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	30 seconds	30 seconds
Injection rate	Flowmeter	Surface	30 seconds	30 seconds
Injection volume	Calculated	Surface	30 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	30 seconds	30 seconds
CO_2 stream temperature	Temperature gauge	Surface and Downhole	30 seconds	30 seconds

Questions/Requests for the Applicant:

- *Please clarify the location/depths of the downhole temperature and pressure gauges listed on Table 2. These should also be depicted on the well schematics. Table 2 contains information regarding whether the gauges are at surface or downhole but does not include the actual depths. This information will need to be provided—and included on the well schematics—once the final well construction and equipment have been determined.*
- *Please explicitly define the annular pressure deviation that would warrant a mechanical integrity investigation. CTV did not provide the requested information.*

Follow-up Questions for the Applicant:

- ***Please define the annular pressure deviation that would warrant a mechanical integrity investigation, as requested.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The maximum pressure thresholds identified for continuous monitoring and the annulus pressure in Attachment C may need to be adjusted to reflect the final permit conditions (e.g., if they change based on the results of pre-operational testing).*

External MITs

To verify external mechanical integrity as required at 40 CFR 146.89(c) and 146.90, CTV proposes to perform MITs annually. CTV also proposes to perform these same MITs prior to commencing injection.

Table 6 of Attachment C lists the MITs to be performed and is reproduced below.

Test Description	Location
Temperature Log	Along wellbore via wireline well log
Radioactive Tracer Survey (RTS)	Along wellbore via iodine

On page 9 of Attachment C, CTV only indicates that it will run a temperature log (and not a radioactive tracer log) and notes that if it elects to conduct an alternate MIT, it will request approval from EPA. (EPA notes that, if CTV opts to use an alternative MIT, the Class VI permit would need to be modified to incorporate this test.) CTV presents procedures for MIT temperature logging but does not describe the radioactive tracer logging procedures.

Questions/Requests for the Applicant:

- *Please revise the temperature logging procedure to include a minimum of 4 hours between runs. Additionally, please provide more extensive temperature logging procedures, e.g., in accordance with the document, "Appendix E – Temperature Logging Procedures – U.S.E.P.A. Region IX," which is available online at: https://archive.epa.gov/region9/water/archive/web/pdf/appendixetemplogreqs.pdf. The text has not been updated to incorporate the details about the temperature logging procedures that EPA requests, and some of the logging details that EPA requires have been left out.*
- *Please provide a detailed description of the MIT testing procedures for RTS. RTS appears to have been removed as a MIT testing procedure and was replaced with continuous distributed temperature sensing. This is acceptable as a secondary MIT, since temperature logs are an approved MIT method. However, consistent with 40 CFR 146.89, CTV must perform the temperature log on the injection well.*
- *The Emergency and Remedial Response Plan includes scenarios for monitoring well MI failures, however no MIT of the monitoring wells is described in the Testing and Monitoring Plan. Please provide procedures and plans for performing MITs in the deep monitoring wells. The revised plan indicates that CTV will use DTS (a fiber optic continuous temperature monitoring system) on the monitoring wells; while this is not an approved MIT method (i.e., that would meet the requirements on 146.89 for the injection well), it may be appropriate for monitoring well MITs, but additional information is required (see below).*
- *Please include MITs on the monitoring wells and the EOR wells to be used for deep monitoring as part of the Testing and Monitoring Plan. The text was updated to include DTS on the deep monitoring wells, no MITs are explicitly described for the EOR wells to be used for monitoring.*
- *Attachment G describes Annulus Pressure Testing Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1. Please also include internal and external MITs during the injection and post-injection phases and describe these in Attachments C and E. This was not included in the updated attachments.*

Follow-up Questions for the Applicant:

- ***Please explicitly state in the introduction to this section of the Testing and Monitoring Plan that CTV will, at a minimum, perform a temperature log on the injection well (i.e., not that it will perform "one of two methods in Table 6").***
- ***Please provide additional detail about the temperature logging procedures or indicate in the plan that CTV plans to perform temperature logging exactly as described in the EPA guidance.***
- ***Please provide additional information on the DTS and its suitability as a secondary MIT method.***
- ***Will DTS be employed in the EOR wells that CTV plans to use for monitoring? If so, please state this in the plan.***

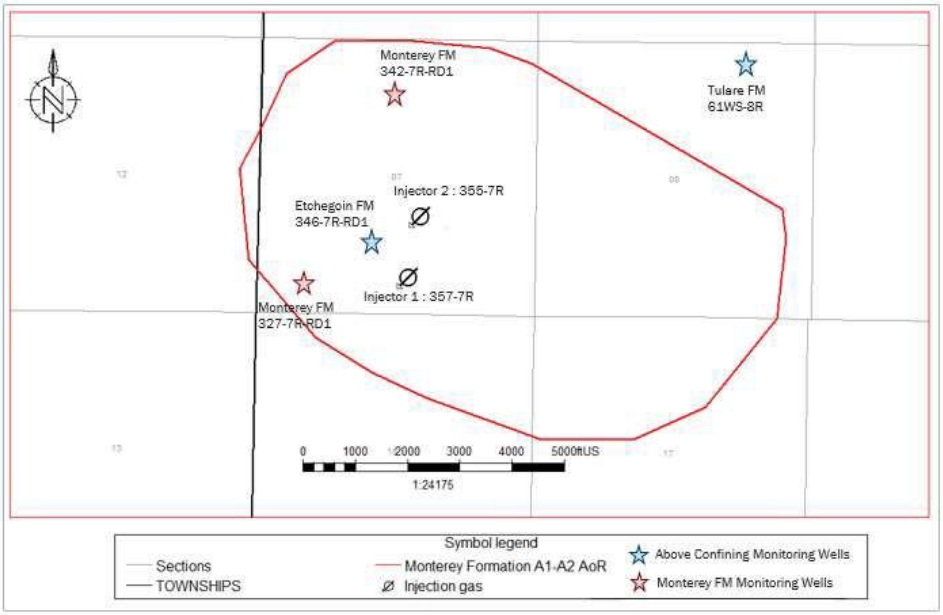
- ***Please include internal and external MITs for Monitoring Well 327-7R-RD1 & 342-7R-RD1 during the injection and post-injection phases and describe these in Attachments C and E as requested.***

Groundwater Quality Monitoring

CTV proposes to monitor groundwater quality in existing wells above the confining zone using direct and indirect methods. To meet the requirements of 40 CFR 146.90(d), CTV proposes to perform the following monitoring above the confining zone:

- Annual injection-phase water quality monitoring and continuous pressure and temperature monitoring via one well located outside of, and to the northeast of, the delineated AoR in the Upper Tulare Formation (the lowermost USDW) and the Lower Tulare Formation. Post-injection water quality sampling will continue annually and continuous pressure monitoring in the USDW is proposed.
- Continuous monitoring of pressure and temperature in the Etchegoin Formation within a monitoring well located to the west of the injection wells.

Attachment E does not describe any monitoring in the Etchegoin or the Monterey Formation A3-A11 Sands after cessation of injection. However, EPA will likely require that post injection phase monitoring



be an extension of injection phase monitoring to confirm continued demonstration that USDWs are not endangered and to inform the non-endangerment demonstration required at 40 CFR 146.93(b)(3).

Figure 2 of the QASP shows the locations of all monitoring wells associated with the project and is reproduced below.

The Etchegoin Formation monitoring well appears to be situated within the AoR and in the anticipated path of the CO_2 plume and pressure front (based on information in Attachment B). The Upper/Lower Tulare Formation monitoring well is outside of the delineated AoR to the northeast of the injection

wells, and down plume. Given that the Tulare Formation does not hold much water within the AoR, this location, while not in the same direction as the deeper monitoring wells may be most appropriate to allow geochemical sampling, although it is unlikely that CO_2 will travel that far down the limb of the anticline. CTV states that additional Upper Tulare monitoring wells will be drilled if increased pressure is observed in the Etchegoin Formation monitoring well or water quality changes in the Tulare Formation that is due to Monterey Formation A1-A2 CO_2 injection. However, it is unclear how a linkage of water quality/pressure changes to CO_2 injection (and not other activities) would be made.

The applicant proposes to monitor water quality in the Upper/Lower Tulare Formation and the Monterey Formation during the injection and post-injection phases. The analytical and field parameters and methods described in Tables 5 and 8 of Attachment C (injection-phase monitoring of the Tulare and Monterey Formations, respectively) are nearly the same as those in Tables 2 and 5 of Attachment E. Additional information about monitoring in the Monterey Formation is described under "CO_2 Plume Tracking" below. CTV also proposes to perform a baseline water analysis in the Etchegoin Formation monitoring zone and in the Tulare Formation monitoring well.

Table 5 of Attachment C (Injection-phase Tulare Formation monitoring) is reproduced in the first two columns of the table on the next page. Because consistency of monitoring parameters above and within the injection zone is appropriate for detecting leakage of the CO_2 plume, EPA evaluated proposed injection and post injection monitoring in the Tulare and Monterey Formations together. EPA's notes and recommendations are provided in the right-hand column; see also the discussion of "Quality Assurance Procedures" below for additional comments on the parameters to be monitored.

The parameters appear to be generally appropriate for groundwater quality monitoring needs for GS projects, and are consistent with other Class VI monitoring programs, except as noted below. As the permit application narrative describes (pg. 39), the Monterey A1-A2 Sands are dominated by quartz and feldspar, which are stable in the presence of CO_2 and carbonic acid. Note that, as additional information is gathered based on the reviews of other parts of the permit application or pre-operational data collection, recommendations or requirements for additional analytical parameters may be provided.

Parameters	Analytical Methods	Evaluation Notes/Recommendations
Tulare Formation		
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B	200.7 and 6010B are both ICP-AES methods, not ICP-OEC. Please explain what ICP-OEC is or revise the table. These were changed to ICP-MS and EPA Method 6020. In Table 17 of the QASP, the final cation is Ti, not Tl as in Attachment C. Please clarify/be consistent. Also, this is "T1" in the tables of Attachment E; please correct the typographical error. Not addressed. Cations of Sb are also mentioned in Table 17 of the QASP; please add this to the ground water monitoring parameters in Attachments C and E. Not addressed. 200.7 is an EPA-approved wastewater analytical method, while 6010B is not. EPA requests that Method 200.7, Rev 4.4 (1994) be specified. These were changed to ICP-MS and EPA Method 6020.
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B	See above. These were changed to ICP-OES and EPA Method 6010B.
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	Attachment E and Table 17 of the QASP also include anions of Cl; please add this to Attachment C for consistency and completeness. Added. Tables 2 and 5 of Attachment E reference EPA Method 300; please revise the method to be consistent with Attachment C (i.e., Method 300.0). Also, please specify that EPA Method 300.0, Rev. 2.1, Part A (1993) will be used. Addressed.
Dissolved CO_2	SM 4500-CO2-C	No comments.
Total Dissolved Solids	SM 2540 C	Attachment E refers to SM 4500 C for TDS; EPA requests the use of SM 2540 C for consistency. Addressed.
Alkalinity	SM 2320 B	Attachment E refers to SM 2510, which is for conductivity, not alkalinity. EPA requests that CTV revise Attachment E to reference SM 2320 B for consistency. (SM 2320 B is an approved wastewater method.) Addressed.
pH (field)	EPA 150.1 / SM4500-H+B	No comments.
Specific Conductance (field)	SM 2510 B	SM 2510 B is named by SM as a laboratory method, and it is not clear whether SM 2510 B can be conducted in the field. EPA Method 120.1 may be more amenable to field screening if SM 2510 B is not. Please clarify if field use of SM 2510 B is possible or revise the table (i.e., field vs. lab designation) or the method. Not addressed.
Temperature (field)	Thermocouple	No comments.
Dissolved Methane	RSK-175/Gas Chromatography	This method was developed by EPA but is not an EPA approved method for wastewater analysis. Please provide information to support the use of this method for dissolved methane analysis. Alternatively, consider using EPA-approved method SM 6211 B and/or 6211 C. Parameter was removed.

EPA recommends in Class VI guidance that monitoring well construction and planned plugging procedures for monitoring wells be reviewed as part of the permit application evaluation to confirm that

these wells will not provide conduits for fluid movement that could endanger USDWs. No monitoring well construction or plugging information was provided in the permit application materials.

CTV should note that the Central Valley Water Board indicated in its consultations with EPA on a prior Class VI project that any newly drilled monitoring wells must be approved by the Water Board and, while existing wells would not need to be approved, the Water Board expressed interest in any plans to use existing wells as monitoring wells.

Attachment C also describes the water quality sampling procedures, the laboratory to be used, and chain of custody procedures. This information is detailed in the QASP as well.

Questions/Requests for the Applicant:

- *Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E as noted in the table above. Further, the same analytes and methods should be used for monitoring of all formations - to provide consistent data to support modeling reviews and a non-endangerment demonstration. Tables 5 and 8 have been updated; however, some additional changes are needed, as noted above.*
- *In addition, please include additional ground water quality parameters to support a robust monitoring program, as follows:*
    - *δ13C, which is mentioned in the QASP, but not in Attachments C and E. This was added to Table 8; the response is acceptable.*
    - *Water density (which is referenced in the Testing and Monitoring Plan as an expected water quality change due to plume movement on pg. 12). This was not included.*
    - *Dissolved O_2 and H_2S. Dissolved O_2 is a primary indicator of water quality. H_2S occurs in the subsurface, may be common in oil fields, and has the potential to be mobilized, and, is listed as a toxic substance by the CDC. H_2S was added to the parameters in Tables 5 and 8; dissolved O_2 was not added as a parameter but is listed under field measurements where it should be measured. The response is acceptable.*
- *Please include the groundwater monitoring well 61WS-8R in Figure 4 of the PISC and Site Closure Plan. This was not added to Figure 4 as requested.*

Follow-up Questions for the Applicant:

- ***Please provide monitoring well construction and plugging plans to confirm that these wells will not provide conduits for fluid movement that could endanger USDWs.***
- ***Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E to incorporate the notes above, i.e., add specific conductance (field), Sb, and water density and revise the chemical symbol for titanium.***
- ***For clarity, please also include the depths of pressure/temperature monitoring gauges on Tables 4, 7, and 9 (only the fluid sampling depths are shown, and a separate depth row for the pressure/temperature gauges would clarify this monitoring).***
- ***Please update the USDW fluid sampling depth for the Tulare Formation well in Attachment E Table 1 to 940 – 960 feet to be consistent with Attachment C.***

- ***Why was dissolved methane removed as a ground water analytical parameter?***
- ***Please include well 61WS-8R in Figure 4 of the PISC and Site Closure Plan.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of groundwater quality analytical parameters may need to be updated to ensure that all applicable parameters are included.*

CO_2 Plume and Pressure Front Tracking

The applicant describes proposals for CO_2 plume and pressure front tracking that include: (1) the use of direct and indirect methods for tracking the pressure front within the injection zone [40 CFR 146.90(g)(1)]; and, (2) direct pressure front monitoring in two monitoring wells and seismic monitoring to indirectly track the extent of the CO_2 plume [40 CFR 146.90(g)(2)].

For post-injection site care, CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. In Attachment E, Table 4 details the methods that will be used to monitor the CO_2 plume post-injection, and Table 6 details the methods that will be used to monitor the associated pressure front. Injection reservoir pressure monitoring will occur to ensure confinement of the reservoir and consistency with computational modeling results. As seen in Table 6 of Attachment E, seismicity monitoring will also occur via surface and shallow borehole seismometers. Table 5 of Attachment E lists the analytical methods that will be used for the injection zone fluid monitoring and analysis.

CO_2 Plume Monitoring

CTV proposes to monitor the plume via direct and indirect monitoring in the Monterey Formation:

Direct plume tracking methods include:

- Annual fluid sampling during the injection and post-injection phases in Monterey Formation A1-A2 Sands via two monitoring wells (327-7R-RD1 and 342-7R-RD1, located to the southwest and the northwest of the injection wells, respectively).

- Quarterly fluid sampling during the injection phase in EOR producers in the Monterey A3-A11 Sands. The location of the EOR wells is not described.

Indirect plume monitoring includes:

- Pulse neutron logging in the Monterey Formation A1-A2 Sands via the same monitoring wells. This logging will be conducted every two years during the injection phase and every 5 years during the post-injection phase.

The parameters and associated analytical methods are presented in Table 8 of Attachment C. They are identical to those proposed for Tulare Formation water quality monitoring described under "Ground Water Monitoring" above. Deep and shallow water quality monitoring should be for the same parameters to provide consistent data on which to evaluate potential fluid movement out of the confining zone.

Figure 2 of the QASP (reproduced under "Groundwater Monitoring" above) shows the location of the monitoring wells in the Monterey Formation A1-A2 Sands. CTV asserts that modeling indicates that the CO_2 plume will reach each of these monitoring wells by the second year of injection.

Pressure Front Monitoring

CTV plans to conduct **direct pressure front monitoring** by continuously monitoring pressure and temperature during the injection and post-injection phases within the Monterey Formation A1-A2 Sands via pressure gauges in monitoring wells 327-7R-RD1 and 342-7R-RD1.

Indirect pressure front monitoring will be accomplished via seismic monitoring throughout the AoR. CTV states that it will monitor seismicity with surface and shallow borehole seismometers it plans to install, as well as monitor seismic data from the Southern California Earthquake Data Center (SCEDC) network. This continuous monitoring will continue throughout the injection and post-injection phases.

Pressure-front monitoring activities are summarized in Table 9 of Attachment C and Table 6 of Attachment E.

Questions/Requests for the Applicant:

- *Please refer to EPA's questions and recommendations under "Groundwater Monitoring" above regarding water quality analysis and revise Table 8 of Attachment C and Table 5 of Attachment E accordingly. Additional revisions are needed, as described in the comments above.*
- *Please elaborate on the monitoring in the Monterey Formation A3-A11 Sands as described on page 12 of Attachment C. Specifically, where are the EOR producers from which CTV plans to sample the Monterey Formation A3-A11 Sands? At what depths will sampling be performed, and what parameters will be analyzed for? (The analytical parameters should be consistent with other monitoring.) Please describe who owns these wells, and whether they will be operational throughout the injection and post-injection periods? Please include the locations of these wells on the relevant figures in Attachments C and E and the QASP. The applicant provided a new Figure 3 that shows the locations of these wells, and their depths are presented in Table 7. The updated plan indicates that the same analytes will be monitored as shown in Table 8. The response is acceptable (pending requested updates to Table 8).*
- *Please describe the seismic monitoring network discussed on pg. 16 of Attachment C, including the number and location of the seismometers that CTV proposes to install. The requested information was not provided.*
- *Please explain the timeframe for which a seismicity baseline will be established, and if historical seismicity will be incorporated into this baseline. CTV says that historical seismicity within the area will be accounted for in the baseline assessment, but does not explain how.*

- *Page 15 of Attachment C says that CTV plans to perform direct pressure monitoring in the Monterey Formation A1-A2 Sands, and Table 9 indicates that pressure and temperature monitoring will be performed. Please revise the statement on pg. 15 to be consistent with the table – to include temperature as well as pressure. The revision has not been made to mention temperature monitoring as detailed in Table 9.*
- *EPA recommends that the sampling/measurement depths be included in Tables 7 and 9 of Attachment C and Tables 4 and 6 of Attachment E for clarity and completeness. Depths were added as requested to Attachment C Table 7; but were not added to Table 9 of Appendix C or Tables 4 and 6 of Attachment E. Note also that, in the updated attachment, CTV identified different injection zone monitoring wells (i.e., 353A-7R and 335X-7R); these wells are located close to the wells identified in maps in the initial plan.*
- *Please make the following changes to the proposed plume and pressure front tracking in Attachments C and E:*
    - *Perform frequent sampling and logging (e.g., quarterly, or semi-annually) early in the injection phase (i.e., at least until the CO_2 plume passes the monitoring well locations). This would allow the acquisition of additional data to validate the modeling, provide early warning of unanticipated fluid movement, and be consistent with other Class VI projects. The requested change was not made.*
    - *Conduct a 3D seismic survey or a vertical seismic profile during injection operations for comparison to the 2019 3D seismic survey described in the application narrative. The requested change was not made.*
    - *Conduct quarterly water quality sampling in the A1-A2 Sands for plume tracking to be consistent with the A3-A11 monitoring activities as well as provide additional data points to validate modeled predictions, and to eventually support the demonstration of non-endangerment. CTV updated Table 7 to align sampling frequencies in the Monterey Formation A1-A2 and A3-A11.*

Follow-up Questions for the Applicant:

- ***Please revise Table 8 of Attachment C and Table 5 of Attachment E to address EPA's comments under groundwater quality monitoring above.***
- ***Please describe the seismic monitoring network and explain how historic seismicity within the area will be accounted for in the baseline assessment.***
- ***Please revise the statement on pg. 15 to describe temperature and pressure monitoring as described above.***
- ***Please add sampling/measurement depths to Table 9 of Appendix C and Tables 4 and 6 of Attachment E as described above.***

- ***Please update the plume and pressure front tracking discussion to include the requested frequent sampling and logging early in the injection phase and a 3D seismic survey or a vertical seismic profile as described above.***

Air/Soil or Other Testing and Monitoring

Based on the currently available information about the geologic setting (i.e., the depth of the injection formations and the lack of evidence for the presence of transmissive faults of fractures), surface air and/or soil gas monitoring are not needed to detect movement of fluid that could endanger USDWs within the AoR.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If, based on the results of planned pre-operational testing, uncertainties about the geologic setting are identified, the need for air and/or soil gas monitoring or other monitoring will be reconsidered.*

Quality Assurance Procedures

The review team evaluated the QASP submitted with the permit application to verify that all the testing activities, analytes, etc., included in the QASP are consistent with proposed injection and post-injection phase testing and monitoring. All the injection and post-injection testing and monitoring activities (except for pressure falloff testing) are addressed in the QASP and the QASP covers activities recommended by EPA. EPA noted a few discrepancies between the tables in the QASP and the activities described in Attachments C and E. These are summarized in the table below:

QASP Table	**EPA comments**
Table 1. Summary of testing and monitoring.	Cement bond logs and standard annulus pressure tests of the injection wells are listed in the QASP, but these tests are not described in Attachment C. Please clarify if these tests are planned to be performed, either as part of pre-operational or injection-phase testing, or revise the QASP accordingly. Cement evaluation was removed from the updated QASP. Please add PFOT and RTS to Table 1. PFOT was added to Table 1 (RTS is no longer planned).
Table 2. Monitoring Well Summary.	Monitoring the A3-A11 Sands via the EOR wells is not included on Table 2 of the QASP; please include this for consistency. Table 2 was updated as requested.
Table 3. Summary of analytical and field parameters for ground water samples.	Please update the placeholders for specific cations and anions in Table 3 to reflect Table 17 of the QASP. Zinc needs to be added to Table 17. This table should address sampling in formations other than the Tulare Formation (per recommendations above). Table 3 was updated as requested. There is a typo in the pH (field): the method “SPA 150.1” should be “EPA 150.1” This has been corrected.

QASP Table	EPA comments
Table 5. Summary of Analytical Parameters for Corrosion Coupons.	Please include the QC Requirements on Table 5. This has been added as requested.
Table 17. Summary of sample containers, preservation treatments, and holding times for ground water samples.	There are a few discrepancies between the analytical parameters mentioned on Table 17 of the QASP and in Attachments C and E. EPA recommends the following changes for consistency: • Please revise the parameter NO_2 in Table 17 of the QASP to be consistent with NO_3, which is a planned analyte, per Attachments C and E. This has been corrected. • Add cations of K (in Tables 5 and of Attachment C and Tables 2 and 5 of Attachment E) to Table 17. This has been added as requested. • Please also make other necessary revisions to Table 17 of the QASP to address EPA's requests related to analytical parameters under "Ground Water Monitoring" above. See comments related to table 17 edits under Groundwater Quality Monitoring.
Other	Please fix the formatting of the Table of Contents for Section B.1. a. This has been corrected.

Follow-up Questions for the Applicant:

- ***Please update Table 4 of the QASP to reflect use of ISBT methods for injectate analysis.***
- ***Please revise Table 17 of the QASP to include zinc and Ti (not Tl) to be consistent with Attachment C.***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Operating Procedures for the A1-A2 Project

In January 2022, EPA provided questions to CTV (*blue, italic text*) about the proposed operating procedures for injection wells 355-7R and 357-7R submitted as part of CTV's Class VI permit application (dated August 30, 2021 and December 2, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided updated operating procedures for the two wells to EPA on March 31, 2022. EPA's evaluation of how the update addresses its questions is presented in red below. Requests for revisions and additional information are presented in ***red, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

The proposed operational procedures (which appear to be specific to Well 357-7R) are described on page 47 of the initial Narrative and summarized in Table 8, which is replicated below:

Table 8 of initial Narrative (for Well 357-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	3,800	Psig
Downhole	6,100	Psig
Average Injection Pressure		
Surface	1,600	Psig
Downhole	4,100	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,730 @ packer	Psig
Annulus Pressure/Tubing Differential	370@packer @ average injection condition	Psig

The proposed operational procedures for Well 355-7R are described in the amended Narrative (Attachment A2) and summarized in a revised Table 8, which is replicated below:

Table 8 of updated Narrative (for Well 355-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	2,900	Psig
Downhole	6,108	Psig
Injection Pressure		
Surface Average / Maximum	1,400/1,600	Psig
Downhole Average / Maximum	4,300 / 4,516	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,720 @ packer	Psig
Annulus Pressure/Tubing Differential	578@packer @ average injection condition	Psig

Injection Pressure

The basis for the proposed maximum injection pressure (MAIP) is described in Attachment B – the AoR and Corrective Action Plan (AoR CA). CTV states that the MAIP will be below 90% of the fracture pressure of the Monterey Formation at the base of the Reef Ridge Shale confining zone, and is calculated as follows:

$$8{,}150 psi \times 0.9 psi/ft = 7{,}335\ psi$$

Where:

Fracture pressure (Fp) at base of confining zone = 8,150psi

Safety factor = 0.9 (90%)

Tables 6 and 7 of the AoR CA provide fracture gradients and fracture pressures for the Monterey Formation A1-A2 reservoir, and are replicated below:

Table 6		
Interval	**Fracture Gradient psi/ft**	**Fracture Pressure (psi) at base of Reef Ridge Shale (8,403 ft)**
Monterey Formation A1-A2	0.97	8,150

Table 7		
Injection Pressure Details	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Fracture gradient (psi/ft)	0.97	0.97
Maximum injection pressure (90% of fracture pressure) (psi)	7,335	7,335
Elevation corresponding to maximum injection pressure (ft MSL)	8,403	8,403
Elevation at the top of the perforated interval (ft MSL)	8,485	8,462
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,407	7,387
Planned maximum injection pressure / gradient (top of perforations)	4,500 / 0.53	4,500 / 0.53

The maximum injection pressure listed in Table 7 of the AoR CA for injection wells 357-7R and 355-7R does not correspond to the maximum injection pressure in Table 8 of the Narrative or the amended Narrative. Additionally, the proposed injection pressures of 4,500 psi in Table 7 of the AoR CA exceed the proposed average injection pressures of 4,100 psi, listed in Table 8 of the Narrative. It appears that, regardless of the discrepancy in maximum injection pressures, CTV proposes to operate at an injection pressure of 4,100 – 4,500 psi, well below 90% of the injection zone fracture pressure. However, the proposed injection pressures will need to be confirmed as being below 90% of the fracture pressure at the top of the perforations (i.e., within the Monterey Formation injection zone), and the discrepancy in maximum injection pressures will need to be resolved.

CTV states in the AoR CA that their current Class II UIC permit mandates a maximum operating pressure gradient of 0.80 psi/ft unless additional testing indicates a higher gradient. It appears that CTV conducted a test(s) to obtain a higher fracture gradient, 0.9 psi/ft, as seen in Table 6 of the AoR CA, above. However, these tests are not described in the application and will need to be provided for validation of the fracture pressure of the injection and confining zones and the corresponding maximum injection pressures. A question for the applicant regarding this topic is included in the AoR CA Evaluation.

Questions/Requests for the applicant:

- *Please provide separate stand-alone versions of Attachment A for Well 357-7R and Well 355-7R that describe operating conditions. The attachments should include the following: injection well operating conditions (e.g., a tabular description of surface and bottomhole maximum injection pressures, annulus pressure, annulus pressure/tubing differential, and the maximum CO_2 injection rate); how the maximum injection pressure was determined; a description of routine shutdown procedures; and tables summarizing reporting of well and project-related monitoring. The applicant provided stand-alone versions of the operating conditions for Wells 357-7R and 355-7R. Each attachment contains a tabular description of surface and downhole minimum and maximum injection pressures, annulus pressure, and the maximum CO_2 injection rate. The*

annulus pressure/tubing differential was not included on the tables, but CTV referenced the pressure differential will meet the requirements of 40 CFR 146.88 (c) in the Annulus Pressure. EPA recommends that this information be included on the table. CTV also described the routine well shutdown procedures, but did not describe the reporting of monitoring data.

Follow-up Requests for the Applicant:

- ***Please include tables summarizing reporting of well and project-related monitoring. A template with this information, called "Summary of Requirements Template," is available at https://www.epa.gov/uic/class-vi-permit-application-templates.***
- ***Please include the annulus pressure/tubing differential on Table 1 for each well.***

Maximum CO_2 Injection Rate

The applicant proposes a daily CO_2 injection rate of 648 to 1,917 tons per day, which equates to 236,520 to 699,705 tons/year (or 3.5 – 10.5 million tons over the planned 15-year injection phase of the project) as seen in Table 5 of the AoR CA and excerpted below. However, the applicant notes in the Narrative that the storage capacity of the Monterey Formation A1-A2 reservoir is approximately 8 – 10 million tonnes of CO_2 based on computational modeling results. The maximum storage capacity of 10 million tonnes of CO_2 is slightly less than the projected maximum volume of 10.5 million tonnes of CO_2 based on daily injection rates as seen in Table 5 below (assuming injection activities will occur 365 days per year). Based on an evaluation of the AoR delineation modeling and geologic site characterization, it appears that the injection and confining zones are appropriately characterized; however, the range of proposed daily injection rates allow for the exceedance of the modeled storage capacity. The applicant should reconcile this inconsistency and provide an updated range of daily CO_2 injection rates that satisfies the modeled CO_2 storage capacity. See the AoR CA evaluation report for additional discussion.

Table 5. Operating details.

Operating Information	Injection Well 1 357-7R	Injection Well 2 355-7R
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft MSL) Z top Z bottom	 7,728 8,010	 7,774 7,949
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15

Injection rate (t/day)*	648 – 1,917	648 – 1,917

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

In the Testing and Monitoring Plan (pg. 5), CTV states that the volume of CO_2 injected into the Monterey Formation A1-A2 Sands will be calculated from the injection flow rate and CO_2 density, and that density will be determined from the Massachusetts Institute of Technology's CO_2 Thermophysical Calculator (https://sequestration.mit.edu/tools/index.html). However, upon investigation of the online calculator, it appears to no longer be operational. The applicant should provide another method by which the CO_2 density will be calculated.

Questions/Requests for the applicant:

- *Please include a description of standard operating procedures to ensure that the maximum daily injection rate will not be exceeded.*
  CTV updated the Operating Procedures for Wells 355-7R and 357-7R to discuss standard operating procedures to ensure that the maximum daily injection rate will not be exceeded. CTV explained that a threshold of 10% over these values will be used to configure the automation and alarms, which equates to 16.5 million cubic feet per day and 4,300 psi. If either threshold is achieved or exceeded, alarms will indicate there is an issue and a response appropriate to the event will be taken. It is unclear how setting the alarm threshold at 10% above the permit limit will avoid a violation of the permit or potential USDW endangerment.
- *Please update the daily CO_2 injection volumes in Table 5 of the AoR CA to ensure they are consistent with the modeled cumulative injection volumes of 8 – 10 million tonnes of CO_2 over 15 years.*
  CTV changed the daily CO_2 injection rate of 648 – 1,917 tonnes/day on Table 5 of the AOR CA to 530 – 794 tonnes/day. This reflects the cumulative injection volume between 8 – 10 million tonnes of CO_2 over 15 years. This response is acceptable, pending resolution of the injection duration (in EPA's follow up questions on the AOR CA).

Follow-up Requests for the Applicant:

- ***The alarm threshold should be set at 90% of the permit's injection pressure limit to avoid a violation of the permit and to ensure protection of USDWs. Please revise the threshold limit.***

Automated Shutdown System

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the automatic shutdown devices are activated if wellhead pressure exceeds the specified shutdown pressure listed in the permit, or if the annulus pressure indicates a loss of external or internal well containment. However, standard operating procedures that support the automated shutdown system are not provided.

Questions/Requests for the applicant:

- *Please include standard operating procedures to support the automated shutdown system. CTV updated the Operating Procedures for Wells 355-7R and 357-7R to include a subsection on the Automated Shutdown System. CTV discusses that data will be collected in an automated system and monitored by a control system, and if an established operating threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented. As CTV describes, they will share information about the monitoring system with EPA when it is established (it is expected that these will be included in well specifications provided later in the permitting process). This update addresses the comment and is acceptable at this point.*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

August 17, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Construction and Plugging Plans for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below in the two Enclosures.

Please submit the information requested in the Enclosures by September 19, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2022.08.17 09:54:33 -07'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Construction and Plugging Plan Evaluation 355-7R
Construction and Plugging Plan Evaluation 357-7R

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Site Characterization Evaluation of the Carbon TerraVault (CTV) Class VI A1-A2 Permit Application

This geologic site characterization evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of the geologic narrative submitted as part of CTV's Class VI permit application (dated August 30, 2021). This review also identifies preliminary questions for the applicant. Where specific information is lacking based on the currently available information, this evaluation identifies testing objectives that EPA recommends be incorporated into the Pre-Operational Testing Plan.

Regional Geology and Geologic Structure

The Elk Hills Oil Field (EHOF) is in Kern County, California, in the southern San Joaquin Basin (Figures 1 and 2) CTV plans to inject CO_2 at the EHOF into the Monterey Formation via 2 injection wells, 355-7R and 357-7R, over a period of 15 years. The 2 injection wells are 1,250 feet apart and will inject into the Monterey Formation A1-A2 reservoir (Monterey A1-A2) at the Northwest Stevens Anticline at ~8,500 ft depth (Figure 8 and pg. 4).

The Monterey Formation at the EHOF also contains the Miocene Reef Ridge Shale (the primary confining zone), which directly overlies the Monterey A1-A2 and has been an effective seal for 40+ years of oil and gas operations (pg. 9). Figures 4 and 5 show the spatial distribution of wells in the EHOF and data available for use in characterizing the injection zone.

The Monterey A1-A2 consists of turbidite sands bounded above and below by siliceous shale (pg. 9). The application asserts that this depositional history has resulted in minimal lateral communication of the Monterey A1-A2 outside the EHOF (Cross Section Figure 3, pg. 4; pg. 9). The reservoir is continuous across the area of review (AoR), with pinch-outs on the channel edges (pg. 9).

The Upper Tulare Formation is the lowermost underground source of drinking water (USDW). The Tulare Formation consists of poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley (pg. 7). It is divided into the Upper Tulare and the Lower Tulare by the Amnicola Clay (a low permeability claystone). An aquifer exemption was approved for the Lower Tulare Formation in 2018, making the Upper Tulare Formation the lowermost USDW.

In addition to the Reef Ridge Shale, the Monterey A1-A2 Sands are separated from the lowermost USDW in the Upper Tulare Formation by the Amnicola Clay (pg. 31), the Lower Tulare Formation, the San Joaquin Formation, a depleted gas reservoir directly underlying the Tulare Formation, and the Etchegoin Formation (pg. 8). The Monterey A1-A2 Sands are separated from the underlying Monterey A3-A11 reservoir by a laterally continuous 20-foot shale known as the A2 Shale (Figure 9). The application asserts that they are not in communication, as evidenced by a pressure differential (of 200-300 psi in the A1-A2 and ~1,700 psi in the A3-A11), and the need for separate pressure maintenance strategies (pg. 10). The A3-A6 reservoir is also considered a viable target for future CO_2-EOR based on its existing waterflood injector infrastructure and high reservoir pressure (pg. 11).

Tests and logs performed during drilling and prior to completion of the 357-7R injection well and the 342-7R-RD1 and 327-7R-RD1 monitoring wells (which are completed in the Monterey Formation and are

located to the west and northwest of the injectors) include Array Compensated True Resistivity, SP logs, caliper logs, compensated spectral natural gamma log, spectral density dual spaced neutron log, and mud logs (Attachment G pg. 4-5). Cement bond logs and MIT tests (temperature log and SAPT) were also performed on the 357-7R injection well.

Questions/Requests for the Applicant:

- ***Please label the injection wells or the injection well site on Figure 2.***
- ***Was any data collected or testing performed during drilling of the 355-7R injection well? If so, please characterize this data.***
- ***The AoR and Corrective Action Plan (on pg. 3) states that, the "Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation." Please clarify the difference between the A2 Shale and the Lower Antelope Shale.***
- ***Does the Antelope Shale provide confinement? If so, please provide additional discussion of the confining properties.***
- ***What is the source of the statement about the pressure differential between the Monterey A1-A2 Sands and the Monterey A3-A11 Sands described on pg. 10?***
- ***Please provide pressure build-up test results for the 357-7R injection well.***
- ***Several of the figures in the narrative that contain data are difficult to read (e.g., Figures 14 and 15); please provide higher resolution versions of this information.***
- ***Please provide a map of the Elk Hills Oil Field that shows the 355-7R and 357-7R injection wells, along with the wells planned for the Elk Hills 26R Storage Project (with a scale that shows distances).***

Objectives for Pre-Operational Testing:

- ***Confirm hydraulic separation of the Monterey A1-A2 Sands and the Monterey Formation A3-A11 reservoir.***
- ***If no pressure build-up test results exist for the 357-7R injection well, perform pressure build-up testing as part of the Pre-Operational Testing Plan.***

Faults and Fractures

The 31S and Northwest Stevens (NWS) anticlines in the EHOF are separated by mid-Miocene thrust faults (pg. 12). The application states that the Reef Ridge Shale and Monterey Formation are well resolved based on seismic data, and there is no evidence of faults penetrating the Reef Ridge Shale or transecting the Monterey Formation (pg. 13). Figure 10 shows reverse faults in seismic profiles, however the resolution is too low to discern formation labels (pg.12). These reverse faults, oriented NW-SE, offset the NWS anticline (pg. 12).

Evidence for confinement includes 3D seismic and well data confirming the absence of faults penetrating the Reef Ridge Shale, 40+ years of previous waterflooding and gas injection operation, pressure differentials across formations (i.e., 230 psi in the Monterey A1-A2 Sands and 1,500 psi in the Etchegoin Formation for a 0.43 psi/ft pressure gradient at 3,600 ft depth), and geochemical analysis of 66 oil samples (Zumberge, 2005; Figure 12).

Questions/Requests for the Applicant:

- ***Please update Figure 10 to clearly label the formations in which the thrust faults terminate.***
- ***Where were the 66 oil samples collected within the EHOF described on pp 13-14, relative to faults within the field?***

Depth, Areal Extent, and Thickness of the Injection and Confining Zones

At the site of the injection wells, the stratigraphic sequence from top to bottom consists of the Tulare Formation, the San Joaquin and Etchegoin Formations, the Reef Ridge Shale confining zone, and the Monterey Formation injection zone (pg. 4, 7). The depths and thicknesses of the injection and confining zones were determined based on wireline logs and 3D seismic data and are presented in Table 1 of the application narrative. In the AoR, the Reef Ridge Shale thickness is controlled by the Monterey Formation deposition patterns and minimum thickness corresponds to a highpoint in the Monterey Formation Sand thickness (pg. 15).

The table below summarizes the depth and thickness of the formations of interest according to available data in the permit application narrative. Some depth/thickness information for the San Joaquin or Etchegoin Formations was not provided; however, this is not critical for the purposes of the application evaluation. Porosity and permeability data are presented as well; additional discussion of these characteristics is provided under "Geomechanical and Petrophysical Characterization."

Unit	**Average Depth within the AoR**	**Thickness Across the AoR**	**Porosity**	**Permeability**
Tulare Formation	600-2,500 ft (pg. 31)	1,200-1,500 ft (pg. 31)	34-40% (pg. 7)	1,410-8,150 mD (pg. 7)
San Joaquin Formation	Not given	Not Given	28%-45% (pg. 8)	64-6,810 mD (pg. 8)
Etchegoin Formation	1,500-4,000 ft (pg. 8)	Not Given	29-37% (pg. 9)	32-826 mD (pg. 9)
Reef Ridge Shale (Confining Zone)	6,929 ft-7,962 ft TVD (Table 1, Figure 13)	1,122-1,892 ft (Table 1, Figure 13)	7.7% (pg. 6); 7% (pg.9); 4 to 14% (Table 2)	0.01 mD (pg. 9); 0.00003 to 0.0917 mD (Table 2)
Monterey Formation A1-A2 Sands (Injection Zone)	8,403 ft – 9,598 ft TVD (Table 1, Figure 13)	27-548 ft (Table 1, Figure 13)	11%-27% (Figures 16 and 17); 16% (pg. 9)	0.1-1,300 mD (Figures 16 and 17); 60 mD (pg. 9)

Questions/Requests for the Applicant:

- ***The depths listed in Table 1 for the Monterey A1-A2 Sands are inconsistent with the logs in Figure 9. It appears, based on the log, that the depth to the Monterey A1-A2 Sands is ~8,500 feet MD or ~7,700 feet TVD at the 357-7R injection well, not 8,403 feet TVD as stated in Table 1. The mean depth to the Monterey Formation is also listed as 5,907 ft when the low and high depths are listed as 8,403 ft and 9,589 ft respectively. Please clarify the discrepancy or revise Table 1.***

- ***There is a typo on Figure 16, "Capitally" for Mercury Injection Capillary* Pressure. Please fix this when the application is updated.**
- ***Please characterize, name, and provide depth and permeability data for the underlying confining unit, if one exists.***

Hydrologic and Hydrogeologic Information

The Lower Tulare Formation, which conformably overlies the shallow marine deposits of the San Joaquin Formation, was approved as an exempt aquifer in 2018. The Upper Tulare Formation is the only USDW in the AoR (pg. 7). The regional extent of the exempted portions of the Lower Tulare Formation is shown in Figures 7, 26, and 29. It extends well beyond the AoR in the southern direction but closely borders the AoR to the north. The depth to the lowest USDW in the Upper Tulare is shown in Figure 28; however, the figure is difficult to read.

The San Joaquin Basin has no appreciable surface or subsurface outflow (pg. 35). The primary source of surface water and fresh groundwater is the Kern River, which drains to the southeast and terminates near the EHOF (pg. 35). Low precipitation rates and high evaporation rates result in almost no groundwater recharge from precipitation, leading to high salinity and TDS concentrations (pg. 35). CTV did not find any water supply wells within the AoR after a search of CALGEM, USGS, Kern County Water Agency (KCWA), West Kern Water District, and the GeoTracker Groundwater Ambient Monitoring and Assessment online database (pg. 36). CTV owns the surface area of the EHOF (pg.35).

Questions/Requests for the Applicant:

- ***It appears that Figure 26 provides information on the depth and regional extent of the area shown in cross section with wireline logs for TDS content, however the resolution is low (pg. 31). Please provide a higher resolution version of Figure 26.***
- ***What is the depth of the Upper Tulare Formation and the separation of this lowermost USDW from the injection zone and the confining zone within the AoR?***
- ***Is the Upper Tulare USDW present within the modeled AoR of the injection wells?***

Geochemistry/Geochemical Data

Limited baseline geochemical data for the Upper Tulare Formation (USDW) and Monterey Formation (injection zone) are provided in the application.

Figure 30 shows the results of water analysis performed on waters from the Upper and Lower Tulare Formations. The produced fluid has been collected during previous operations to establish a baseline and characterize the region. Hydrocarbon content in the injection zone was determined through fractional distillation and chromatography (pg. 37). Figure 30 is difficult to read, but it appears that the analysis is from 1995, and the analytes include some, but not all, of those planned as part of injection and post-injection phase monitoring. The TDS values of the Upper Tulare Formation appear to be 4,800-4,900 mg/L.

The application states that water sampling was not performed in the Monterey A1-A2 Sands because reservoir depletion has reduced water saturation to residual levels. However, geochemical analysis was

performed using fluid produced during oil and gas operations (pg.37). CTV provides an example of the water geochemistry analysis taken from well 381-17R from a sand underlying the Monterey A1-A2 Sands (Figure 31). Figure 33 presents a 2021 analysis from nearby Well 353-7R. The figure is difficult to read, so it is unclear what analytes were measured, and if all the analytes planned during operational testing are addressed. It appears that the TDS of the Monterey A1-A2 Sands is about 24,000 mg/L.

CTV's Testing and Monitoring Plan (Attachment C) includes monitoring the overlying Etchegoin/San Joaquin Formations and the Tulare Formation for groundwater quality and geochemical changes and the Monterey Formation as part of direct plume tracking activities. Water quality will need to be established in each of these formations prior to injection operations to provide a baseline for comparison to future monitoring results.

Questions/Requests for the Applicant:

- ***Please provide clear/legible versions of the sample analyses in Figures 30 and 31 to allow a review of the sampling performed.***
- ***Where is Well 381-17R?***
- ***What is the total dissolved solids (TDS) content of the Monterey Formation? Please indicate how many data points or measurements are available to support this measurement (i.e., based on past field operations) and, if they are not from throughout the AoR, please provide information to support a determination that the Monterey Formation is not a USDW.***
- ***Is any water quality data available for the Etchegoin Formation? If so, please provide this.***
- ***In the Testing and Monitoring Plan, CTV states that they obtained a baseline analysis for the 61WS-8R well (apparently for the Tulare Formation). Please provide this analysis if it is not the same as is provided in Figure 30.***

Objectives for Pre-Operational Testing:

- ***Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan.***

Geomechanical and Petrophysical Characterization

Capillary pressure was determined using mercury injection capillary pressure analysis from 18 wells. The average rock strength of the confining zone is 2,452 psi according to brittleness calculations and the average ductility of the confining zone is 1.24 as derived from compressional sonic data from 18 wells with 59,214 data points using a calculation methodology from Ingram and Urai (1999) and Ingram et al. (1997) (pg.23). The applicant concludes that brittleness of less than 2 is evidence that the confining layer is sufficiently ductile to "anneal" discontinuities and that there are no fractures for fluid migration (Figure 19). The application states that this conclusion is further supported by historical water and gas injection data at the site in addition to millions of years of confinement of oil and gas in the Monterey Formation by the Reef Ridge Shale (pg. 23).

In the EHOF, the maximum principal stress direction is northeast-southwest as determined by a study of EHOF fracture gradients and borehole breakout (Castillo, 1997; Figure 21) Table 3 of the application narrative is reproduced below.

Stress	Reef Ridge Shale Confining Layer (Well: 374A-7R-RD1)	Monterey Formation A1-A2 Reservoir (Well: 372-7R-RD1)
Pore Pressure Gradient (psi/foot)	0.433	0.2
Overburden Gradient (psi/foot)	0.93	0.94
Minimum Horizontal Stress Gradient (psi/foot)	0.73	0.97

The GEOMECH geomechanical model, along with the GEM equation of state compositional reservoir simulator, were used to determine failure pressures under a base case and three additional scenarios; this modeling is described on pages 25-28 of the application narrative. Descriptions of variations from the base case for other scenarios are given below:

- Reduced Young's Modulus: to model uncertainty in the cap rock Young's Modulus, a second case was run with a value of 8E05 psi.
- Reduced Injection Rate: sensitivity to injection rate was studied by reducing the injection rate to 20 million cbf per day.
- Thinner cap rock: the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet.

Table 4 of the application narrative, which presents the results of the modeling, is reproduced below:

Geomechanical Scenario Results	
Scenario	**Failure pressure (psi)**
Base Case	8,306
Reduced Young's Modulus	8,388
Reduced Injection Rate	8,340
Thinner Cap Rock	7,600

Figure 23 shows the change in normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. See also the evaluation of the AoR CA (Attachment B) for additional information.

Porosity and Permeability

As shown in the table under "Depth, Areal Extent, and Thickness of the Injection and Confining Zones," above, porosity values for the Reef Ridge Shale are approximately 7-14% and reported porosities of the Monterey A1-A2 Sands range from 11%-27%. The permeability of the Reef Ridge Shale is about 0.01 mD, and Monterey Formation permeability ranges from 0.1-1,300 mD. Permeability and porosity for the Reef Ridge Shale in the 355X-30R well are presented in Table 2 of the application.

Formation porosity and permeability used as inputs for the geomodel were determined using wireline log data, including SP logs, gamma ray, borehole caliper, resistivity, neutron porosity, and bulk density (pg. 17). Porosity is determined from bulk density using a 2.65 matrix density calibrated from particle density (Figure 15) and porosity data. Clay volume is determined from neutron-density separation and is calibrated to core data. A permeability function was calculated using mercury injection capillary

pressure porosity and clay values (Figure 16). The application states (on pg. 17) that core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. However, it is unclear which wells are the source of this data.

Questions/Requests for the Applicant:

- ***Please update Figure 23 to include base case pressure.***
- ***Please discuss the selection of the base case parameter values (i.e., Young's Modulus, thickness, etc.) in the geomechanical modeling.***
- ***Please explain what is meant by "anneal discontinuities" in the discussion on page 23.***
- ***The application references core data from 13 wells on page 17.***
    - ***To which wells does this refer and where are they located?***
    - ***If they are not distributed throughout the AoR, please describe how they are representative of the entire area that will be affected by injection.***
- ***Where are the 18 wells that are the source of ductility data referred to on pg. 23 located?***
- ***The application states that, "The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of .8 psi/foot," and that, "the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI" (pg. 46). Please clarify the sources of data used to determine failure pressure, fracture pressure, and fracture gradient.***

Mineralogy of the Injection and Confining Zones

X-ray diffraction (XRD) data from 108 data points in 9 wells was analyzed to determine injection zone mineralogy. Fourier Transform Infrared Spectroscopy from 36 points in 1 well located outside the AoR but within the EHOF was used to characterize confining zone mineralogy (pg. 16-17). Figure 14 presents an example XRD analysis from well 367-7R located within the AoR. The applicant addresses the use of a single well for characterizing the mineralogy of the confining zone, citing that it is representative of the formation because of depositional continuity and consistency of facies and properties within the EHOF (Figure 15).

The Monterey A1-A2 Sand intervals consist of 43% quartz, 38% potassium feldspar, albite, and oligoclase as well as 7% total clay. The Reef Ridge Shale consists of 47.1% silica polymorphs (Opal-CT, chert, and cristobalite), 29.5% total clay, 14.5% potassium feldspar, albite, and oligoclase, and 3.7% quartz (pg.16).

Questions/Requests for the Applicant:

- ***Please provide a map of the 9 well locations used for XRD described on pages 16-17.***
- ***What evidence is there for depositional continuity and facies consistency within the EHOF, as described on page 17?***

Seismic History and Seismic Risk

The application notes that the "EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills

area (DOE, 1997)" (pg.29). Seismic activity in the region stems from the San Andreas Fault (12 miles west of the project site) and the White Wolf fault (25 miles southeast of the site) (pg. 29). Regional seismic data dating back to 1932 was gathered from the Southern California Earthquake Data Center (SCEDC) and USGS databases (Pg.29).

Figure 24 shows the eight (8) magnitude 5.0 or greater earthquakes that have occurred within a 30-mile radius of the EHOF. These earthquakes have an average depth of 6.3 miles, well below the Monterey Formation (pg.29). It is stated that there have been no earthquakes within the EHOF greater than magnitude 3.0. Site characteristics, including low factor amplification due to thin sediment, high density soil, and soft rock, based on shear-wave velocity (V_S) are asserted to further reduce seismic risk. The largest known earthquake in the region was a 7.5 magnitude 1952 earthquake in nearby Kern County which did not affect reservoir containment (pg. 30).

CTV will install borehole and surface seismometers to establish a baseline and assess natural and induced seismicity (pg. 29).

The evaluation of seismic risk also reflects other elements of the comprehensive permit application review (described elsewhere in this report), including porosity and permeability of the injection and confining zones; regional structural features; information on faults in the vicinity of the project site; formation pressure; and the geomechanical properties of the injection and confining zones.

Seismic risk and risk mitigation will also be considered in the review of the following aspects of the permit application:

- Predictions of plume and pressure front behavior over time, including pressure build-up over time, and pressure dissipation following cessation of injection.
- The ability of the injection well to maintain mechanical integrity under stress.
- Wells within the project area and the status of well corrective action.
- Planned injection pressures.
- Seismic monitoring and emergency and remedial response planning.

Questions/Requests for the Applicant:

- ***Please include all earthquakes of magnitude 3.0 and above in Figure 24.***
- ***To inform an evaluation and documentation that there is no significant seismic risk, EPA recommends that CTV describe how the project:***
  - ***has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected.***
  - ***will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;***
  - ***will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and***
  - ***poses a low risk of inducing a felt seismic event.***

Objectives for Pre-Operational Testing:

- ***Establish baseline seismicity after borehole and surface seismometers are installed.***

Surface Air and/or Soil Gas Monitoring Data

No soil gas or surface air data were submitted with the permit application. At this point, we do not believe this will be necessary; however, if the results of future reviews necessitate surface air and/or soil gas monitoring, we would request baseline data.

Facies Changes in the Injection or Confining Zones

Depths to the confining and injection zones are presented on structural and isopach maps based on 3D seismic and wireline log data (Figure 13). However, the locations and number of wells used to characterize formation depths was not provided.

Figure 3 of the application shows a cross section of formations across the San Joaquin Basin and Figure 6 shows a stratigraphic cross section with well types for the Northwest Stevens anticline. Figure 12 shows a stratigraphic column with oil samples grouped into families. There appear to be logs on the figure used to correlate formations laterally, but they could not be distinguished.

Page 41 of the application describes the development of a geo-cellular model as part of the A1-A2 reservoir characterization and plume modeling. This is supported by cross sections in Figures 34 and 35 (which appear to be outputs of the AoR delineation model) that the applicant asserts also demonstrate the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers also supports predictable plume development. The application states that the modeled plume migration (Figures 34 and 35) is consistent with the structure of the anticline.

Figure 4 identifies "data coverage" for the Reef Ridge Shale and per Figures 5 and 8, several wells have core data in the Reef Ridge Shale and the Monterey Formation; however, it is unclear what information is available from the wells on the map and how it informed the application.

On page 11, the application concludes that the Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core data, as well as 3D seismic data. Discussion and questions for the applicant regarding lateral continuity of the Confining Zone are discussed above in the section on "Mineralogy of the Injection and Confining Zones."

Questions/Requests for the Applicant:

- ***Please clarify what data sources were used to determine inputs for the geomodel where applicable, e.g., the inputs for sand vs. shale facies as discussed on pg. 40.***
- ***Please also discuss how a sufficient number and distribution of formation characterization data are available to demonstrate a lack of local heterogeneities that could affect storage or confinement of CO_2.***
- ***Please specify the names, number, and locations of wells used to characterize formation thicknesses for the maps in Figure 13.***

Objectives for Pre-Operational Testing:

- ***Determine if there are any heterogeneities within the Monterey A1-A2 Sands that could affect its suitability for injection, including facies changes that could facilitate preferential flow.***

Structure of the Injection and Confining Zones

Regional structure of the injection and confining zones is controlled by San Andreas Fault development resulting in mid-Miocene anticlines (pg. 3). The application describes the anticlines that form the Elk Hills Oil Field, which CTV asserts will contribute to confinement. See the discussions of "Regional Geology and Geologic Structure" and "Faults and Fractures," above.

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

The proposed injectate will consist of at least 95% CO_2 with mixtures of water and oxygen that will be controlled for corrosion mitigation (pg. 46). The applicant states that corrosiveness of the stream will be "very low as long as the entrained water is kept in solution with the CO_2" which will be accomplished by limiting its water content (pg. 46).

Existing subsurface fluid information is based on extensive and ongoing CO_2 injection activity in the EHOF region. CTV has injected 6.3 billion cubic feet of gas containing up to 44% CO_2 into the Monterey A1-A2 Sands since 2011 without any changes to injectivity (pg. 38-39). A 2021 analysis from an oil sample in the 353-7R well showed a 6.5 mole % CO_2 content (pg. 38). The applicant states that low water volume in the formation (15% saturation in the gas cap and 85% in the thin oil band) and low residual oil saturation (15%) will also dissolve only a small amount of CO_2. Furthermore, the Monterey A1-A2 Sands is dominated by quartz and feldspar which are stable in the presence of CO_2 and carbonic acid (pg. 39).

There is no geochemical analysis of water samples from the Reef Ridge Shale because the shale will only provide fluid for analysis if stimulated (pg. 39). The CO_2 composition used for the geomodel and its interaction/solubility is established by the Peng-Robinson Equation of State (AoR and CA Plan, pg. 2).

Questions/Requests for the Applicant:

- ***Please provideevidence for the statement in the Application on page 39 that the quartz and feldspar in the Monterey A1-A2 Sands are stable in the presence of CO_2 and carbonic acid?***
- ***Please elaborate on why use of the Peng-Robinson Equation of State supports compatibility of the CO_2 with any fluid which may be contained within the Reef Ridge Shale.***

Objectives for Pre-Operational Testing:

- ***Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and provide verification that it will not react with the formation matrix.***

Injection Zone Storage Capacity

Modeled storage capacity of the Monterey Formation A1-A2 reservoir was 8-10 million tons of CO_2 (pg. 41). The forecasted/proposed injection rate is 0.25 - 0.75 million tons per year for 15 years; according to

Table 8 (Proposed operational procedures); an average estimate of 8 million tonnes and a maximum of 10 million tonnes will be injected.

Injection zone storage capacity is discussed in the Evaluation of the AoR CA and above in the "Structure of the Injection Zone and Confining Zone" section. Any additional follow up questions/requests for the applicant will be provided in the AoR modeling evaluation.

Confining Zone Integrity

Fluid confinement is supported by 3D seismic data (pg. 12) and historic operating experience in addition to core data (pg. 20) and geochemical analysis (pg. 13). The capillary entry pressure of the Reef Ridge Shale is 4,220 psi in a CO_2-brine system, reducing the likelihood of deformation (pg. 20). There are no faults extending into the Reef Ridge Shale. See additional discussion and questions for the applicant above.

Questions/Requests for the Applicant:

- ***Were any other tests performed to corroborate pressure measurements in the Reef Ridge Shale?***
- ***The application, on pg. 14, states that there is a pressure differential of 1,300 psi between the overlying Etchegoin Formation and Monterey Formation due to the sealing nature of the Reef Ridge Shale. What is the source of the pressure data for this statement?***

Objectives for Pre-Operational Testing:

- ***Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate via laboratory experiments.***
- ***A step rate test should be performed to establish the fracture pressure of the confining zone.***

Evaluation of the Proposed Emergency and Remedial Response Plan for the Carbon TerraVault Class VI A1-A2 Reservoir Project

EPA has completed a review of the proposed Emergency and Remedial Response Plan (ERP) for the proposed Carbon TerraVault1 (CTV) Class VI geologic sequestration (GS) project (Attachment F to CTV's August 2021 Class VI permit application). While the evaluation of certain response scenarios is pending other reviews (e.g., the presence of pathways for fluid movement based on the geologic evaluation) the plan appears to be complete. EPA has the following questions and recommendations for the applicant:

Local Resources and Infrastructure

a) Please include the nearest town/community and its distance to the project area as part of the nearby infrastructure.
b) Please provide a version of Figure 1 at a wider scale (i.e., that shows more than just the AoR) to provide context for the Emergency and Remedial Response Plan. Identify the injection wells on the map.

Potential Risk Scenarios

The list of items in this section does not match the events and scenarios described in the following section. Please revise the list.

Emergency Identification and Response Actions

EPA recommends some additions/revisions to the descriptions and response actions for the scenarios identified in the Emergency and Remedial Response Plan. These are presented in the table below:

Event/Scenario	EPA Comment/Recommendation
1. All	a) EPA recommends that the Actionable Testing limits methods in Table 7 of the QASP be referenced in the Emergency and Remedial Response Plan.
2. Well Integrity Failure	b) A mechanical integrity (MI) failure of a monitoring well can also occur in the post-injection time frame; please update the "timing of the event" accordingly. c) The statement that CTV must notify the UIC Program Director is not an event that may signal loss of MI. Please make this a separate statement outside of the list on page 3. d) Consider including "Limit access to wellhead to authorized personnel only" to the response actions for major and minor emergencies. e) The response to a major or minor MI failure should also include necessary actions to identify the location/nature of the damage to the well or wellhead and confirm internal and external integrity prior to restarting injection (upon approval of the UIC Program Director).
3. Well Integrity Failure – Major or Serious Emergency	a) Please clarify what would constitute a major or serious emergency (e.g., a verified loss or increase of pressure or fluid volumes and/or loss of mechanical integrity is discovered). b) Response to a major emergency may also include communicating with CTV personnel or other operators in the field and local authorities to initiate evacuation plans, as necessary.

Event/Scenario	EPA Comment/Recommendation
4. Well Integrity Failure –Minor Emergency	a) Please clarify what would constitute a minor emergency (e.g., downhole and surface sensor/monitoring equipment failure, procedural maintenance error or plant issue). b) Clarify that, if contamination is detected or a loss of integrity has occurred, then the situation becomes a major emergency and the actions under "Major or Serious Emergency" would be taken. c) "Initiate shutdown plan" is on the list of response actions twice.
5. Injection Well Monitoring Equipment Failure – Major or Serious Emergency	a) Please describe what constitutes a Major or Serious emergency (e.g., failure of sensors that will require shutdown of well to repair, extended repair time, and/or well reentry). b) Responses to a Major monitoring equipment failure emergency may also include: • Verifying whether any contamination has occurred (e.g., via handheld CO_2 monitors). • Communicating with CTV personnel/other operators in the field and local authorities to isolate the area or initiate evacuation plans, as necessary if contamination is detected. • Demonstrating internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director).
6. Injection Well Monitoring Equipment Failure –Minor Emergency	a) Please describe what constitutes a Minor emergency (e.g., sensor or monitoring failure that does not require shutdown of the well to repair). b) Potential response actions may also include actions to identify the location/nature of the damage and reset monitoring devices and/or confirm internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director). c) "Initiate shutdown plan" is on the list of response actions twice.
7. Potential Brine or CO_2 Leakage to USDW	a) EPA recommends that the introduction to this scenario be broadened to encompass any evidence of CO_2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address events associated with unanticipated fluid movement pathways, any potential USDW endangerment/unacceptable changes in water quality, and CO_2 leakage to the land surface. b) The severity of an event involving CO_2/brine leakage to a USDW would be serious, not low. c) Detection methods may also include pressure or water quality changes in the Etchegoin Formation monitoring well. d) The response actions should also address well integrity issues (e.g., by following responses under the MI failure scenario) or a risk to air quality (i.e., to isolate the nearby area and establish a perimeter using a hand-held air-quality monitors). e) The response equipment for this scenario should also include groundwater remediation equipment.

Event/Scenario	EPA Comment/Recommendation
8. Natural Disaster	a) The severity of these types of events could range up to serious or catastrophic. b) These types of events may occur in any of the project phases (e.g., construction and post-injection) not just the injection phase. c) For Major or Serious natural disasters, potential response actions may also include: • Initiating evacuation procedures; • Referencing the response actions described under the CO_2 leakage scenario if contamination or endangerment of a USDW is detected; or • Confirming mechanical integrity/taking appropriate steps if an injection/monitoring well has been damaged.
9. Induced Seismic Event	a) This section and the title should refer to induced or naturally occurring seismic events since all seismic events have the potential to affect the injection wells and the necessary responses would be the same. b) It is unclear whether the area encompassed by "the AoR inclusive of a ¼ mile buffer," as described on page 8 is as large as a 2-mile radius of the injection wells, as described on Table 2. Please modify the introductory statement to reflect the area addressed in Table 2. c) The severity of seismic events could be major. d) Seismic events that may necessitate a response could occur during the injection or post injection phases. e) Please clarify what is meant by "seismic monitoring wells" as a detection method; EPA assumes this refers to the monitoring network that is described in the Testing and Monitoring Plan, and therefore recommends that similar terminology be used.
10. Induced Seismic Event—Table 2	a) Please modify the title to Table 2 to be consistent with the magnitude in the green response level (i.e., M 1.5). b) Please explain how the selected seismic thresholds (i.e., magnitude, distance from the project) are considered protective of USDWs.
11. Induced Seismic Event—Table 2, Green Level	a) Add the response action: Document the event in semiannual reports to EPA.
11. Induced Seismic Event—Table 2, Yellow Level	a) Potential response actions should also include: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Review seismic and operational data to determine the location and magnitude of seismic event. If the event falls within or near the extents of the plume, estimate potential impact to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. • Document the event in semiannual reports to EPA.

Event/Scenario	EPA Comment/Recommendation
12. Induced Seismic Event—Table 2, Orange Level	a) EPA recommends the following additions to the response actions: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Document the event in semiannual reports to EPA. • Expand Step 3 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).
13. Induced Seismic Event—Table 2, Magenta Level	a) EPA recommends the following changes to the response actions: • Please describe the "rate reduction plan" in Step 1. Does this refer to gradual shutdown? • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event). • Add: Document the event in semiannual reports to EPA.
14. Induced Seismic Event—Table 2, Red Level	a) EPA recommends the following changes to the response actions: • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).

Response Personnel and Equipment

a) Are any of the personnel to be notified a 24-hour contact, such as a 24-hour emergency coordinator in the control room? If so, please include this in the plan.

b) In Table 3, EPA recommends the following additions/changes:

- The UIC Program Director will be an EPA Region 9 staff person (David Albright; albright.david@epa.gov.
- Consider also including: the local/community medical center, Poison Control Center, California Office of Emergency Services, and the State Water Quality Control Board.

Plan Review

EPA recommends that plan reviews take place within 30 days of significant changes or on a timeframe prescribed by the EPA Director.

Staff Training and Exercise Procedures

There are several typos in this section; please revise.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

December 15, 2021 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the site characterization, financial responsibility, and emergency and remedial response plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below, and in the three Enclosures.

Considerations of Specific Federal Laws

40 CFR §144.4 requires that EPA consider the potential applicability of several specific Federal Laws, including the Wild and Scenic Rivers Act (WSRA), National Historic Preservation Act (NHPA), Endangered Species Act (ESA), Coastal Zone Management Act (CZMA), and the Fish and Wildlife Conservation Act (FWCA). To expedite our consideration of these laws, please describe how the proposed project will satisfy applicable requirements under those Federal Laws. For the ESA and NHPA,we have included some guidance below to assist you with obtaining the required information.

Endangered Species Act (ESA)

The ESA requires EPA to ensure, in consultation with the U.S. Fish and Wildlife Services (FWS), that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or adversely affect its critical habitat. We recommend that you use FWS's project planning tool to map out your project area and do a search for potential endangered species within the project area. The tool can be accessed here: https://ecos.fws.gov/ipac/.

Based on the results of your search, you may need to hire a Wildlife Consultant to provide additional analysis or otherwise show how your project will not cause harm to endangered species with habitat located near the CTV A1-A2 project area. Please provide a report depicting the results of the FWS project planning tool, including a map of the project area and any listed endangered or threatened species habitat near the site. Please include any comments or reports made by a Wildlife Consultant, if applicable.

National Historic Preservation Act (NHPA)

NHPA §106 requires a federal agency to take certain steps before it commits to any "undertaking," including the issuance of a permit or license, that has the potential to adversely affect property that is listed, or eligible for listing, in the National Register for Historic Places. The NHPA requires EPA, before issuing a permit, to adopt measures when feasible to mitigate potential adverse effects of the permitted activity and properties listed or eligible for listing in the National Register of Historic Places. The Act's requirements are to be implemented in cooperation with State Historic Preservation Officer and upon notice to, and when appropriate, in consultation with the Advisory Council on Historic Preservation.

To facilitate EPA's consideration of NHPA compliance for CTV's proposed project, we request that you identify the Historic Places designated in the National Register for Historic Places (https://www.nps.gov/subjects/nationalregister/database- research.htm) in close proximity to the CTV A1-A2 project site. Based on the results of your review of the National Register of Historic Places listings in Kern County, you may need to hire an archaeologist to provide additional analysis or otherwise show how your project will not adversely affect the identified historic places located near the CTV A1-A2 project site. Please provide a list of the Historic Places near the site. Please include any comments or reports made by an archaeologist, if applicable.

Please submit the information requested in the Enclosures, and regarding compliance with the above referenced Federal Laws by January 21, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Michele Dermer at (415) 972-3417.

Sincerely,

DAVID ALBRIGHT

Digitally signed by DAVID ALBRIGHT
Date: 2021.12.15 15:52:18 -08'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Site Characterization
Financial Responsibility
Emergency and Remedial Response Plan

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

CTV-Elk Hills Oil Field Class VI A1-A2 Project
Review of Financial Responsibility Information

EPA reviewed the financial responsibility demonstration, including cost estimates and information about draft financial instruments, provided in the August 2021 Class VI permit application for the proposed Carbon TerraVault1 (CTV) Class VI geologic sequestration project.

Pursuant to 40 CFR 146.85, Class VI permit applicants must demonstrate financial responsibility for: performing corrective action on deficient wells in the area of review (AoR), plugging injection wells, post-injection site care (PISC) and site closure, and emergency and remedial response. To make this demonstration, they must estimate the cost of each of these activities and provide qualifying financial instruments.

Cost Estimates

It appears that CTV used EPA's Cost Estimation Tool for Class VI Financial Responsibility to develop their cost estimates. EPA's guidance recommends that the financial responsibility cost estimates in a Class VI permit application be based on a third-party cost estimate of the activities an applicant plans to perform. These project-specific estimates of the covered costs are necessary to ensure that sufficient resources are available to cover the costs of EPA engaging a third party to complete the activities, should an operator become financially insolvent.

Therefore, EPA requests that CTV provide an independent estimate of the costs of the activities described in the project plans for which financial responsibility is required, specifically:

- Plugging injection wells 357-7R and 355-7R. Separate estimates specific to each well are requested.
- Post-injection site care that includes all post-injection groundwater quality monitoring and plume and pressure front tracking activities described in the PISC and Site Closure Plan.
- Site closure that includes the cost of plugging all the monitoring wells at the site (including the Etchegoin, Tulare, and Monterey Formation monitoring wells).
    - EPA also requests that CTV elaborate on the ownership and planned future use of the EOR wells to be used for monitoring in the Monterey A3-11 Sands, as described on page 12 of the Testing and Monitoring Plan. (Financial assurance for plugging these wells may be needed.)
- Emergency and remedial response that describes all the response activities under the various emergency scenarios described in the Emergency and Remedial Response Plan.

Based on the information currently available in the AoR and Corrective Action Plan, it does not appear that any corrective action is needed. However, if, based on additional evaluation, a larger AoR is determined to be needed or there are any deficient wells in the AoR, the cost estimate would need to account for corrective action on these wells. The outcomes of other aspects of the permit application review may affect cost estimates for other activities.

Financial Instrument Demonstration

CTV plans to provide financial assurance for injection well plugging and PISC and site closure by posting a letter of credit (LOC) that will be backed by its Credit Agreement with Citibank, N.A. CTV will provide financial assurance for emergency and remedial response via an environmental insurance policy.

Limited information was provided with the permit application, and it is anticipated that CTV will provide additional information and draft financial instruments as the time for issuance of any Class VI permits for the facility nears. EPA recommends that CTV consult the *UIC Program Class VI Financial Responsibility Guidance* as it develops the instruments, including:

- The recommended specifications for a letter of credit (beginning on page 31) and insurance (on page 32), and
- The recommended financial instrument language provided in Appendix B of the Guidance (on page B-2 for a LOC and page B-17 for a certificate of insurance).

In addition, regarding the Letter of Credit, EPA requests that CTV clarify whether other liabilities are covered using the same line of credit and, if so, how the funds specified for Class VI financial responsibility under the LOC will be protected from other liabilities.

Evaluation of Construction and Plugging Procedures for Injection Well 355-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

This well construction and plugging evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of several related activities associated with the construction and plugging of the 355-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands. These activities are described in an update to CTV's Class VI permit application that was submitted on December 2, 2021, including updated sections of the permit application narrative (Narrative A2), Attachments D2 and G2, and logging and testing information about the 355-7R injection well. This review also identifies preliminary questions for the applicant. (Note that the permit application contains common information that applies to both injection wells planned for the project. Therefore, there is some repetition between this evaluation and EPA's evaluation of attachments relevant to Well 357-7R. This is necessary to provide a complete evaluation for each Class VI permit record.)

Injection Well Construction

Narrative A2 and Attachment G2 describe the construction design for Well 355-7R. Well 355–7R is an existing Class II pressure maintenance well, approved by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 355–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2. Well 355-7R was drilled in 1973; Narrative A2 contains the following brief construction details regarding Well 355-7R:

1. The well design exceeds criteria for all anticipated load cases, accounting for safety factors.
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. 13-3/8" and 9-5/8" casing string were cemented with 30 cubic feet and 35 cubic feet returns to surface, respectively.
4. A cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval, from the base of the 7" casing to approximately 5,200 feet.
5. Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provide continual awareness to potential anomalous injection conditions.
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

Table 5: Temperature profile and casing construction data for the 355-7R injector.

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Table 5 of the Narrative A2, reproduced above, matches the casing specifications listed in Attachment G2 for Well 355-7R (see below). Attachment G2 also includes tubing and packer specifications for Well 355-7R, which are excerpted below. The tubing and packer specifications in Attachment G2 mostly correspond to Table 7 of the Narrative A2, however there appear to be typos regarding: tubing outside diameter and weight (in the Narrative A2) and regarding packer tensile rating (in Attachment G2).

Injection Well 355-7R Construction Details (from Attachment G2)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,398	4.500	3.920	13.5	L-80	Long	9,020	8,540

Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

CTV states that all the well materials and the stainless-steel wellhead are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. The Applicant notes that the Class G Portland cement used to complete well 355-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor and long string (injection string), had cement returns to surface according to Narrative A2. A CBL indicated that the top of cement in the injection string annulus is above 5,200 ft, which is above the Reef Ridge Shale upper confining layer, reported as 6,929 ft-7,962 ft true vertical depth (TVD), per Table 1 of the Narrative A2.

The cement integrity is supported by information from existing wells and a CBL in Well 355-7R. California Resources Corporation (CRC) has conducted standard annulus pressure tests (SAPTs) historically to ensure continued internal mechanical integrity of the well. No SAPT results were provided in the permit application materials, however. These tests will also be conducted prior to injection and every five years thereafter and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1 of Attachment G2 is illegible, so information such as geologic formation tops (for the injection and confining zones and the Base of the USDW), perforation depths, and casing depths, cannot be evaluated. The applicant will need to resubmit an updated, resolvable casing diagram for Well 355-7R that demonstrates proper construction, including either that the base of the lowermost USDW is covered by the surface casing in accordance with 40 CFR 146.86(b)(2), or how the construction otherwise ensures protection of USDWs, per 40 CFR 146.86(a)(1). According to the tables on Page G2, the surface casing is set to a depth of 500 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW. . Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.

Multiple sources of anthropogenic CO_2 are being considered for the Elk Hills A1-A2 Injection Project. These include the Elk Hills NGCC Power Plant as well as third party existing and proposed industrial sources in the Southern San Joaquin Valley area. The CO_2 stream will be approximately 95% CO_2 by volume, also containing residual water (25#/mmscf) and oxygen (<50 parts per million) which will be controlled for corrosion mitigation. The applicant notes that the CO_2 stream corrosivity is low if the entrained water is kept in solution with the CO_2. The applicant states that the 25#/mmscf water volume specification is conservative and should allow for water solubility across super-critical CO_2 operating

ranges. The water content of 25#/mmscf equates to approximately 0.4 ppm and is unlikely to present corrosion concerns. However, water solubility will vary with depth and time as temperatures and pressures change. Gas phase CO_2 is likely to exist in the lowered depths of the tubing string early in the injection phase, resulting in the possibility of existing free phase water. According to Well 355-7R Construction Details (Attachment G2), excerpted above, L-80 tubing is currently installed in the well. CTV states that they plan to configure the well with corrosion-resistant tubing; however, the type of tubing planned for installation is not specified. No details were provided as to the amount of time free phase water can persist without severely damaging the tubing. According to Table 1 in *Attachment C – Testing and Monitoring Plan,* CTV will analyze the following CO_2 stream constituents based on established ASTM methods: O_2, N_2, CO, CH_4, H_2S, total hydrocarbons, total Sulfur, and CO_2 purity. It appears that H_2O was excluded from the CO_2 stream constituent analysis and will need to be included (a request was provided with the testing and monitoring evaluation). Additionally, the applicant does not state if the compatibility of the CO_2 stream and well construction components will be determined prior to well operation. Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.

The well construction and cementing criteria described in the Narrative A2 and Attachment G2 appear to be acceptable, however an updated casing diagram, in addition to addressing the deficiencies noted below, is needed. Additionally, the applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials. This will be needed prior to operation of Well 355-7R.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. However, the applicant did not provide discussion regarding safety valves and automated shut-off devices in Attachment G2.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings).

Questions/Requests for the applicant:

- *There appear to be typos regarding tubing outside diameter and weight and the packer tensile rating for Well 355-7R in Attachment G2. Please reconcile these inconsistencies:*
  - *The outside diameter of the injection tubing (on Table 6 of Narrative A2) is 00.*
  - *The tensile rating (of "10,0000" lbs) for the packer on pg G2 of Attachment G2.*
- *Please explain how the current well architecture—with the 7" (injection/long) string cemented to 5,200 ft, which is above the confining layer was engineered and constructed to ensure protection of USDWs, per 40 CFR 146.86(a)(1).*

- *Please describe the fluid in the annulus between the tubing and the long string casing, including how it is a non-corrosive fluid, as required by 40 CFR 146.88(c).*
- *Please describe the specific materials that will be removed from well 355-7R, and provide details regarding the corrosion-resistant tubing, packer, and wellhead materials that will replace these.*
- *Is Well 355-7R equipped with automatic shutoff systems connected to the real-time surface monitoring equipment and alarms, as required at 146.88(e)(2)? If so, please describe these systems in Attachment G2 and how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G2 to include these required components.*
- *Please discuss the duration that free phase water is expected to be present at the beginning of the injection phase and the corresponding impact on tubing integrity. For example, please provide additional discussion regarding the study of this phenomenon, e.g., in existing, nearby CO_2 injection wells.*
- *Figure 1 of Attachment G2 is illegible. Please submit an updated, resolvable diagram for Well 355-7R that includes the following information:*
  - *All relevant formations (e.g., the injection and confining zones and the base of the USDW);*
  - *Either surface casing that extends through the base of the USDW, per 40 CFR 146.86(b)(2), or an explanation of how the well's construction otherwise ensures protection of USDWs, per 40 CFR 186(a)(1);*
  - *The depths of the perforations; and*
  - *Please label the well diagram to indicate that the well is a Class VI (i.e., not Class II) well.*
- *What is the surface elevation (i.e., relative to mean sea level) at the location of the well?*
- *Please include relevant information from Narrative A2 about the construction of the well into Attachment G2 for completeness.*
- *Please provide versions of Attachments A2 and G2 in full page mode to improve their legibility.*
- *For completeness, please include the description of testing of the deep monitoring wells (i.e., as described in Attachment G) in Attachment G2.*
- *Please explain how the injection well's design will mitigate potential shallow compression related to land subsidence while still complying with the requirement to cement to the surface.*
- *Please provide the most recent SAPT reports for the well.*

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 355-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in Narrative A2 and in Attachment G2. Attachment G2 identifies several tests that CTV indicates have been performed and were provided. These include deviation checks, a cement bond log, and open-hole well logs. CTV notes that mechanical integrity tests, including a temperature log and SAPT, were also acquired after the drilling of 355-7R; however, these were not provided. Attachment G2 also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2

Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed. Despite the deficiencies listed here, the proposed testing and logging program is considered comprehensive and generally acceptable.

Questions/Requests for the applicant:

- *Please provide the results of the temperature log and SAPT that were performed on Well 355-7R.*
- *Figure 2 of the 355-7R Logging and Testing document is illegible. Please provide a legible log plot demonstrating open-hole well logs for Well 355-7R.*
- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones.*

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow

(anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
  - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
  - *Step-by-step procedures that would be employed during stimulation.*

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for

each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1?*
- *Please include information about MITs on the deep monitoring wells in Attachment G2 for completeness.*

Injection Well Plugging Plan

CTV states that, before plugging the injection well, it will determine the bottom-hole pressure needed to successfully squeeze cement for plugging operations. At least one external MIT will be conducted prior to plugging, including but not limited to a temperature log. The temperature log will be run over the entire depth of the well and the results will be compared to temperature logs performed before and during CO_2 injection. Generic procedures for plugging wells are described in the attachment. Specific plugging procedures will be needed.

During plugging operations, CTV states that the cement slurry and displacement fluids will be over-balanced to prevent reservoir fluids from entering the wellbore during cementing operations. Table 1 of Attachment D2—Injection Well Plugging Plan, describes the various types of plug information and is excerpted below. The plugging details listed in Table 1 are consistent with injection well construction details; however, the applicant did not provide a plugging diagram. Also, because the well diagram (Figure 1 of Attachment G2) and the perforation depths are illegible, it is not possible to confirm that the placement of plugs, as described below, are appropriate.

Plug #1 (bottom-hole cement plug) will cover all perforations and will extend at least 100 ft. above the uppermost perforations. However, the uppermost perforation depth is illegible on the well diagram, thus preventing confirmation of cement coverage by Plug #1 to 100 ft above the uppermost perforation.

Table 1: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.184	6.184, 6.276, 6.366	6.184, 6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,692	8,371	1,384	25
Sacks of cement to be used (each plug)	58	1322	258	4
Slurry volume to be pumped (ft^3)	67	1520	297	5
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,371	1,384	25	0
Bottom of plug (ft)	8,692	8,371	1,384	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

The Base of the USDW will be covered by Plugs #2 and #3. If cement exists behind the casing and across the Base of the USDW, a 100 ft. cement plug will be placed inside the casing across this interface. If the top of cement behind the casing is found to be below the Base of the USDW, a cement squeeze will be performed through perforations. Additionally, a 100 ft cement plug will be placed inside the casing across the freshwater-saltwater interface. Plug #4 (the surface plug) will plug the casing at the surface with at least 25 ft of cement. The diameter of the boring for Plug #4 listed in Table 1 above (6.366 in.) does not correspond to the Well 355-7R construction details listed in Attachment G2 (6.184 in). All cement plugs will be composed of a Class G cement blend that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The applicant does not explicitly state if this is the same cement used to cement the casing strings in well construction.

The plugging procedures that will be used to place these plugs appear to be acceptable, provided responses to the questions below are adequate. The plugging plan does not include a schematic.

Questions/Requests for the applicant:

- *Please include "flushing" among the steps to be completed prior to injection well plugging, in accordance with 40 CFR 146.92(a).*
- *Please provide a plugging schematic that includes:*
  - *Labels of the USDW and other relevant formations (i.e., the injection and confining zones) and all perforations; and*
  - *Plug coverage (for Plugs #1-4) that corresponds to the depth of the Base of the USDW and the perforations in Figure 1 of Attachment G2.*
- *Please provide a full-page printout of Attachment D2.*

- *Please confirm that the Class G cement blend is the same as the Class G Portland cement that was used in the well's construction, and that this cement is CO_2-resistant.*
- *Please revise the diameter of boring for Plug #4 listed in Table 1 of Attachment D2 (6.366 in.) to correspond to the Well 355-7R construction details listed in Attachment G2 (6.184 in).*

Evaluation of Construction and Plugging Procedures for Injection Well 357-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

This well construction and plugging evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of several related activities associated with construction and plugging of the 357-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands. These activities are described in the permit application narrative, and Attachment D to the permit application dated August 30, 2021, and an updated version of Attachment G (a file entitled Attachment G—Final), submitted on December 2, 2021. This review also identifies preliminary questions for the applicant. (Note that the permit application contains common information that applies to both injection wells planned for the project. Therefore, there is some repetition between this evaluation and EPA's evaluation of the attachments relevant to Well 355-7R. This is necessary to provide a complete evaluation for each Class VI permit record.)

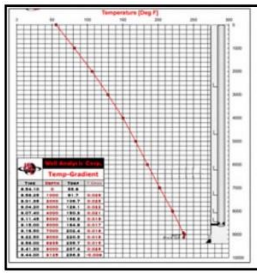
Injection Well Construction

Attachment A--Narrative (referred to as The Narrative herein) and Attachment G describe the well construction design for Well 357-7R. Well 357-7R is an existing Class II pressure maintenance well that is currently permitted by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 357–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2.

Well 357-7R was drilled in 1980; the Narrative contains the following brief construction details regarding Well 357-7R:

1. Descriptions of the conductor, surface, and intermediate casing.
2. Cement across each casing string with cement returns to surface during completion. A cement bond log was acquired to confirm cement along the well.
3. Casing specifications that exceed the operating conditions of the well (per Table 5 of the Narrative, reproduced below).
4. Long string casing diameter of seven inches with stainless steel tubing of 4.5 inches. This casing and tubing size will enable monitoring devices to be installed, cased hole logs to be acquired and Mechanical Integrity Testing (MIT) to be conducted.

Table 5: Temperature profile and casing construction data for the 357-7R injector.



Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Table 5 of the Narrative, pictured above, corresponds to the casing specifications listed in Attachment G for Well 357-7R, pictured below. Attachment G also includes tubing and packer specifications for Well

357-7R, which are excerpted below. The tubing and packer specifications in Attachment G mostly correspond to Table 7 of the Narrative, however the packer burst strength (psi) and collapse rating (psi) differ between the documents.

Injection Well 357-7R Construction Detials (Attachment G)

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

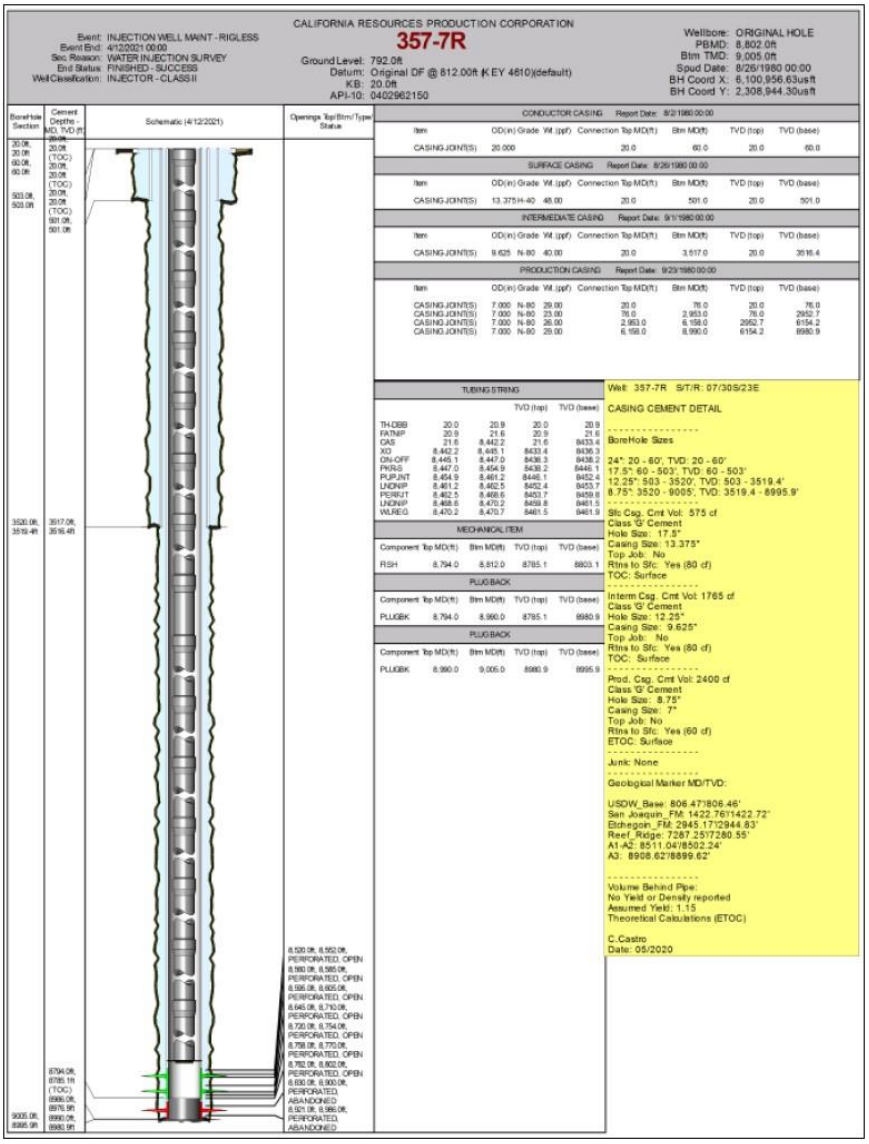
Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,447	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

All well materials noted in the tables above, in addition to the stainless-steel wellhead, are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are mostly consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. However, the surface pressure field gauges listed in Tables 10, 11, 12, and 14 of the QASP show a maximum calibrated working pressure of 3,000 psi, which is lower than the maximum surface injection pressure of 3,800 psi. The Applicant notes that the Class G Portland cement used to complete Well 357-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor, had cement returns to surface according to Figure 1 of Attachment G (reproduced below). The cement integrity is supported by data from existing wells and a cement bond log (CBL) in Well 357-7R. California Resources Corporation (CRC) has conducted MITs and standard annulus pressure test (SAPTs) every five years (no SAPT results were provided with the application materials, however). These tests will also be conducted prior to injection and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1: Injection Well 357-7R casing diagram (Attachment G)



Relevant geologic formation tops were noted in Figure 1 of Attachment G. The figure shows that the Base of the USDW is approximately 806 ft. TVD (true vertical depth), which is behind both the long string and intermediate casing. The surface casing is set to a depth of 501 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW in accordance with 40 CFR 146.86(a)(1). Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.

The San Joaquin and Etchegoin Formation tops are located at depths of 1,422 ft TVD and 2,945 ft TVD, respectively, and are also protected by the long string and intermediate casing. The Reef Ridge Shale

(confining zone), Monterey Formation A1-A2 (reservoir), and Monterey Formation A3 are located at depths of 7,281 ft TVD, 8,502 ft TVD, and 8,900 ft TVD, respectively; these three formations will be behind the long string casing. The depth of the Etchegoin Formation on the well diagram is consistent with information in the permit application narrative, and the depth of the Monterey Formation A1-A2 Sands differs from the depth reported on Figure 13 of the permit application narrative of 8,403 ft – 9,598 ft TVD.

The perforations for Well 357-7R are shown at depths of 8,782 to 8,830 feet. The perforations are also described in the AoR and Corrective Action Plan; however, they are presented in depth relative to mean sea level, so confirmation that the depths are consistent is not possible.

Multiple sources of anthropogenic CO_2 are being considered for the Elk Hills A1-A2 Injection Project. These include the Elk Hills NGCC Power Plant as well as third party existing and proposed industrial sources in the Southern San Joaquin Valley area. The CO_2 stream will be approximately 95% CO_2 by volume, also containing residual water (25#/mmscf) and oxygen (<50 parts per million) which will be controlled for corrosion mitigation. The applicant notes that the CO_2 stream corrosivity is low if the entrained water is kept in solution with the CO_2. The applicant states that the 25#/mmscf water volume specification is conservative and should allow for water solubility across super-critical CO_2 operating ranges. The water content of 25#/mmscf equates to approximately 0.4 ppm and is unlikely to present corrosion concerns. However, water solubility will vary with depth and time as temperatures and pressures change. Gas phase CO_2 is likely to exist in the lowered depths of the tubing string early in the injection phase, resulting in the possibility of existing free phase water. Stainless steel (13 CR-95) tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present. However, no details were provided as to the amount of time that free phase water can persist without severely damaging the tubing. According to Table 1 in *Attachment C – Testing and Monitoring Plan,* CTV will analyze the following CO_2 stream constituents based on established ASTM methods: O_2, N_2, CO, CH_4, H_2S, total hydrocarbons, total Sulfur, and CO_2 purity. It appears that H_2O was excluded from the CO_2 stream constituent analysis and will need to be included (a request was provided with the testing and monitoring evaluation). Additionally, the applicant does not state if the compatibility of the CO_2 stream and well construction components will be determined prior to well operation. Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.

Figure 1 of Attachment G, excerpted above, demonstrates the casing design for Well 357-7R. The well construction and cementing criteria described in the Narrative and Attachment G appear to be acceptable, except as noted in the questions below. However, the applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials. This will be needed prior to operation of Well 357-7R.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. However, the applicant did not describe safety valves and automated shut-off devices in Attachment G.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been

cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings).

Questions/requests for the applicant:

- *Please reconcile the following differences between Attachment G and Table 7 of the Narrative:*
  - *The burst rating of the packer is 8,160 psi on Table 7 of Attachment A and 8,000 psi on page G3, and*
  - *The tensile strength of the packer on page G3 has a typo, with an extra 0 in "10,0000."*
- *There are several discrepancies in the descriptions of Well 357-7R between tables 5, 6, and 7 of Attachment A and the tables on pages G2 and G3 of Attachment G. Please make the tables and the well bore diagram in Attachment G (if needed) consistent.*
  - *Attachment A, Table 5, and the Table on page G2 indicate that the intermediate casing in Well 357-7R is to a depth of 3,517 ft; on Table 6, this depth is 3,516 ft.*
  - *The conductor casing material is H-40 in Attachment A, Table 5 and Attachment G, and it is J-55 in Table 6.*
  - *The surface casing material is H-40 in Table 5 and in Attachment G, pg. 2, and it is H-80 in Table 6.*
- *Please verify that the annulus between the tubing and the long string casing is filled with a non-corrosive fluid, as required by 40 CFR 146.88(c), and describe the fluid.*
- *Please confirm that the surface casing extends through the base of the lowermost USDW, in accordance with 40 CFR 146.86(b)(2). If it does not, please explain how the well will otherwise meet the requirements of 40 CFR 146.86(a)(1).*
- *Is Well 357-7R equipped with real-time surface monitoring equipment and alarms and, if so, are these connected to automatic shutoff systems, as required at 146.88(e)(2)? If so, please describe these in Attachment G and describe how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G to include these required components.*
- *Please provide additional detail about the construction procedures for Well 357-7R, for example, to be consistent with the level of detail in the construction procedures for Well 355-7R on page 2 of Attachment A2.*
- *Please include relevant information from the narrative (Attachment A) about the construction of the well into Attachment G for completeness.*
- *In Figure 1 of Attachment G (Well 357-7R casing diagram), the top of cement for the existing bottom-hole plug is listed at 8,794 ft MD / 8,785 ft TVD while the base of the open perforated interval is 8,802 ft. Please revise Figure 1 to correct this inconsistency.*
- *Please label the well diagram to indicate that the well is a Class VI (i.e., not Class II) well.*
- *Please explain how the injection well's design will mitigate potential shallow compression resulting from land subsidence and comply with the requirement to cement to the surface.*
- *What is the surface elevation (i.e., relative to mean sea level) at the location of the well?*

- *Please discuss the duration that free phase water is expected to be present at the beginning of the injection phase and the corresponding impact on tubing integrity. For example, please provide additional discussion regarding the study of this phenomenon, e.g., in existing, nearby CO_2 injection wells.*
- *Please include alternative pressure monitoring devices to those listed in Tables 10, 11, 12, and 14 of the QASP with pressure field gauges with higher pressure ratings to function at the maximum surface injection pressure of 3,800 psi safely and reliably.*
- *Please provide the most recent SAPT reports for the well.*

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 357-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in the Narrative and in Attachment G. Table 1 of the Pre-Operational Testing Plan for Well 357-7R identifies several tests that CTV indicates have been performed, and that these were provided. These include deviation checks, cement bond log, open-hole well logs, mechanical integrity test, SAPT, injection zone and confining layer core, reservoir conditions and fluid, injection zone and confining layer fracture gradients, and pressure testing. Attachment G also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2 Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed. Despite the deficiencies listed here, the proposed testing and logging program is considered comprehensive and generally acceptable.

Questions/Requests for the applicant:

- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones.*

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).
- Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

- Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

- Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

- Determine if there are any heterogeneities within the Monterey A1-A2 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

- Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation

program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
  - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
  - *Step-by-step procedures that would be employed during stimulation.*

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1?*

Injection Well Plugging Plan

Plugging details for Well 357-7R are provided in Table 1, which is reproduced below. Before plugging the injection well, CTV will determine the bottom-hole pressure needed to successfully squeeze cement for plugging operations. At least one external MIT will be conducted prior to plugging, including but not limited to a temperature log. The temperature log will be run over the entire depth of the well and the results will be compared to temperature logs performed before and during CO_2 injection. Generic procedures for plugging wells are described in the attachment. Specific plugging procedures will be needed.

Table 1: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.184	6.366	6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,785	2,970	1,448	25
Sacks of cement to be used (each plug)	65	25	25	5
Slurry volume to be pumped (ft^3)	75	28	28	6
Slurry weight (lb./gal)	15.6	15.6	15.6	15.6
Calculated top of plug (ft)	8,427	2,845	1,323	0
Bottom of plug (ft)	8,785	2,970	1,448	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

CTV states that, during plugging operations, the cement slurry and displacement fluids will be over-balanced to prevent reservoir fluids from entering the wellbore during cementing operations. Table 1 of Attachment D—Injection Well Plugging Plan describes the various types of plug information, which is excerpted below. The plugging details listed in Table 1 are consistent with injection well construction details, however the applicant did not provide a plugging diagram.

Plug #1 (bottom-hole cement plug) will cover all perforations and will extend at least 100 ft. above the uppermost perforations. However, based on Figure 1 of Attachment G, the uppermost perforations occur at 8,520 ft, resulting in the top of the plug occurring 93 ft above the uppermost perforation. The cement volume will need to be revised for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.

The Base of the USDW will be covered by Plugs #2 and #3. If cement exists behind the casing and across the Base of the USDW, a 100 ft. cement plug will be placed inside the casing across this interface. If the top of cement behind the casing is found to be below the Base of the USDW, a cement squeeze will be performed through perforations. Additionally, a 100 ft cement plug will be placed inside the casing across the freshwater-saltwater interface. However, Figure 1 of Attachment G lists the Base of the USDW at 806 ft TVD. The inconsistency in depth between Plugs #2, #3, and the Base of the USDW will need to be resolved, and the corresponding well construction and plugging information updated accordingly.

Plug #4 (the surface plug) will plug the casing at the surface with at least 25 ft of cement. All cement plugs will be composed of a Class G cement blend that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The applicant does not explicitly state if this is the same cement used to cement the casing strings in well construction.

The plugging procedures that will be used to place these plugs appear to be acceptable, provided responses to the questions below are adequate. The plugging plan does not include a schematic.

Questions/Requests for the applicant:

- *Please include "flushing" among the steps to be completed prior to injection well plugging, in accordance with 40 CFR 146.92(a).*
- *Please revise the cement volume for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.*
- *Please reconcile the inconsistency in depth between Plugs #2, #3, and the Base of the USDW as shown in Table 1 of Attachment D and Figure 1 of Attachment G.*
- *Please correct the typo in the second bullet at the bottom of Attachment D, pg. 3, referring to the ">10,000 mg/L DTS."*
- *Please provide a plugging schematic and label the USDW and other relevant formations (i.e., the injection and confining zones) and perforations on the plugging diagram.*
- *Please confirm that the Class G cement blend is the same as the Class G Portland cement that was used in the well's construction, and that this cement is CO_2-resistant.*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

February 3, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit Nos. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3; Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Construction and Plugging Procedures for the two proposed injection wells for the subject permit application – Well 355-7R and Well 357-7R. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the two Enclosures.

Please submit the information requested in the Enclosures, by March 31, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or call Michele Dermer at (415) 972-3417.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.02.03 06:55:57 -08'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: Construction and Plugging Procedures for Injection Well 355-7R
Construction and Plugging Procedures for Injection Well 357-7R

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Evaluation of the AoR Delineation Modeling Approach in Carbon TerraVault's Monterey Formation A1-A2 Class VI Permit Application

This area of review (AoR) delineation modeling evaluation report for the proposed Carbon TerraVault 1 LLC (CTV) Class VI geologic sequestration project summarizes EPA's review of the modeling performed by CTV as described in the Area of Review and Corrective Action Plan (AoR CA), which is Attachment B to CTV's August 2021 permit application and associated files submitted to the AoR and Corrective Action Module of the GSDT. This review also addresses modeling-relevant site characterization information in the permit application narrative and in the PISC and Site Closure Plan (Attachment E). Because the AoR modeling accounts for both of CTV's proposed injection wells (357-7R and 355-7R), this evaluation applies to both wells. Clarifying questions for CTV and requests for supplemental information are provided in blue within the text below.

This report describes and evaluates how site-specific data (e.g., geologic data and planned operational conditions) described in the UIC permit application are incorporated into CTV's geomodel and their computational modeling approach. Note that EPA did not perform independent, duplicative modeling of CTV's AoR. It is assumed, however, that planned pre-operational testing will confirm the site characterization information. Please note that modifications to the model parameters may be needed if this testing yields results that are significantly different than the model inputs.

Evaluation of the Geomodel

Representation of Site Geologic Features

To delineate the Class VI AoR, the geological layering, formation thicknesses, and petrophysical properties of the project site (as described in the permit application narrative and evaluated in the geologic site characterization report) need to be integrated into a geomodel and then into a numerical model domain that is consistent with available information to generate predictions of plume and pressure front movement.

The CTV injection wells will inject into the Monterey Formation's A1-A2 Sands in the Elk Hills Oil Field (EHOF) within the San Joaquin Valley of California. The injection zone is within the Northwest Stevens Anticline, a northwest-southeast trending anticlinal structure located in the EHOF. The injection zone consists of stacked turbidite sands within the Monterey Formation and is interbedded with siliceous shales and clays. The Monterey Formation A1-A2 Sands pinch out towards the southeast, while the lowermost sands are present across the entire structure (as seen in Figure 1 of the AoR CA). The confining unit above the Monterey Formation is the Reef Ridge Shale, which is a regionally extensive deep marine, clay-rich interval with an average gross thickness of about 1,000 ft and a low matrix permeability. It has acted as the primary sealing unit for all Monterey Formation accumulations in the EHOF based on historical production well performance.

CTV used geologic and hydrologic data derived from multiple sources for their geomodel and numerical modeling approach. These sources include well data, open-hole well logs and core (Figure 2 in AoR CA), and reservoir performance information (including production and injection rates and volumes, reservoir, and wellbore pressures). The representation of site geologic features, including lithologic properties, geomechanical behavior, and fault presence, appears to be appropriate and is reflected in the

applicant's static geomodel and computational model. However, some information was omitted, including the injection zone fracture pressure derivation and stratigraphic discretization.

Questions/Requests for the applicant:

- *Please show the location of CTV's proposed Class VI injection wells in Figure 2 of the AoR CA. Additionally, provide a legend defining the various well icons in the figure.*

Representation of Hydrogeologic Properties and Lithology

Porosity, permeability, and rock types

Figure 3 of the AoR CA shows well penetrations that have data from open hole triple-combo logs (resistivity, neutron porosity, bulk density) and core data. Model parameters including porosity, facies, and clay volume were derived from the open hole logs and upscaled into the geological model using Gaussian random function simulation (kriging). Mercury injection capillary pressure (MICP) permeability data from core analysis was used to constrain the porosity-permeability function seen in Figure 5 of the AoR CA. Permeability is a function of porosity and clay volume. Figure 7 shows that the highest porosity and permeability values exist near the crest of the anticline, with decreased values on the limbs of the anticline. Additional discussion of porosity and permeability is included in pgs. 17-20 of the permit application narrative.

Questions/Requests for the Applicant:

- *The correlation coefficient in Figure 5 is illegible. Additionally, it is unclear what value (porosity or clay volume) is represented on the X-axis. Please render the correlation coefficient so that it is legible and clarify what value is used on the X-axis.*
- *The axes in Figure 6 are illegible. Please edit this figure so the X and Y axes are legible.*

Geomechanical properties

The geomechanical properties of the Monterey Formation A1-A2 reservoir and Reef Ridge Shale confining zone were derived from compressional sonic data and MICP measurements in 18 wells. Borehole breakout data from the EHOF and literature reviews also aided in characterizing fracture behavior. A corresponding geomechanical model was generated to assess the failure pressures for the reservoir and confining zone. CTV included relevant discussion concerning geomechanical modeling and properties in the permit application narrative; please also see the geologic site characterization report for discussion.

A summary of fracture pressure data for the Monterey Formation A1-A2 reservoir is provided in Table 6 of the AoR CA, which is replicated below. The applicant states that injection pressure will be below 90% of the Monterey Formation A1-A2 fracture gradient at the shallowest point of the Reef Ridge Shale base in the AoR (8,403 ft as seen in Table 7 of the AoR CA, replicated below). The planned maximum subsurface wellbore injection pressure for the project is 4,500 PSI.

Table 6: Summary of the fracture pressure data for the Monterey Formation A1-A2 reservoir.

Interval	Fracture Gradient PSI/foot	Fracture Pressure (PSI) at base of Reef Ridge Shale (8,403 feet)
Monterey Formation A1-A2	0.97	8,150

Table 7. Injection pressure details.

Injection Pressure Details	Injection Well 1 357-7R	Injection Well 2 355-7R
Fracture gradient (psi/ft)	0.97	0.97
Maximum injection pressure (90% of fracture pressure) (psi)	7,335	7,335
Elevation corresponding to maximum injection pressure (ft MSL)	8,403	8,403
Elevation at the top of the perforated interval (ft MSL)	8,485	8,462
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,407	7,387
Planned maximum injection pressure / gradient (top of perforations)	4,500 / 0.53	4,500 / 0.53

Questions/Requests for the Applicant:

- *What data from which tests were used to establish the fracture pressure listed in Table 6 of the AoR CA? Additionally, please discuss how testing during the pre-operational phase will further establish the fracture pressure of the injection zone. If Step Rate Testing (SRT) will be used to determine fracture pressure, please describe the testing procedure, including the fluid to be used and how it is representative of the CO_2 injectate.*
- *The elevations at the top of the perforated intervals (ft MSL) for Injection Wells 357-7R and 355-7R in Table 7 of the AoR CA do not correspond with the perforated interval depths for these Injection Wells in Table 5 of the AoR CA. Please revise this discrepancy and edit Table 5 and/or Table 7 accordingly.*
- *The planned injection pressure / gradient for Injection Wells 357-7R and 355-7R is listed as 4,500 psi / 0.53 psi/ft in the last row of Table 7 of the AoR CA. Please clarify if these values are indeed a maximum, or if they are a planned injection pressure/gradient. If they are not a maximum, please edit Table 7 to exclude the word "Maximum" in "Planned maximum injection pressure / gradient (top of perforations)."*

Objectives for Pre-Operational Testing:

- *Confirm the fracture pressure of the injection and confining zones, i.e., by performing an SRT in each zone.*

Geomodel – 3D model grid resolution and discretization

The Petrel static geomodel was used as the framework for the GEM numerical model. The geo-cellular grid is uniformly spaced throughout a 6.4 square mile area with a cell size of 150 ft x 150 ft. The model grid is oriented at 55 degrees, which corresponds to both the structural trend of the anticline and the depositional environment. The model boundaries were selected based on plume extent and the peripheral area of elevated pressure.

The reservoir was separated into two zones, corresponding to the A1 and A2 sands, each with 8 and 13 layers respectively and an average grid cell height of 11.5 ft (Figure 4 in AoR CA). Grid resolution was idealized based on simulation run-time and retaining reservoir heterogeneity. Note that the grid files were not submitted to the GSDT because, as CTV noted, the file is too large. However, the grid files are not needed at this time to support the evaluation.

Questions/Requests for the Applicant:

- *Please discuss how the lateral dimensions and vertical thickness of the Petrel static geomodel were chosen, and the significance of such values (i.e., 10 miles x 10 miles laterally, 3,000 ft thick).*
- *Please discuss how the total grid dimensions laterally and vertically (i.e., 200 x 200 cells laterally, 50 layers vertically) were chosen.*
- *Please discuss the vertical layers (stratigraphy) that were included in the model and why cell size height may vary between vertical layers.*
- *Please discuss why the Monterey Formation A1-A2 Sands were modeled as two separate zones, when according to the geologic narrative, they comprise a single hydraulically connected injection zone.*
- *Please show the extent of the AoR and the location of CTV's proposed Class VI injection wells in Figure 3 of the AoR CA.*
- *Please label the vertical layers shown in Figure 4 of the AoR CA, especially the injection and confining layers. Additionally, please show the location of CTV's proposed Class VI injection wells on the inset base map and cross-sectional views.*

Fault stability

Faults were not incorporated into the geomodel due to the lack of evidence of faults that transect the Monterey or Reef Ridge Shale Formations in the AoR. CTV included relevant discussion concerning fault stability in the permit application narrative; please also see the geologic site characterization report for discussion.

Evaluation of the Computational Model Design

The applicant's discussion of computational model design includes but is not limited to subsurface phase properties and behavior, CO_2 plume size and extent, boundary and initial conditions, timeframe and time steps, operational information, model calibration and sensitivity analysis, and injection zone storage capacity. EPA considers the applicant's evaluation of the computational model design and associated components to be appropriate and relatively complete, however there are several outstanding questions that need to be addressed in order to consider the material in this section sufficient. These questions are included under "Questions/Requests for the Applicant" in each of the following sub-headings, below.

Routines for Relevant Subsurface Processes

The applicant used Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM) to perform the AoR delineation. GEM is capable of modeling three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. The applicant states that CMG incorporates all relevant physics-based approaches to relate relative permeability to interfacial tension (IFT), velocity, composition, and hysteresis. CTV also referenced multiple CO_2 sequestration peer reviewed papers in which CMG's GEM software has been used. The Peng-Robinson Equation of State is used for the computational modeling of the CO_2 plume, and establishes the interaction or solubility of CO_2 and residual oil in the reservoir. The solubility of CO_2 in water is modeled by Henry's Law as a function of pressure, temperature, and salinity.

The permit application states that the evolution of the CO_2 plume involved: integrating reservoir characteristics and wells found in the static Petrel 3D geomodel; inputting injection pressure and rates in the GEM computational modeler; and assessing CO_2 plume movement throughout the injection and post-injection intervals until the plume reached pressure and compositional equilibrium.

Spatial extent

The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. In the AoR scenario, CO_2 was injected into the reservoir until the reservoir reached the initial discovery pressure of 4,000 psi. This process ensures that there is no increased pressure front beyond the original reservoir limits.

Questions/Requests for the Applicant:

- *Please explain the specific method used to define the AoR boundaries (i.e., percent CO_2 saturation cutoff or a qualitative method).*

Boundary conditions

No-flow boundary conditions were established for the Monterey Formation A1-A2 reservoir in the computational modeling. The overlying confining unit, the Reef Ridge Shale, is continuous through the area, has a low permeability (less than 0.01 mD), and has confined oil and gas operations (that include injection) since discovery of the field. Well performance data from the Monterey Formation A1-A2 oil and gas reservoir, shown in Figure 9 of AoR CA, indicates no connection to an aquifer. Historical production shows minimal water production, supporting the lack of aquifer connectivity. Gas injection and subsequent gas blow-down supports lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir. Finally, reservoir pressure is approximately 230 psi and has not shown an increase due to aquifer influx.

Questions/Requests for the Applicant:

- *Please provide historical pressure data for the Monterey Formation A1-A2 reservoir demonstrating pressure isolation.*

Time Steps and Model Timeframe

The computational modeling results for CO_2 plume development at 4 different time-steps are shown in plan view (Figure 10) and cross-sectional view (Figure 11). The time-steps are Year 2 injection, Year 4 injection, Year 50 post injection, and year 100 post injection. The model simulation appears to have occurred over a 115-year timeframe (i.e., the 15-year injection phase plus 100 years post-injection), but this is not clear. For all layers within the model and at all time-steps, the CO_2 plume remains within the 2.1 square mile AoR. Within the first 2 years of injection, the CO_2 plume is largely defined. After 2 years, the CO_2 concentration within the plume increases until the 50 years post injection time-step. The CO_2 concentration is largely unchanged between the 50-year and 100-year post injection time-steps.

CO_2 injected into the Monterey Formation A1-A2 reservoir will be soluble in both water and oil. Due to the low remaining oil and water saturations in the reservoir, the injected CO_2 that will be dissolved in oil and water is predicted to be 0.5% and 1.3%, respectively. The remaining 98% of the injectate will be stored in the reservoir as supercritical CO_2. Figure 12 of the AoR CA demonstrates the cumulative storage for each of these mechanisms (oil, water, supercritical CO_2).

Questions/Requests for the Applicant:

- *Please add the injection wells to Figures 10 and 11.*
- *Please label the vertical layers on Figure 11.*
- *Please provide additional time steps in Figures 10 and 11, in particular, to represent the full extent of the injection phase (i.e., to the end of the injection phase) and the early post-injection phase (e.g., at 1, 3, 5, and 10 years after cessation of injection).*
- *Please add a discussion regarding the time at which the CO_2 plume is expected to reach its maximum vertical and lateral extent. Additionally, please discuss the boundaries at which this extent is defined.*
- *Please clarify the total simulation period (i.e., whether it is 100 years total or the injection period plus 100 years).*
- *Based on Figure 12, there is no additional CO_2 to be stored after year 5 of injection; however, the permit application narrative indicates injection will occur for 15 years. Please clarify this difference.*

Initial Conditions and Operational Information

Initial model conditions at the beginning of CO_2 injection have been established and verified over time during oil and gas production from the Monterey Formation A1-A2 reservoir. Initial conditions for the model are given in Table 4, which is replicated below. Operational information is presented in Table 5.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	240	Fahrenheit	8,300	Fluid Analysis
Formation pressure	200-300	Pounds per square inch	8,300	Pressure Test
Fluid density	61	Pounds per cubic foot	8,300	Water analysis
Salinity	25,000	Parts per million	8,300	Water analysis

Table 5. Operating details.

Operating Information	Injection Well 1 357-7R	Injection Well 2 355-7R
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft MSL) Z top Z bottom	 7,728 8,010	 7,774 7,949
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15
Injection rate (t/day)*	648 – 1,917	648 – 1,917

Questions/Requests for the Applicant:

- *The initial conditions in Table 4 were established at a depth of 8,300 ft MSL. The perforation intervals for Injection Wells 357-7R and 355-7R specified in Table 5 are above 8,300 ft MSL. Please explain how the initial conditions at a depth of 8,300 ft MSL would be representative of the perforation intervals in Injection Wells 357-7R and 355-7R.*
- *Please add the reference elevation to Table 4.*

Relative permeability and capillary pressure curves

Gas, oil, and water are all present in the Monterey Formation A1-A2 reservoir. Contact depths have been derived from open-hole logs, production analysis, and history matching, and saturations have been assumed; however, the plan does not provide the basis for the assumptions. With all three phases present in the reservoir, three-phase relative permeability relationships were used in the computational model to characterize the flow of each phase. To determine three-phase relative permeability, two sets of two-phase relative permeability data are needed: water-oil and gas-oil relative permeability. The two-phase relative permeability relationships allow the determination of Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Core flood and MICP data were used to determine the two-phase relative permeability relationships. Figure 8 of the AoR CA presents the relative permeability curves used in the computational modeling.

Questions/Requests for the Applicant:

- *Please explain the method used for determining the saturation values for gas, oil, and water.*
- *Please include definitions for Krw, Krow, Krg, and Krog.*

- *Please explain how the relative permeability relationships vary with rock type, and how these permeability relationships were derived.*

Potential Pathways for Fluid Movement

Faults

CTV included relevant discussion concerning fault stability in the permit application narrative; please also see the geologic site characterization report for discussion.

Wells in the AoR

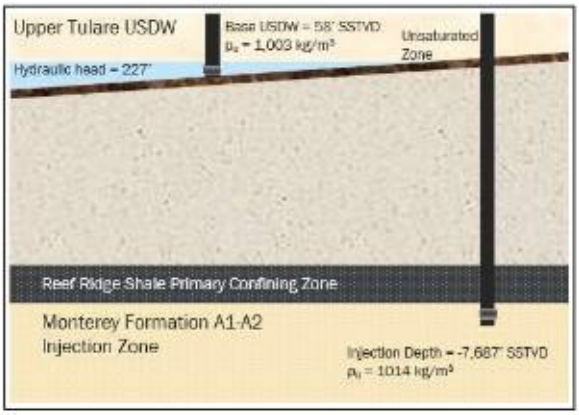
The AoR CA says that complete documentation of the 152 wells in the AoR (tabulated in Table 8 of the AoR CA) that penetrate the Reef Ridge Shale confining zone is given in Appendix 1, and Figure 15 of the AoR CA shows a map view of the 152 wells that penetrate the Reef Ridge Shale confining layer and Monterey Formation A1-A2 reservoir. However, it is unclear how many of the 152 wells penetrate the entire Reef Ridge Shale or are completed in the Reef Ridge Shale, and if they are accounted for in the computational model. Additional discussion regarding wells in the AoR is presented under "Corrective Action on Wells in the AoR," below.

Calculation of critical pressure

CTV submitted their critical pressure calculation to the GSDT in a file titled "Critical—Pressure—Calculation.PDF." Using the inputs from Figure 4 and equation listed on pg. 3 of the Critical—Pressure—Calculation PDF, the critical pressure was calculated to be 3,400 psi. The final pressure of the Monterey Formation A1-A2 reservoir will be at or below the initial reservoir pressure of 4,000 psi, ensuring that post-injection conditions replicate those of initial conditions to the extent possible. Therefore, the AoR is based on the extent of the modeled CO_2 plume.

$$\frac{P_{i,f}}{\rho_i g} + z_i = \frac{P_u}{\rho_u g} + z_u$$

Figure 4: Schematic section of the storage site with inputs to critical pressure calculation. Values for the USDW are based on the 326-7R well. The injection depth is based on the 357-7R injector. Using data from wells 357-7R injector and 326-7R the critical pressure is 3,400 PSI.



Questions/Requests for the Applicant:

- *Please define the variables shown in the critical pressure calculation and their corresponding values shown in Figure 4 of the Critical—Pressure—Calculation PDF.*
- *The injection depth shown in Figure 4 of the Critical—Pressure—Calculation PDF (7,687 ft SSTVD) is different than the perforated depths shown in Table 5 of the AoR CA (7,728 ft MSL). Please confirm that this difference is due to ground level reference elevation. If not, please change the depth in Figure 4 and/or Table 5 to reflect the correct injection depth.*
- *If any of the 152 wells in the AoR penetrate the entire Reef Ridge Shale, please explain how they are accounted for in the geomodel.*

Representation of Fluid Properties

Because a baseline injectate analysis has not yet been performed, limited information about the CO_2 stream is available and relevant CO_2 injectate fluid properties for the numerical modeling are not included in the AoR CA. The applicant did not submit an operating plan for the proposed wells with this information. Additionally, the applicant did not include reactive transport modeling as part of the overall modeling effort. It appears this might be due to the low water saturation (~15%) and dominant quartz/feldspar mineralogic framework of the reservoir, as noted in the permit application narrative. However, an explanation regarding the lack of reactive transport modeling is needed.

Questions/Requests for the Applicant:

- *Please update the AoR CA to include fluid properties for the CO_2 injectate used in the computational modeling, including but not limited to viscosity, density, salinity, and fluid compressibility.*
- *Please explain why reactive transport modeling was not performed or included in the computational model.*

Objectives for Pre-Operational Testing:

- *Confirm that the properties of the CO_2 stream based on pre-operational injectate sampling are consistent with the model inputs.*

Model Calibration and Sensitivity Analyses

CTV used information derived from extensive past injection operations to inform a sensitivity analysis. The CO_2 plume model results were compared with the area of the reservoir that has been depleted by oil and gas operations.

As a computational model sensitivity, CTV maintained the injection rate for 9 years, with an increase in the final post-injection pressure and total CO_2 injected. The left panel in Figure 13 of the AoR CA represents this scenario, and the panel on the right demonstrates CO_2 plume development at a post injection reservoir pressure equivalent to the initial reservoir pressure. At a final reservoir pressure of 5,750 psi, which is greater than the initial reservoir pressure of 4,000 psi, the reservoir can store 193 BCF of CO_2, which is an increase of 61 BCF relative to initial reservoir pressure storage capacity. Both scenarios demonstrating the difference in CO_2 plume development are depicted in Figure 13 at 100 years post injection. The CO_2 plume remains within the AoR in both scenarios, with CO_2 concentrations

increasing in the northwestern portion of the AoR. The applicant concludes that this scenario demonstrates that the AoR is consistent with a larger volume of injected CO_2 and the potential impact to the Upper Tulare USDW is conservative. Monitoring wells will be used for CO_2 plume and pressure front tracking, via fluid sampling and pressure and temperature monitoring. Reservoir pressures based on monitoring data and injection volumes will be integrated in order to complete material balance equations to verify pore volumes and AoR edges. Additionally, the CO_2 plume and water contact will be calculated from the monitoring well pressure, CO_2 saturation, and column height. If the reservoir pressure associated with injected volumes does not follow the anticipated trend from computational modeling, CTV will reevaluate the AoR. (Additional evaluation of the proposed plume and pressure front tracking will be presented in the Testing and Monitoring report.)

Questions/Requests for the Applicant:

- *Please discuss the genesis and evolution of minor CO_2 concentrations pictured in Figure 13 in the central to eastern portions of the AoR.*
- *Please provide a version of Figure 13 corresponding to the end of the injection period and/or the time at which the plume and pressure front are expected to be at their maximum extent.*
- *Was a sensitivity analysis conducted on grid geometry and petrophysical properties?*
  - *If so, please discuss the sensitivity analysis and its results.*
  - *If not, please perform a sensitivity analysis*

Injection Zone Storage Capacity

As stated in the "Model Calibration and Sensitivity Analyses" section above, the storage capacity of the injection zone appears to be 132 BCF of CO_2 at initial reservoir pressure conditions of 4,000 psi (193 BCF minus 61 BCF as mentioned in the discussion of Model Calibration and Validation of the AoR CA, pg.15). The injection zone does have the potential to store an increased volume of CO_2 at higher pressures while the CO_2 remains within the defined AoR.

Questions/Requests for the Applicant:

- *The modeled injection zone storage capacity is not explicitly stated in the AoR CA. Please confirm if the volume of 132 BCF is correct. If it is not correct, please provide the correct volume.*

Presentation of Model Results

Map and cross-sectional views of the simulated plume and pressure front were provided in the AoR CA. The maps show the position of the plume and pressure front after 2 years and 4 years of injection, and 50 years and 100 years post-injection. Figures 10 and 11 show the applicant's proposed AoR as delineated by the simulated CO_2 plume.

The differences in the predicted position of the plume and pressure front between the injection and post-injection time-steps were minor, suggesting that the plume movement may remain stable after injection ceases. Updated modeling will be necessary when pre-operational site data becomes available.

Corrective Action on Wells in the AoR

The AoR CA says that documentation of the 152 wells in the AoR that penetrate the Reef Ridge Shale confining zone is provided in Appendix 1. However, no tabulation of these wells is provided. There is an

Excel file (AoR—Well--List) containing the name, surface location, and status of 152 wells, but it does not contain information on drill date, type, and depth to Reef Ridge Shale confining zone that is required at 40 CFR 146.84 (c)(2). Table 8 of the AoR CA indicates that 40 of the 152 wells are plugged (which corresponds to information in the Excel file). Figure 15 of the AoR CA shows a map view of the 152 wells that penetrate the Reef Ridge Shale confining layer and Monterey Formation A1-A2 Sands. These wells were reviewed for corrective action.

All 152 wells in the AoR penetrate the confining zone. This determination was made by reviewing open hole logs and deviation surveys of each well. The AoR CA plan says that well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The wells located within the AoR were last reviewed in Q1 of 2021.

The AoR CA also states (pg. 18) that 14 wells (shown in Table 9) will be plugged before commencement of CO_2 injection. These are abandoned wells that penetrate and are currently perforated in the Monterey Formation A1-A2 Sands or the Etchegoin Formation. It is unclear based on the text if these are the only wells that penetrate entirely through the Reef Ridge Shale, however.

The AoR CA plan says that the corrective action assessment for each well in Appendix 1 included the generation of wellbore/casing diagrams, determination of cement tops for each casing string, review of open perforations and cement plug depths. However, Appendix 1 has not been provided.

Protection of the USDW was determined by assessing all wells within the AoR that penetrate the Reef Ridge Shale. Wells were determined to not need corrective action if they had: surface or intermediate casing over the USDW; were cemented over the USDW; had cement in the intermediate casing-surface casing annulus, above the surface casing shoe; and there was cement in the production casing annulus, above the Reef Ridge Shale. The application states that all wells within the AoR meet these criteria.

Questions/Requests for the Applicant:

- *Please provide additional documentation to support the statement that all the wells meet the corrective action evaluation criteria for protection of the USDW, as described on pg. 18. For example, are the wells that penetrate the Reef Ridge Shale confining zone and Monterey Formation A1-A2 Sands cemented over these zones? If cement coverage is absent for these wells over the Reef Ridge Shale confining zone and Monterey Formation A1-A2 Sands injection reservoir, it may be necessary to address corrective action of these wells in the AoR CA Plan.*
- *Please provide Appendix 1. The table should include a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion, as required at 40 CFR 146.84 (c)(2).*
- *Please provide the plugging and abandonment (P&A) procedure for the 14 wells identified in Table 9 of the AoR CA to demonstrate that plugging will ensure isolation of the Monterey Formation A1-A2 Sands.*
- *Please clarify the distinction of the 14 wells on Table 9 to be plugged. Specifically, are these wells deficient in any manner; are they the only wells that penetrate the entire thickness of the Reef Ridge Shale; or, are they just slated to be plugged as part of field operations?*
- *Please denote Injection Wells 357-7R and 355-7R, the monitoring wells, and the 14 wells to be plugged on Figure 15 of the AoR CA.*

AoR Reevaluation Schedule

CTV described the procedures and timing for AoR reevaluations to be performed during the injection and post-injection phases, and the information that will be considered in the reevaluations. At this point in the permit application review, the five-year default reevaluation schedule in the Class VI Rule appears to be appropriate.

Questions/Requests for the Applicant:

- *EPA requests the following revisions to the AoR reevaluation procedures to provide a more robust analysis:*
    - *Include a review of the full suite of water quality data collected from monitoring wells in addition to CO_2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation). Also, review and provide any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.*
    - *Clarify that the reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation).*
    - *Specify that, if the results of the modeling comparison are consistent, a report describing this determination will be provided.*
    - *Describe the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).*

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An unscheduled reevaluation of the AoR will take place if any of the following scenarios occur:

1) Change in operations such as an increase in injection rates, or injection pressure.

2) Differences between the computational model for CO_2 plume development and observed CO_2 plume development, including unexpected changes in fluid content or pressure outside of the Monterey Formation A1-A2 reservoir that are not related to well integrity, or reservoir pressure that does not behave as predicted with increased injection volumes.

3) Seismic events occur that indicate the presence of faults near/intersecting the confining zone; events that are larger than a 3.5 magnitude and that could be associated with CO_2 injection.

CTV will discuss any such event with the UIC Program Director to determine if an AoR reevaluation is necessary. If an unscheduled reevaluation is triggered, the AoR reevaluation procedures described in the AoR CA plan will be initiated.

Questions/Requests for the Applicant:

- *Please describe the specific injection rate and injection pressure increase CTV referenced that would necessitate an AoR reevaluation, and how such an increase would not involve an exceedance of permit limits.*
- *Please clarify the degree of change in reservoir pressure (e.g., outside three standard deviations from the average) that would be needed to necessitate an AoR reevaluation.*

- *Please clarify the timing for conducting an AoR reevaluation (i.e., within 6 months) if any of the triggering events occur.*
- *Please clarify the area over which seismic events greater than M3.5 (e.g., consistent with the Emergency and Remedial Response Plan) would trigger an AoR reevaluation.*
- *EPA recommends that the following events be added to the triggers for an AoR reevaluation:*
    - *Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.*
    - *Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).*
    - *Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);*
    - *A significant change in injection operations, as measured by wellhead monitoring;*
    - *Significant land-use changes that would impact site access; and*
    - *Any other activity prompting a model recalibration.*

Post-Injection Site Care Plan

Certain elements of the applicant's Post-Injection Site Care (PISC) and Site Closure Plan (Attachment E) are based on the modeling effort and the results and are evaluated below. See also the Testing and Monitoring report (for an evaluation of CTV's post-injection monitoring plan).

As required in 40 CFR 146.93(a)(2)(i) and (ii), the applicant presented the pre- and post-injection pressure differentials and associated maps in the AoR CA. Figure 3 of Attachment E shows the predicted maximum extent of the CO_2 plume and pressure front at site closure.

Figures 4 and 5 of Attachment E show the injection and monitoring wells, and the predicted extent of the CO_2 plume in plan view and cross-sectional view, respectively.

Questions/Requests for the Applicant:

- *Figure 1 in Attachment E shows the reservoir pressure stabilizing at the same time as injection cessation. Please clarify if reservoir pressure will stabilize at this point, or if pressure will stabilize a year after injection cessation as noted in Attachment E, "Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]."*
- *Please update Figure 1 to reflect the planned 15-year injection period.*
- *CTV submitted an updated version of Attachment E in December 2021; however, this document appears to be identical to the initial plan submitted in August 2021. Please clarify what information was updated in the December 2021 version.*

Post-Injection Site Care Time Frame

The applicant proposed a 50-year post injection site care time frame and will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). The applicant is not proposing an alternative post-injection site care timeframe, so no evaluation relative to the criteria at 40 CFR 146.93(c) is needed.

Non-Endangerment Demonstration Criteria

CTV did not identify the contents of or criteria by which it would support a non-endangerment demonstration at the end of the post-injection site care phase. EPA recommends that CTV propose and include in the PISC and Site Closure Plan a set of criteria that are as specific as possible and can be supported by the data CTV will collect during injection and post-injection testing and monitoring. Incorporating this into the PISC and Site Closure Plan will help reduce future uncertainty and help ensure that CTV will collect the types and amounts of data that are needed to inform a demonstration that site closure is appropriate. EPA recommends that the non-endangerment demonstration criteria address the evaluation of available groundwater and plume monitoring data; comparison of monitoring data to model predictions; evaluation of the CO_2 plume and reservoir pressure; and an evaluation of any unanticipated events that occurred during the project. See, e.g., Section 3.4 of EPA's "UIC Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance."

Some specific recommendations to support the preparation of a section of the PISC and Site Closure Plan related to non-endangerment demonstration criteria are provided below:

- *The criteria should specify that the same delineation model that supported the initial AoR delineation will be used in AoR reevaluations and to make the non-endangerment demonstration. This will facilitate verification and/or model calibration using actual monitoring and operational data.*
- *The criteria should discuss the predicted behavior of the CO_2 plume and pressure front, supported by maps and graphs (e.g., of pressure profiles or extent of the plume and pressure front) in the context of the data that will be collected to demonstrate that the plume and pressure front are behaving as predicted at various points in time.*
- *The data that will support the non-endangerment demonstration should be consistent with the final injection and post-injection phase testing and monitoring strategies in Attachments C and E. They should also be specific as to the types/locations of data that will be gathered and compared against the model prediction to facilitate model validation (e.g., the formations for which groundwater quality data will be collected and pressure monitoring locations).*
- *The criteria should include an evaluation of natural and artificial potential conduits for fluid movement.*
- *The non-endangerment criteria should include evaluations of mobilized fluids and passive seismic data.*
- *The non-endangerment criteria should include a summary of any emergencies or other unanticipated events that may occur during the injection and post-injection phases. This may be presented in a table that shows (1) examples of unanticipated events that might occur, and (2) the types of data that might be used to demonstrate that any associated issues have been resolved such that they will no longer endanger USDWs.*

Evaluation of Proposed Testing and Monitoring Activities at Carbon TerraVault's Monterey Formation A1-A2 Class VI Project

This testing and monitoring evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's review of the testing and monitoring the applicant proposes to conduct during and following injection operations into the Monterey Formation A1-A2 Sands. Due to the similarities of certain monitoring activities (e.g., groundwater monitoring and plume and pressure front tracking) to be performed in the injection and post-injection phases, these activities (as described in Attachments C and E of the Class VI permit application dated August 30, 2021, and Attachment E with information specific to well 355-7R submitted on December 3, 2021) are evaluated in a single report. This review identifies preliminary questions for the applicant, includes requests for supplemental information, and provides some considerations for future testing/analytical requirements. Note that, because of the interdependencies between the testing and monitoring strategy and other aspects of the permit application, additional questions may arise as other reviews proceed. This evaluation addresses both injection wells (Well 357-7R and Well 355-7R); specific evaluations unique to each well are detailed under "Injection Well Testing" below. CTV will need to prepare separate Testing and Monitoring Plans for each injection well if Class VI injection permits are issued.

CTV notes that they will report the results of all injection-phase testing and monitoring activities in compliance with the requirements of 40 CFR 146.91. All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases.

Carbon Dioxide Stream Analysis

To meet the requirements of 40 CFR 146.90(a), CTV plans to analyze the carbon dioxide (CO_2) stream quarterly for the constituents identified in Table 1 of the Testing and Monitoring Plan, which is replicated below.

Parameter	Analytical Method(s)
Oxygen	ASTM D1945
Nitrogen	ASTM D1945
Carbon Monoxide	ASTM D1945
Total hydrocarbons	ASTM D1945
Methane	ASTM D1945
Hydrogen Sulfide	ASTM D1945/D6228
CO_2 purity	ASTM D1945
Total Sulfur	ASTM 3246

There are no EPA-approved analytical methods for CO_2 injection streams, and the methods listed on Table 1 are not included among EPA-approved wastewater analytical methods in 40 CFR Part 136 (nor are they used in other Class VI CO_2 injection permits). Many of the analytes are to be analyzed using

ASTM D1945, which is the Standard Test Method for Analysis of Natural Gas by Gas Chromatography. Based on the physical states of natural gas and CO_2, this test may be appropriate for CO_2 injectate analysis; however, no specific information or justification was provided in the application materials and there is no publicly available (free-of-charge) information available about these ASTM methods.

Table 4 of the Quality Assurance Surveillance Plan (QASP), Summary of Analytical Parameters for CO_2 Stream, also lists analysis of ethanol using method EPA 8260B. Although there is no EPA-approved analytical method for ethanol analysis in wastewater, this method is acceptable.

CTV is evaluating several sources of CO_2 as injectate for the project, and states that it will notify EPA prior to switching or adding CO_2 sources so that the sampling procedures can be reassessed. EPA will require that a sample be analyzed prior to initiation of injection.

CTV states that it will increase the sampling frequency if there is a significant change in the chemical or physical characteristics of the CO_2 injectate, a change in the CO_2 injectate source, or if the facility or injection well experiences a downtime over more than 30 days. Any change in the injection fluid would require advance notice and written approval from EPA.

Questions/Requests for the Applicant:

- *Please provide additional information on the ASTM methods listed in Table 1, including why CTV considers them to be appropriate for CO_2 injectate analyses. For example, ASTM D1945 is for the analysis of natural gas. Does the method clearly indicate that it can be used to analyze CO_2 injectate?*
- *Please update Table 1 to reflect that the analytical method for total sulfur is ASTM D3246 (the "D" is missing from the table).*
- *Please add analysis of ethanol using EPA method 8260B to Table 1 to be consistent with Table 4 of the QASP.*
- *Please add quarterly sampling of argon, hydrogen, oxides of nitrogen, ammonia, and δ13C to the list of analytes to fully characterize the CO_2 stream.*
- *Please also add H_2O as a CO_2 stream analyte on Table 1 to provide information about the presence of free phase water, as discussed in Attachment G.*
- *ASTM D3246 appears to have several available subparts for various substances to be tested; please specify the method to be used for sulfur analysis of the CO_2 injectate.*
- *Please clarify the year of all the ASTM methods (e.g., ASTM D3246-15) in Table 1.*
- *CTV states that quarterly sampling will begin three months after the date of authorization of injection; please revise this timeline to begin three months after the commencement of injection so that the testing schedule is consistent with injection operations.*

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *EPA will require a baseline injectate sample be analyzed for the same parameters as in the Testing and Monitoring Plan prior to commencement of injection.*
- *If this sample or any updated information about injection formation fluids indicates that any injectate constituents may lead to geochemical reactions that could affect operations or change aquifer properties, additional analytical parameters for the injectate analysis may be requested.*

Injection Well Testing

The subsections below describe: the planned quarterly corrosion monitoring; continuous recording of injection pressure, rate, and volume to evaluate internal mechanical integrity; and annual external MITs that will meet the requirements at 40 CFR 146.90(b), (c), and (e). This portion of the testing and monitoring evaluation addresses both injection wells (Well 357-7R and Well 355-7R); however, CTV will need to provide a Testing and Monitoring Plan for each well, with unique well-specific testing (particularly for corrosion monitoring and continuous monitoring) that reflects each well's design.

Corrosion Monitoring

CTV proposes to conduct corrosion monitoring using the coupon method. The corrosion coupons will be in the pipeline that feeds CO_2 injectate to the injectors. Corrosion monitoring will occur between the compressor and wellhead, according to Table 1 of the QASP.

Samples of the materials used in the construction of the pipeline and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials will be weighed, measured, and photographed prior to installation. The coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The specific methods by which the samples will be handled are not described in the testing and monitoring plan; however, Table 5 of the QASP indicates that analytical methods include NACE TM0169/G31 and EPA 1110A SW846.

CTV says that, if the corrosion rate is greater than 0.3 mils/year, it will initiate consultation with regulatory agencies (in this case EPA), and may run a casing inspection log to assess the thickness and quality of the casing.

The proposed coupons will be composed of the materials summarized in Attachment C, Table 3. The materials identified for corrosion monitoring were compared to the list of proposed construction materials for the injection well in Attachment G (Construction details) for Well 357-7R (submitted with the initial permit application on August 30, 2021) and Well 355-7R (submitted December 2, 2021). The first two columns of the table below are adapted from Table 3 of the Testing and Monitoring Plan (list of equipment coupon with material of construction), with review notes in the right-hand columns.

Coupon (Attachment C, Table 3)	**Construction Material (Attachment C, Table 3)**	**Review Notes based on Information in Attachment G**	
		Well 357-7R	**Well 355-7R**
Pipeline	CS A106B	Not identified	Not identified
Casing	N80 Steel	Intermediate and Long-string: N80 (pg. 2)	Intermediate and Long-string: N-80, K-55 (Table 5)
Tubing	13 CR-95	13 CR-95 (pg. 2)	L-80 (Table 6)
Wellhead	Stainless steel	Not identified	Not identified

The coupons proposed for corrosion monitoring of the casing and tubing match those described in Attachment G for injector 357-7R. However, it appears that Well 355-7R has different construction, and a corrosion testing program specific to the 355-7R injector is needed. Although the materials of

construction for the pipelines and wellheads are not described in Attachment G, it is assumed that coupons would be selected to represent these materials.

Questions/Requests for the Applicant:

- *Please describe the corrosion coupons for a corrosion testing program specific to the 355-7R injector.*
- *Please clarify that CTV will discuss any detected corrosion rate of more than 0.3 mils/year with EPA.*
- *For completeness, please include the details about the analytical methods for corrosion coupon monitoring that are described in Table 5 of the QASP into the Testing and Monitoring Plan.*
- *Please provide the list of construction materials to be used for the pipeline and wellhead so that they can be compared to the proposed coupon materials for the corrosion testing program.*
- *Under "monitoring details," Attachment C says that the coupons will be sent to a lab for analysis every 6 months. Corrosion monitoring must be performed on a quarterly basis, per 146.90(c); please revise the Testing and Monitoring Plan accordingly.*

Continuous Monitoring to Evaluate Internal Mechanical Integrity

CTV will install and use continuous recording devices to monitor: injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Surface injection pressure will be set to a minimum of 1,200 psi, eventually reaching 2,000 psi at the cessation of injection operations, as noted in the discussion of "Operational Procedures" in the permit application narrative. For Well 357-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 3,800 psi (surface) and 6,100 psi (downhole) are not exceeded. For Well 355-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 2,900 psi (surface) and 6,108 psi (downhole) are not exceeded.

Additionally, a surface pressure gauge will be installed on the annulus to monitor the annular pressure and ensure the integrity of the packer and tubing. However, the annular pressure needed to signify a mechanical integrity issue is not indicated by CTV.

The maximum injection rate of 30 million standard cubic feet per day (mmscfpd) and average injection rate of 10-15 mmscfpd will be monitored by a surface flowmeter. The calculation of injection volumes will be calculated using the injection flow rate and CO_2 stream density and will be used to ensure the maximum expected injection volume does not exceed 10 million tonnes.

Temperature gauges will be employed at surface and downhole to monitor the temperature of the injectate and ensure it is consistent with the expected temperature of the CO_2 stream at a given depth. Additional evaluation of the well monitoring equipment will be provided in the Well Construction reports for the injection wells.

Table 2 of Attachment C lists sampling devices, locations, and frequencies for continuous monitoring and is replicated below.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	30 seconds	30 seconds
Injection rate	Flowmeter	Surface	30 seconds	30 seconds
Injection volume	Calculated	Surface	30 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	30 seconds	30 seconds
CO_2 stream temperature	Temperature gauge	Surface and Downhole	30 seconds	30 seconds

Questions/Requests for the Applicant:

- *Please clarify the location/depths of the downhole temperature and pressure gauges listed on Table 2. These should also be depicted on the well schematics.*
- *Please add monitoring of the annulus fluid volume to Table 2 to match the activities required at 40 CFR 146.90(b).*
- *Please explain the appropriateness of a 30 second minimum sampling and recording frequency versus at a higher frequency (e.g., 10 seconds).*
- *Please explicitly define the annular pressure deviation that would warrant a mechanical integrity investigation.*

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The maximum pressure thresholds identified for continuous monitoring and the annulus pressure in Attachment C may need to be adjusted to reflect the final permit conditions (e.g., if they change based on the results of pre-operational testing).*

External MITs

To verify external mechanical integrity as required at 40 CFR 146.89(c) and 146.90, CTV proposes to perform MITs annually. CTV also proposes to perform these same MITs prior to commencing injection.

Table 6 of Attachment C lists the MITs to be performed and is reproduced below.

Test Description	Location
Temperature Log	Along wellbore via wireline well log
Radioactive Tracer Survey (RTS)	Along wellbore via iodine

On page 9 of Attachment C, CTV only indicates that it will run a temperature log (and not a radioactive tracer log) and notes that if it elects to conduct an alternate MIT, it will request approval from EPA. (EPA notes that, if CTV opts to use an alternative MIT, the Class VI permit would need to be modified to incorporate this test.) CTV presents procedures for MIT temperature logging but does not describe the radioactive tracer logging procedures.

Questions/Requests for the Applicant:

- *Please revise the temperature logging procedure to include a minimum of 4 hours between runs. Additionally, please provide more extensive temperature logging procedures, e.g., in accordance with the document, "Appendix E – Temperature Logging Procedures – U.S.E.P.A. Region IX," which is available online at: https://archive.epa.gov/region9/water/archive/web/pdf/appendixetemplogreqs.pdf.*
- *Please provide a detailed description of the MIT testing procedures for RTS.*
- *CTV states that MITs will be performed annually, within 30 days of the injection authorization date. Please revise this timeline to coincide with the commencement of injection so that the testing schedule is consistent with injection operations.*
- *Table 6 describes the location of the RTS to be "along wellbore via iodine" it is assumed that this refers to the specific tracer to be used. Please clarify and edit the table to read "along wellbore via iodine tracer," if appropriate.*
- *The Emergency and Remedial Response Plan includes scenarios for monitoring well MI failures, however no MIT of the monitoring wells is described in the Testing and Monitoring Plan. Please provide procedures and plans for performing MITs in the deep monitoring wells.*
- *Please include MITs on the monitoring wells and the EOR wells to be used for deep monitoring as part of the Testing and Monitoring Plan.*
- *Attachment G describes Annulus Pressure Testing Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1. Please also include internal and external MITs during the injection and post-injection phases and describe these in Attachments C and E.*

Pressure Fall-Off Testing (PFOT)

CTV states that it will perform pressure fall-off tests during the injection phase to meet the requirements of 40 CFR 146.90(f). However, the attachment also says that "CTV does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2 Sands. CTV says that it will consider pressure fall-off testing if the injection rate decreases, with a simultaneous injection pressure increase outside the results of computational modeling. A pressure fall-off test must be performed prior to injection and at least once every 5 years, per the Class VI Rule.

Attachment C also provides a brief description of PFOT procedures.

Questions/Requests for the Applicant:

- *Please clarify in the Testing and Monitoring Plan that a pressure fall-off test will be performed every 5 years during the injection phase, as required by 40 CFR 146.90(f).*
- *Please provide more detailed PFOT procedures, e.g., in accordance with the document, "EPA Region 9 UIC Pressure Falloff Requirements," which is available online at: https://archive.epa.gov/region9/water/archive/web/pdf/falloff-testing-guidlines.pdf.*

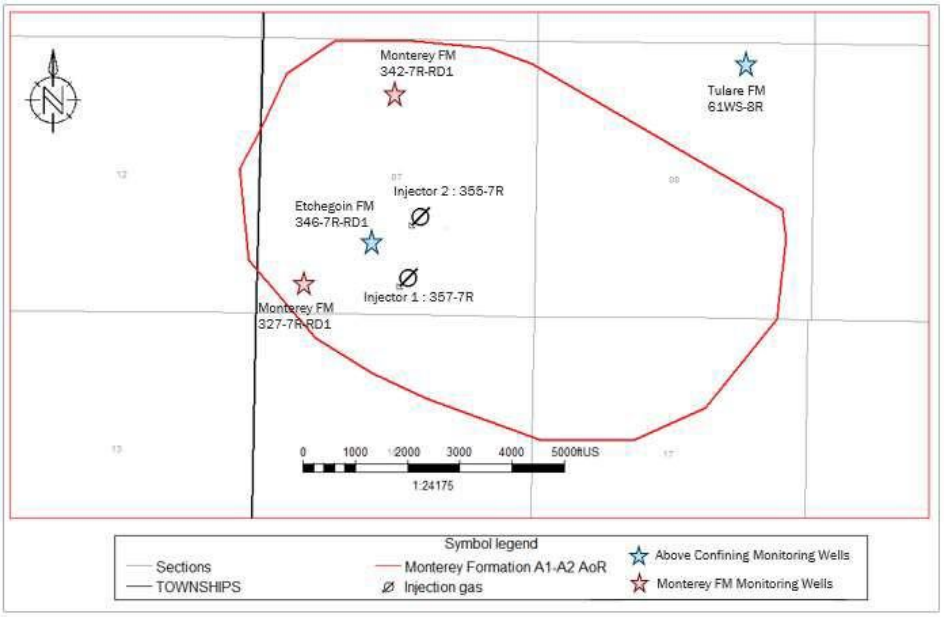
Groundwater Quality Monitoring

CTV proposes to monitor groundwater quality in existing wells above the confining zone using direct and indirect methods. To meet the requirements of 40 CFR 146.90(d), CTV proposes to perform the following monitoring above the confining zone:

- Annual injection-phase water quality monitoring and continuous pressure and temperature monitoring via one well located outside of, and to the northeast of, the delineated AoR in the Upper Tulare Formation (the lowermost USDW) and the Lower Tulare Formation. Post-injection water quality sampling will continue annually and continuous pressure monitoring in the USDW is proposed.
- Continuous monitoring of pressure and temperature in the Etchegoin Formation within a monitoring well located to the west of the injection wells.

Attachment E does not describe any monitoring in the Etchegoin or the Monterey Formation A3-A11 Sands after cessation of injection. However, EPA will likely require that post injection phase monitoring be an extension of injection phase monitoring to confirm continued demonstration that USDWs are not endangered and to inform the non-endangerment demonstration required at 40 CFR 146.93(b)(3).

Figure 2 of the QASP shows the locations of all monitoring wells associated with the project and is reproduced below.



The Etchegoin Formation monitoring well appears to be situated within the AoR and in the anticipated path of the CO_2 plume and pressure front (based on information in Attachment B). The Upper/Lower Tulare Formation monitoring well is outside of the delineated AoR to the northeast of the injection wells, and down plume. Given that the Tulare Formation does not hold much water within the AoR, this location, while not in the same direction as the deeper monitoring wells may be most appropriate to allow geochemical sampling, although it is unlikely that CO_2 will travel that far down the limb of the anticline. CTV states that additional Upper Tulare monitoring wells will be drilled if increased pressure is observed in the Etchegoin Formation monitoring well or water quality changes in the Tulare Formation that is due to Monterey Formation A1-A2 CO_2 injection. However, it is unclear how a linkage of water quality/pressure changes to CO_2 injection (and not other activities) would be made.

The applicant proposes to monitor water quality in the Upper/Lower Tulare Formation and the Monterey Formation during the injection and post-injection phases. The analytical and field parameters and methods described in Tables 5 and 8 of Attachment C (injection-phase monitoring of the Tulare and Monterey Formations, respectively) are nearly the same as those in Tables 2 and 5 of Attachment E. Additional information about monitoring in the Monterey Formation is described under "CO_2 Plume Tracking" below. CTV also proposes to perform a baseline water analysis in the Etchegoin Formation monitoring zone and in the Tulare Formation monitoring well.

Table 5 of Attachment C (Injection-phase Tulare Formation monitoring) is reproduced in the first two columns of the table on the next page. Because consistency of monitoring parameters above and within the injection zone is appropriate for detecting leakage of the CO_2 plume, EPA evaluated proposed injection and post injection monitoring in the Tulare and Monterey Formations together. EPA's notes and recommendations are provided in the right-hand column; see also the discussion of "Quality Assurance Procedures" below for additional comments on the parameters to be monitored.

The parameters appear to be generally appropriate for groundwater quality monitoring needs for GS projects, and are consistent with other Class VI monitoring programs, except as noted below. As the permit application narrative describes (pg. 39), the Monterey A1-A2 Sands are dominated by quartz and feldspar, which are stable in the presence of CO_2 and carbonic acid. Note that, as additional information is gathered based on the reviews of other parts of the permit application or pre-operational data collection, recommendations or requirements for additional analytical parameters may be provided.

Parameters	Analytical Methods	Evaluation Notes/Recommendations
Tulare Formation		
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B	200.7 and 6010B are both ICP-AES methods, not ICP-OEC. Please explain what ICP-OEC is or revise the table. In Table 17 of the QASP, the final cation is Ti, not Tl as in Attachment C. Please clarify/be consistent. Also, this is "T1" in the tables of Attachment E; please correct the typographical error. Cations of Sb are also mentioned in Table 17 of the QASP; please add this to the ground water monitoring parameters in Attachments C and E. 200.7 is an EPA-approved wastewater analytical method, while 6010B is not. EPA requests that Method 200.7, Rev 4.4 (1994) be specified.
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B	See above.
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	Attachment E and Table 17 of the QASP also include anions of Cl; please add this to Attachment C for consistency and completeness. Tables 2 and 5 of Attachment E reference EPA Method 300; please revise the method to be consistent with Attachment C (i.e., Method 300.0). Also, please specify that EPA Method 300.0, Rev. 2.1, Part A (1993) will be used.
Dissolved CO_2	SM 4500-CO2-C	No comments.
Total Dissolved Solids	SM 2540 C	Attachment E refers to SM 4500 C for TDS; EPA requests the use of SM 2540 C for consistency.
Alkalinity	SM 2320 B	Attachment E refers to SM 2510, which is for conductivity, not alkalinity. EPA requests that CTV revise Attachment E to reference SM 2320 B for consistency. (SM 2320 B is an approved wastewater method.)
pH (field)	EPA 150.1 / SM4500-H+B	No comments.
Specific Conductance (field)	SM 2510 B	SM 2510 B is named by SM as a laboratory method, and it is not clear whether SM 2510 B can be conducted in the field. EPA Method 120.1 may be more amenable to field screening if SM 2510 B is not. Please clarify if field use of SM 2510 B is possible or revise the table (i.e., field vs. lab designation) or the method.
Temperature (field)	Thermocouple	No comments.
Dissolved Methane	RSK-175/Gas Chromatography	This method was developed by EPA but is not an EPA approved method for wastewater analysis. Please provide information to support the use of this method for dissolved methane analysis. Alternatively, consider using EPA-approved method SM 6211 B and/or 6211 C.

EPA recommends in Class VI guidance that monitoring well construction and planned plugging procedures for monitoring wells be reviewed as part of the permit application evaluation to confirm that

these wells will not provide conduits for fluid movement that could endanger USDWs. No monitoring well construction or plugging information was provided in the permit application materials.

CTV should note that the Central Valley Water Board indicated in its consultations with EPA on a prior Class VI project that any newly drilled monitoring wells must be approved by the Water Board and, while existing wells would not need to be approved, the Water Board expressed interest in any plans to use existing wells as monitoring wells.

Attachment C also describes the water quality sampling procedures, the laboratory to be used, and chain of custody procedures. This information is detailed in the QASP as well.

Questions/Requests for the Applicant:

- *Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E as noted in the table above. Further, the same analytes and methods should be used for monitoring of all formations - to provide consistent data to support modeling reviews and a non-endangerment demonstration.*
- *In addition, please include additional ground water quality parameters to support a robust monitoring program, as follows:*
    - *δ13C, which is mentioned in the QASP, but not in Attachments C and E.*
    - *Water density (which is referenced in the Testing and Monitoring Plan as an expected water quality change due to plume movement on pg. 12).*
    - *Dissolved O_2 and H_2S. Dissolved O_2 is a primary indicator of water quality. H_2S occurs in the subsurface, may be common in oil fields, and has the potential to be mobilized, and, is listed as a toxic substance by the CDC.*
- *Please include sampling/measurement depths in Table 4 of Attachment C and Table 1 of Attachment E for clarity and completeness.*
- *Table 4 of Attachment C indicates that CTV will perform pressure and temperature monitoring in the Tulare Formation, but Table 1 of Attachment E indicates that only pressure monitoring is planned. Please revise Attachment E to be consistent or explain why temperature monitoring will not continue in the post-injection phase.*
- *Please include quarterly (rather than annual) water quality monitoring during the injection phase to: confirm that the CO_2 is being confined, help validate modeled predictions, and eventually support the non-endangerment demonstration.*
- *Please add water quality monitoring of the Etchegoin Formation - to provide earlier warning of water quality changes than would be identified in the Tulare Formation monitoring well.*
- *Please explain the appropriateness of a single Tulare Formation monitoring well location relative to the anticipated direction of plume and pressure front movement, and, given the size of the injection operation. Additionally, please confirm that the predominant groundwater flow direction in the Tulare Formation is easterly. If flow direction is not easterly, provide an updated groundwater well monitoring plan that includes appropriate well placement in relation to groundwater flow direction.*
- *Please provide schematics of all the wells to be used for monitoring that depict the sampling equipment/gauges to be used, and their depths, including the EOR wells (to be used for plume tracking), and the sampling at two depths in the Tulare Formation monitoring well.*
- *Please also provide plugging and abandonment plans for all the monitoring wells.*

- *Attachment C states that pressure and temperature monitoring in the Etchegoin Formation is planned at 3,828 feet TVD, which is significantly shallower than the Reef Ridge Shale confining zone (at 6929 feet, per the permit application narrative). Please explain how monitoring at this depth will provide early indication of pressure changes above the confining zone.*
- *Please include post-injection pressure and temperature monitoring in the Etchegoin Formation to Attachment E.*
- *Please describe post-injection monitoring in the Tulare Formation well that continues the injection-phase monitoring, including post-injection monitoring in the Lower Tulare Formation and continuous temperature (in addition to pressure) monitoring.*
- *The PISC and Site Closure Plan states (on page 4) that sampling in the Tulare Formation will occur every 5 years, and Table 1 lists the Tulare Formation fluid sampling frequency as annual. Please revise the text to match Table 1.*
- *The Testing and Monitoring Plan states, on page 7, that additional Tulare Formation monitoring wells would be drilled if pressure or composition changes due to CO_2 injection are detected. Please describe how this linkage to CO_2 injection would be made.*
- *Please include the groundwater monitoring well 61WS-8R in Figure 4 of the PISC and Site Closure Plan.*
- *Is Zalco laboratory a state-certified laboratory? Please note that EPA's Class VI UIC guidance recommends use of a laboratory that is state-certified.*

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of groundwater quality analytical parameters may need to be updated to ensure that all applicable parameters are included.*

CO_2 Plume and Pressure Front Tracking

The applicant describes proposals for CO_2 plume and pressure front tracking that include: (1) the use of direct and indirect methods for tracking the pressure front within the injection zone [40 CFR 146.90(g)(1)]; and, (2) direct pressure front monitoring in two monitoring wells and seismic monitoring to indirectly track the extent of the CO_2 plume [40 CFR 146.90(g)(2)].

For post-injection site care, CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. In Attachment E, Table 4 details the methods that will be used to monitor the CO_2 plume post-injection, and Table 6 details the methods that will be used to monitor the associated pressure front. Injection reservoir pressure monitoring will occur to ensure confinement of the reservoir and consistency with computational modeling results. As seen in Table 6 of Attachment E, seismicity monitoring will also occur via surface and shallow borehole seismometers. Table 5 of Attachment E lists the analytical methods that will be used for the injection zone fluid monitoring and analysis.

CO_2 Plume Monitoring

CTV proposes to monitor the plume via direct and indirect monitoring in the Monterey Formation:

Direct plume tracking methods include:

- Annual fluid sampling during the injection and post-injection phases in Monterey Formation A1-A2 Sands via two monitoring wells (327-7R-RD1 and 342-7R-RD1, located to the southwest and the northwest of the injection well, respectively).

- Quarterly fluid sampling during the injection phase in EOR producers in the Monterey A3-A11 Sands. The location of the EOR wells is not described.

Indirect plume monitoring includes:

- Pulse neutron logging in the Monterey Formation A1-A2 Sands via the same monitoring wells. This logging will be conducted every two years during the injection phase and every 5 years during the post-injection phase.

The parameters and associated analytical methods are presented in Table 8 of Attachment C. They are identical to those proposed for Tulare Formation water quality monitoring described under "Ground Water Monitoring" above. Deep and shallow water quality monitoring should be for the same parameters to provide consistent data on which to evaluate potential fluid movement out of the confining zone.

Figure 2 of the QASP (reproduced under "Groundwater Monitoring" above) shows the location of the monitoring wells in the Monterey Formation A1-A2 Sands. CTV asserts that modeling indicates that the CO_2 plume will reach each of these monitoring wells by the second year of injection.

Pressure Front Monitoring

CTV plans to conduct **direct pressure front monitoring** by continuously monitoring pressure and temperature during the injection and post-injection phases within the Monterey Formation A1-A2 Sands via pressure gauges in monitoring wells 327-7R-RD1 and 342-7R-RD1.

Indirect pressure front monitoring will be accomplished via seismic monitoring throughout the AoR. CTV states that it will monitor seismicity with surface and shallow borehole seismometers it plans to install, as well as monitor seismic data from the Southern California Earthquake Data Center (SCEDC) network. This continuous monitoring will continue throughout the injection and post-injection phases.

Pressure-front monitoring activities are summarized in Table 9 of Attachment C and Table 6 of Attachment E.

Questions/Requests for the Applicant:

- *Please refer to EPA's questions and recommendations under "Groundwater Monitoring" above regarding water quality analysis and revise Table 8 of Attachment C and Table 5 of Attachment E accordingly.*
- *Please edit Table 8 to refer to the Monterey Formation, rather than the Tulare Formation to reflect monitoring in the A3-A11 Sands.*
- *Please elaborate on the monitoring in the Monterey Formation A3-A11 Sands as described on page 12 of Attachment C. Specifically, where are the EOR producers from which CTV plans to sample the Monterey Formation A3-A11 Sands? At what depths will sampling be performed, and what parameters will be analyzed for? (The analytical parameters should be consistent with other monitoring.) Please describe who owns these wells, and whether they will be operational throughout the injection and post-injection periods? Please include the locations of these wells on the relevant figures in Attachments C and E and the QASP.*
- *Please describe the seismic monitoring network discussed on pg. 16 of Attachment C, including the number and location of the seismometers that CTV proposes to install.*
- *Please explain the timeframe for which a seismicity baseline will be established, and if historical seismicity will be incorporated into this baseline.*
- *Page 15 of Attachment C says that CTV plans to perform direct pressure monitoring in the Monterey Formation A1-A2 Sands, and Table 9 indicates that pressure and temperature monitoring will be performed. Please revise the statement on pg. 15 to be consistent with the table – to include temperature as well as pressure.*
- *EPA recommends that the sampling/measurement depths be included in Tables 7 and 9 of Attachment C and Tables 4 and 6 of Attachment E for clarity and completeness.*
- *Attachment C states (pg. 11) that, if plume development is not consistent with modeling results, CTV will assess whether additional monitoring of the plume is necessary. Please clarify in the plan that this determination would be made in consultation with the UIC Program Director and that this would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.*
- *Please make the following changes to the proposed plume and pressure front tracking in Attachments C and E:*
    - *Perform frequent sampling and logging (e.g., quarterly, or semi-annually) early in the injection phase (i.e., at least until the CO_2 plume passes the monitoring well locations). This would allow the acquisition of additional data to validate the modeling, provide early warning of unanticipated fluid movement, and be consistent with other Class VI projects.*
    - *Conduct a 3D seismic survey or a vertical seismic profile during injection operations for comparison to the 2019 3D seismic survey described in the application narrative.*
    - *Conduct quarterly water quality sampling in the A1-A2 Sands for plume tracking to be consistent with the A3-A11 monitoring activities as well as provide additional data points to validate modeled predictions, and to eventually support the demonstration of non-endangerment.*

Air/Soil or Other Testing and Monitoring

Based on the currently available information about the geologic setting (i.e., the depth of the injection formations and the lack of evidence for the presence of transmissive faults of fractures), surface air and/or soil gas monitoring are not needed to detect movement of fluid that could endanger USDWs within the AoR.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If, based on the results of planned pre-operational testing, uncertainties about the geologic setting are identified, the need for air and/or soil gas monitoring or other monitoring will be reconsidered.*

Quality Assurance Procedures

The review team evaluated the QASP submitted with the permit application to verify that all the testing activities, analytes, etc., included in the QASP are consistent with proposed injection and post-injection phase testing and monitoring. All the injection and post-injection testing and monitoring activities (except for pressure falloff testing) are addressed in the QASP and the QASP covers activities recommended by EPA. EPA noted a few discrepancies between the tables in the QASP and the activities described in Attachments C and E. These are summarized in the table below:

QASP Table	**EPA comments**
Table 1. Summary of testing and monitoring.	Cement bond logs and standard annulus pressure tests of the injection wells are listed in the QASP, but these tests are not described in Attachment C. Please clarify if these tests are planned to be performed, either as part of pre-operational or injection-phase testing, or revise the QASP accordingly. Please add PFOT and RTS to Table 1.
Table 2. Monitoring Well Summary.	Monitoring the A3-A11 Sands via the EOR wells is not included on Table 2 of the QASP; please include this for consistency.
Table 3. Summary of analytical and field parameters for ground water samples.	Please update the placeholders for specific cations and anions in Table 3 to reflect Table 17 of the QASP. This table should address sampling in formations other than the Tulare Formation (per recommendations above). There is a typo in the pH (field): the method “SPA 150.1” should be “EPA 150.1”
Table 5. Summary of Analytical Parameters for Corrosion Coupons.	Please include the QC Requirements on Table 5.
Table 17. Summary of sample containers, preservation treatments, and holding times for ground water samples.	There are a few discrepancies between the analytical parameters mentioned on Table 17 of the QASP and in Attachments C and E. EPA recommends the following changes for consistency: • Please revise the parameter NO_2 in Table 17 of the QASP to be consistent with NO_3, which is a planned analyte, per Attachments C and E.

QASP Table	EPA comments
	• Add cations of K (in Tables 5 and of Attachment C and Tables 2 and 5 of Attachment E) to Table 17. • Please also make other necessary revisions to Table 17 of the QASP to address EPA's requests related to analytical parameters under "Ground Water Monitoring" above.
Other	Please fix the formatting of the Table of Contents for Section B.1. a.

Evaluation of Operating Procedures in Carbon TerraVault's Monterey Formation A1-A2 Permit Application

This evaluation for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration project summarizes our review of proposed operating procedures for injection wells 355-7R and 357-7R, per 40 CFR 146.82(a)(7),(9),(10) and 146.88. CTV submitted information about Wells 355-7R and 357-7R in their initial Class VI permit application narrative dated August 30, 2021 and submitted additional information about injection Well 355-7R in an amended Narrative (Attachment A2, submitted on December 2, 2021). Operation of the two injection wells is evaluated in this single report. Our review identifies preliminary questions and includes requests for supplemental information from the applicant. This evaluation of the proposed operating conditions, particularly injection rates and pressures, was performed in conjunction with EPA's evaluation of the applicant's AoR delineation modeling (which is documented in a separate report).

The proposed operational procedures (which appear to be specific to Well 357-7R) are described on page 47 of the initial Narrative and summarized in Table 8, which is replicated below:

Table 8 of initial Narrative (for Well 357-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	3,800	Psig
Downhole	6,100	Psig
Average Injection Pressure		
Surface	1,600	Psig
Downhole	4,100	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,730 @ packer	Psig
Annulus Pressure/Tubing Differential	370@packer @ average injection condition	Psig

The proposed operational procedures for Well 355-7R are described in the amended Narrative (Attachment A2) and summarized in a revised Table 8, which is replicated below:

Table 8 of updated Narrative (for Well 355-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	2,900	Psig
Downhole	6,108	Psig
Injection Pressure		
Surface Average / Maximum	1,400/1,600	Psig
Downhole Average / Maximum	4,300 / 4,516	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,720 @ packer	Psig
Annulus Pressure/Tubing Differential	578@packer @ average injection condition	Psig

Injection Pressure

The basis for the proposed maximum injection pressure (MAIP) is described in Attachment B – the AoR and Corrective Action Plan (AoR CA). CTV states that the MAIP will be below 90% of the fracture pressure of the Monterey Formation at the base of the Reef Ridge Shale confining zone, and is calculated as follows:

$$8{,}150 psi \times 0.9 psi/ft = 7{,}335\ psi$$

Where:

Fracture pressure (Fp) at base of confining zone = 8,150psi

Safety factor = 0.9 (90%)

Tables 6 and 7 of the AoR CA provide fracture gradients and fracture pressures for the Monterey Formation A1-A2 reservoir, and are replicated below:

Table 6		
Interval	**Fracture Gradient psi/ft**	**Fracture Pressure (psi) at base of Reef Ridge Shale (8,403 ft)**
Monterey Formation A1-A2	0.97	8,150

Table 7		
Injection Pressure Details	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Fracture gradient (psi/ft)	0.97	0.97
Maximum injection pressure (90% of fracture pressure) (psi)	7,335	7,335
Elevation corresponding to maximum injection pressure (ft MSL)	8,403	8,403
Elevation at the top of the perforated interval (ft MSL)	8,485	8,462
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,407	7,387
Planned maximum injection pressure / gradient (top of perforations)	4,500 / 0.53	4,500 / 0.53

The maximum injection pressure listed in Table 7 of the AoR CA for injection wells 357-7R and 355-7R does not correspond to the maximum injection pressure in Table 8 of the Narrative or the amended Narrative. Additionally, the proposed injection pressures of 4,500 psi in Table 7 of the AoR CA exceed the proposed average injection pressures of 4,100 psi, listed in Table 8 of the Narrative. It appears that, regardless of the discrepancy in maximum injection pressures, CTV proposes to operate at an injection pressure of 4,100 – 4,500 psi, well below 90% of the injection zone fracture pressure. However, the proposed injection pressures will need to be confirmed as being below 90% of the fracture pressure at the top of the perforations (i.e., within the Monterey Formation injection zone), and the discrepancy in maximum injection pressures will need to be resolved.

CTV states in the AoR CA that their current Class II UIC permit mandates a maximum operating pressure gradient of 0.80 psi/ft unless additional testing indicates a higher gradient. It appears that CTV conducted a test(s) to obtain a higher fracture gradient, 0.9 psi/ft, as seen in Table 6 of the AoR CA, above. However, these tests are not described in the application and will need to be provided for validation of the fracture pressure of the injection and confining zones and the corresponding maximum injection pressures. A question for the applicant regarding this topic is included in the AoR CA Evaluation.

Questions/Requests for the applicant:

- *Please provide separate stand-alone versions of Attachment A for Well 357-7R and Well 355-7R that describe operating conditions. The attachments should include the following: injection well operating conditions (e.g., a tabular description of surface and bottomhole maximum injection pressures, annulus pressure, annulus pressure/tubing differential, and the maximum CO_2 injection rate); how the maximum injection pressure was determined; a description of routine shutdown procedures; and tables summarizing reporting of well and project-related monitoring.*
- *Attachment E (the PISC and Site Closure Plan), page 1 states that the Monterey Formation A1-A2 reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. Please clarify that injection limits (e.g., pressures) will be based on the fracture pressure of the injection zone.*

- *The maximum downhole injection pressures in Table 8 of the Narrative (6,100 psi for Well 357-7R and 6,108 psi for Well 355-7R) do not correspond to the pressure listed in Table 7 of the AoR CA (7,335 psi). Please reconcile this difference and update the tables as needed.*
- *Please confirm that the maximum downhole injection pressures in Table 8 of the Narrative (6,100 psi for Well 357-7R and 6,108 psi for Well 355-7R) are correct, i.e., that there is a 900 psi difference in surface pressure and an 8 psi difference in downhole pressure.*
- *Please provide the fracture pressure (psi) at the top of the perforations in injection wells 357-7R and 355-7R within the Monterey Formation and confirm the proposed maximum injection pressure does not exceed 90% of this value, per the requirement at 40 CFR 146.88(a).*

Annulus Pressure and Annulus/Tubing Pressure Differential

The applicant notes in Attachment C (the Testing and Monitoring Plan) that the surface pressure of the casing-tubing annulus for injection wells 357-7R and 355-7R will remain between 0 – 800 psi during injection operations.

Regarding Well 357-7R and in Table 8 of the initial Narrative excerpted above, the annulus pressure/tubing differential is 370 psi at the packer at the average injection pressure of 4,100 psi, resulting in a 3,730 psi annulus pressure at the packer. Table 8 defines the 3,730 psi annulus pressure as a proposed limit or permitted value, however this pressure occurs at the average injection pressure of 4,100 psi. Clarification is needed to ensure that the 3,730 psi annulus pressure at the packer is indeed a proposed maximum limit and corresponds to a maximum injection pressure. Additionally, the applicant will need to confirm that the 3,730 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C. If the above is confirmed, the annulus pressure of 3,730 psi at the packer is well below the tubing and packer burst strengths of 12,450 psi and 8,160 psi respectively, as noted in Table 7 of Attachment A, which is excerpted below.

Casing specifications for Well 357-7R (Table 6 of Attachment A)

Table 6. Casing details.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	60	24	0.55	20	J-55	94
Surface	501	17.5	0.33	13.375	H-80	48
Intermediate	3516	12.25	0.395	9.625	N-80	40
Long String	2,953	8.75	0.317	7	N-80	23
	6,158	8.75	0.362	7	N-80	26
	6,158 – 8,990	8.75	0.408	7	N-80	29

Tubing specifications for Well 357-7R (Table 7 of Attachment A)

Table 7. Tubing and packer details.

Material	Setting Depth	Tensile Strength	Burst Strength	Collapse Strength	Material
Tubing	8,454	105,000	12,450	12,760	13 CR-95
Packer	8,447	10,000	8,160	7,020	Baker-Hornet, Ni plated

Regarding Well 355-7R, the same clarifications need to be made regarding proposed maximum annulus pressure and the equivalent surface pressure as described for well 357-7R above. In Table 8 of the updated Narrative, the annulus pressure/tubing differential is 578 psi at the packer at the average injection pressure of 4,300 psi, resulting in a 3,720 psi annulus pressure at the packer. Clarification is needed to ensure that the 3,720 psi annulus pressure at the packer is indeed a proposed maximum limit and corresponds to a maximum injection pressure. Additionally, the applicant will need to confirm that the 3,720 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C. If the above is confirmed, the annulus pressure of 3,720 psi at the packer is well below the tubing and packer burst strengths of 9,020 psi and 8,000 psi respectively, as noted in Table 6 and 7 of Attachment A2, excerpted below.

Tubing specifications for Well 355-7R (Table 6 of Attachment A2)

Table 6. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,398	00	3.920	135	L-80	Long	9,020	8,540

Packer specifications for Well 355-7R (Table 7 of Attachment A2)

Table 7. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	8,000	8,000	6.466	6.184

Questions/Requests for the applicant:

- *For injection well 357-7R, please clarify that a 3,730 psi annulus pressure at the packer is the proposed maximum limit and that it corresponds with the maximum injection pressure. Additionally, please confirm that a 3,730 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C.*
- *For injection well 355-7R, please clarify that a 3,720 psi annulus pressure at the packer is the proposed maximum limit and that it corresponds with the maximum injection pressure.*

Additionally, please confirm that a 3,720 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C.

- *The outside diameter of the injection tubing for Well 355-7R (on Table 6 of Narrative A2) is stated as "00." Please correct.*

Maximum CO_2 Injection Rate

The applicant proposes a daily CO_2 injection rate of 648 to 1,917 tons per day, which equates to 236,520 to 699,705 tons/year (or 3.5 – 10.5 million tons over the planned 15-year injection phase of the project) as seen in Table 5 of the AoR CA and excerpted below. However, the applicant notes in the Narrative that the storage capacity of the Monterey Formation A1-A2 reservoir is approximately 8 – 10 million tonnes of CO_2 based on computational modeling results. The maximum storage capacity of 10 million tonnes of CO_2 is slightly less than the projected maximum volume of 10.5 million tonnes of CO_2 based on daily injection rates as seen in Table 5 below (assuming injection activities will occur 365 days per year). Based on an evaluation of the AoR delineation modeling and geologic site characterization, it appears that the injection and confining zones are appropriately characterized; however, the range of proposed daily injection rates allow for the exceedance of the modeled storage capacity. The applicant should reconcile this inconsistency and provide an updated range of daily CO_2 injection rates that satisfies the modeled CO_2 storage capacity. See the AoR CA evaluation report for additional discussion.

Table 5. Operating details.

Operating Information	Injection Well 1 357-7R	Injection Well 2 355-7R
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft MSL) Z top Z bottom	 7,728 8,010	 7,774 7,949
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15
Injection rate (t/day)*	648 – 1,917	648 – 1,917

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

In the Testing and Monitoring Plan (pg. 5), CTV states that the volume of CO_2 injected into the Monterey Formation A1-A2 Sands will be calculated from the injection flow rate and CO_2 density, and that density will be determined from the Massachusetts Institute of Technology's CO_2 Thermophysical Calculator (https://sequestration.mit.edu/tools/index.html). However, upon investigation of the online calculator, it appears to no longer be operational. The applicant should provide another method by which the CO_2 density will be calculated.

Questions/Requests for the applicant:

- *Please include a description of standard operating procedures to ensure that the maximum daily injection rate will not be exceeded.*
- *Please update the daily CO_2 injection volumes in Table 5 of the AoR CA to ensure they are consistent with the modeled cumulative injection volumes of 8 – 10 million tonnes of CO_2 over 15 years.*
- *The Massachusetts Institute of Technology's CO_2 Thermophysical Calculator is no longer operational. Please revise the methodology by which the CO_2 density will be calculated.*

Shutdown Procedures

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the shutdown plan will be initiated in response to multiple risk scenarios, including well integrity failure, monitoring equipment failure, natural disasters, USDW contamination, CO_2 leakage, and seismic events. The Plan defines "initiating the shutdown plan" as immediately ceasing injection. It also states (on pg 1) that "gradual cessation of injection" may be appropriate in certain circumstances if approved by the UIC Program Director. However, the application does not describe procedures for shutting down the well, either for routine workovers or in response to emergency events (other than those that warrant an immediate shutdown). Documenting such procedures will ensure that procedures are in place to shut down the well in a manner that will not damage the well and cause a mechanical integrity issue.

Questions/Requests for the applicant:

- *Please describe the procedures for "gradual cessation of injection," i.e., the rate of injection volume reduction over a specified number of days.*
- *Please also describe routine well shutdown procedures (e.g., for well workovers), and if these would be the same as the gradual shutdown procedures discussed above.*

Automated Shutdown System

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the automatic shutdown devices are activated if wellhead pressure exceeds the specified shutdown pressure listed in the permit, or if the annulus pressure indicates a loss of external or internal well containment. However, standard operating procedures that support the automated shutdown system are not provided.

Questions/Requests for the applicant:

- *Please include standard operating procedures to support the automated shutdown system.*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

January 11, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and No. R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the area of review (AOR) delineation, testing and monitoring activities, and operating procedures for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the three Enclosures.

Please submit the information requested in the Enclosures by February 25, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Michele Dermer at (415) 972-3417.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.01.11 10:58:13 -08'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: AOR Delineation Modeling Approach
Testing and Monitoring Activities
Operating Procedures

cc (via email): Mark Ghann-Amoah, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Site Characterization Evaluation of the Carbon TerraVault (CTV) Class VI A1-A2 Permit Application

This geologic site characterization evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of the geologic narrative submitted as part of CTV's Class VI permit application (dated August 30, 2021). This review also identifies preliminary questions for the applicant. Where specific information is lacking based on the currently available information, this evaluation identifies testing objectives that EPA recommends be incorporated into the Pre-Operational Testing Plan.

Regional Geology and Geologic Structure

The Elk Hills Oil Field (EHOF) is in Kern County, California, in the southern San Joaquin Basin (Figures 1 and 2) CTV plans to inject CO_2 at the EHOF into the Monterey Formation via 2 injection wells, 355-7R and 357-7R, over a period of 15 years. The 2 injection wells are 1,250 feet apart and will inject into the Monterey Formation A1-A2 reservoir (Monterey A1-A2) at the Northwest Stevens Anticline at ~8,500 ft depth (Figure 8 and pg. 4).

The Monterey Formation at the EHOF also contains the Miocene Reef Ridge Shale (the primary confining zone), which directly overlies the Monterey A1-A2 and has been an effective seal for 40+ years of oil and gas operations (pg. 9). Figures 4 and 5 show the spatial distribution of wells in the EHOF and data available for use in characterizing the injection zone.

The Monterey A1-A2 consists of turbidite sands bounded above and below by siliceous shale (pg. 9). The application asserts that this depositional history has resulted in minimal lateral communication of the Monterey A1-A2 outside the EHOF (Cross Section Figure 3, pg. 4; pg. 9). The reservoir is continuous across the area of review (AoR), with pinch-outs on the channel edges (pg. 9).

The Upper Tulare Formation is the lowermost underground source of drinking water (USDW). The Tulare Formation consists of poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley (pg. 7). It is divided into the Upper Tulare and the Lower Tulare by the Amnicola Clay (a low permeability claystone). An aquifer exemption was approved for the Lower Tulare Formation in 2018, making the Upper Tulare Formation the lowermost USDW.

In addition to the Reef Ridge Shale, the Monterey A1-A2 Sands are separated from the lowermost USDW in the Upper Tulare Formation by the Amnicola Clay (pg. 31), the Lower Tulare Formation, the San Joaquin Formation, a depleted gas reservoir directly underlying the Tulare Formation, and the Etchegoin Formation (pg. 8). The Monterey A1-A2 Sands are separated from the underlying Monterey A3-A11 reservoir by a laterally continuous 20-foot shale known as the A2 Shale (Figure 9). The application asserts that they are not in communication, as evidenced by a pressure differential (of 200-300 psi in the A1-A2 and ~1,700 psi in the A3-A11), and the need for separate pressure maintenance strategies (pg. 10). The A3-A6 reservoir is also considered a viable target for future CO_2-EOR based on its existing waterflood injector infrastructure and high reservoir pressure (pg. 11).

Tests and logs performed during drilling and prior to completion of the 357-7R injection well and the 342-7R-RD1 and 327-7R-RD1 monitoring wells (which are completed in the Monterey Formation and are

located to the west and northwest of the injectors) include Array Compensated True Resistivity, SP logs, caliper logs, compensated spectral natural gamma log, spectral density dual spaced neutron log, and mud logs (Attachment G pg. 4-5). Cement bond logs and MIT tests (temperature log and SAPT) were also performed on the 357-7R injection well.

Questions/Requests for the Applicant:

- ***Please label the injection wells or the injection well site on Figure 2.***
- ***Was any data collected or testing performed during drilling of the 355-7R injection well? If so, please characterize this data.***
- ***The AoR and Corrective Action Plan (on pg. 3) states that, the "Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation." Please clarify the difference between the A2 Shale and the Lower Antelope Shale.***
- ***Does the Antelope Shale provide confinement? If so, please provide additional discussion of the confining properties.***
- ***What is the source of the statement about the pressure differential between the Monterey A1-A2 Sands and the Monterey A3-A11 Sands described on pg. 10?***
- ***Please provide pressure build-up test results for the 357-7R injection well.***
- ***Several of the figures in the narrative that contain data are difficult to read (e.g., Figures 14 and 15); please provide higher resolution versions of this information.***
- ***Please provide a map of the Elk Hills Oil Field that shows the 355-7R and 357-7R injection wells, along with the wells planned for the Elk Hills 26R Storage Project (with a scale that shows distances).***

Objectives for Pre-Operational Testing:

- ***Confirm hydraulic separation of the Monterey A1-A2 Sands and the Monterey Formation A3-A11 reservoir.***
- ***If no pressure build-up test results exist for the 357-7R injection well, perform pressure build-up testing as part of the Pre-Operational Testing Plan.***

Faults and Fractures

The 31S and Northwest Stevens (NWS) anticlines in the EHOF are separated by mid-Miocene thrust faults (pg. 12). The application states that the Reef Ridge Shale and Monterey Formation are well resolved based on seismic data, and there is no evidence of faults penetrating the Reef Ridge Shale or transecting the Monterey Formation (pg. 13). Figure 10 shows reverse faults in seismic profiles, however the resolution is too low to discern formation labels (pg.12). These reverse faults, oriented NW-SE, offset the NWS anticline (pg. 12).

Evidence for confinement includes 3D seismic and well data confirming the absence of faults penetrating the Reef Ridge Shale, 40+ years of previous waterflooding and gas injection operation, pressure differentials across formations (i.e., 230 psi in the Monterey A1-A2 Sands and 1,500 psi in the Etchegoin Formation for a 0.43 psi/ft pressure gradient at 3,600 ft depth), and geochemical analysis of 66 oil samples (Zumberge, 2005; Figure 12).

Questions/Requests for the Applicant:

- ***Please update Figure 10 to clearly label the formations in which the thrust faults terminate.***
- ***Where were the 66 oil samples collected within the EHOF described on pp 13-14, relative to faults within the field?***

Depth, Areal Extent, and Thickness of the Injection and Confining Zones

At the site of the injection wells, the stratigraphic sequence from top to bottom consists of the Tulare Formation, the San Joaquin and Etchegoin Formations, the Reef Ridge Shale confining zone, and the Monterey Formation injection zone (pg. 4, 7). The depths and thicknesses of the injection and confining zones were determined based on wireline logs and 3D seismic data and are presented in Table 1 of the application narrative. In the AoR, the Reef Ridge Shale thickness is controlled by the Monterey Formation deposition patterns and minimum thickness corresponds to a highpoint in the Monterey Formation Sand thickness (pg. 15).

The table below summarizes the depth and thickness of the formations of interest according to available data in the permit application narrative. Some depth/thickness information for the San Joaquin or Etchegoin Formations was not provided; however, this is not critical for the purposes of the application evaluation. Porosity and permeability data are presented as well; additional discussion of these characteristics is provided under "Geomechanical and Petrophysical Characterization."

Unit	**Average Depth within the AoR**	**Thickness Across the AoR**	**Porosity**	**Permeability**
Tulare Formation	600-2,500 ft (pg. 31)	1,200-1,500 ft (pg. 31)	34-40% (pg. 7)	1,410-8,150 mD (pg. 7)
San Joaquin Formation	Not given	Not Given	28%-45% (pg. 8)	64-6,810 mD (pg. 8)
Etchegoin Formation	1,500-4,000 ft (pg. 8)	Not Given	29-37% (pg. 9)	32-826 mD (pg. 9)
Reef Ridge Shale (Confining Zone)	6,929 ft-7,962 ft TVD (Table 1, Figure 13)	1,122-1,892 ft (Table 1, Figure 13)	7.7% (pg. 6); 7% (pg.9); 4 to 14% (Table 2)	0.01 mD (pg. 9); 0.00003 to 0.0917 mD (Table 2)
Monterey Formation A1-A2 Sands (Injection Zone)	8,403 ft – 9,598 ft TVD (Table 1, Figure 13)	27-548 ft (Table 1, Figure 13)	11%-27% (Figures 16 and 17); 16% (pg. 9)	0.1-1,300 mD (Figures 16 and 17); 60 mD (pg. 9)

Questions/Requests for the Applicant:

- ***The depths listed in Table 1 for the Monterey A1-A2 Sands are inconsistent with the logs in Figure 9. It appears, based on the log, that the depth to the Monterey A1-A2 Sands is ~8,500 feet MD or ~7,700 feet TVD at the 357-7R injection well, not 8,403 feet TVD as stated in Table 1. The mean depth to the Monterey Formation is also listed as 5,907 ft when the low and high depths are listed as 8,403 ft and 9,589 ft respectively. Please clarify the discrepancy or revise Table 1.***

- ***There is a typo on Figure 16, "Capitally" for Mercury Injection Capillary* Pressure. Please fix this when the application is updated.**
- ***Please characterize, name, and provide depth and permeability data for the underlying confining unit, if one exists.***

Hydrologic and Hydrogeologic Information

The Lower Tulare Formation, which conformably overlies the shallow marine deposits of the San Joaquin Formation, was approved as an exempt aquifer in 2018. The Upper Tulare Formation is the only USDW in the AoR (pg. 7). The regional extent of the exempted portions of the Lower Tulare Formation is shown in Figures 7, 26, and 29. It extends well beyond the AoR in the southern direction but closely borders the AoR to the north. The depth to the lowest USDW in the Upper Tulare is shown in Figure 28; however, the figure is difficult to read.

The San Joaquin Basin has no appreciable surface or subsurface outflow (pg. 35). The primary source of surface water and fresh groundwater is the Kern River, which drains to the southeast and terminates near the EHOF (pg. 35). Low precipitation rates and high evaporation rates result in almost no groundwater recharge from precipitation, leading to high salinity and TDS concentrations (pg. 35). CTV did not find any water supply wells within the AoR after a search of CALGEM, USGS, Kern County Water Agency (KCWA), West Kern Water District, and the GeoTracker Groundwater Ambient Monitoring and Assessment online database (pg. 36). CTV owns the surface area of the EHOF (pg.35).

Questions/Requests for the Applicant:

- ***It appears that Figure 26 provides information on the depth and regional extent of the area shown in cross section with wireline logs for TDS content, however the resolution is low (pg. 31). Please provide a higher resolution version of Figure 26.***
- ***What is the depth of the Upper Tulare Formation and the separation of this lowermost USDW from the injection zone and the confining zone within the AoR?***
- ***Is the Upper Tulare USDW present within the modeled AoR of the injection wells?***

Geochemistry/Geochemical Data

Limited baseline geochemical data for the Upper Tulare Formation (USDW) and Monterey Formation (injection zone) are provided in the application.

Figure 30 shows the results of water analysis performed on waters from the Upper and Lower Tulare Formations. The produced fluid has been collected during previous operations to establish a baseline and characterize the region. Hydrocarbon content in the injection zone was determined through fractional distillation and chromatography (pg. 37). Figure 30 is difficult to read, but it appears that the analysis is from 1995, and the analytes include some, but not all, of those planned as part of injection and post-injection phase monitoring. The TDS values of the Upper Tulare Formation appear to be 4,800-4,900 mg/L.

The application states that water sampling was not performed in the Monterey A1-A2 Sands because reservoir depletion has reduced water saturation to residual levels. However, geochemical analysis was

performed using fluid produced during oil and gas operations (pg.37). CTV provides an example of the water geochemistry analysis taken from well 381-17R from a sand underlying the Monterey A1-A2 Sands (Figure 31). Figure 33 presents a 2021 analysis from nearby Well 353-7R. The figure is difficult to read, so it is unclear what analytes were measured, and if all the analytes planned during operational testing are addressed. It appears that the TDS of the Monterey A1-A2 Sands is about 24,000 mg/L.

CTV's Testing and Monitoring Plan (Attachment C) includes monitoring the overlying Etchegoin/San Joaquin Formations and the Tulare Formation for groundwater quality and geochemical changes and the Monterey Formation as part of direct plume tracking activities. Water quality will need to be established in each of these formations prior to injection operations to provide a baseline for comparison to future monitoring results.

Questions/Requests for the Applicant:

- ***Please provide clear/legible versions of the sample analyses in Figures 30 and 31 to allow a review of the sampling performed.***
- ***Where is Well 381-17R?***
- ***What is the total dissolved solids (TDS) content of the Monterey Formation? Please indicate how many data points or measurements are available to support this measurement (i.e., based on past field operations) and, if they are not from throughout the AoR, please provide information to support a determination that the Monterey Formation is not a USDW.***
- ***Is any water quality data available for the Etchegoin Formation? If so, please provide this.***
- ***In the Testing and Monitoring Plan, CTV states that they obtained a baseline analysis for the 61WS-8R well (apparently for the Tulare Formation). Please provide this analysis if it is not the same as is provided in Figure 30.***

Objectives for Pre-Operational Testing:

- ***Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan.***

Geomechanical and Petrophysical Characterization

Capillary pressure was determined using mercury injection capillary pressure analysis from 18 wells. The average rock strength of the confining zone is 2,452 psi according to brittleness calculations and the average ductility of the confining zone is 1.24 as derived from compressional sonic data from 18 wells with 59,214 data points using a calculation methodology from Ingram and Urai (1999) and Ingram et al. (1997) (pg.23). The applicant concludes that brittleness of less than 2 is evidence that the confining layer is sufficiently ductile to "anneal" discontinuities and that there are no fractures for fluid migration (Figure 19). The application states that this conclusion is further supported by historical water and gas injection data at the site in addition to millions of years of confinement of oil and gas in the Monterey Formation by the Reef Ridge Shale (pg. 23).

In the EHOF, the maximum principal stress direction is northeast-southwest as determined by a study of EHOF fracture gradients and borehole breakout (Castillo, 1997; Figure 21) Table 3 of the application narrative is reproduced below.

Stress	Reef Ridge Shale Confining Layer (Well: 374A-7R-RD1)	Monterey Formation A1-A2 Reservoir (Well: 372-7R-RD1)
Pore Pressure Gradient (psi/foot)	0.433	0.2
Overburden Gradient (psi/foot)	0.93	0.94
Minimum Horizontal Stress Gradient (psi/foot)	0.73	0.97

The GEOMECH geomechanical model, along with the GEM equation of state compositional reservoir simulator, were used to determine failure pressures under a base case and three additional scenarios; this modeling is described on pages 25-28 of the application narrative. Descriptions of variations from the base case for other scenarios are given below:

- Reduced Young's Modulus: to model uncertainty in the cap rock Young's Modulus, a second case was run with a value of 8E05 psi.
- Reduced Injection Rate: sensitivity to injection rate was studied by reducing the injection rate to 20 million cbf per day.
- Thinner cap rock: the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet.

Table 4 of the application narrative, which presents the results of the modeling, is reproduced below:

Geomechanical Scenario Results	
Scenario	**Failure pressure (psi)**
Base Case	8,306
Reduced Young's Modulus	8,388
Reduced Injection Rate	8,340
Thinner Cap Rock	7,600

Figure 23 shows the change in normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. See also the evaluation of the AoR CA (Attachment B) for additional information.

Porosity and Permeability

As shown in the table under "Depth, Areal Extent, and Thickness of the Injection and Confining Zones," above, porosity values for the Reef Ridge Shale are approximately 7-14% and reported porosities of the Monterey A1-A2 Sands range from 11%-27%. The permeability of the Reef Ridge Shale is about 0.01 mD, and Monterey Formation permeability ranges from 0.1-1,300 mD. Permeability and porosity for the Reef Ridge Shale in the 355X-30R well are presented in Table 2 of the application.

Formation porosity and permeability used as inputs for the geomodel were determined using wireline log data, including SP logs, gamma ray, borehole caliper, resistivity, neutron porosity, and bulk density (pg. 17). Porosity is determined from bulk density using a 2.65 matrix density calibrated from particle density (Figure 15) and porosity data. Clay volume is determined from neutron-density separation and is calibrated to core data. A permeability function was calculated using mercury injection capillary

pressure porosity and clay values (Figure 16). The application states (on pg. 17) that core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. However, it is unclear which wells are the source of this data.

Questions/Requests for the Applicant:

- ***Please update Figure 23 to include base case pressure.***
- ***Please discuss the selection of the base case parameter values (i.e., Young's Modulus, thickness, etc.) in the geomechanical modeling.***
- ***Please explain what is meant by "anneal discontinuities" in the discussion on page 23.***
- ***The application references core data from 13 wells on page 17.***
    - ***To which wells does this refer and where are they located?***
    - ***If they are not distributed throughout the AoR, please describe how they are representative of the entire area that will be affected by injection.***
- ***Where are the 18 wells that are the source of ductility data referred to on pg. 23 located?***
- ***The application states that, "The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of .8 psi/foot," and that, "the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI" (pg. 46). Please clarify the sources of data used to determine failure pressure, fracture pressure, and fracture gradient.***

Mineralogy of the Injection and Confining Zones

X-ray diffraction (XRD) data from 108 data points in 9 wells was analyzed to determine injection zone mineralogy. Fourier Transform Infrared Spectroscopy from 36 points in 1 well located outside the AoR but within the EHOF was used to characterize confining zone mineralogy (pg. 16-17). Figure 14 presents an example XRD analysis from well 367-7R located within the AoR. The applicant addresses the use of a single well for characterizing the mineralogy of the confining zone, citing that it is representative of the formation because of depositional continuity and consistency of facies and properties within the EHOF (Figure 15).

The Monterey A1-A2 Sand intervals consist of 43% quartz, 38% potassium feldspar, albite, and oligoclase as well as 7% total clay. The Reef Ridge Shale consists of 47.1% silica polymorphs (Opal-CT, chert, and cristobalite), 29.5% total clay, 14.5% potassium feldspar, albite, and oligoclase, and 3.7% quartz (pg.16).

Questions/Requests for the Applicant:

- ***Please provide a map of the 9 well locations used for XRD described on pages 16-17.***
- ***What evidence is there for depositional continuity and facies consistency within the EHOF, as described on page 17?***

Seismic History and Seismic Risk

The application notes that the "EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills

area (DOE, 1997)" (pg.29). Seismic activity in the region stems from the San Andreas Fault (12 miles west of the project site) and the White Wolf fault (25 miles southeast of the site) (pg. 29). Regional seismic data dating back to 1932 was gathered from the Southern California Earthquake Data Center (SCEDC) and USGS databases (Pg.29).

Figure 24 shows the eight (8) magnitude 5.0 or greater earthquakes that have occurred within a 30-mile radius of the EHOF. These earthquakes have an average depth of 6.3 miles, well below the Monterey Formation (pg.29). It is stated that there have been no earthquakes within the EHOF greater than magnitude 3.0. Site characteristics, including low factor amplification due to thin sediment, high density soil, and soft rock, based on shear-wave velocity (V_S) are asserted to further reduce seismic risk. The largest known earthquake in the region was a 7.5 magnitude 1952 earthquake in nearby Kern County which did not affect reservoir containment (pg. 30).

CTV will install borehole and surface seismometers to establish a baseline and assess natural and induced seismicity (pg. 29).

The evaluation of seismic risk also reflects other elements of the comprehensive permit application review (described elsewhere in this report), including porosity and permeability of the injection and confining zones; regional structural features; information on faults in the vicinity of the project site; formation pressure; and the geomechanical properties of the injection and confining zones.

Seismic risk and risk mitigation will also be considered in the review of the following aspects of the permit application:

- Predictions of plume and pressure front behavior over time, including pressure build-up over time, and pressure dissipation following cessation of injection.
- The ability of the injection well to maintain mechanical integrity under stress.
- Wells within the project area and the status of well corrective action.
- Planned injection pressures.
- Seismic monitoring and emergency and remedial response planning.

Questions/Requests for the Applicant:

- ***Please include all earthquakes of magnitude 3.0 and above in Figure 24.***
- ***To inform an evaluation and documentation that there is no significant seismic risk, EPA recommends that CTV describe how the project:***
  - ***has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected.***
  - ***will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;***
  - ***will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and***
  - ***poses a low risk of inducing a felt seismic event.***

Objectives for Pre-Operational Testing:

- ***Establish baseline seismicity after borehole and surface seismometers are installed.***

Surface Air and/or Soil Gas Monitoring Data

No soil gas or surface air data were submitted with the permit application. At this point, we do not believe this will be necessary; however, if the results of future reviews necessitate surface air and/or soil gas monitoring, we would request baseline data.

Facies Changes in the Injection or Confining Zones

Depths to the confining and injection zones are presented on structural and isopach maps based on 3D seismic and wireline log data (Figure 13). However, the locations and number of wells used to characterize formation depths was not provided.

Figure 3 of the application shows a cross section of formations across the San Joaquin Basin and Figure 6 shows a stratigraphic cross section with well types for the Northwest Stevens anticline. Figure 12 shows a stratigraphic column with oil samples grouped into families. There appear to be logs on the figure used to correlate formations laterally, but they could not be distinguished.

Page 41 of the application describes the development of a geo-cellular model as part of the A1-A2 reservoir characterization and plume modeling. This is supported by cross sections in Figures 34 and 35 (which appear to be outputs of the AoR delineation model) that the applicant asserts also demonstrate the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers also supports predictable plume development. The application states that the modeled plume migration (Figures 34 and 35) is consistent with the structure of the anticline.

Figure 4 identifies "data coverage" for the Reef Ridge Shale and per Figures 5 and 8, several wells have core data in the Reef Ridge Shale and the Monterey Formation; however, it is unclear what information is available from the wells on the map and how it informed the application.

On page 11, the application concludes that the Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core data, as well as 3D seismic data. Discussion and questions for the applicant regarding lateral continuity of the Confining Zone are discussed above in the section on "Mineralogy of the Injection and Confining Zones."

Questions/Requests for the Applicant:

- ***Please clarify what data sources were used to determine inputs for the geomodel where applicable, e.g., the inputs for sand vs. shale facies as discussed on pg. 40.***
- ***Please also discuss how a sufficient number and distribution of formation characterization data are available to demonstrate a lack of local heterogeneities that could affect storage or confinement of CO_2.***
- ***Please specify the names, number, and locations of wells used to characterize formation thicknesses for the maps in Figure 13.***

Objectives for Pre-Operational Testing:

- ***Determine if there are any heterogeneities within the Monterey A1-A2 Sands that could affect its suitability for injection, including facies changes that could facilitate preferential flow.***

Structure of the Injection and Confining Zones

Regional structure of the injection and confining zones is controlled by San Andreas Fault development resulting in mid-Miocene anticlines (pg. 3). The application describes the anticlines that form the Elk Hills Oil Field, which CTV asserts will contribute to confinement. See the discussions of "Regional Geology and Geologic Structure" and "Faults and Fractures," above.

CO_2 Stream Compatibility with Subsurface Fluids and Minerals

The proposed injectate will consist of at least 95% CO_2 with mixtures of water and oxygen that will be controlled for corrosion mitigation (pg. 46). The applicant states that corrosiveness of the stream will be "very low as long as the entrained water is kept in solution with the CO_2" which will be accomplished by limiting its water content (pg. 46).

Existing subsurface fluid information is based on extensive and ongoing CO_2 injection activity in the EHOF region. CTV has injected 6.3 billion cubic feet of gas containing up to 44% CO_2 into the Monterey A1-A2 Sands since 2011 without any changes to injectivity (pg. 38-39). A 2021 analysis from an oil sample in the 353-7R well showed a 6.5 mole % CO_2 content (pg. 38). The applicant states that low water volume in the formation (15% saturation in the gas cap and 85% in the thin oil band) and low residual oil saturation (15%) will also dissolve only a small amount of CO_2. Furthermore, the Monterey A1-A2 Sands is dominated by quartz and feldspar which are stable in the presence of CO_2 and carbonic acid (pg. 39).

There is no geochemical analysis of water samples from the Reef Ridge Shale because the shale will only provide fluid for analysis if stimulated (pg. 39). The CO_2 composition used for the geomodel and its interaction/solubility is established by the Peng-Robinson Equation of State (AoR and CA Plan, pg. 2).

Questions/Requests for the Applicant:

- ***Please provideevidence for the statement in the Application on page 39 that the quartz and feldspar in the Monterey A1-A2 Sands are stable in the presence of CO_2 and carbonic acid?***
- ***Please elaborate on why use of the Peng-Robinson Equation of State supports compatibility of the CO_2 with any fluid which may be contained within the Reef Ridge Shale.***

Objectives for Pre-Operational Testing:

- ***Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and provide verification that it will not react with the formation matrix.***

Injection Zone Storage Capacity

Modeled storage capacity of the Monterey Formation A1-A2 reservoir was 8-10 million tons of CO_2 (pg. 41). The forecasted/proposed injection rate is 0.25 - 0.75 million tons per year for 15 years; according to

Table 8 (Proposed operational procedures); an average estimate of 8 million tonnes and a maximum of 10 million tonnes will be injected.

Injection zone storage capacity is discussed in the Evaluation of the AoR CA and above in the "Structure of the Injection Zone and Confining Zone" section. Any additional follow up questions/requests for the applicant will be provided in the AoR modeling evaluation.

Confining Zone Integrity

Fluid confinement is supported by 3D seismic data (pg. 12) and historic operating experience in addition to core data (pg. 20) and geochemical analysis (pg. 13). The capillary entry pressure of the Reef Ridge Shale is 4,220 psi in a CO_2-brine system, reducing the likelihood of deformation (pg. 20). There are no faults extending into the Reef Ridge Shale. See additional discussion and questions for the applicant above.

Questions/Requests for the Applicant:

- ***Were any other tests performed to corroborate pressure measurements in the Reef Ridge Shale?***
- ***The application, on pg. 14, states that there is a pressure differential of 1,300 psi between the overlying Etchegoin Formation and Monterey Formation due to the sealing nature of the Reef Ridge Shale. What is the source of the pressure data for this statement?***

Objectives for Pre-Operational Testing:

- ***Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate via laboratory experiments.***
- ***A step rate test should be performed to establish the fracture pressure of the confining zone.***

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

November 4, 2022 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Site Characterization and Emergency and Remedial Response Plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included in the two Enclosures.

Please submit the information requested in the Enclosures by December 5, 2022. If you have any questions about this letter and the Enclosures, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,
DAVID ALBRIGHT
Digitally signed by DAVID ALBRIGHT
Date: 2022.11.04 10:44:34 -07'00'
David Albright
Manager, Groundwater Protection Section

Enclosures: Site Characterization Evaluation
Emergency and Remedial Response Plan Evaluation

cc (via email): William Long, Inland District, CalGEM
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Amit Garg, CalGEM

Review of Carbon TerraVault (CTV) Responses to EPA's Site Characterization Questions about the Class VI A1-A2 Permit Application

In December 2021, EPA provided questions presented in ***blue, bold, and italic text*** to CTV about the geologic narrative submitted as part of CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated narrative and a table summarizing their responses to EPA on March 2, 2022. EPA's May 2022 evaluation of how the narrative addressed its questions is presented in ***red, bold and italic*** text. CTV submitted an updated narrative (Attachment A Site Evaluation v3) to EPA on June 20, 2022. This document evaluates how the updated narrative addresses EPA's May 5, 2022 questions (in purple text). Requests for revisions and additional information are presented in ***purple, bold and italic*** text. Previous responses that require no further information are not included in this enclosure.

Regional Geology and Geologic Structure

The Elk Hills Oil Field (EHOF) is in Kern County, California, in the southern San Joaquin Basin (Figures 1 and 2) CTV plans to inject CO_2 at the EHOF into the Monterey Formation via 2 injection wells, 355-7R and 357-7R, over a period of 15 years. The 2 injection wells are 1,250 feet apart and will inject into the Monterey Formation A1-A2 reservoir (Monterey A1-A2) at the Northwest Stevens Anticline at ~8,500 ft depth (Figure 8 and pg. 4).

The Monterey Formation at the EHOF also contains the Miocene Reef Ridge Shale (the primary confining zone), which directly overlies the Monterey A1-A2 and has been an effective seal for 40+ years of oil and gas operations (pg. 9). Figures 4 and 5 show the spatial distribution of wells in the EHOF and data available for use in characterizing the injection zone.

The Monterey A1-A2 consists of turbidite sands bounded above and below by siliceous shale (pg. 9). The application asserts that this depositional history has resulted in minimal lateral communication of the Monterey A1-A2 outside the EHOF (Cross Section Figure 3, pg. 4; pg. 9). The reservoir is continuous across the area of review (AoR), with pinch-outs on the channel edges (pg. 9).

The Upper Tulare Formation is the lowermost underground source of drinking water (USDW). The Tulare Formation consists of poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley (pg. 7). It is divided into the Upper Tulare and the Lower Tulare by the Amnicola Clay (a low permeability claystone). An aquifer exemption was approved for the Lower Tulare Formation in 2018, making the Upper Tulare Formation the lowermost USDW.

In addition to the Reef Ridge Shale, the Monterey A1-A2 Sands are separated from the lowermost USDW in the Upper Tulare Formation by the Amnicola Clay (pg. 31), the Lower Tulare Formation, the San Joaquin Formation, a depleted gas reservoir directly underlying the Tulare Formation, and the Etchegoin Formation (pg. 8). The Monterey A1-A2 Sands are separated from the underlying Monterey A3-A11 reservoir by a laterally continuous 20-foot shale known as the A2 Shale (Figure 9). The application asserts that they are not in communication, as evidenced by a pressure differential (of 200-300 psi in the A1-A2 and ~1,700 psi in the A3-A11), and the need for separate pressure maintenance strategies (pg. 10). The A3-A6 reservoir is also considered a viable target for future CO_2-EOR based on its existing

waterflood injector infrastructure and high reservoir pressure (pg. 11).[1]

Tests and logs performed during drilling and prior to completion of the 357-7R injection well and the 342-7R-RD1 and 327-7R-RD1 monitoring wells (which are completed in the Monterey Formation and are located to the west and northwest of the injectors) include Array Compensated True Resistivity, SP logs, caliper logs, compensated spectral natural gamma log, spectral density dual spaced neutron log, and mud logs (Attachment G pg. 4-5). Cement bond logs and MIT tests (temperature log and SAPT) were also performed on the 357-7R injection well.

- ***Please provide pressure build-up test results for the 357-7R injection well. CTV requested technical discussion prior to inclusion in the pre-operational testing plan. The response is acceptable at this stage of the permit application review. EPA will schedule a technical discussion.***

Objectives for Pre-Operational Testing:

- ***Confirm hydraulic separation of the Monterey A1-A2 Sands and the Monterey Formation A3-A11 reservoir.***
- ***If no pressure build-up test results exist for the 357-7R injection well, perform pressure build-up testing as part of the Pre-Operational Testing Plan.***

Geochemistry/Geochemical Data

Limited baseline geochemical data for the Upper Tulare Formation (USDW) and Monterey Formation (injection zone) are provided in the application.

Figure 30 shows the results of water analysis performed on waters from the Upper and Lower Tulare Formations. The produced fluid has been collected during previous operations to establish a baseline and characterize the region. Hydrocarbon content in the injection zone was determined through fractional distillation and chromatography (pg. 37). Figure 30 is difficult to read, but it appears that the analysis is from 1995, and the analytes include some, but not all, of those planned as part of injection and post-injection phase monitoring. The TDS values of the Upper Tulare Formation appear to be 4,800-4,900 mg/L.

The application states that water sampling was not performed in the Monterey A1-A2 Sands because reservoir depletion has now reduced water saturation to residual levels. However, geochemical analysis was performed using fluid produced during oil and gas operations (pg.37). CTV provides an example of the water geochemistry analysis taken from well 381-17R from a sand underlying the Monterey A1-A2 Sands (Figure 31). Figure 33 presents a 2021 analysis from nearby Well 353-7R. The figure is difficult to read, so it is unclear what analytes were measured, and if all the analytes planned during operational testing are addressed. It appears that the TDS of the Monterey A1-A2 Sands is about 24,000 mg/L.

CTV's Testing and Monitoring Plan (Attachment C) includes monitoring the overlying Etchegoin/San Joaquin Formations and the Tulare Formation for groundwater quality and geochemical changes and the Monterey Formation as part of direct plume tracking activities. Water quality will need to be established in each of these formations prior to injection operations to provide a baseline for comparison to future

[1] Note: CA SB905 now prohibits enhanced oil recovery with CO2.

monitoring results.

Questions/Requests for the Applicant:

- ***Please provide clear/legible versions of the sample analyses in Figures 30 and 31 to allow a review of the sampling performed.*** The revised figures (now Figures 33 and 34) are legible. The TDS of the four samples in the Upper Tulare Formation ranges from 4,800 to 4,900 mg/L. EPA has no further questions.
- ***Where is Well 381-17R***? CTV referenced page 40; however a revised Figure 34 on page 39 shows the well, which is just outside the eastern edge of the AoR. EPA has no further questions.
- ***What is the total dissolved solids (TDS) content of the Monterey Formation? Please indicate how many data points or measurements are available to support this measurement (i.e., based on past field operations) and, if they are not from throughout the AoR, please provide information to support a determination that the Monterey Formation is not a USDW.*** CTV referenced page 40; however Figure 34 on page 39 shows the requested water quality information. EPA has no further questions.
- ***Is any water quality data available for the Etchegoin Formation? If so, please provide this.*** CTV responded that this is included in the pre-operational testing plan. It is assumed that no current water quality data exist. The response is acceptable at this point in the permit application review. No further questions.
- ***In the Testing and Monitoring Plan, CTV states that they obtained a baseline analysis for the 61WS-8R well (apparently for the Tulare Formation). Please provide this analysis if it is not the same as is provided in Figure 30.*** CTV responded that it will drill a new monitoring well and baseline results will be included in pre-operational testing. However, they did not provide any specific information about the location or construction of the well (which has ramifications for the testing and monitoring and financial responsibility evaluations).

Follow-up Questions/Requests for the Applicant:

- ***Where will the new Tulare Formation monitoring well that CTV references above be located?*** CTV responded that the USDW monitoring well will be located on the pad for 61WS-8R (it is shown on Figure 1 of the Testing and Monitoring Plan and its construction is shown in Appendix 1_TM Monitoring Well Schematics). Data will be gathered on the new USDW monitoring well and provided as part of pre-operational testing. No further questions in the context of the geology evaluation.
    - ***Is this well in addition to the existing well 61WS-8R?*** CTV responded that it reviewed the 61WS-8R well and determined that it was not an adequate monitoring well; therefore, the new well will replace that well.
    - ***CTV should provide specific information about the construction of this well and include this well in the Testing and Monitoring Plan and PISC and Site Closure Plan, and address it in the financial responsibility cost estimates.*** CTV responded that it will update the Testing and Monitoring Plan, PISC and Site Closure Plan, provide well construction details, and address this in the financial responsibility cost estimates.
        - ***Please update the modules listed above to reflet the construction of the new monitoring well.***

Objectives for Pre-Operational Testing:

- ***Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan.***

Review of Carbon TerraVault (CTV) Responses to EPA's Questions on the Proposed Emergency and Remedial Response Plan

In December 2021, EPA provided questions to CTV about the draft Emergency and Remedial Response Plan submitted as part of CTV's Class VI permit application (dated August 30, 2021). CTV provided an updated Emergency and Remedial Response Plan to EPA on March 2, 2022. EPA's May 2022 evaluation of how the updated plan addresses its questions is presented in red below. CTV submitted an updated Emergency and Remedial Response Plan (v3) to EPA on June 20, 2022. EPA's evaluation of how CTV's June 2022 update addresses its questions is presented in purple below. Requests for revisions and additional information are presented in ***purple, bold, and italic*** below. Previous responses that require no further information are not included in this enclosure.

Potential Risk Scenarios

The list of items in this section does not match the events and scenarios described in the following section.

- ***Please revise the list.*** The list was edited as requested.
    - ***Please remove earthquakes under "natural disaster" since these are addressed under the seismic events scenario.***

The list in this section also includes "CO_2 leakage to USDW or land surface," which appears to also be addressed under the "Potential Brine or CO_2 Leakage to a USDW" scenario.

- ***Please delete this item. This was edited as requested.***

Emergency Identification and Response Actions

EPA recommends some additions/revisions to the descriptions and response actions for the scenarios identified in the Emergency and Remedial Response Plan. These are presented in the table below:

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
1. All	a) EPA recommends that the Actionable Testing limits methods in Table 7 of the QASP be referenced in the Emergency and Remedial Response Plan.	a) This addition was not made. ***Please add to the introduction that the Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP.*** Edited as requested. ***Under the "Brine or CO_2 Leakage to USDW" scenario, please add other indicators of leakage including elevated pH levels in the Tulare Formation (e.g., 0.2) and pressure increases in the Etchegoin Formation of 0.001 psi detected by the pressure gauge.*** The information was added as requested; but there is a typo in the spelling of "Tulare."

		Please revise the text.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
2. Well Integrity Failure	a) A mechanical integrity (MI) failure of a monitoring well can also occur in the post-injection time frame; please update the "timing of the event" accordingly. b) The statement that CTV must notify the UIC Program Director is not an event that may signal loss of MI. Please make this a separate statement outside of the list on page 3. c) Consider including "Limit access to wellhead to authorized personnel only" to the response actions for major and minor emergencies. d) The response to a major or minor MI failure should also include necessary actions to identify the location/nature of the damage to the well or wellhead and confirm internal and external integrity prior to restarting injection (upon approval of the UIC Program Director).	***a) Please edit the timing of this event from "Injection/monitoring" to "injection/post-injection."*** Edited as requested. ***b)*** The requested change was made. No further questions. ***c)*** The requested change was made. No further questions. ***d)*** The requested changes were made. Note that there is a typo on page 5, "Preform a well log…". ***Please correct the typo.*** This edit was not made under major emergency***; please correct the text as requested.***
3. Well Integrity Failure – Major or Serious Emergency	a) Please clarify what would constitute a major or serious emergency (e.g., a verified loss or increase of pressure or fluid volumes and/or loss of mechanical integrity is discovered). b) Response to a major emergency may also include communicating with CTV personnel or other operators in the field and local authorities to initiate evacuation plans, as necessary.	a) The requested change was made. No further questions. b) The requested change was made. No further questions.
4. Well Integrity Failure – Minor Emergency	a) Please clarify what would constitute a minor emergency (e.g., downhole and surface sensor/monitoring equipment failure, procedural maintenance error or plant issue). b) Clarify that, if contamination is detected or a loss of integrity has occurred, then the situation becomes a major emergency and the actions under "Major or Serious Emergency" would be taken. c) "Initiate shutdown plan" is on the list of response actions twice.	a) The requested change was made. No further questions. b) The revised text is acceptable. No further questions. c) No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
5. Injection Well Monitoring Equipment Failure – Major or Serious Emergency	a) Please describe what constitutes a Major or Serious emergency (e.g., failure of sensors that will require shutdown of well to repair, extended repair time, and/or well reentry). b) Responses to a Major monitoring equipment failure emergency may also include: • Verifying whether any contamination has occurred (e.g., via handheld CO_2 monitors). • Communicating with CTV personnel/other operators in the field and local authorities to isolate the area or initiate evacuation plans, as necessary if contamination is detected. • Demonstrating internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director).	a) The requested change was made. No further questions. b) The requested changes were made. No further questions.
6. Injection Well Monitoring Equipment Failure – Minor Emergency	a) Please describe what constitutes a Minor emergency (e.g., sensor or monitoring failure that does not require shutdown of the well to repair). b) Potential response actions may also include actions to identify the location/nature of the damage and reset monitoring devices and/or confirm internal and external well integrity prior to restarting injection (upon approval of the UIC Program Director). c) "Initiate shutdown plan" is on the list of response actions twice.	a) The requested change was made. No further questions. b) The requested changes were made. No further questions. c) The requested change was made. No further questions. ***Please remove reference to shutting in and restarting the well (in items 5 and 7) under the minor emergency scenario.***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
7. Potential Brine or CO_2 Leakage to USDW	a) EPA recommends that the introduction to this scenario be broadened to encompass any evidence of CO_2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address events associated with unanticipated fluid movement pathways, any potential USDW endangerment/unacceptable changes in water quality, and CO_2 leakage to the land surface. b) The severity of an event involving CO_2/brine leakage to a USDW would be serious, not low. c) Detection methods may also include pressure or water quality changes in the Etchegoin Formation monitoring well. d) The response actions should also address well integrity issues (e.g., by following responses under the MI failure scenario) or a risk to air quality (i.e., to isolate the nearby area and establish a perimeter using a hand-held air-quality monitors). e) The response equipment for this scenario should also include groundwater remediation equipment.	a) The response actions address CO_2 or fluid movement out of the injection zone (e.g., to the Etchegoin) or CO_2 detected by hand-held monitors at the surface. No further questions. b) The requested change was made. No further questions. c) The requested change was made. No further questions. d) The requested change was made. No further questions. e) The requested change was made. No further questions. ***EPA requests the following changes:*** • ***Please add performing MITs to the response actions, e.g., as part of the reference the MI failure scenario if a loss is detected.*** • ***Please revise all of the response actions to describe shut in of both injection wells, where mentioned.***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
8. Natural Disaster	a) The severity of these types of events could range up to serious or catastrophic. b) These types of events may occur in any of the project phases (e.g., construction and post-injection) not just the injection phase. c) For Major or Serious natural disasters, potential response actions may also include: • Initiating evacuation procedures; • Referencing the response actions described under the CO_2 leakage scenario if contamination or endangerment of a USDW is detected; or • Confirming mechanical integrity/taking appropriate steps if an injection/monitoring well has been damaged.	a) The requested change was made. No further questions. b) The requested change was made. No further questions. c) The requested changes were made. No further questions. ***EPA requests the following changes:*** ***a) Please remove mention of earthquakes from the introduction to this section (or reference the induced seismicity scenario).*** ***b) The severity of these types of events could range from minor to catastrophic.*** ***c) Please make the following revisions to potential response actions for Major or Serious natural disasters:*** • ***Revise the response actions to describe shut in of both injection wells (#3).*** • ***Edit item 5 to read, "If ~~there is~~ contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario."*** • ***Edit item 6 to read, "…initiate evacuation procedures (if necessary)."*** • ***Add "Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred."***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
9. Induced Seismic Event	a) This section and the title should refer to induced or naturally occurring seismic events since all seismic events have the potential to affect the injection wells and the necessary responses would be the same. b) It is unclear whether the area encompassed by "the AoR inclusive of a ¼ mile buffer," as described on page 8 is as large as a 2-mile radius of the injection wells, as described on Table 2. Please modify the introductory statement to reflect the area addressed in Table 2. c) The severity of seismic events could be major. d) Seismic events that may necessitate a response could occur during the injection or post injection phases. e) Please clarify what is meant by "seismic monitoring wells" as a detection method; EPA assumes this refers to the monitoring network that is described in the Testing and Monitoring Plan, and therefore recommends that similar terminology be used.	a) The requested change was made. No further questions. ***b)*** The introduction now refers to epicenters "within the AoR, inclusive of a two mile buffer" and Table 2 refers to "a two-mile radius of the injection well." ***Please revise the table to be consistent with the introduction.*** Edited as requested. c) The requested change was made. No further questions. d) The requested change was made. No further questions. e) The requested change was made. No further questions. ***EPA requests the following changes:*** • ***The severity of seismic events could range from minor to major; please revise this to be consistent with the table.*** • ***Please revise or delete the sentence on pg. 10, "An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase," as this contradicts reference to the injection and post-injection phases above.*** • ***Please clarify how California Geological Survey staff will be among response personnel.***
10. Induced Seismic Event—Table 2	a) Please modify the title to Table 2 to be consistent with the magnitude in the green response level (i.e., M 1.5). b) Please explain how the selected seismic thresholds (i.e., magnitude, distance from the project) are considered protective of USDWs.	a) The requested change was made. No further questions. b) The table has been revised to tie the magnitude-specific responses to USDW protection. No further questions.
11. Induced Seismic Event—Table 2, Green Level	a) Add the response action: Document the event in semiannual reports to EPA.	a) The requested change was made. No further questions.

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
12. Induced Seismic Event—Table 2, Yellow Level	a) Potential response actions should also include: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Review seismic and operational data to determine the location and magnitude of seismic event. If the event falls within or near the extents of the plume, estimate potential impact to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. • Document the event in semiannual reports to EPA.	a) The requested changes were made. No further questions. ***Please revise Step 2 to reference shut down of both injection wells.***
13. Induced Seismic Event—Table 2, Orange Level	a) EPA recommends the following additions to the response actions: • Initiate gradual shutdown of the well if it is determined to be appropriate. • Document the event in semiannual reports to EPA. • Expand Step 3 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).	a) The requested changes were made. No further questions. ***EPA requests the following changes:*** • ***Step 2: Please reference shut down of both injection wells.*** • ***Edit Step 5: "Report findings to the UIC Program Director and perform corrective actions."***
14. Induced Seismic Event—Table 2, Magenta Level	a) EPA recommends the following changes to the response actions: • Please describe the "rate reduction plan" in Step 1. Does this refer to gradual shutdown? • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. • Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event). • Add: Document the event in semiannual reports to EPA.	a) The rate reduction plan was not described***. Please describe this procedure or clarify in the E&RR Plan if it refers to gradual shutdown of the well.*** This term still is not consistent with the operating plan or other parts of Attachment F. ***Please revise Step 1 to read "Initiate gradual shutdown plan in both injection wells."*** ***EPA requests the following changes:*** • ***Edit Step 9: "If USDW contamination or endangerment is detected, or CO_2 leaked."*** • ***Edit Step 11: "Report findings to the UIC Program Director and perform corrective actions."***

Event/Scenario	EPA Comment/Recommendation	Evaluation of CTV's Updated Plan
15. Induced Seismic Event—Table 2, Red Level	a) EPA recommends the following changes to the response actions: • Expand Step 8 to apply to USDW contamination/endangerment and a CO_2 leak. Expand Step 9 on reviewing seismic and operational data to describe additional actions if the event falls within or near the CO_2 plume (e.g., to estimate potential impact to USDWs or determine if the storage complex has been compromised by the event).	a) The requested changes were made. No further questions. ***EPA requests the following changes:*** • ***Step 1: Please reference shut down of both injection wells.*** • ***"Review seismic and operational data" is on the list twice (items 7 and 10).*** • ***Please add "Assess monitoring plans and, where necessary, intensify the monitoring plan to ensure containment" similar to the responses at the magenta level.*** • ***Edit Step 9: "If USDW contamination or endangerment is detected, or CO_2 leaked."*** • ***Edit Step 11: "Report findings to the UIC Program Director and perform corrective actions."***

EPA Response/request	CTV Change / Response
Injection Well Construction	
QASP show a maximum calibrated working pressure of 3,000 psi, which is lower than the maximum surface injection pressure of 3,800 psi	QASP Tables 10-12 were updated.
Please clarify why the risk factors (temperature, pressure and corrosivity) are considered to be low and include further justification as to why the downhole shutoff system is not necessary.	Page 7 of each respective COP document, under "Alarms and shut off devices".
Please confirm the base of the lowermost USDW. Please note the definition of USDW (40 CFR 146.3) below.	The surface casing is at 501' and the USDW is at 806'. There is an intermediate string of casing between the surface string and long-string that is cemented to surface and will protect the USDW. Historical drilling in the Elk Hills oil field used these drilling practices to mitigate fluid losses and hole stability issues due to the unsaturated Tulare sand interval.
Please provide data or sources as evidence that lead to the determination that no subsidence has occurred in the area.	Further support added to page 4 and 5 of each respective document.
EPA requests that, for clarity, the conductor casing grade (which was reported as H-40 in the initial application) be included on Table 1. If this information was incorrect, please explain how the conductor casing is suitable for CO2 injection.	H-40 or better grade conductor casing was utilized in construction, which is suitable for CO2 injection because the material will not come into contact
Because the tubing grade was changed from 13CR-95 to L-80 CRA, please ensure that the coupons used in the corrosion monitoring section of the Testing and Monitoring Plan are revised accordingly.	The Testing and Monitoring Plan has been updated to account for the chagne.
Please update the QASP to show equipment with pressure ratings of 5,000 psi.	QASP Tables 10-12.
Please update Attachment G2 to include the pre-operation testing plan for the deep monitoring wells.	CTV will include in preoperational testing plan
Please provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.	CTV will include in preoperational testing plan
Injection Well Pre-operational Testing	
Please provide an updated pre-operational testing plan that describes the tests identified in CTV's responses to questions in this document. For example, the plan should include: an SAPT of an appropriate test duration and MITs on monitoring wells 342-7R-RD1 and 327-7R-RD1.	CTV will include in preoperational testing plan
Monitoring Well Pre-operational Testing	
Please include an external MIT in the pre-operational testing plan for wells that are proposed to be converted to monitoring wells.	CTV will include in preoperational testing plan

EPA Response/request	CTV Change / Response
Injection Well Construction	
There appear to be typos regarding: tubing outside diameter and weight (in the Narrative A2) and regarding packer tensile rating (in Attachment G2).	Packer tensile rating in 355-7R COP doc
Figure 1 of Attachment G2 is illegible	Replaced Figure 1 with more legible table.
Please clarify why the risk factors (temperature, pressure and corrosivity) are considered to be low and include further justification as to why the downhole shutoff system is not necessary.	Page 7 of each respective COP document, under "Alarms and shut off devices".
Please confirm the base of the lowermost USDW. Please note the definition of USDW (40 CFR 146.3) below.	The surface casing is at 500' and the USDW is at 840'. There is an intermediate string of casing between the surface string and long-string that is cemented to surface and will protect the USDW. Historical drilling in the Elk Hills oil field used these drilling practices to mitigate fluid losses and hole stability issues due to the unsaturated Tulare sand interval.
Please provide data or sources as evidence that lead to the determination that no subsidence has occurred in the area.	Further support added to page 4 and 5 of each respective document
EPA requests that, for clarity, the conductor casing grade (which was reported as H-40 in the initial application) be included on Table 1. If this information was incorrect, please explain how the conductor casing is suitable for CO2 injection.	H-40 or better grade conductor casing was utilized in construction, which is suitable for CO2 injection because the material will not come into contact with CO2 with intermediate and long string casing.
Because the tubing grade was changed from 13CR-95 to L-80 CRA, please ensure that the coupons used in the corrosion monitoring section of the Testing and Monitoring Plan are revised accordingly.	The Testing and Monitoring Plan has been updated to account for the change.
Please update Attachment G2 to include the pre-operation testing plan for the deep monitoring wells.	CTV will include in preoperational testing plan
Please provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials.	CTV will include in preoperational testing plan
Injection Well Pre-operational Testing	
Please provide an updated pre-operational testing plan that describes the tests identified in CTV's responses to questions in this document. For example, the plan should include: an SAPT of an appropriate test duration and MITs on monitoring wells 342-7R-RD1 and 327-7R-RD1.	CTV will include in preoperational testing plan
Monitoring Well Pre-operational Testing	
Please include an external MIT in the pre-operational testing plan for wells that are proposed to be converted to monitoring wells.	CTV will include in preoperational testing plan

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

Elk Hills A1-A2 Storage Project

Facility Information

Facility name: CTV I: Elk Hills A1-A2
357-7R and 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in the individual Well Construction, Operating and Plugging details (COP) documents) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the Elk Hills A1-A2 Storage facility that may be affected as a result of an emergency event at the project site include:

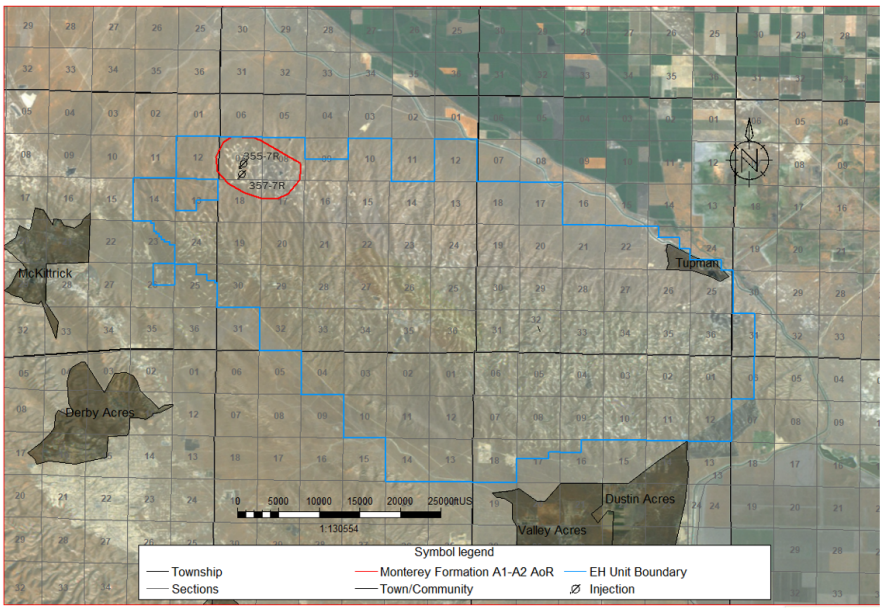
1. Elk Hills oil and gas production resources not associated with the Elk Hills A1-A2 Storage project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the Elk Hills A1-A2 Storage project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest town/community from the project is McKittrick, 3.1 miles from the AoR. The population was 115 at the 2010 U.S. Census.

Infrastructure in the vicinity of the Elk Hills A1-A2 Storage facility that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CTV that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.1 miles from the census designated area of McKittrick.



Potential Risk Scenarios

The following events related to the Elk Hills A1-A2 facility that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- Potential Brine or CO2 Leakage to a USDW;
- A natural disaster (e.g., tornado, lightning strike); or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/Post-Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Perform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Perform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well or Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.

- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- Verify whether contamination has occurred via handheld CO2 monitors.
- Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
  - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
  - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) movement out of the injection zone or CO_2 leakage into a USDW. This may be identified through elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO2 leakage into a USDW. For example, a pressure increase of 50 PSI or a pH of 1.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing

2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits are 0.001 PSI for the pressure gauge and 0.2 for pH.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue perform MITs, refer to the Mechanical Integrity Failure scenario.
    - If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. Natural disasters (e.g., tornado or lightning strike) may disturb surface and/or subsurface facilities.

Severity: Minor to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
    - Communicate with CTV personnel and local authorities to initiate evacuation procedures (if necessary).
    - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.
    - Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred.
    - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills A1-A2 site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Minor to Major

Timing of event: Injection / Post injection

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and perform corrective actions. 6. Document the event in semiannual reports to the EPA

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual shutdown of the injection wells if it is determined appropriate. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected or endangerment, or CO2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan for all injection wells. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination or endangerment is detected, or CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	**Phone Number**
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For

responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

Carbon Dioxide Hazards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercise and drills simulating potential emergency situations.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

March 8, 2023 Sent by email only

Travis Hurst
Carbon TerraVault 1, LLC
28590 Highway 119
Tupman, CA 93276

Subject: Underground Injection Control (UIC) Permit Application
Carbon TerraVault 1, LLC (CTV) A1-A2 Project
Class VI Pre-Construction Permit No. R9UIC-CA6-FY21-1 and R9UIC-CA6-FY22-3
Technical Review of Application

Dear Mr Hurst,

The United States Environmental Protection Agency, Region 9 (EPA) has conducted a technical evaluation of the Monitoring Plan for the subject permit application. Based on this evaluation, we have identified additional information or clarification needed for continued evaluation of the permit application. These comments are included below, and in the Enclosure.

Please submit the information requested in the Enclosures by April 10, 2023. If you have any questions about this letter and the Enclosure, please contact me at (415) 972-3971, or Elise Nord at (415) 972-3079.

Sincerely,

DAVID ALBRIGHT Digitally signed by DAVID ALBRIGHT
Date: 2023.03.08 11:51:22 -08'00'

David Albright
Manager, Groundwater Protection Section

Enclosures: Monitoring Plan Comments

cc (via email): Chris Jones, CalGEM Inland District
Clay Rodgers, Central Valley Regional Water Quality Control Board
Janice Zinky, CA State Water Resources Control Board
Emily Reader, CalGEM

Review of Carbon Review of Carbon TerraVault (CTV) Responses to EPA's Questions about Proposed Testing and Monitoring Activities at the A1-A2 Class VI Project

In January 2022, EPA provided questions to CTV (*blue, italic text*) about proposed injection and post-injection monitoring activities submitted with CTV's Class VI permit application (dated August 30, 2021) for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project. CTV provided an updated Testing and Monitoring Plan and PISC and Site Closure Plan to EPA on March 31, 2022. EPA's evaluation of how the updated plans address its questions is presented in red below. CTV responded to EPA's request on November 4, 2022. EPA's evaluation of the response is in green text. Requests for revisions and additional information are presented in ***green, bold, and italic*** below.

Carbon Dioxide Stream Analysis

To meet the requirements of 40 CFR 146.90(a), CTV plans to analyze the carbon dioxide (CO_2) stream quarterly for the constituents identified in Table 1 of the Testing and Monitoring Plan, which is replicated below.

Parameter	Analytical Method(s)
Oxygen	ASTM D1945
Nitrogen	ASTM D1945
Carbon Monoxide	ASTM D1945
Total hydrocarbons	ASTM D1945
Methane	ASTM D1945
Hydrogen Sulfide	ASTM D1945/D6228
CO_2 purity	ASTM D1945
Total Sulfur	ASTM 3246

There are no EPA-approved analytical methods for CO_2 injection streams, and the methods listed on Table 1 are not included among EPA-approved wastewater analytical methods in 40 CFR Part 136 (nor are they used in other Class VI CO_2 injection permits). Many of the analytes are to be analyzed using ASTM D1945, which is the Standard Test Method for Analysis of Natural Gas by Gas Chromatography. Based on the physical states of natural gas and CO_2, this test may be appropriate for CO_2 injectate analysis; however, no specific information or justification was provided in the application materials and there is no publicly available (free-of-charge) information available about these ASTM methods.

Table 4 of the Quality Assurance Surveillance Plan (QASP), Summary of Analytical Parameters for CO_2 Stream, also lists analysis of ethanol using method EPA 8260B. Although there is no EPA-approved analytical method for ethanol analysis in wastewater, this method is acceptable.

CTV is evaluating several sources of CO_2 as injectate for the project, and states that it will notify EPA prior to switching or adding CO_2 sources so that the sampling procedures can be reassessed. EPA will require that a sample be analyzed prior to initiation of injection.

CTV states that it will increase the sampling frequency if there is a significant change in the chemical or physical characteristics of the CO_2 injectate, a change in the CO_2 injectate source, or if the facility or injection well experiences a downtime over more than 30 days. Any change in the injection fluid would require advance notice and written approval from EPA.

Questions/Requests for the Applicant:

- *Please add analysis of ethanol using EPA method 8260B to Table 1 to be consistent with Table 4 of the QASP. Ethanol was added as an analyte as requested, using ISBT methods. However, Table 4 of the QASP references ASTM methods, and should reflect the methods described in the Testing and Monitoring Plan. (See the discussion of the updated QASP below.)*
- *CTV states that quarterly sampling will begin three months after the date of authorization of injection; please revise this timeline to begin three months after the commencement of injection so that the testing schedule is consistent with injection operations. The applicant made the requested edit in the first paragraph, but not in subsequent discussions under Sample Location and Frequency.*

Follow-up Questions for the Applicant:

- ***Please make global edits (e.g., under Sample Location and Frequency) to reflect that quarterly injectate sampling will begin three months after commencement of injection.*** *CTV made edits in the subsection, "Sampling Location and Frequency" and globally across Attachment C to clarify that quarterly sampling will begin three months after the commencement of injection. The response is acceptable.*

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *EPA will require a baseline injectate sample to be analyzed for the same parameters as in the Testing and Monitoring Plan prior to commencement of injection.*
- *If this sample or any updated information about injection formation fluids indicates that any injectate constituents may lead to geochemical reactions that could affect operations or change aquifer properties, additional analytical parameters for the injectate analysis may be requested.*

Injection Well Testing

The subsections below describe: the planned quarterly corrosion monitoring; continuous recording of injection pressure, rate, and volume to evaluate internal mechanical integrity; and annual external MITs that will meet the requirements at 40 CFR 146.90(b), (c), and (e). This portion of the testing and monitoring evaluation addresses both injection wells (Well 357-7R and Well 355-7R); however, CTV will need to provide a Testing and Monitoring Plan for each well, with unique well-specific testing (particularly for corrosion monitoring and continuous monitoring) that reflects each well's design.

Corrosion Monitoring

CTV proposes to conduct corrosion monitoring using the coupon method. The corrosion coupons will be in the pipeline that feeds CO_2 injectate to the injectors. Corrosion monitoring will occur between the compressor and wellhead, according to Table 1 of the QASP.

Samples of the materials used in the construction of the pipeline and injection well that are exposed to CO_2 injectate will be monitored for corrosion using corrosion coupons. Representative materials will be weighed, measured, and photographed prior to installation. The coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The specific methods by which the samples will be handled are not described in the testing and monitoring plan; however, Table 5 of the QASP indicates that analytical methods include NACE TM0169/G31 and EPA 1110A SW846.

CTV says that, if the corrosion rate is greater than 0.3 mils/year, it will initiate consultation with regulatory agencies (but does not specify which agencies), and may run a casing inspection log to assess the thickness and quality of the casing.

The proposed coupons will be composed of the materials summarized in Attachment C, Table 3. The materials identified for corrosion monitoring were compared to the list of proposed construction materials for the injection well in Attachment G (Construction details) for Well 357-7R (submitted with the initial permit application on August 30, 2021) and Well 355-7R (submitted December 2, 2021). The first two columns of the table below are adapted from Table 3 of the Testing and Monitoring Plan (list of equipment coupon with material of construction), with review notes in the right-hand columns.

Coupon (Attachment C, Table 3)	**Construction Material (Attachment C, Table 3)**	**Review Notes based on Information in Attachment G**	
		Well 357-7R	**Well 355-7R**
Pipeline	CS A106B	Not identified	Not identified
Casing	N80 Steel	Intermediate and Long-string: N80 (pg. 2)	Intermediate and Long-string: N-80, K-55 (Table 5)
Tubing	13 CR-95	13 CR-95 (pg. 2)	L-80 (Table 6)
Wellhead	Stainless steel	Not identified	Not identified

The coupons proposed for corrosion monitoring of the casing and tubing match those described in Attachment G for injector 357-7R. However, it appears that Well 355-7R has different construction, and a corrosion testing program specific to the 355-7R injector is needed. Although the materials of construction for the pipelines and wellheads are not described in Attachment G, it is assumed that coupons would be selected to represent these materials.

Questions/Requests for the Applicant:

- *Please describe the corrosion coupons for a corrosion testing program specific to the 355-7R injector. Additional details were added to the sample description text regarding the coupon usage and application. CTV also provided additional details on Table 3 including N80 steel for*

casing and chrome alloy for the tubing; however, these do not match the materials described in the well construction descriptions.

- *For completeness, please include the details about the analytical methods for corrosion coupon monitoring that are described in Table 5 of the QASP into the Testing and Monitoring Plan. Attachment C references an ASTM method for prep/cleaning/evaluating corrosion test specimens. This differs from the QASP, which references NACE and EPA methods.*
- *Please provide the list of construction materials to be used for the pipeline and wellhead so that they can be compared to the proposed coupon materials for the corrosion testing program. Table 3 has been updated to include coupons made of carbon steel for the pipeline and chrome alloy for the wellhead; the response is acceptable at this point in the permit application review. EPA will need to verify that the corrosion coupons for the pipeline and wellhead are appropriate to the materials described in the well specifications when they are provided.*

Follow-up Questions for the Applicant:

- ***Please explain how using N80 steel coupons and chrome alloy are appropriate for monitoring the casing and tubing of each of the wells, as constructed.*** *CTV added text to Attachment C explaining that K-55 grade sections of the 7" casing will be above the packer and behind tubing and will not be directly exposed to the CO_2 injectate. The wellbore materials expected to come into contact with the CO_2 injectate include the N80 grade long string casing and the CRA tubing. Table 3 reflects this information (and is consistent with well construction information submitted by CTV in December 2022), and the response is acceptable.*
- ***Please modify the Testing and Monitoring Plan or the QASP so that the analytical methods for corrosion monitoring are consistent.*** *CTV edited the "Sample Handling and Measurement" section to reference NACE TM0169/G31 and EPA 1110A SW846. The response is acceptable.*

Continuous Monitoring to Evaluate Internal Mechanical Integrity

CTV will install and use continuous recording devices to monitor: injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Surface injection pressure will be set to a minimum of 1,200 psi, eventually reaching 2,000 psi at the cessation of injection operations, as noted in the discussion of "Operational Procedures" in the permit application narrative. For Well 357-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 3,800 psi (surface) and 6,100 psi (downhole) are not exceeded. For Well 355-7R, the surface and downhole pressure gauges will ensure the maximum allowable injection pressures of 2,900 psi (surface) and 6,108 psi (downhole) are not exceeded.

Additionally, a surface pressure gauge will be installed on the annulus to monitor the annular pressure and ensure the integrity of the packer and tubing. However, the annular pressure needed to signify a mechanical integrity issue is not indicated by CTV.

The maximum injection rate of 30 million standard cubic feet per day (mmscfpd) and average injection rate of 10-15 mmscfpd will be monitored by a surface flowmeter. The calculation of injection volumes will be calculated using the injection flow rate and CO_2 stream density and will be used to ensure the maximum expected injection volume does not exceed 10 million tonnes.

Temperature gauges will be employed at surface and downhole to monitor the temperature of the injectate and ensure it is consistent with the expected temperature of the CO_2 stream at a given depth.

Additional evaluation of the well monitoring equipment will be provided in the Well Construction reports for the injection wells.

Table 2 of Attachment C lists sampling devices, locations, and frequencies for continuous monitoring and is replicated below.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	30 seconds	30 seconds
Injection rate	Flowmeter	Surface	30 seconds	30 seconds
Injection volume	Calculated	Surface	30 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	30 seconds	30 seconds
CO_2 stream temperature	Temperature gauge	Surface and Downhole	30 seconds	30 seconds

Questions/Requests for the Applicant:

- *Please clarify the location/depths of the downhole temperature and pressure gauges listed on Table 2. These should also be depicted on the well schematics. Table 2 contains information regarding whether the gauges are at surface or downhole but does not include the actual depths. This information will need to be provided—and included on the well schematics—once the final well construction and equipment have been determined. CTV updated Table 2 to present the downhole depths of sampling devices for both injection wells. These depths match the Injection & Monitoring Well Schematics_v2 document added by reference to the Monitoring Devices, Location, and Frequency subsection. The response is acceptable.*
- *Please explicitly define the annular pressure deviation that would warrant a mechanical integrity investigation. CTV did not provide the requested information.*

Follow-up Questions/Requests for the Applicant:

- ***Please define the annular pressure deviation that would warrant a mechanical integrity investigation, as requested.*** *CTV expanded the Annular Pressure Monitoring subsection to explain the annular monitoring methodology and the pressure deviations that would warrant investigation. These deviations include a pressure decrease to 0 psi, pressure drops below 100 psi that cannot be stabilized after three attempts, and pressure increases above 1000 psi. The response is acceptable.*

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The maximum pressure thresholds identified for continuous monitoring and the annulus pressure in Attachment C may need to be adjusted to reflect the final permit conditions (e.g., if they change based on the results of pre-operational testing).*

External MITs

To verify external mechanical integrity as required at 40 CFR 146.89(c) and 146.90, CTV proposes to perform MITs annually. CTV also proposes to perform these same MITs prior to commencing injection.

Table 6 of Attachment C lists the MITs to be performed and is reproduced below.

Test Description	Location
Temperature Log	Along wellbore via wireline well log
Radioactive Tracer Survey (RTS)	Along wellbore via iodine

On page 9 of Attachment C, CTV only indicates that it will run a temperature log (and not a radioactive tracer log) and notes that if it elects to conduct an alternate MIT, it will request approval from EPA. (EPA notes that, if CTV opts to use an alternative MIT, the Class VI permit would need to be modified to incorporate this test.) CTV presents procedures for MIT temperature logging but does not describe the radioactive tracer logging procedures.

Questions/Requests for the Applicant:

- *Please revise the temperature logging procedure to include a minimum of 4 hours between runs. Additionally, please provide more extensive temperature logging procedures, e.g., in accordance with the document, "Appendix E – Temperature Logging Procedures – U.S.E.P.A. Region IX," which is available online at: https://archive.epa.gov/region9/water/archive/web/pdf/appendixetemplogreqs.pdf. The text has not been updated to incorporate the details about the temperature logging procedures that EPA requests, and some of the logging details that EPA requires have been left out.*
- *Please provide a detailed description of the MIT testing procedures for RTS. RTS appears to have been removed as a MIT testing procedure and was replaced with continuous distributed temperature sensing. This is acceptable as a secondary MIT, since temperature logs are an approved MIT method. However, consistent with 40 CFR 146.89, CTV must perform the temperature log on the injection well.*
- *The Emergency and Remedial Response Plan includes scenarios for monitoring well MI failures, however no MIT of the monitoring wells is described in the Testing and Monitoring Plan. Please provide procedures and plans for performing MITs in the deep monitoring wells. The revised plan indicates that CTV will use DTS (a fiber optic continuous temperature monitoring system) on the monitoring wells; while this is not an approved MIT method (i.e., that would meet the requirements on 146.89 for the injection well), it may be appropriate for monitoring well MITs, but additional information is required (see below).*
- *Please include MITs on the monitoring wells and the EOR wells to be used for deep monitoring as part of the Testing and Monitoring Plan. The text was updated to include DTS on the deep monitoring wells, no MITs are explicitly described for the EOR wells to be used for monitoring.*
- *Attachment G describes Annulus Pressure Testing Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1. Please also include internal and external MITs during the injection and post-injection phases and describe these in Attachments C and E. This was not included in the updated attachments.*

Follow-up Questions/Requests for the Applicant:

- ***Please explicitly state in the introduction to this section of the Testing and Monitoring Plan***

that CTV will, at a minimum, perform a temperature log on the injection well (i.e., not that it will perform "one of two methods in Table 6"). *CTV added the requested statement to the new External Mechanical Integrity Testing section, indicating that, at a minimum, CTV will perform a temperature log on the injection wells. The response is acceptable.*

- ***Please provide additional detail about the temperature logging procedures or indicate in the plan that CTV plans to perform temperature logging exactly as described in the EPA guidance.*** *CTV added the subsection "Description of Temperature Logging with Wireline" to provide the requested level of detail about the temperature logging procedures. The subsection now includes specific procedures that are consistent with EPA guidelines, and the response is acceptable.*

- ***Please provide additional information on the DTS and its suitability as a secondary MIT method.*** *CTV added the subsections "Description of Temperature Logging using Distributed Temperature Sensing (DTS)" and "Description of Passive Temperature Logging using DTS" to justify the use of DTS as a MIT method for the monitoring wells. CTV clarified that DTS will not be installed on the Monterey Formation A3-A11 wells, though DTS will be installed on other monitoring wells for passive external MI monitoring. The response is acceptable given that CTV DTS is used in addition to performing temperature logging, as required at 40 CFR 146.89.*

- ***Will DTS be employed in the EOR wells that CTV plans to use for monitoring? If so, please state this in the plan.*** *CTV clarified that DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above confining zone monitoring wells. CTV added a subsection on Internal MIT for Monterey Formation A3-A11 Monitoring Wells to explain that the A3-A11 monitoring wells are not configured with tubing and packer that would allow SAPT or annulus monitoring; therefore, they plan to perform fluid sampling for CO_2 which will serve as a proxy for internal MI of the A3-A11 wells. The presence of CO_2 in the wellbore would indicate leakage, in which case they would notify EPA. Specific testing details and parameters for fluid sampling in wells A3-A11 are given in Tables 8 and 9, respectively. The response is acceptable. However, based on Table 4 of the PISC and Site Closure Plan, it does not appear that CTV plans to perform fluid sampling in the deep monitoring wells in the post-injection phase.*

- ***Please include internal and external MITs for Monitoring Well 327-7R-RD1 & 342-7R-RD1 during the injection and post-injection phases and describe these in Attachments C and E as requested.*** *CTV stated in their response document that Well 342-7R-RD1 is not a monitoring well in the project, and it appears to have been removed throughout the permit application. Only Monitoring Well 327-7R-RD1 is planned for use in the Etchegoin Formation. The updated Attachment C now has two separate subsections for internal and external MITs. Table 6 describes internal MITs that will be performed on Well 327-7R-RD1 and includes testing frequencies for the injection and post-injection phases. Table 7 gives potential external MIT methods that may be performed on monitoring wells; however, external MITs for monitoring wells are not explicitly identified. CTV states that they will utilize an approved method under 40 CFR 146.89(c), and CTV may seek future EPA approval for use of DTS.*

Additional Follow-up Questions/Requests for the Applicant:

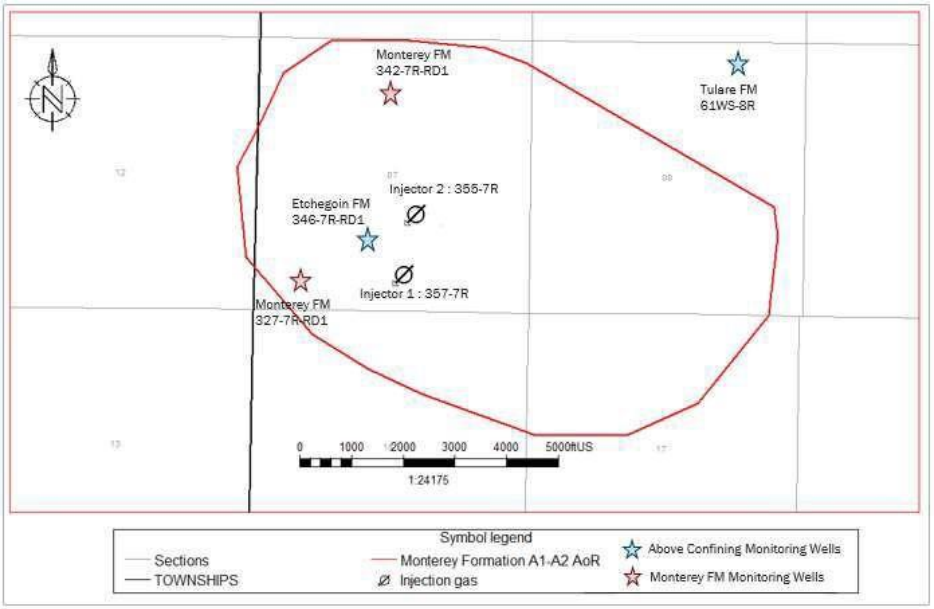
- ***Please confirm that at least one external MIT will be performed on the monitoring wells.***
- ***Please include quarterly sampling in the A3-A11 wells on Table 4 of the PISC and Site Closure Plan to provide consistency/continuity of injection-phase monitoring.***

Groundwater Quality Monitoring

CTV proposes to monitor groundwater quality in existing wells above the confining zone using direct and indirect methods. To meet the requirements of 40 CFR 146.90(d), CTV proposes to perform the following monitoring above the confining zone:

- Annual injection-phase water quality monitoring and continuous pressure and temperature monitoring via one well located outside of, and to the northeast of, the delineated AoR in the Upper Tulare Formation (the lowermost USDW) and the Lower Tulare Formation. Post-injection water quality sampling will continue annually and continuous pressure monitoring in the USDW is proposed.
- Continuous monitoring of pressure and temperature in the Etchegoin Formation within a monitoring well located to the west of the injection wells.

Attachment E does not describe any monitoring in the Etchegoin or the Monterey Formation A3-A11 Sands after cessation of injection. However, EPA will likely require that post injection phase monitoring



be an extension of injection phase monitoring to confirm continued demonstration that USDWs are not endangered and to inform the non-endangerment demonstration required at 40 CFR 146.93(b)(3).

Figure 2 of the QASP shows the locations of all monitoring wells associated with the project and is reproduced below.

The Etchegoin Formation monitoring well appears to be situated within the AoR and in the anticipated path of the CO_2 plume and pressure front (based on information in Attachment B). The Upper/Lower Tulare Formation monitoring well is outside of the delineated AoR to the northeast of the injection wells, and down plume. Given that the Tulare Formation does not hold much water within the AoR, this

location, while not in the same direction as the deeper monitoring wells may be most appropriate to allow geochemical sampling, although it is unlikely that CO_2 will travel that far down the limb of the anticline. CTV states that additional Upper Tulare monitoring wells will be drilled if increased pressure is observed in the Etchegoin Formation monitoring well or water quality changes in the Tulare Formation that is due to Monterey Formation A1-A2 CO_2 injection. However, it is unclear how a linkage of water quality/pressure changes to CO_2 injection (and not other activities) would be made.

The applicant proposes to monitor water quality in the Upper/Lower Tulare Formation and the Monterey Formation during the injection and post-injection phases. The analytical and field parameters and methods described in Tables 5 and 8 of Attachment C (injection-phase monitoring of the Tulare and Monterey Formations, respectively) are nearly the same as those in Tables 2 and 5 of Attachment E. Additional information about monitoring in the Monterey Formation is described under "CO_2 Plume Tracking" below. CTV also proposes to perform a baseline water analysis in the Etchegoin Formation monitoring zone and in the Tulare Formation monitoring well.

Table 5 of Attachment C (Injection-phase Tulare Formation monitoring) is reproduced in the first two columns of the table on the next page. Because consistency of monitoring parameters above and within the injection zone is appropriate for detecting leakage of the CO_2 plume, EPA evaluated proposed injection and post injection monitoring in the Tulare and Monterey Formations together. EPA's notes and recommendations are provided in the right-hand column; see also the discussion of "Quality Assurance Procedures" below for additional comments on the parameters to be monitored.

The parameters appear to be generally appropriate for groundwater quality monitoring needs for GS projects, and are consistent with other Class VI monitoring programs, except as noted below. As the permit application narrative describes (pg. 39), the Monterey A1-A2 Sands are dominated by quartz and feldspar, which are stable in the presence of CO_2 and carbonic acid. Note that, as additional information is gathered based on the reviews of other parts of the permit application or pre-operational data collection, recommendations or requirements for additional analytical parameters may be provided.

Parameters	Analytical Methods	Evaluation Notes/Recommendations
Tulare Formation		
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl)	ICP-OEC EPA 200.7/6010B	200.7 and 6010B are both ICP-AES methods, not ICP-OEC. Please explain what ICP-OEC is or revise the table. These were changed to ICP-MS and EPA Method 6020. In Table 17 of the QASP, the final cation is Ti, not Tl as in Attachment C. Please clarify/be consistent. Also, this is "T1" in the tables of Attachment E; please correct the typographical error. Not addressed. Standardized to Ti in the QASP, Attachment C, and Attachment E. Cations of Sb are also mentioned in Table 17 of the QASP; please add this to the ground water monitoring parameters in Attachments C and E. Not addressed. Sb added to Attachment C and Attachment E. 200.7 is an EPA-approved wastewater analytical method, while 6010B is not. EPA requests that Method 200.7, Rev 4.4 (1994) be specified. These were changed to ICP-MS and EPA Method 6020.
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OEC EPA 200.7/6010B	See above. These were changed to ICP-OES and EPA Method 6010B.
Anions (Br, Ca, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	Attachment E and Table 17 of the QASP also include anions of Cl; please add this to Attachment C for consistency and completeness. Added. Tables 2 and 5 of Attachment E reference EPA Method 300; please revise the method to be consistent with Attachment C (i.e., Method 300.0). Also, please specify that EPA Method 300.0, Rev. 2.1, Part A (1993) will be used. Addressed.
Dissolved CO_2	SM 4500-CO2-C	No comments.
Total Dissolved Solids	SM 2540 C	Attachment E refers to SM 4500 C for TDS; EPA requests the use of SM 2540 C for consistency. Addressed.
Alkalinity	SM 2320 B	Attachment E refers to SM 2510, which is for conductivity, not alkalinity. EPA requests that CTV revise Attachment E to reference SM 2320 B for consistency. (SM 2320 B is an approved wastewater method.) Addressed.
pH (field)	EPA 150.1 / SM4500-H+B	No comments.
Specific Conductance (field)	SM 2510 B	SM 2510 B is named by SM as a laboratory method, and it is not clear whether SM 2510 B can be conducted in the field. EPA Method 120.1 may be more amenable to field screening if SM 2510 B is not. Please clarify if field use of SM 2510 B is possible or revise the table (i.e., field vs. lab designation) or the method. Not addressed. Changed to APHA 2510.
Temperature (field)	Thermocouple	No comments.
Dissolved Methane	RSK-175/Gas Chromatography	This method was developed by EPA but is not an EPA approved method for wastewater analysis. Please provide information to support the use of this method for dissolved methane analysis. Alternatively, consider using EPA-approved method SM 6211 B and/or 6211 C. Parameter was removed. Change not made.

EPA recommends in Class VI guidance that monitoring well construction and planned plugging procedures for monitoring wells be reviewed as part of the permit application evaluation to confirm that

these wells will not provide conduits for fluid movement that could endanger USDWs. No monitoring well construction or plugging information was provided in the permit application materials.

CTV should note that the Central Valley Water Board indicated in its consultations with EPA on a prior Class VI project that any newly drilled monitoring wells must be approved by the Water Board and, while existing wells would not need to be approved, the Water Board expressed interest in any plans to use existing wells as monitoring wells.

Attachment C also describes the water quality sampling procedures, the laboratory to be used, and chain of custody procedures. This information is detailed in the QASP as well.

Questions/Requests for the Applicant:

- *Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E as noted in the table above. Further, the same analytes and methods should be used for monitoring of all formations - to provide consistent data to support modeling reviews and a non-endangerment demonstration. Tables 5 and 8 have been updated; however, some additional changes are needed, as noted above.*

- *In addition, please include additional ground water quality parameters to support a robust monitoring program, as follows:*
    - *δ13C, which is mentioned in the QASP, but not in Attachments C and E. This was added to Table 8; the response is acceptable.*
    - *Water density (which is referenced in the Testing and Monitoring Plan as an expected water quality change due to plume movement on pg. 12). This was not included.*
    - *Dissolved O_2 and H_2S. Dissolved O_2 is a primary indicator of water quality. H_2S occurs in the subsurface, may be common in oil fields, and has the potential to be mobilized, and, is listed as a toxic substance by the CDC. H_2S was added to the parameters in Tables 5 and 8; dissolved O_2 was not added as a parameter but is listed under field measurements where it should be measured. The response is acceptable.*

- *Please include the groundwater monitoring well 61WS-8R in Figure 4 of the PISC and Site Closure Plan. This was not added to Figure 4 as requested.*

Follow-up Questions for the Applicant:

- ***Please provide monitoring well construction and plugging plans to confirm that these wells will not provide conduits for fluid movement that could endanger USDWs.*** *CTV provided Monitoring Well Construction and Plugging Plans for monitoring wells 327-7R-RD1, 335X-7R, and 353A-7R (Attachment G). The plans are consistent with EPA templates for well construction and plugging. However, it is noted that there are some discrepancies between the data tables in the Monitoring Well Construction and Plugging plans and similar data tables within the well schematics that CTV submitted in May 2022. Additionally, the plans state that the cement type used for plugging will be API Spec 10A. The tables within the well schematics, and within the plans, indicate Class G type cement will be used. Although equivalent to each other, the schematics should reference the same type as described in the plans (API Spec 10A).*

- ***Please update Tables 5 and 8 of Attachment C and Tables 2 and 5 of Attachment E to incorporate the notes above, i.e., add specific conductance (field), Sb, and water density and revise the chemical symbol for titanium.*** *CTV made some of the requested changes and*

revisions to Table 5 and 9 (formerly Table 8) of Attachment C and Tables 2 and 5 of Attachment E (as noted above).

- ***For clarity, please also include the depths of pressure/temperature monitoring gauges on Tables 4, 7, and 9 (only the fluid sampling depths are shown, and a separate depth row for the pressure/temperature gauges would clarify this monitoring).*** *CTV updated the relevant tables (now Tables 4, 8, and 10) to include depths for pressure and temperature monitoring, with separate rows for each measurement; pressure and temperature monitoring will occur at the same depths. The response is acceptable.*

- ***Please update the USDW fluid sampling depth for the Tulare Formation well in Attachment E Table 1 to 940 – 960 feet to be consistent with Attachment C.*** *CTV updated Table 1 of Attachment E to be consistent with Table 4 of Attachment C. The response is acceptable.*

- ***Why was dissolved methane removed as a ground water analytical parameter?*** *CTV states in their response document that dissolved methane is not considered a necessary component to understanding leakage from the CO_2 reservoir into the USDW. However monitoring for methane would be consistent with other Class VI projects and is recommended in the UIC Class VI Testing Guidance document.*

- ***Please include well 61WS-8R in Figure 4 of the PISC and Site Closure Plan.*** *CTV clarified in their response document that the 61WS-8R monitoring well is not being considered for the project. The USDW monitoring well planned for the project is shown on Figure 1 of Attachment C, Figure 3 of Attachment E, and Figure 2 of the QASP. The response is acceptable.*

Additional Follow-up Questions/Requests for the Applicant:

- ***Please update the groundwater analytical parameters to include testing for dissolved methane with an EPA approved method.***
- ***Please update the monitoring well schematics data tables to address the inconsistencies with the plugging plans in Attachment G.***
- ***APHA 2510 is a laboratory (not a field) method. Please revise the Tables 5 and 9 and/or the Sampling Methods section on pg. 10 to state that this test is planned for a laboratory setting and not the field, or, specify a new testing method for field use.***
- ***Please add water density as a testing parameter to Tables 5 and 9 of Attachment C, Tables 2 and 5 of Attachment E, and Table 3 of the QASP.***
- ***CTV stated in their response to questions about MITs (see above) that Well 342-7R-RD1 is not a monitoring well in the project. Therefore, there is only one Etchegoin monitoring well, to the southwest of the injectors. Please include a description of how CTV will monitor for water quality changes above the confining zone in the northwestern portion of the plume.***

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of groundwater quality analytical parameters may need to be updated to ensure that all applicable parameters are included.*

CO_2 Plume and Pressure Front Tracking

The applicant describes proposals for CO_2 plume and pressure front tracking that include: (1) the use of direct and indirect methods for tracking the pressure front within the injection zone [40 CFR 146.90(g)(1)]; and, (2) direct pressure front monitoring in two monitoring wells and seismic monitoring to indirectly track the extent of the CO_2 plume [40 CFR 146.90(g)(2)].

For post-injection site care, CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. In Attachment E, Table 4 details the methods that will be used to monitor the CO_2 plume post-injection, and Table 6 details the methods that will be used to monitor the associated pressure front. Injection reservoir pressure monitoring will occur to ensure confinement of the reservoir and consistency with computational modeling results. As seen in Table 6 of Attachment E, seismicity monitoring will also occur via surface and shallow borehole seismometers. Table 5 of Attachment E lists the analytical methods that will be used for the injection zone fluid monitoring and analysis.

CO_2 Plume Monitoring

CTV proposes to monitor the plume via direct and indirect monitoring in the Monterey Formation:

Direct plume tracking methods include:

- Annual fluid sampling during the injection and post-injection phases in Monterey Formation A1-A2 Sands via two monitoring wells (327-7R-RD1 and 342-7R-RD1, located to the southwest and the northwest of the injection wells, respectively).

- Quarterly fluid sampling during the injection phase in EOR producers in the Monterey A3-A11 Sands. The location of the EOR wells is not described.

Indirect plume monitoring includes:

- Pulse neutron logging in the Monterey Formation A1-A2 Sands via the same monitoring wells. This logging will be conducted every two years during the injection phase and every 5 years during the post-injection phase.

The parameters and associated analytical methods are presented in Table 8 of Attachment C. They are identical to those proposed for Tulare Formation water quality monitoring described under "Ground Water Monitoring" above. Deep and shallow water quality monitoring should be for the same parameters to provide consistent data on which to evaluate potential fluid movement out of the confining zone.

Figure 2 of the QASP (reproduced under "Groundwater Monitoring" above) shows the location of the monitoring wells in the Monterey Formation A1-A2 Sands. CTV asserts that modeling indicates that the CO_2 plume will reach each of these monitoring wells by the second year of injection.

Pressure Front Monitoring

CTV plans to conduct **direct pressure front monitoring** by continuously monitoring pressure and temperature during the injection and post-injection phases within the Monterey Formation A1-A2 Sands via pressure gauges in monitoring wells 327-7R-RD1 and 342-7R-RD1.

Indirect pressure front monitoring will be accomplished via seismic monitoring throughout the AoR. CTV states that it will monitor seismicity with surface and shallow borehole seismometers it plans to install, as well as monitor seismic data from the Southern California Earthquake Data Center (SCEDC) network. This continuous monitoring will continue throughout the injection and post-injection phases.

Pressure-front monitoring activities are summarized in Table 9 of Attachment C and Table 6 of Attachment E.

Questions/Requests for the Applicant:

- *Please refer to EPA's questions and recommendations under "Groundwater Monitoring" above regarding water quality analysis and revise Table 8 of Attachment C and Table 5 of Attachment E accordingly. Additional revisions are needed, as described in the comments above.*

- *Please elaborate on the monitoring in the Monterey Formation A3-A11 Sands as described on page 12 of Attachment C. Specifically, where are the EOR producers from which CTV plans to sample the Monterey Formation A3-A11 Sands? At what depths will sampling be performed, and what parameters will be analyzed for? (The analytical parameters should be consistent with other monitoring.) Please describe who owns these wells, and whether they will be operational throughout the injection and post-injection periods? Please include the locations of these wells on the relevant figures in Attachments C and E and the QASP. The applicant provided a new Figure 3 that shows the locations of these wells, and their depths are presented in Table 7. The updated plan indicates that the same analytes will be monitored as shown in Table 8. The response is acceptable (pending requested updates to Table 8).*

- *Please describe the seismic monitoring network discussed on pg. 16 of Attachment C, including the number and location of the seismometers that CTV proposes to install. The requested information was not provided.*

- *Please explain the timeframe for which a seismicity baseline will be established, and if historical seismicity will be incorporated into this baseline. CTV says that historical seismicity within the area will be accounted for in the baseline assessment, but does not explain how.*

- *Page 15 of Attachment C says that CTV plans to perform direct pressure monitoring in the Monterey Formation A1-A2 Sands, and Table 9 indicates that pressure and temperature monitoring will be performed. Please revise the statement on pg. 15 to be consistent with the table – to include temperature as well as pressure. The revision has not been made to mention temperature monitoring as detailed in Table 9.*

- *EPA recommends that the sampling/measurement depths be included in Tables 7 and 9 of Attachment C and Tables 4 and 6 of Attachment E for clarity and completeness. Depths were added as requested to Attachment C Table 7; but were not added to Table 9 of Appendix C or Tables 4 and 6 of Attachment E. Note also that, in the updated attachment, CTV identified different injection zone monitoring wells (i.e., 353A-7R and 335X-7R); these wells are located close to the wells identified in maps in the initial plan.*

- *Please make the following changes to the proposed plume and pressure front tracking in Attachments C and E:*
    - *Perform frequent sampling and logging (e.g., quarterly, or semi-annually) early in the injection phase (i.e., at least until the CO_2 plume passes the monitoring well locations).*

This would allow the acquisition of additional data to validate the modeling, provide early warning of unanticipated fluid movement, and be consistent with other Class VI projects. The requested change was not made.

- *Conduct a 3D seismic survey or a vertical seismic profile during injection operations for comparison to the 2019 3D seismic survey described in the application narrative. The requested change was not made.*
- *Conduct quarterly water quality sampling in the A1-A2 Sands for plume tracking to be consistent with the A3-A11 monitoring activities as well as provide additional data points to validate modeled predictions, and to eventually support the demonstration of non-endangerment. CTV updated Table 7 to align sampling frequencies in the Monterey Formation A1-A2 and A3-A11.*

Follow-up Questions/Requests for the Applicant:

- ***Please revise Table 8 of Attachment C and Table 5 of Attachment E to address EPA's comments under groundwater quality monitoring above.*** *CTV made some of the requested revisions. See EPA's evaluation and Follow-up Questions for the Applicant in Groundwater Monitoring above.*
- ***Please describe the seismic monitoring network and explain how historic seismicity within the area will be accounted for in the baseline assessment.*** *CTV expanded the subsection "Induced Seismicity and Fault Monitoring" to describe the proposed seismic network and explain the seismic analysis, which includes a baseline study and continuous monitoring. CTV specified that 7 borehole and near-surface seismic sensor locations will make up the seismic network. Seismic data will be collected for at least 12 months from the seismic network prior to injection to establish baseline seismicity. Historical seismic data will be obtained from the Southern California Seismic Network and reviewed to assist in establishing the baseline. The response is acceptable.*
- ***Please revise the statement on pg. 15 to describe temperature and pressure monitoring as described above.*** *CTV updated the text to clarify that both pressure and temperature of the plume will be monitored. The response is acceptable.*
- ***Please add sampling/measurement depths to Table 9 of Appendix C and Tables 4 and 6 of Attachment E as described above.*** *CTV added a depth column to Table 10 (formerly Table 9) of Attachment C and Tables 4 and 6 of Attachment E. The response is acceptable.*
- ***Please update the plume and pressure front tracking discussion to include the requested frequent sampling and logging early in the injection phase and a 3D seismic survey or a vertical seismic profile as described above.*** *CTV updated Table 4 of Attachment E to reflect quarterly fluid sampling for direct plume monitoring but did not include a 3D seismic survey or a vertical seismic profile.*

Additional Follow-up Questions/Requests for the Applicant:

- ***Please include a map of the 7 seismic monitoring locations in Attachment C.***
- ***Please update the plume and pressure front tracking discussion to include a 3D seismic survey or a vertical seismic profile.***

Air/Soil or Other Testing and Monitoring

Based on the currently available information about the geologic setting (i.e., the depth of the injection formations and the lack of evidence for the presence of transmissive faults of fractures), surface air

and/or soil gas monitoring are not needed to detect movement of fluid that could endanger USDWs within the AoR.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If, based on the results of planned pre-operational testing, uncertainties about the geologic setting are identified, the need for air and/or soil gas monitoring or other monitoring will be reconsidered.*

Quality Assurance Procedures

The review team evaluated the QASP submitted with the permit application to verify that all the testing activities, analytes, etc., included in the QASP are consistent with proposed injection and post-injection phase testing and monitoring. All the injection and post-injection testing and monitoring activities (except for pressure falloff testing) are addressed in the QASP and the QASP covers activities recommended by EPA. EPA noted a few discrepancies between the tables in the QASP and the activities described in Attachments C and E. These are summarized in the table below:

QASP Table	EPA comments
Table 1. Summary of testing and monitoring.	Cement bond logs and standard annulus pressure tests of the injection wells are listed in the QASP, but these tests are not described in Attachment C. Please clarify if these tests are planned to be performed, either as part of pre-operational or injection-phase testing, or revise the QASP accordingly. Cement evaluation was removed from the updated QASP. Please add PFOT and RTS to Table 1. PFOT was added to Table 1 (RTS is no longer planned).
Table 2. Monitoring Well Summary.	Monitoring the A3-A11 Sands via the EOR wells is not included on Table 2 of the QASP; please include this for consistency. Table 2 was updated as requested.
Table 3. Summary of analytical and field parameters for ground water samples.	Please update the placeholders for specific cations and anions in Table 3 to reflect Table 17 of the QASP. Zinc needs to be added to Table 17. Zinc was added to Table 17 as requested. This table should address sampling in formations other than the Tulare Formation (per recommendations above). Table 3 was updated as requested. There is a typo in the pH (field): the method “SPA 150.1” should be “EPA 150.1” This has been corrected.
Table 5. Summary of Analytical Parameters for Corrosion Coupons.	Please include the QC Requirements on Table 5. This has been added as requested.

Table 17. Summary of sample containers, preservation treatments, and holding times for ground water samples.	There are a few discrepancies between the analytical parameters mentioned on Table 17 of the QASP and in Attachments C and E. EPA recommends the following changes for consistency: • Please revise the parameter NO_2 in Table 17 of the QASP to be consistent with NO_3, which is a planned analyte, per Attachments C and E. This has been corrected. • Add cations of K (in Tables 5 and of Attachment C and Tables 2 and 5 of Attachment E) to Table 17. This has been added as requested. • Please also make other necessary revisions to Table 17 of the QASP to address EPA's requests related to analytical parameters under "Ground Water Monitoring" above. See comments related to Table 17 edits under Groundwater Quality Monitoring.
Other	Please fix the formatting of the Table of Contents for Section B.1. a. This has been corrected.

Follow-up Questions/Requests for the Applicant:

- ***Please update Table 4 of the QASP to reflect use of ISBT methods for injectate analysis.*** *CTV updated Table 4 to use equivalent ISBT methods described in Table 1 of Attachment C. The response is acceptable.*
- ***Please revise Table 17 of the QASP to include zinc and Ti (not Tl) to be consistent with Attachment C.*** *CTV included Zn and corrected Ti. The response is acceptable.*

Additional Follow-up Questions/Requests for the Applicant:

- ***Please update Table 3 of the QASP to indicate that APHA 2510 is a laboratory (not a field) method.***

Questions/Requests for the Applicant:	Response
Please label the injection wells or the injection well site on Figure 2.	Complete
Was any data collected or testing performed during drilling of the 355-7R injection well? If so, please characterize this data.	During the drilling of 355-7R in 1973, the following characterizing logging measurements were obtained – Gamma Ray (GR), Spontaneous potential (SP), Resistivity (Dual induction laterlog), Density, Neutron Porosity and formation dip from 10,509' to 3,393', covering the Etchegoin, Reef Ridge and Monterey formations. In addition, 28 sidewall core samples were also obtained over the same interval, however no detailed analysis of the core samples was performed at the time.
The AoR and Corrective Action Plan (on pg. 3) states that, the "Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation." Please clarify the difference between the A2 Shale and the Lower Antelope Shale.	The A2 Shale lies directly beneath the Monterey Formation A1-A2 reservoir and provides hydraulic separation with the Monterey Formation A3-A11 reservoir. The Lower Antelope Shale is at the base of the Monterey Formation.
Does the Antelope Shale provide confinement? If so, please provide additional discussion of the confining properties.	The Lower Antelope Shale does not provide confinement for the Monterey Formation A1-A2 reservoir.
What is the source of the statement about the pressure differential between the Monterey A1- A2 Sands and the Monterey A3-A11 Sands described on pg. 10?	Figure 10.
Please provide pressure build-up test results for the 357-7R injection well.	Request technical discussion prior to inclusion in the preoperational testing plan.
Several of the figures in the narrative that contain data are difficult to read (e.g., Figures 14 and 15); please provide higher resolution versions of this information.	Complete
Please provide a map of the Elk Hills Oil Field that shows the 355-7R and 357-7R injection wells, along with the wells planned for the Elk Hills 26R Storage Project (with a scale that shows distances).	Complete - Figure 8
Faults and Fractures	
Please update Figure 10 to clearly label the formations in which the thrust faults terminate.	Complete
Where were the 66 oil samples collected within the EHOF described on pp 13-14, relative to faults within the field?	See Figure 2
Depth, Areal Extent, and Thickness of the Injection and Confining Zones	
The depths listed in Table 1 for the Monterey A1-A2 Sands are inconsistent with the logs in Figure 9. It appears, based on the log, that the depth to the Monterey A1-A2 Sands is ~8,500 feet MD or ~7,700 feet TVD at the 357-7R injection well, not 8,403 feet TVD as stated in Table 1. The mean depth to the Monterey Formation is also listed as 5,907 ft when the low and high depths are listed as 8,403 ft and 9,589 ft respectively. Please clarify the discrepancy or revise Table 1.	Table 1 depths represents the distribution over the AoR and are in true vertical depth. The logs in figure 9 are annotated with measured depth and sub-sea true vertical depth. The 5,907 foot value in table has been updated.
There is a typo on Figure 16, "Capitally" for Mercury Injection Capillary Pressure. Please fix this when the application is updated.	Complete
Please characterize, name, and provide depth and permeability data for the underlying confining unit, if one exists.	See page 10
Hydrologic and Hydrogeologic Information	
It appears that Figure 26 provides information on the depth and regional extent of the area shown in cross section with wireline logs for TDS content, however the resolution is low (pg. 31). Please provide a higher resolution version of Figure 26.	Complete
What is the depth of the Upper Tulare Formation and the separation of this lowermost USDW from the injection zone and the confining zone within the AoR?	Page 34

Is the Upper Tulare USDW present within the modeled AoR of the injection wells?	Yes, refer to page 34 and 35.
Geochemistry/Geochemical Data	
Please provide clear/legible versions of the sample analyses in Figures 30 and 31 to allow a review of the sampling performed.	Complete
Where is Well 381-17R?	Page 40
What is the total dissolved solids (TDS) content of the Monterey Formation? Please indicate how many data points or measurements are available to support this measurement (i.e., based on past field operations) and, if they are not from throughout the AoR, please provide information to support a determination that the Monterey Formation is not a USDW.	Page 40
Is any water quality data available for the Etchegoin Formation? If so, please provide this	Included in preoperational testing plan.
In the Testing and Monitoring Plan, CTV states that they obtained a baseline analysis for the 61WS-8R well (apparently for the Tulare Formation). Please provide this analysis if it is not the same as is provided in Figure 30.	CTV will drill a new monitoring well. Baseline results will be included in preoperational testing plan.
Geomechanical and Petrophysical Characterization	
Please update Figure 23 to include base case pressure.	Base case pressure is in the red line that is covered by the reduced Young's Modulus case.
Please discuss the selection of the base case parameter values (i.e., Young's Modulus, thickness, etc.) in the geomechanical modeling.	See page 28 and 29.
Please explain what is meant by "anneal discontinuities" in the discussion on page 23.	Uncompacted, low-density shales are extremely ductile and can thus accommodate large amounts of strain without undergoing brittle failure and loss of top seal integrity.
The application references core data from 13 wells on page 17. o To which wells does this refer and where are they located? o If they are not distributed throughout the AoR, please describe how they are representative of the entire area that will be affected by injection.	Updated Figure22.
Where are the 18 wells that are the source of ductility data referred to on pg. 23 located?	See Figure 19.
The application states that, "The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of .8 psi/foot," and that, "the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI" (pg. 46). Please clarify the sources of data used to determine failure pressure, fracture pressure, and fracture gradient.	The tensile failure for Reef Ridge is 7,500PSI based on geomechanical modeling. The Reef Ridge Shale confining layer fracture pressure will be addressed in preoperational testing. The Monterey Formation fracture gradient is 0.82 based on a test in 327-7R-RD1. See table 3 and page 26.
Mineralogy of the Injection and Confining Zones	
Please provide a map of the 9 well locations used for XRD described on pages 16-17.	See Figure 17.
What evidence is there for depositional continuity and facies consistency within the EHOF, as described on page 17?	See Figure 16 and page 17 text.
Seismic History and Seismic Risk	
Please include all earthquakes of magnitude 3.0 and above in Figure 24.	Updated
To inform an evaluation and documentation that there is no significant seismic risk, EPA recommends that CTV describe how the project:	See page 31 and 32
has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected.	

will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;	
will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and	
poses a low risk of inducing a felt seismic event.	
Facies Changes in the Injection or Confining Zones	
Please clarify what data sources were used to determine inputs for the geomodel where applicable, e.g., the inputs for sand vs. shale facies as discussed on pg. 40.	See Figure 16 and page 17 text.
Please also discuss how a sufficient number and distribution of formation characterization data are available to demonstrate a lack of local heterogeneities that could affect storage or confinement of CO2.	See Figure 16 and page 17 text.
Please specify the names, number, and locations of wells used to characterize formation thicknesses for the maps in Figure 13.	See Figure 16
CO2 Stream Compatibility with Subsurface Fluids and Minerals	
Please provide evidence for the statement in the Application on page 39 that the quartz and feldspar in the Monterey A1-A2 Sands are stable in the presence of CO2 and carbonic acid?	Included in preoperational testing plan.
Please elaborate on why use of the Peng-Robinson Equation of State supports compatibility of the CO2 with any fluid which may be contained within the Reef Ridge Shale.	Due to the extremely low permeability of the Reef Ridge Shale (< 0.01mD) and the high capillary entry pressure (4,220psi), the Peng Robinson Equation of State based simulation is valid to model the project over the expected reservoir pressure range of 250 – 4,000psi as there should be no entry of the CO2 injectate into the Reef Ridge.
Confining Zone Integrity	
Were any other tests performed to corroborate pressure measurements in the Reef Ridge Shale?	Included in preoperational testing plan.
The application, on pg. 14, states that there is a pressure differential of 1,300 psi between the overlying Etchegoin Formation and Monterey Formation due to the sealing nature of the Reef Ridge Shale. What is the source of the pressure data for this statement?	See Figure 13.

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E.3 Paleontological Records Search

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17 July 2023

Kristin Pittack
QK, Inc.
5080 California Avenue, Suite 200
Bakersfield, CA 93612

RE: Paleontological Records Search – CRC TerraVault 1

Dear Ms. Pittack:

This letter presents the results of a paleontological records search conducted for the California Resources Corporation (CRC) TerraVault 1 project (Project), located in an unincorporated portion of western Kern County, California. The Project alignment lies in the Elk Hills region, within the Elk Hills Oil Field, on land with surface and mineral rights privately held by CRC. The Project area is located approximately 12.75 miles west of Interstate 5 and five miles south of State Route 58. The majority of the Project alignment follows existing and maintained pipeline rights-of-way.

The purpose of Project earthwork is the construction of a captured carbon dioxide (CO_2) compression and pumping facility on 3.17 acres of land, construction of six new wells, conversion of 15 existing wells to injector or monitoring wells, and installation of approximately 14 miles of associated pipelines. The pipeline is primarily planned to be installed above ground alongside existing pipelines, except for road crossings, which will be installed via conventional cut-and-cover trenching techniques, and sensitive feature (e.g., waterways, levees, or highway interchanges) crossings, which will used trenchless installation methods such as horizontal directional drilling (HDD) and bores. In addition, pipeline that will not be collocated with existing pipelines will require installation of new sleepers, which will involve excavation of boreholes measuring approximately eight inches in diameter. Use of temporary storage and laydown areas is also proposed, and will utilize existing cleared areas.

Methods

A review of published geological maps covering the Project alignment and surrounding area was conducted to determine the specific geologic units underlying the Project alignment. Each geologic unit was subsequently assigned a paleontological resource potential following guidelines developed by the Society of Vertebrate Paleontology (SVP, 2010). In addition, a search of the paleontological collection records housed at the San Diego Natural History Museum (SDNHM) was conducted in order to determine if any documented fossil collection localities occur at the Project alignment or within the immediate surrounding area.

Results

Published geological reports (e.g., Dibblee et al., 1999) covering the Project area indicate that the proposed Project is underlain at the surface by the Pleistocene-age Tulare Formation. This geologic unit and its paleontological potential are summarized below.

The SDNHM does not have any recorded fossil collection localities within a one-mile radius of the Project alignment—the nearest recorded SDNHM fossil locality from the Tulare Formation is located

in the Buena Vista Hills approximately 6 miles south of the southeast end of the alignment. This is discussed in more detail below. A map (Figure 1) of the Project vicinity is attached at the end of this report.

Tulare Formation – The Pleistocene-age (approximately 2.5 to 0.6 million years old) Tulare Formation underlies the entire Project alignment, and is exposed throughout the Elk Hills region (Bowersox, 2006; Maher et al., 1975). Strata of the Tulare Formation record the transition from the marine conditions that dominated the Miocene and Pliocene history of the San Joaquin basin and the estuarine, lacustrine, fluvial, and alluvial fan conditions that characterized the Quaternary history of the basin. The SDNHM has one recorded fossil collection locality from the Tulare Formation to the south, in the Buena Vista Hills. This locality was documented during paleontological monitoring of excavation associated with construction of a new oil well. Collection of a bulk matrix sample and screen washing, floating, and picking of this sample resulted in the recovery of a partial snake vertebra, whole and partial vertebrae of lizards, lizard jaws with teeth, and numerous teeth and a dentary fragment of the cotton rat *Sigmodon* sp. Additional rodent cheek teeth, incisors, and jaw fragments were recovered, along with postcranial elements of unidentified mammals. More broadly, the Tulare Formation has produced important fossil remains of plants (silicified wood and pond weed algae), freshwater organisms (diatoms, ostracods, clams, mussels, snails, bony fishes, and the river dolphin *Parapontoporia* sp.), and terrestrial mammals, including horses, tapirs, camels, deer, elk, ground sloths, coyotes, bears, rabbits, gopher, mice, wood rats, squirrels, and the holotype specimens of an extinct bone-crushing dog (*Hyaenognathus pachyodon*) and saber-toothed cat (*Ischyrosmilus ischynus*) (Boessenecker and Poust, 2015; Fitch et al., 1983; Jefferson, 1991; Lohman, 1938; Merriam 1903, 1905; Pilsbry, 1935; Woodring et al., 1932, 1940). These scientifically significant finds demonstrate the high paleontological potential of the Tulare Formation.

Summary and Recommendations

The high paleontological potential of the Tulare Formation suggests that construction of the proposed Project may result in impacts to paleontological resources. Any proposed excavation activities that extend deep enough to encounter previously undisturbed strata of this geologic unit (i.e., grading, borehole augering, trenching, or other miscellaneous excavations that extend below the depth any previously imported artificial fill or disturbed sediments present along the Project alignment) have the potential to impact the paleontological resources preserved therein. If such excavation is required for Project construction, implementation of a complete paleontological resource mitigation program during ground-disturbing activities is recommended.

If you have any questions concerning these findings please feel free to contact me at kmueller@sdnhm.org.

Sincerely,



Kirstin Mueller
Assistant Report Writer
San Diego Natural History Museum

Enc: Figure 1: Project map

Literature Cited

Boessenecker, R.W. and A.W. Poust. 2015. Freshwater occurrence of the extinct dolphin *Parapontoporia* (Cetacea: Lipotidae) from the upper Pliocene nonmarine Tulare Formation of California. Palaeontology 58: 489-496.

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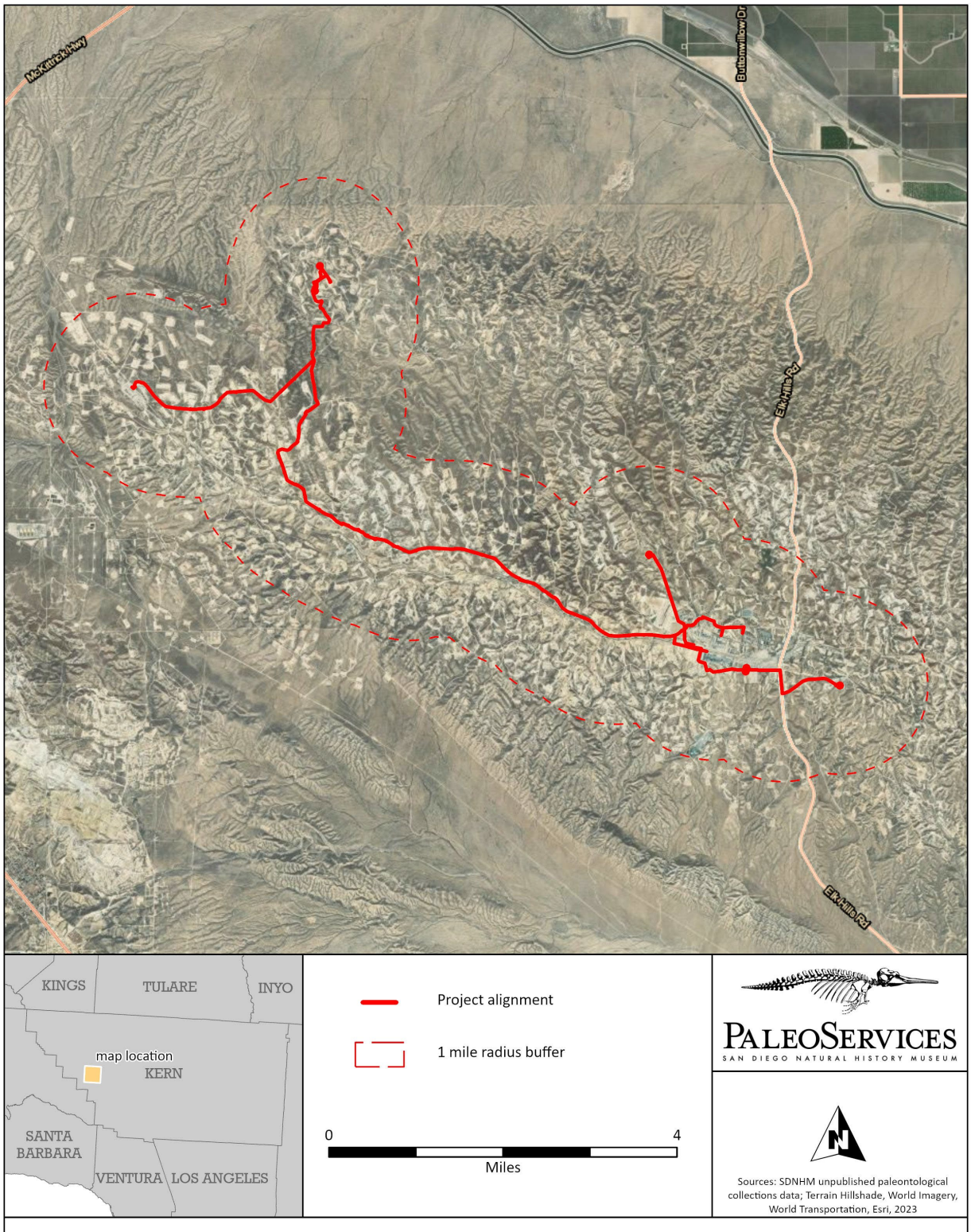

Figure 1: Records Search Map, CRC TerraVault 1, Kern County, CA

Appendix F

Hazards and Hazardous Materials Technical Documentation

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CARB LCFS REPORT #1
SITE BASED RISK ASSESSMENT

CTV Elk Hills Oil Field (EHOF)

1. Introduction

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate six CO_2 geologic sequestration injection wells at the Elk Hills Oil Field (EHOF) located in Kern County, California. The EHOF Storage Complex is divided into two non-contiguous areas referred to as "26R" and "A1-A2". The 26R project will be developed with four injectors, three wells to be drilled prior to the initiation of injection and the existing 373-35R well. The A1-A2 project will be developed with two injectors that are existing wells (355-7R and 357-7R). Storage Complex and injection well locations are shown on Figure 1. CTV plans to inject 7.7 million metric tons of CO_2 into reservoir A1-A2 and 38 million metric tons into reservoir 26R. Both A1-A2 and 26R are depleted hydrocarbon reservoirs.

During its more than 100-year history, the EHOF has been studied and documented extensively. Due to its numerous and prolific producing zones, it is one of the most fully characterized oil fields in the United States. The Monterey Formation sequestration zone has had extensive operations that includes injection of 1,430 million barrels of water and 1,220 million cubic feet (MMCF) of gas with no reservoir containment issues over 40+ years. Computational modeling that has simulated the CO_2-EOR process and CO_2 sequestration confirms containment of the injected volumes (see Report 3 Storage Complex Delineation and Corrective Action Plan).

This Site Based Risk Assessment ("Risk Assessment") is a component of the CTV application to the California Air Resources Board (CARB) for Sequestration Site Certification consistent with the Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard ("LCFS Protocol"; CARB, 2018). This report is one of thirteen separate reports submitted to CARB, and includes required information regarding the likelihood that CO_2 will be retained within the storage complex (Section 2, Appendix A) and a Risk Management Plan (Section 3).

2. Carbon Dioxide Retention Analysis

Per LCFS Protocol Section C.2.2.(f), CARB requires that that there be a 90% probability that 99% of injected CO_2 will remain within the Storage Complex for 100 years after the end of CO_2 injection in order to obtain Permanence Certification. LCFS Protocol Section C.2.4.1 requires a modeling analysis to quantify the retention probability. Appendix A is a detailed retention modeling analysis performed by Blade Energy Partners ("Blade") to evaluate if the EHOF Project will meet the LCFS Protocol CO_2 retention criteria, and results are briefly summarized here.

There are 150 existing wellbores in A1-A2 and 204 existing wellbores in 26R. The National Risk Assessment Partnership's Open-IAM software (Vasylkivska et al., 2021), augmented by

Python code written by Blade, was used to quantify the risk of leaking CO_2 up the annulus of these wells. Risks from other potential leak paths identified, such as leakage up the interior of the casing, leakage across the caprock through faults or features, and leakage from earthquake damage, were considered low and were not included in the Blade study (these pathways are discussed in Section 3 below). It was assumed that all the existing wells will be abandoned in compliance with existing regulation, and in accordance with best practices (there are no legacy abandoned wells in the EHOF Storage Complex).

Two single-well Open-IAM models were built, one for A1-A2 and one for 26R. Monte Carlo simulations were performed using the effective permeability of the leak path as the stochastic parameter to generate 2,000 realizations of the amount of CO_2 leaked into the atmosphere from a single type well. This result was scaled up to the entire reservoir by randomly selecting N realizations out of the pool of 2,000 realizations (where N is the number of wells in the reservoir), and then totaling the amount of CO_2 leaked from these N realizations. This was repeated 2,000 times to generate the probability distribution of the amount of CO_2 that escaped from the reservoir.

Due to limitations of the Open-IAM, any CO_2 that escapes from the reservoirs was assumed to have escaped into the atmosphere. This overestimates the amount of CO_2 escaping into the atmosphere because both reservoirs, A1-A2 and 26R, have multiple dissipation zones between the storage reservoir and USDW that can sequester CO_2 that escapes from the reservoirs.

The key parameter of the problem is the probability distribution of the leak-path permeability in the annulus. Four probability distributions were examined. The underlying leak path permeabilities are based on available literature and conservative assumptions.

Results show that reservoirs A1-A2 and 26R can meet CARB's Permanence Certification criterion that there is 90% probability that 99% of the injected CO_2 remains in the reservoir for 100 years after end of CO_2 injection, even under conservative assumptions. For the most conservative assumption modeled (uniform distribution from a minimum of 0.01 millidarcies [mD] to a maximum of 100 mD), results show that there is 100% probability that less than 1% of total injected CO_2 leaks to the atmosphere in 100 years after cessation of injection. For this case, the 90% probability leakage is 0.16%, well below the 1% CARB threshold.

3. Risk Management Plan

This Risk Management Plan (RMP) is developed to comply with LCFS Protocol Section C.2.2. The RMP summarizes the activities evaluated for risk, what those risks are, how they are ranked, and the steps CTV will take to manage, monitor, avoid, or minimize those risks. As required in LCFS Protocol Section 2.2.(b), the risk assessment examines scenarios listed in Report 11 Emergency and Remedial Response Plan.

CTV has conducted the RMP utilizing the risk classification outlined in the LCFS Protocol (Table 1). Each of the potential pathways for leakage to surface was characterized with probability of occurrence and severity of potential consequence.

Severity of potential consequences are classified as insubstantial, substantial, or catastrophic. For the purposes of the RMP, "insubstantial" risks were taken to be those events, that if they occur will not lead to endangerment of human health or the environment as measured by an exceedance of regulatory screening levels in drinking water sources or indoor air for regulated constituents. Substantial risks were taken to be those events, that if they were to occur, would likely lead to exceedance of human health or environmental screening levels in drinking water or indoor air but would not pose imminent threat of property damage or acute sickness/bodily harm/death. Catastrophic risks were taken to be those events that would lead to property damage, acute sickness/bodily harm/death, or significant environmental degradation.

Each scenario is discussed in detail in the following sections. In summary, all risks were categorized as "Low" or "Low/Medium" for the Project (Table 2: Risk Scenarios and Classification). This can be attributed to low CO_2 leakage potential (Section 2), lack of water-supply wells within the Storage Complete (and therefore lack of a complete pathway for drinking-water contamination), CRC's operating and drilling experience, EHOF production and injection history, and comprehensive mitigation and monitoring plans (Report 8 Testing and Monitoring Plan). The potential consequences on health, safety and the environment are low and justification is summarized in Table 3.

3.1. Injection or Monitoring Well Failure

Wells within the EHOF are monitored and maintained to prevent wellbore integrity issues. CO_2 migration could occur along an injection, production or monitoring well due to a poor or subsequently degraded cement bond or corrosion of the casing and completion. Any well that penetrates the Reef Ridge Shale creates a possible migration pathway if the CO_2 plume reaches its position (wells penetrating the confining zone within the Storage Complex are evaluated in Report 3 Storage Complex Delineation and Corrective Action Plan). From extensive operating records, CRC can establish that active and abandoned wellbores within the project area are not and will not become pathways for leakage to the surface:

- Over 1.4 billion barrels (bbls) of water and 331 billion cubic feet (BCF) of natural gas have been injected into the Monterey Formation sequestration reservoir. The Reef Ridge Shale has contained all injected fluids, demonstrating that there are no pathways from existing wellbores.

- All the production, Class II injection wells and Class VI injection wells involved in the project will be permitted by CalGEM and the U.S. EPA, in accordance with the appropriate provisions and other regulations. As part of the Underground Injection Control (UIC) permitting process, CRC will be required to demonstrate to CalGEM and the U.S. EPA that existing wellbores do not pose a threat of leakage.

- Injection well tubing and casing pressures are monitored continuously. The injection designs for each injector are engineered to govern the rate, and pressure of CO_2 injection. Pressure monitors on the injection wells are programmed to flag pressures that statistically deviate from design. Leakage on either the inside or outside of the injection wellbore would cause pressure inflections that would be detected through this approach.

- Injectors will be monitored with mechanical integrity testing (MIT) and pressure tests to ensure internal and external integrity. If monitoring data leads to identification of a well integrity issue, CRC will address the issue with corrective actions.

Severity: Insubstantial. Integrity loss at the injection well and/or monitoring well may endanger shallow groundwater (i.e., Tulare Formation). However, as stated in Report 2 Geologic Evaluation, there are no records of water supply wells within the Storage Complex. Therefore there is no groundwater used as drinking water and no complete pathway for exposure to contaminated groundwater.

Probability of Occurrence: <1%: The probability that an existing or new well causes leakage to surface is less than 1%. This is supported by over forty years of experience with existing wells, the large volumes of injected water and gas that have safely operated in the Monterey Formation without instances of injectate at the surface. Moreover, a monitoring program that assesses the mechanical integrity of wells and operating parameters will ensure that well integrity is maintained.

Risk Scenario Classification: Low (Table 1).

Risk Management Measures: Well maintenance, monitoring and control of injection flow and pressure, automatic and manual shutdown in the case of integrity failure, response actions listed in Report 11 Emergency and Remedial Response Plan.

Detection methods: Mechanical integrity testing, injection well pressure and rate monitoring, annulus pressure monitoring, surface monitoring data and inspection (CO_2 at surface), listed in Report 8 Testing and Monitoring Plan.

3.2. Equipment Failure

Damage to or failure of pipelines and surface equipment can result in CO_2 leakage. Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well but does not necessarily indicate leakage.

There is a possibility of fugitive emissions from surface equipment in the event of equipment failure. CO_2 will occasionally need to be vented from surface equipment for operational maintenance. CTV will monitor and report this CO_2 as part of its facility-wide reporting requirements under 40 CFR Part 98 Subpart W and the analogous state provisions at Division 3, Chapter 1, Subchapter 10 of Title 17 of the California Code of Regulations. The amount of CO_2 emissions attributed to surface equipment associated with the project will be included in the mass balance information reported to CARB.

Severity: Insubstantial. As discussed in Section 3.1 there is no pathway for drinking water contamination. Operational CO_2 venting and minor CO_2 fugitive emissions do not pose an acute risk to human health or the environment.

Probability of Occurrence: <1%. CTV use of prevailing industry design and construction practices and compliance with applicable regulatory and monitoring requirements will reduce to

the maximum extent practicable the risk of leakage from surface facilities due to equipment failure. Project facilities and pipelines will utilize proven construction materials and control processes common to new CO_2 projects. Operations and maintenance will follow established industry practices and standards demonstrated to be effective. Facilities will also be designed to follow the elements of process safety management specified in OSHA's Occupational Safety and Health Standard 29 CFR 1910.119. Other field pipelines will comply with California's Code of Regulations, Title 8. The unique and centralized automation and control system currently in use at the EHOF (CCF) will facilitate real-time operational control over the project and ensure the safety and reliability of the facilities.

Risk Scenario Classification: Low Risk (Table 1).

Risk Management Measures: Well and surface equipment maintenance, CCF continuous monitoring and control of flow and pressure, response actions listed in Report 11 Emergency and Remedial Response Plan.

Detection methods: Facility-wide equipment monitoring including activities listed in the Inspection and Leak Detection Plan (Report 8 Testing and Monitoring Plan).

3.3. Natural Disaster

The EHOF is in the San Joaquin Valley, which is characterized by hot, dry summers and has historically enjoyed cool rainy winters with dense tule fog. Although not common, potential desert natural disasters include lighting strikes, flash-flooding and earthquakes.

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., lightning strike) may affect surface facilities.

Severity: Insubstantial to catastrophic depending on nature of disaster.

Probability of Occurrence: <1%.

Earthquakes: As given in Report 2 Geologic Evaluation the San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due in part to the thickness and high level of clay in the primary confining layer Reef Ridge Shale. The 1952 Kern County earthquake, the largest in the region, occurred southeast of the EHOF near Frazier Park with an estimated magnitude of 7.5. Regionally there were no reservoir containment issues associated with oil and gas operations and the Reef Ridge Shale. Moreover, there was no impact to Elk Hills infrastructure.

Lightning Strikes: The EHOF is located in an area that has 0-0.25 flashes/square kilometer/year, the lowest lightning strike density in the United States (Figure 2). In the more than 100-year operating history of the EHOF, there has not been a single recorded impact on oil operations from lighting.

Flooding: The Storage Complex is not located within a FEMA mapped flood zone (Figure 3). The southern San Joaquin basin is semi-arid and receives 3.5 to 28 inches of rain per year. In the over 100-year history of the EHOF, these volumes of rain have not impacted field infrastructure. This can be attributed to adequate infrastructure engineering and efficient runoff associated with the EHOF anticlinal character.

Risk Scenario Classification: Low (Table 1).

Risk Management Measures: Infrastructure rated to specifications consistent with local, State and Federal regulations, initiation of shut-down in the event of natural disasters and extreme weather events.

Detection methods: Not applicable.

3.4. Fluid Leakage to Shallow Groundwater

Leakage out of the Storage Complex could result in elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into shallow groundwater. However, as stated in Report 2 Geologic Evaluation, CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the Storage Complex. Therefore there is no groundwater used as drinking water and no complete pathway for exposure to contaminated groundwater.

Severity: Insubstantial (no pathway for drinking water contamination).

Probability of Occurrence: <1%

Identified Wellbores: see probabilistic analysis in Appendix 1-1.

Unknown Wellbores: Wells at the EHOF have been permitted through CalGEM under rules that require operators to provide extensive and detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details and injection/production history of every well. As a result, CTV has checked for the presence of old, unknown wells in the EHOF over many years. Moreover, the extensive Monterey Formation water and gas injection has never leaked to surface through an unknown well.

Faults and Fractures: After reviewing geologic, geomechanical, geochemical, seismic, operating, and other data (Report 2 Geologic Evaluation), CTV has concluded that there are no known transmissive faults or fractures that transect the Reef Ridge Shale interval in the project area. CRC reprocessed the EHOF 3-D seismic survey in 2019. This updated seismic volume provides enhanced imaging in areas of tight folds and steeply dipping beds, confirming no transmissive faults. With 40 years of water and gas injection, there has not been an instance of fluid migration outside the Monterey Formation. There have been over 1.4 billion bbls of water and 331 BCF of gas injected into the NWS and 31S structures with no reservoir confinement issues. The Elk Hills CO_2 operations will remain within previously developed areas, negating the potential for CO_2 to

encounter undocumented/identified wells and transmissive features. The trapping of oil and natural gas within the formation demonstrates containment within the sequestration zone. Differences in water and oil chemistry indicate clear separation between different layers in the formation.

Migration through Reef Ridge Confining Layer: Geologic evaluation confirms that the Reef Ridge seal has been secure over geologic timeframes. Therefore, diffusion of CO_2 through the cap rock is not expected to result in significant loss from the storage reservoir given the low permeability (<0.01 mD) and thickness (>700 feet) of the confining Reef Ridge Shale, and fact that the project will operate at less than pre-discovery pressure. In addition, the presence of gas caps trapped over millions of years further demonstrates that gas will not migrate through the Reef Ridge shale.

Risk Scenario Classification: Low (Table 1)

Risk Management Measures: CTV will operate the project to ensure containment of CO_2. Contamination to shallow groundwater will be avoided by ensuring injection well integrity through well maintenance and mechanical integrity testing; maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer; reviewing monitoring well data to understand plume extent; monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Groundwater monitoring above the confining zone, atmospheric monitoring, injection pressure monitoring, as given in Report 8 Testing and Monitoring Plan.

3.5. Induced Seismic Event

Water injection operations have been implicated in low level seismic occurrences at a limited number of oil and gas fields around the world, including some in California. Operations at the EHOF include extensive water and gas injection, with no record of induced seismic events.

Severity: Insubstantial. Induced seismicity, if it were to occur would be expected to be low-level based on observations from water injection operations.

Probability of Occurrence: <1% given operational experience at EHOF and lack of previous induced seismicity, the project operating pressure of the Monterey Formation sequestration zone will be less than the pressure required to fracture the reservoir and Reef Ridge confining layer, and pressures will be at or less than pre-discovery pressure.

Risk Scenario Classification: Low (Table 1).

Risk Management Measures: 1. Continuously monitor injection pressures to ensure no fracturing of the reservoir and confining Reef Ridge Shale. Pressure monitors on the injection wells are programmed to flag pressures that significantly deviate from plan. Large induced seismicity events would affect pressure and be detected through this approach; 2. Ensure that the operating pressure of the Monterey Formation sequestration zone will be less than the pressure

required to fracture the reservoir and Reef Ridge confining layer; 3. Install a permanent seismic system to monitor for induced events.

Detection methods: Seismic monitoring system (Report 8 Testing and Monitoring Plan). CRC has designed a seismic monitoring plan that will detect seismic events at a magnitude of 0-1. In addition, CTV will monitor the Southern California Earthquake Data Center (SCEDC) and the USGS databases for large events that may impact operations.

3.6. CO_2 Leakage to Atmosphere

Structures are located within the Storage Complex related to the EHOF operations, and field personnel will also be present within the field. No basements are present within these buildings. CO_2 leakage to the breathing space could cause injury to workers at sufficiently high levels.

Severity: Insubstantial to catastrophic depending on CO_2 levels in the breathing space.

Probability of Occurrence: <1%; for same reasons given for fluid leakage to shallow groundwater (Section 3.4) wellbore failure (Section 3.1), and equipment failure (Section 3.2) the project will be operated in a way to minimize to the greatest extent practicable CO_2 releases to the atmosphere.

Risk Scenario Classification: Low to Medium (Table 1).

Risk Management Measures: Use of gas monitors by field personnel; additional mitigation measures listed in sections above to reduce probability of CO_2 leakage.

Detection methods: Gas monitors are worn by all field personnel. Any monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. Additional detection includes atmospheric and leak detection monitoring (Report 8 Testing and Monitoring Plan).

3.7. Well Operations (Drilling or Workover)

There exists the possibility that drilling a new well into or through a CO_2 injection zone could create a leakage pathway.

Severity: Insubstantial to catastrophic based on the induced leakage rate; no drinking-water pathway exists; however, CO_2 levels in worker breathing space has the potential to cause injury.

Probability of Occurrence: <1%; given risk management measures listed below and that CRC operates the EHOF there is negligible probability of unregulated drilling that would lead to a leakage event. There have been 964 wells drilled in the NWS and 31S structures targeting the Monterey Formation without incident. CRC is the only operator of the EHOF, reducing the potential that well operations will be conducted without knowledge of the project. Strata beneath the storage complex have been delineated with exploration wells. There are no production targets below the storage complex, limiting the probability that wells will ever be drilled through the Monterey Formation sequestration zone.

Risk Scenario Classification: Low to Medium (Table 1).

Risk Management Measures: Existing state and federal regulations are intended to mitigate this risk. Several regulations and guidelines specifically address zonal isolation during well construction. These regulations and guidelines are designed to ensure that wellbores pose no significant risk of leakage of fluids, including CO_2, to groundwater or the surface. They include the following requirements: Surface casing strings require a sufficient volume of cement to be pumped into the casing well-bore annulus so that the entire annulus is filled to surface; A minimum of 500 linear feet of cement is required above oil and gas zones in an intermediate or production casing string, which further provides zonal isolation. All well designs within the EHOF are approved by CalGEM, and a drilling permit is issued prior to commencement of any drilling operations. All permits are publicly available through CalGEM.

Detection methods: CRC operates the EHOF and tracks all well drilling activities, which must also be approved by U.S. EPA and/or CalGEM.

3.8. Summary

After assessing potential risk of release from the subsurface, CRC has concluded that release of injected CO_2 from the subsurface is improbable, all risks are 'low' or 'low/medium' and manageable.

- The structure and stratigraphy of the EHOF is ideally suited for the injection and trapping of CO_2. The stratigraphy within the CO_2 injection zones is porous, permeable, and thick, providing an excellent target and ample capacity for long-term CO_2 sequestration. Between the surface and the Monterey Formation reservoirs, naturally occurring dense and thick overlying shales exist, including the Reef Ridge Shale, which serve as excellent seals that have proven capable of containing fluids and gases for millions of years.

- CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the Storage Complex. Therefore there is no groundwater used as drinking water and no complete pathway for exposure to contaminated groundwater.

- CRC has concluded that existing and future boreholes present little risk of release to the surface for the following reasons: 1) the operating history is well documented and does not indicate leakage from man-made pathways due to past production activities; 2) adequate regulatory and operations procedures exist to ensure that new boreholes will not create pathways for release of CO_2 from the subsurface; and 3) Risk modeling indicates low leakage potential (Appendix 1-1).

- There are no transmissive faults through the Reef Ridge Shale within 31S and NWS structures. This is confirmed by seismic analysis and an extensive history of water and gas injection.

- The operating pressures are far less than the failure pressures needed to breach the Reef Ridge caprock.

In summary, based on a careful assessment of the potential risk of release of CO_2 from the subsurface, CRC has determined that there are no reasonably expected pathways that are likely to result in significant loss of CO_2 to the atmosphere or risks to human health and the environment. Further, given the detailed knowledge of the field and the operating protocols, CRC believes that it would be able to detect and mitigate any leakage to the surface that could arise. CRC will employ adequate monitoring protocols to detect any release of CO_2 from the subsurface. Finally, there are no scenarios identified that can be classified as high risk.

References

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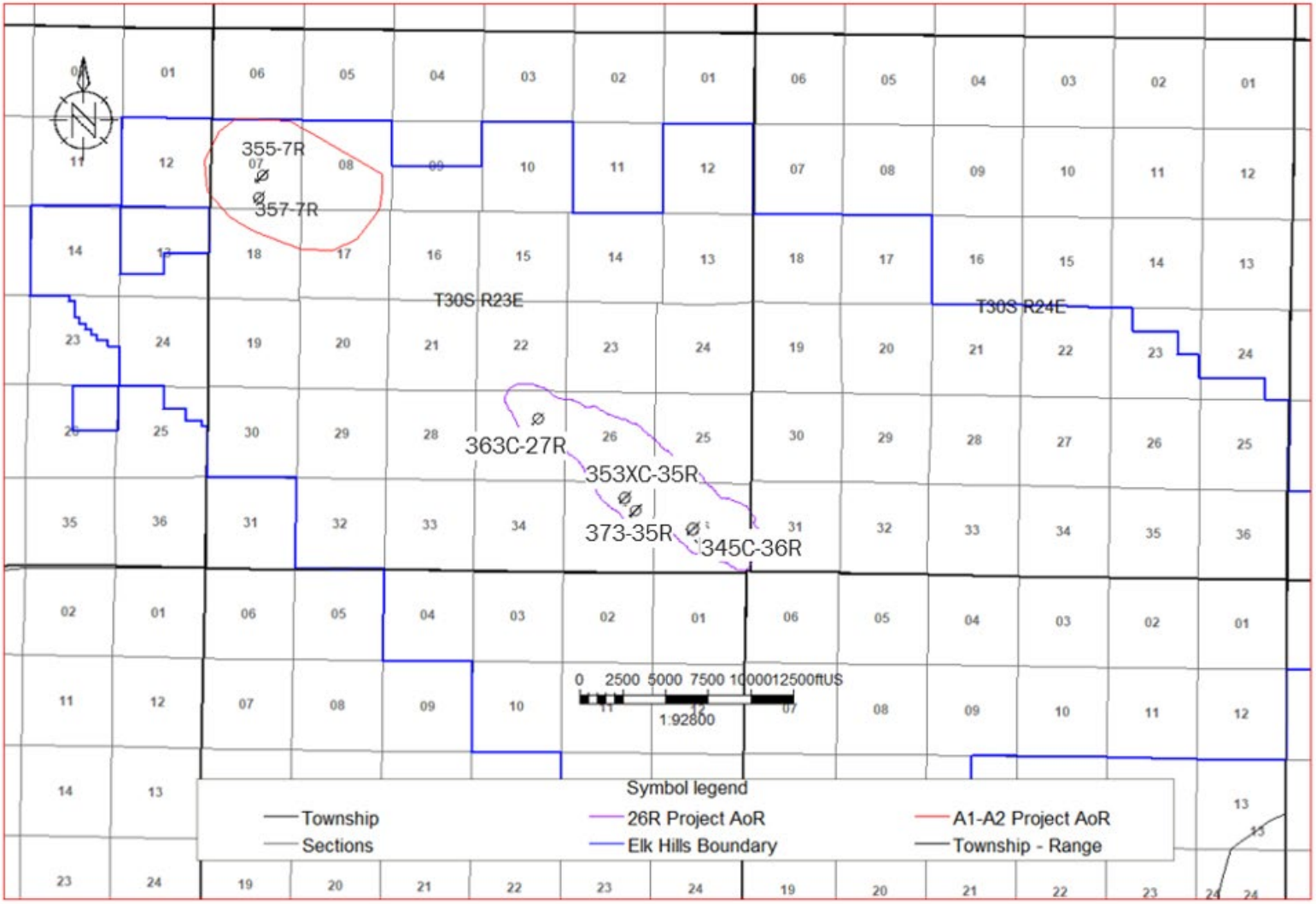
FIGURES



Note: Surface expression of the Storage Complex is the same as the Area of Review (AoR) shown

CRC ELK HILLS OIL FIELD

Storage Complex and Injection Well Location Map

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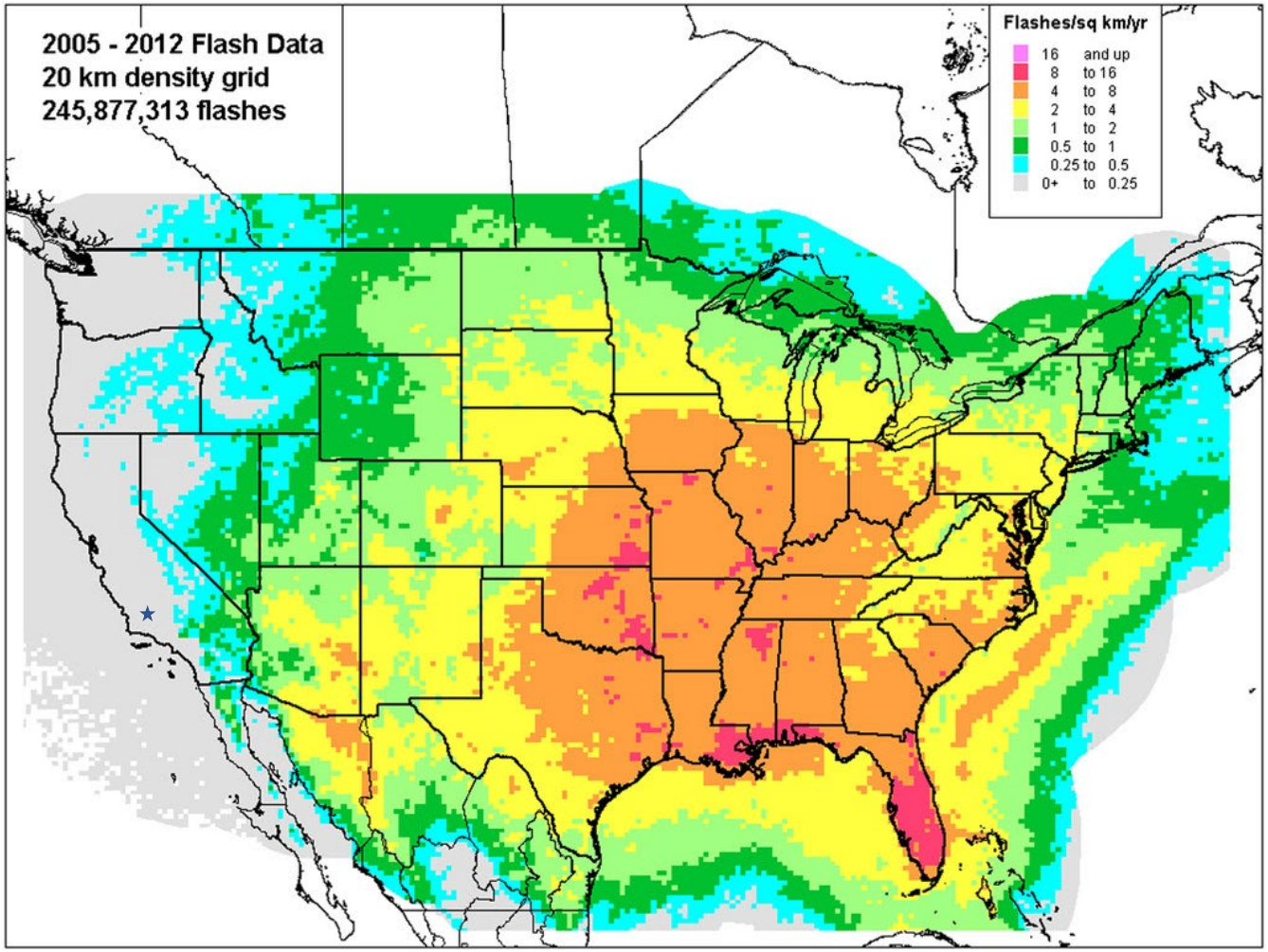
Figure 1



From Holle (2014); map of cloud-to-ground lightning flash density (km−2 yr−1) from the National Lightning Detection Network for the contiguous United States and adjacent areas on a 20 km by 20 km grid for all hours from 2005 to 2012. The density scale is in the top-right portion of the map. Project location shown by blue star symbol.

CRC ELK HILLS OIL FIELD

Lightning Flash Density

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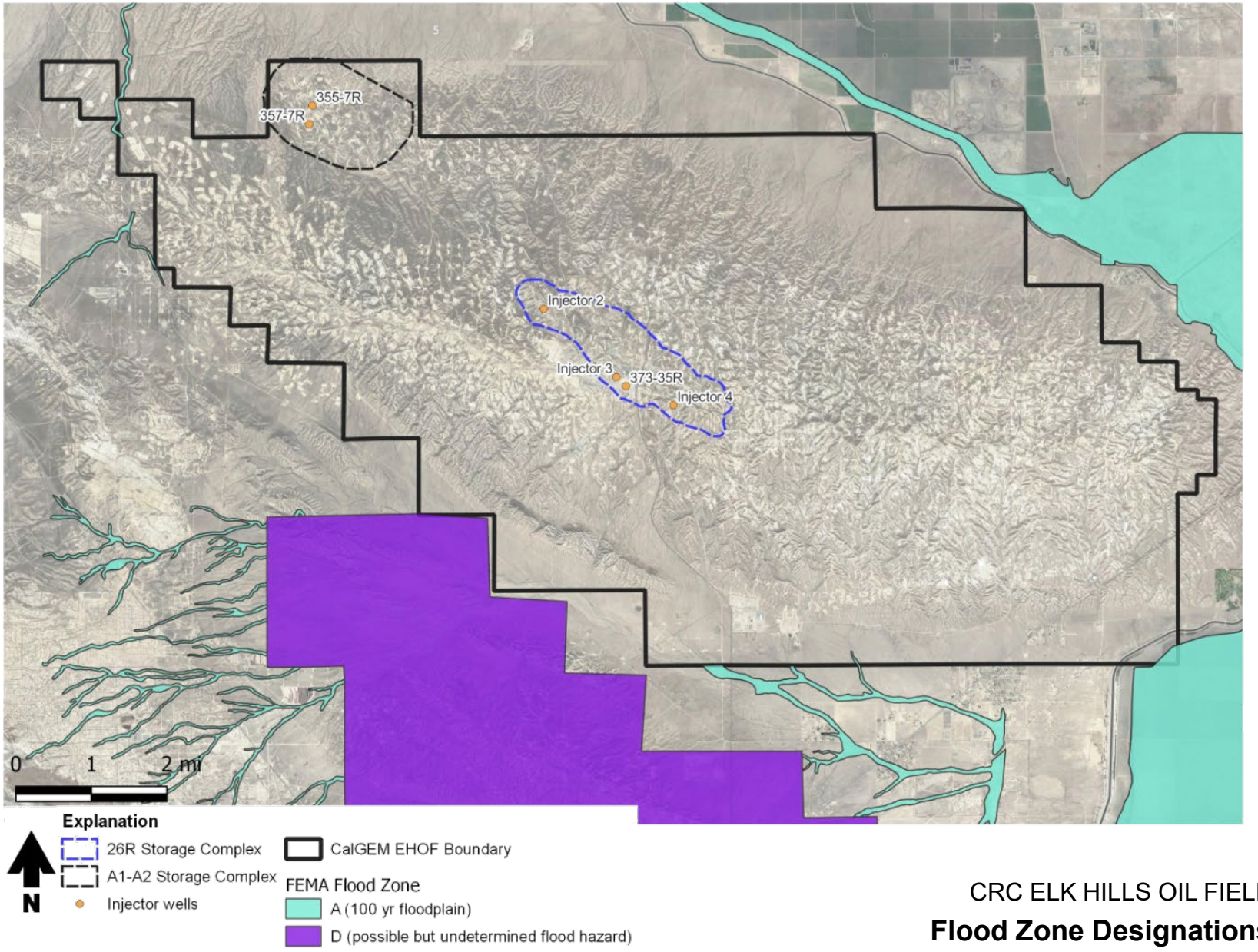
Figure 2



CRC ELK HILLS OIL FIELD

Flood Zone Designations

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Figure 3

TABLES

Table 1. LCFS Protocol Risk Scenario Classification

	Insubstantial[2]	Substantial[2]	Catastrophic[2]
> 5%[1]	Medium risk	High risk	High risk
1-5%[1]	Low risk	Medium risk	High risk
< 1%[1]	Low risk	Medium risk	Medium risk

[1] Probability of occurrence over 100 years
[2] Severity of potential consequences

Table 2. EHOF Risk Assessment Results

Scenario	Consequence	Probability	Risk
Injection or Monitoring Well Failure	Insubstantial	<1%	Low
Equipment failure	Insubstantial	<1%	Low
Natural Disaster	Insubstantial to Catastrophic	<1%	Low/ Medium
Fluid Leakage to Shallow Groundwater	Insubstantial	<1%	Low
CO_2 leakage to Atmosphere	Insubstantial to Catastrophic	<1%	Low/ Medium
Induced Seismic Event	Insubstantial	<1%	Low
Well Operations (drilling/workover)	Insubstantial to Catastrophic	<1%	Low/ Medium

Table 3. EHOF Project Characteristics

Project Characteristics	Description
Monitoring and Mitigation	CRC will employ a robust monitoring and mitigation plan (Report 8 Testing and Monitoring Plan) that includes well, reservoir, near surface and atmospheric data. These activities will effectively mitigate a potential leak and in the unlikely event of leakage, minimize the potential consequences.
Groundwater	Within the storage complex area there is no protected water. The area is partially void of groundwater with air sands, the aquifer is exempt by the EPA, or the TDS is above 10,000 mg/L. No drinking-water supply wells are present within the Storage Complex.
Geography	The EHOF is semi-arid, with limited vegetation and no residents. Oil and gas development is the only activity that occurs within the 75 square mile field boundary. CRC owns the entire surface of the EHOF.
Experience	CRC has extensive experience operating water and gas injections within the EHOF. The geology and reservoirs of the field and associated hydrodynamics, storage capacity and seals have been well established. To date, neither injected water nor gas has leaked out of the proposed storage complex.
Personnel	CRC operations personnel have extensive experience with injection wells and facilities. There will be added training and procedures to address CO_2 injectate.
Equipment Design	Facilities and infrastructure will be designed/updated to standards and processes for CO_2 injection. Alarms and safety processes will be established for incidents. These procedures are well established and time-tested via 40+ years of industry CO_2 EOR operations
Site Selection – Dissipation Zone	The Monterey Formation sequestration reservoir has high injectivity. Consequently, lower injection pressures are required which lowers the driving force for leaks. In the event of a leak, it is highly unlikely that the injectate would reach the surface or groundwater given the multiple layers of thick, low-permeability, and extensive sealing formations interbedded with high permeability, low pressure dissipation intervals that overly the Monterey Formation.

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Environmental Impact Report

SCH# 2022030180

Volume 3

Appendix G - K

CARBON TERRAVAULT I (KERN COUNTY)

by California Resources Corporation *(PP22405)*

Zone Change Case No. 5, Map No. 119
Zone Change Case No. 4, Map No. 120
Conditional Use Permit No. 13, Map No. 118
Conditional Use Permit No. 14, Map No. 118
Conditional Use Permit No. 5, Map No. 119
Conditional Use Permit No. 6, Map No. 119
Conditional Use Permit No. 3, Map No. 120
Conditional Use Permit No. 2, Map No. 138

Kern County
Planning and Natural Resources Department
Bakersfield, California

December 2023

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Draft
Environmental Impact Report

SCH# 2022030180

Volume 3

Appendix G - K

CARBON TERRAVAULT I (KERN COUNTY)

by California Resources Corporation *(PP22405)*

Zone Change Case No. 5, Map No. 119
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Conditional Use Permit No. 3, Map No. 120
Conditional Use Permit No. 2, Map No. 138

Kern County
Planning and Natural Resources Department
Bakersfield, California

December 2023

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Appendix G

Hydrology and Water Quality Technical Documentation

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G.1 Hydrology Report

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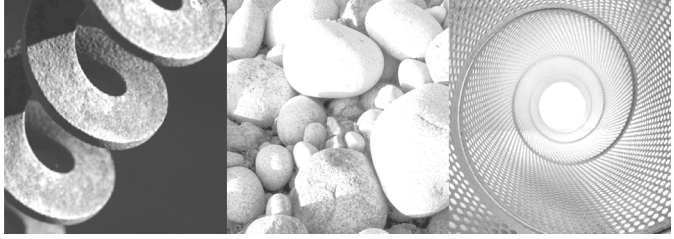

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Hydrology Report

For the California Resources Corporation, LLC, Carbon TerraVault 1 Project

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Acronyms and Abbreviations

Basin Plan	Tulare Lake Basin Water Quality Control Plan
BMP	best management practices
CEQA	California Environmental Quality Act
CO_2	captured carbon dioxide
CRC	California Resources Corporation
CTV 1	Carbon TerraVault 1 Project
CWA	Clean Water Act
DWR	California Department of Water Resources
EPA	United States Environmental Protection Agency
FEMA	Federal Emergency Management Agency
FIRM	Flood Insurance Rate Map
GSA	Groundwater Sustainability Agency
GSP	Groundwater Sustainability Plan
mg/l	milligrams per liter
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NWS	National Weather Service
RWQCB	Regional Water Quality Control Board's
SGMA	Sustainable Groundwater Management Act
Subbasin	Kern County Subbasin
SWRCB	State Water Resources Control Board
SWPPP	Stormwater Pollution Prevention Plan
TMDL	total maximum daily load
TDS	total dissolved solids
USACE	United States Army Corps of Engineers
WKWD	West Kern Water District

Chapter 1. Introduction

The California Resources Corporation, LLC (CRC) proposes to implement the Carbon TerraVault 1 Project (CTV 1 or project), which includes implementation of a 5,745-acre carbon capture and sequestration field. The project would include the construction and operation of a captured carbon dioxide (CO_2) compression and pumping facility, construction and modifications of injection well sites, conversion of existing well sites, and installation of approximately 14 miles of associated pipelines. The project objective is to contribute to California's goals for carbon neutrality by 2045 by reducing industrial activities to no net CO_2 contribution and potentially supporting direct removal of CO_2 from the air. CTV 1 has the capacity for up to 48 million metric tons of estimated storage and would be capable of sequestering over 1.5 million metric tons of CO_2 per year. The project site is located within the San Joaquin Valley's Elk Hills Oil Field, which comprises an approximate 75 square-mile (47,800 acres) complex with surface and mineral rights privately held by CRC.

This Hydrology Report (report) was prepared to describe hydrology and water quality conditions within the project area, as well as analyze potential environmental impacts of implementing the project. The report is organized by the following chapters:

- Chapter 1 Introduction. Briefly describes the project and purpose of the report.
- Chapter 2 Environmental Setting. Describes existing hydrology and water quality conditions in the project area and vicinity.
- Chapter 3 Regulatory Setting. Provides a brief overview of relevant Federal, State, and local laws and regulations pertaining to the protection of hydrology and water quality in the project area.
- Chapter 4 Environmental Impacts. Analyzes potential hydrology and water quality impacts associated with implementation of the project, based on the environmental checklist in Appendix G of the State California Environmental Quality Act (CEQA) Guidelines. Based on the analysis, the project would result in no significant impacts and no environmental commitments would be required.
- Chapter 5 References. Lists the sources of information cited throughout this report.

Chapter 2. Environmental Setting

This chapter discusses existing hydrology and water quality conditions of the Kern County region and project area.

2.1 Regional Setting

2.1.1 Kern County Subbasin Hydrologic Region

The project area is located in the Kern County Subbasin (Subbasin), which is bounded by the Kern County Line to the north; the granitic bedrock of the Sierra Nevada foothills to the east; the Tehachapi mountains to the southeast; and by the marine sediments of the San Emigdio Mountains and Coast Ranges to the southwest and west. The San Joaquin Valley represents the southern portion of the Great Central Valley of California. The San Joaquin Valley is a structural trough up to 200 miles long and 70 miles wide filled with up to 32,000 feet of marine and continental sediments deposited during periodic inundation by the Pacific Ocean and by erosion of the surrounding mountains, respectively. Continental deposits shed from the surrounding mountains forming an alluvial wedge that thickens from the valley margins toward the axis of the structural trough. This depositional axis is slightly west of the series of rivers, lakes, sloughs, and marshes that mark the current and historic axis of surface drainage in the San Joaquin Valley. Water bearing formations in the Subbasin are found in the shallow to intermediate depths of the groundwater Subbasin and are primarily continental deposits of Tertiary and Quaternary age (California Department of Water Resources [DWR] 2006).

The project area is in the western portion of the Subbasin within the Elk Hills Oil Field, which comprises approximately 75 square-miles (47,800 acres). The water bearing unit is the Tulare formation, which contains up to 2,200 feet of interbedded, oxidized to reduced sands, and gypsiferous clays and gravels derived predominantly from Coast Range sources. The Elk Hills fold is identified as a restrictive structure that serves as a barrier to groundwater movement. Water quality is characterized as primarily sodium-sulfate to calcium-sodium sulfate type (DWR 2006). **Figure 2-1** shows the project area within the Subbasin.

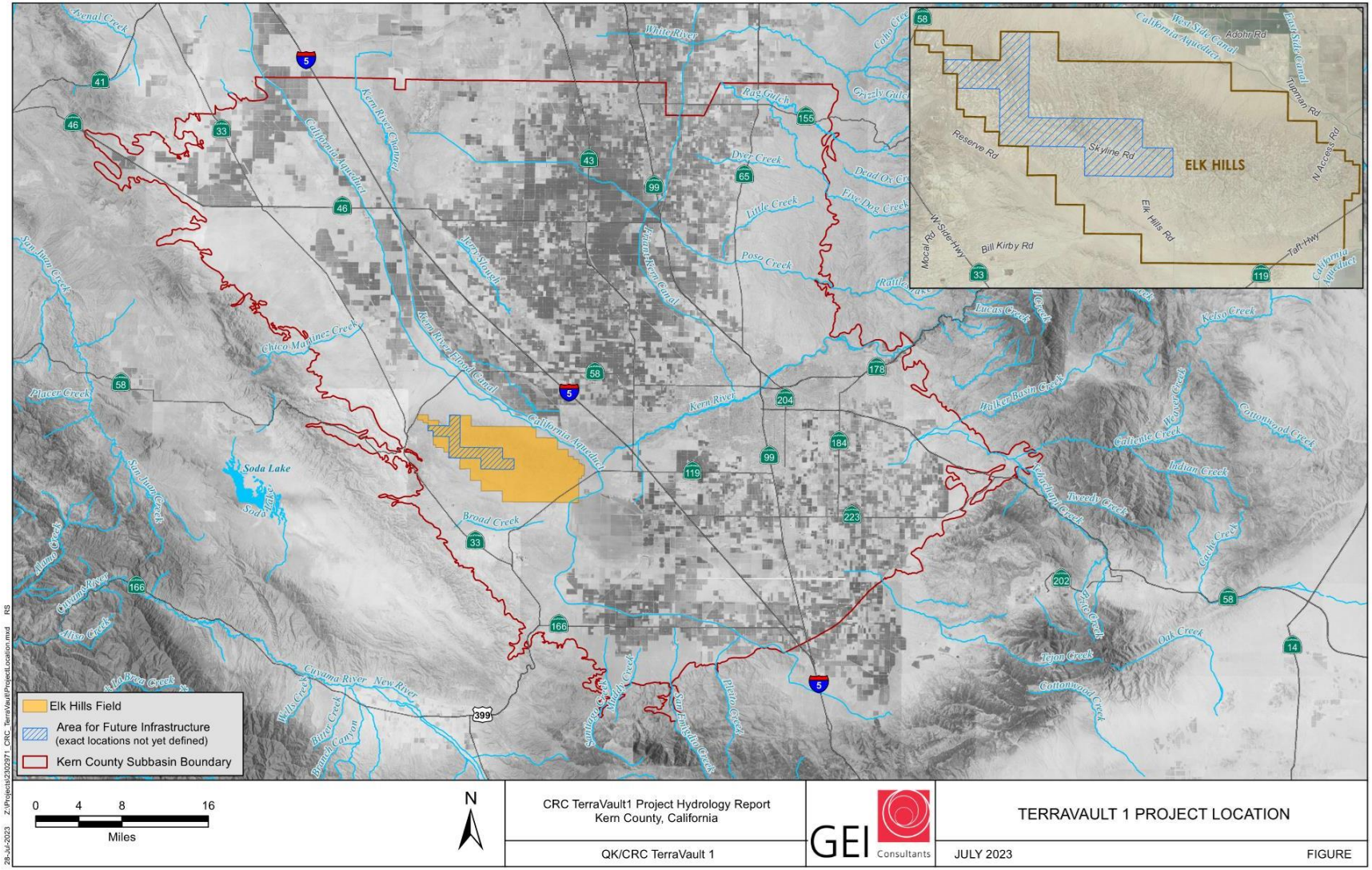

Figure 2-1. Carbon TerraVault 1 Project Area within the Kern County Subbasin (05-022.14)

2.1.2 Climate

Climate in the region is characterized as arid to semi-arid with average annual precipitation of six to seven inches per year. Approximately 95 percent of the precipitation falls between October and April (DWR 2015). Average precipitation by day within the Bakersfield – Buttonwillow area, located approximately six miles north of the project area, has ranged from zero to 0.37 inches between January 2010 and July 2023. During this same time span and in the same area, average temperature by day ranges from 42.7 degrees Fahrenheit in late December to 85 degrees Fahrenheit in mid-August (National Weather Service [NWS] and National Oceanic and Atmospheric Administration [NOAA] 2023).

2.2 Project Area Setting

The project area is located within the Elk Hills Oil Field, which is at the western extent of the Subbasin. The West Kern Water District (WKWD) Management Area Plan describes the western side of the Subbasin as steeply tilted, overturned, and cut by thrust faults originating from compressional forces driven by orogenic processes and lateral movement along the San Andreas fault during the Pleistocene era. Folding and faulting activities have resulted in unconformities between geologic formations (WKWD 2022). The west-side fold belt includes anticlines that extend from Kettleman Hills at the north through Lost Hills to Elk Hills at the southern end (Kern Groundwater Authority [KGA] 2022).

The project area is located within the Elk Hills, a spur of the Temblor Range that extends southeastward approximately 16 miles and is 6 miles wide, reaching a maximum elevation of 1,551 feet. This elevation is 1,000 to 1,200 feet above the main floor of the San Joaquin Valley (Soils Engineering Inc. 2022). The Elk Hills is a surficial expression of a large subsurface anticline[1], composed of stratified alluvial soils that have been uplifted. The anticlines in the Elk Hills have been eroded primarily by streams to varying depths, and often serve as drainage features to the hills. Structurally, the Elk Hills are broad and flat-topped, with steeper dips along the edge that are deformed by narrow, flat-topped anticlines. The anticline plays an important role in capturing oil within the permeable rock units and in trapping oil below impermeable layers, which developed the Elk Hills Oil Field and makes up the entirety of the project area (WKWD 2022; Soils Engineering Inc. 2022).

CTV 1 has two main areas of interest (sites) within Elk Hills. Folding and faulting has created local barriers and restrictive structures that confine both project areas. The eastern site resides mainly on the northern limb and on the hinge of the eastern portion the Elk Hills Anticline. The western site

[1] An anticline is an arch of stratified rock in which the layers bend downward in opposite directions from the crest (Merriam-Webster 2023).

resides on the hinge and on the northern limbs of the Heller Anticline. The rest of the western site area resides on the northern limb of the Elk Hills Anticline (Soils Engineering Inc. 2022).

Figure 2-2 shows the area of the captured carbon dioxide compression and pumping infrastructure with the relevant Aquifer Exemption areas, existing pipelines and injection wells that would be retrofitted for the project, and the general area where new infrastructure would be constructed.

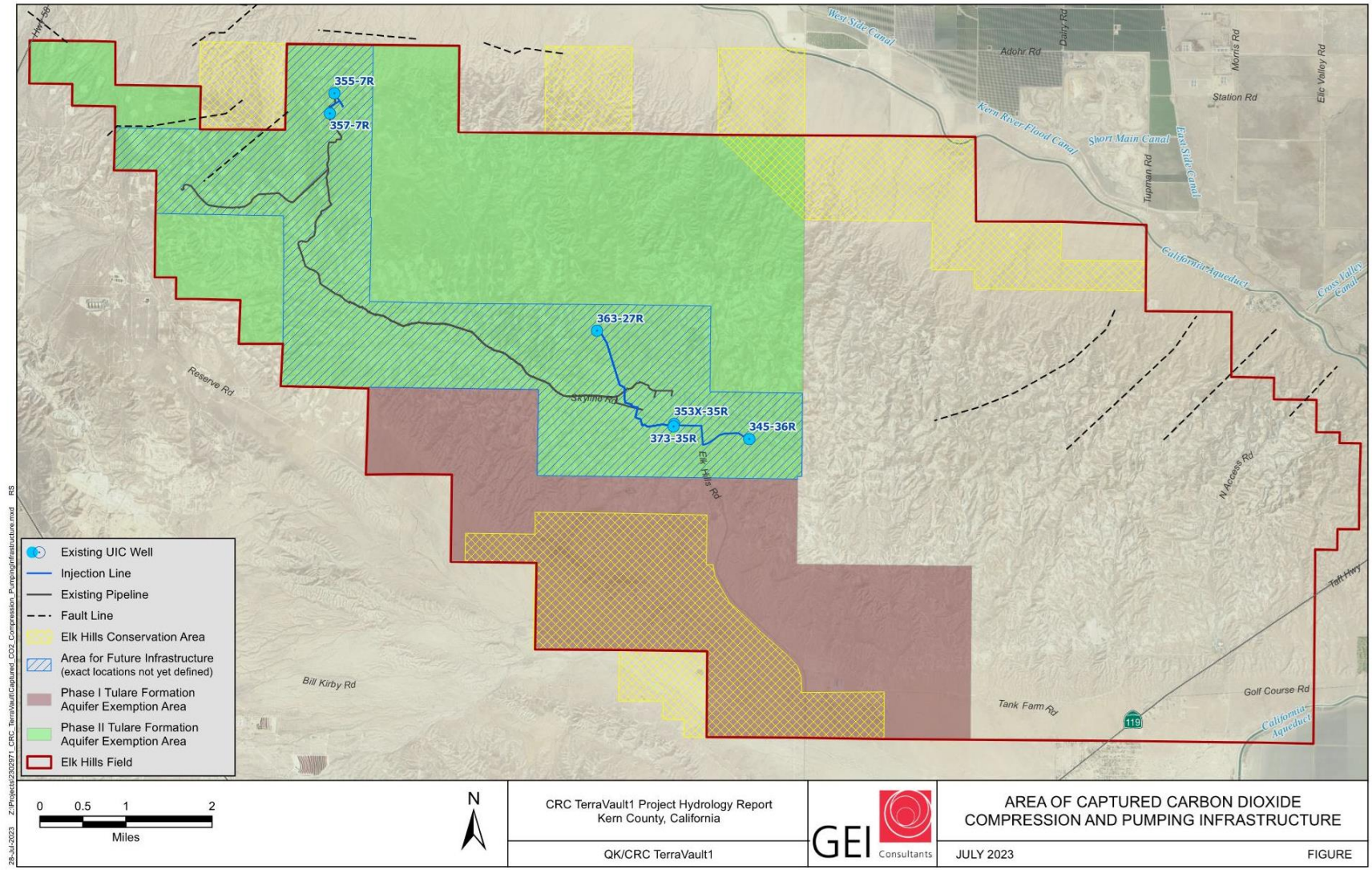

Figure 2-2. General Location of Project Facilities

2.2.1 Hydrogeology

The project area is underlain with Tertiary and Quaternary Pliocene-Pleistocene non-marine sedimentary rocks consisting of loosely consolidated sandstone, shale, and gravel deposits. The Tertiary and Quaternary deposits underlying Elk Hills and nearby areas are up to 24,000 feet thick (Soils Engineering Inc. 2022). The Tulare formation lies at the surface of the Elk Hills and consists of alternating beds of non-marine sand, gravel, silt, and clay (most noticeably the Amnicola, Tulare, and Corcoran clay units). The Tulare formation consists of both unsaturated and saturated zones. The upper units of the Tulare formation are mostly unsaturated, while the lower units can be saturated with both water and oil (Soils Engineering Inc. 2022).

The western anticline in the Elk Hills is believed to divert the movement of groundwater south through the Buena Vista Valley towards Buena Vista Lake. The shallow and eastern anticlines are considered "shallow wrinkles" and not regarded as having significant impacts to groundwater in the area (WKWD 2022). In addition to faults, barriers to groundwater movement include folds, such as the Elk Hills, angular unconformities, and contacts with crystalline and consolidated sedimentary rocks at the Subbasin margins. Corcoran clay, which exists in the project area, significantly impedes vertical groundwater movement where present (DWR 2006; Soils Engineering Inc. 2022).

From ground surface to approximately 200 feet below ground surface, is Undifferentiated Alluvium/Tulare Formation with air filled sands. This is generally followed by layers of E-clay mixed with more Undifferentiated Alluvium/ Tulare Formation until it transitions to the Upper Tulare Formation, Amnicola Clay, then Lower Tulare Formation.

To support its oilfield operations, CRC obtained Aquifer Exemptions for the Tulare Formation within the Elk Hills. Tulare Clay is a regional clay-rich layer up to 300 feet thick and extends from the Elk Hills to the Taft Sanitary Landfill and across the eastern Buena Vista Oil Field. Data from the Taft Sanitary Landfill shows that the Tulare Clay provides hydraulic isolation between aquifer intervals located immediately above and below the Tulare Clay layer (CRC 2015). The Tulare Formation is confined above by Amnicola Claystone, a regionally extensive layer that separates the Upper and Lower Tulare Formations. The Amnicola Claystone is approximately 75 to 100 feet thick. Lateral confinement from underground sources of drinking water is primarily achieved through pressure containment. Injected fluids are expected to flow towards low-pressure areas and into the currently unsaturated zones in both the Upper and Lower Tulare Formations (EPA 2018a, b). Based on a thorough review of documents submitted by the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources and the State Water Resources Control Board (SWRCB), the United States Environmental Protection Agency (EPA) approved the Elk Hills Oil Field Phase I and Phase II Aquifer Exemptions in March 2018.

2.2.2 Surface Water Hydrology and Quality

Elevation ranges throughout the project area. There are no surface water bodies (creeks, streams, or rivers) within the project area (RWQCB 2018). However, there are surficial drainages throughout the project area that drain in the direction of the natural topography. Generally, local drainages that exist within the northwestern area of the Project typically drain down-slope to the north, while drainages within the more southeastern area of the Project drain to the north down slopes facing north, and south on slopes facing south, towards the Buena Vista Lake area (Soils Engineering Inc. 2022). Surface water flow is unlikely to exist within these local drainages unless during heavy precipitation events. As part of the requirements of the Clean Water Act (CWA), beneficial uses for surface and ground waters must be identified in the Central Valley Regional Water Quality Control Board's (RWQCB) Tulare Lake Basin Water Quality Control Plan (Basin Plan). Because the project area contains no surface water bodies, there are no surface water beneficial uses associated with the project area (RWQCB 2018).

2.2.3 Groundwater Resources and Quality

Natural groundwater recharge within the Subbasin is primarily from stream seepage along the eastern Subbasin and the Kern River. Topography of the Elk Hills and the subsurface geology effectively impede any natural source of groundwater supply in the project area. There are multiple drainages across all sections that flow down slope typically to the north on the western portion. The eastern portion typically drains to the north on the northern sections and to the south on the southern sections. Cross Sections and well data presented in the Aquifer Exemption application and EPA approval letter confirm there is no appreciable quantity of groundwater in the project area.

Water quality in the area above the Tulare Clay is poor, which is consistent with aquifers associated with the Coast Range alluvium. Published water quality data indicate a range of about 4,000 to 6,800 milligrams per liter (mg/l) total dissolved solids (TDS) within the Elk Hills area. No water quality data are available from below the Tulare Formation, but water samples from wells located to the north, southwest, and southeast indicate an average of about 4,000 mg/l TDS. Samples from the Elk Hills indicate TDS in the Upper Tulare increases with depth (CRC 2015). Since groundwater is not of sufficient supply or quality in the Elk Hills, fresh water supplies are available from WKWD or the Kern-Delta Water District with existing infrastructure to deliver water to customers (EPA 2018b).

2.2.4 Oil and Gas Production

The project area produces petroleum. Impacts to WKWD's groundwater supply by these operations, both actual and potential, are continuously monitored and evaluated. To date, no significant threat to groundwater quality has occurred because of local oil and gas operations. Water produced water in western Kern County is typically managed by either recycling it for

enhanced oil recovery operations, such as steam or cyclic steam flooding, or by permitted disposal under the regulatory oversight of the California Department of Oil and Gas. A significant percentage of the oil field produced water in the project area is either recycled into the same geologic zones it was produced from or is sequestered in deeper zones that are isolated from sources of drinking water. This water is supplemented by water purchased from WKWD, which indicates that very little water is disposed of, since purchasing fresh water is more expensive than recycling water (WKWD 2022).

2.3 Erosion

Erosion and sedimentation are natural processes driven by surface runoff that can be accelerated by human activities, such as construction earthwork activities. During construction, removal of vegetation or impervious areas (concrete, asphalt, etc.) expose soils to precipitation and surface runoff and can accelerate surface soil erosion. The process may result in loss of topsoil and creation of erosional features including rills and gullies. Erosion potential is determined by four principal factors: the characteristics of the soil, extent of vegetative cover, topography, and climate. Soil texture and permeability determine the resistance of soil to entrainment by surface runoff. Vegetative cover plays a critical role in controlling erosion by shielding and binding the soil. Slope influences the rate of runoff and is directly correlated with erosion potential where flatter topography has a much lower potential for erosion. The intensity and duration of rainfall determines the extent and the capacity for flowing water to detach and transport soil particles.

Excessive erosion can cause a loss of land or possibly increase flooding. Increased sedimentation can also restrict storm drains and channels and lead to flooding during storms that the drainage system should capably handle. In addition, development can increase the likelihood of erosion and sedimentation along unlined drainage channels because of increased storm water flows.

The project area soils consist of: Elk Hills – Torriorthents Stratified and Eroded Complexes, well drained with 9 to 50 percent slopes; Elk Hills sandy loams, eroded, well drained with 9 to 50 percent slopes; and Kimberlina sandy loams, well drained with 5 to 9 percent slopes. In general, sandy soils with relatively low cohesion and soils located on steep topography have a higher potential for erosion. Therefore, the project area is susceptible to erosion by wind and water (Soils Engineering Inc. 2022).

2.4 Flooding

A Flood Insurance Rate Map (FIRM) is the official map prepared by the Federal Emergency Management Agency (FEMA) to delineate both the special flood hazard areas and the flood risk premium zones applicable to a community. FEMA designates flood zones using a series of letters, for example, Zone A indicate areas of the 100-year flood where base flood elevations are not known; Zone AE indicate areas where 100-year flood elevations have been calculated; and Zone X indicates areas that experience minimal flooding. The project area is located in two FIRM areas

(FIRMS 06029C2200E and 06029C2225E). Both FIRM areas are designated as Zone X and are outside of the 0.2 percent annual chance floodplain (FEMA 2008a, 2008b, 2023).

2.4.1 Dam Failure, Seiche, and Tsunami

The United States Army Corps of Engineers (USACE) prepares flood inundation maps in the event of a dam failure, including the closest dam, Lake Isabella Dam east of Bakersfield (USACE 2017). The Lake Isabella Dam is located over 60 miles to the east of the project area and the flood waters would not reach the project area due to distance and topography.

A tsunami is a series of ocean waves generated by sudden displacements in the sea floor, landslides, or volcanic activity. A seiche is a standing wave in an oscillating body of water. The project area is located approximately 65 miles east of the Pacific Ocean and there are no enclosed bodies of water within the project area. Therefore, the risk for tsunami or seiche in the project area is very low.

Chapter 3. Regulatory Setting

This chapter discusses applicable Federal, State, regional, and local regulations.

3.1 Federal Plans, Policies, Regulations, and Laws

3.1.1 Clean Water Act

Regulatory authorities exist on both the State and federal levels for the control of water quality in California. The EPA is the federal agency, governed by the CWA, responsible for water quality management. The purpose of the CWA is to protect and maintain the quality and integrity of the nation's waters by requiring states to develop and implement state water plans and policies. Section 303 of the CWA requires states to establish water quality standards consisting of designated beneficial uses of water bodies and water quality standards to protect those uses for all Waters of the United States.

Under Section 303(d) of the CWA, states, territories, and authorized tribes are required to develop lists of impaired waters. Impaired waters are the waters that do not meet water quality standards, even after point sources of pollution have installed the minimum required levels of pollution control technology. The law requires that these jurisdictions establish priority rankings for water on the lists and develop action plans to improve water quality. This process includes development of Total Maximum Daily Loads (TMDL) that set discharge limits for non-point source pollutants. The Ducheny Bill (AB 1740) requires the SWRCB and its nine RWQCBs to post this list and to provide an estimated completion date for each TMDL. The list is administered by the Regional Boards, in this case, the Central Valley RWQCB. The project area does not contain any surface waters and therefore, no surface water resources are included in the California 303(d) List of Impaired Water Bodies.

3.1.1 National Pollutant Discharge Elimination System

Part of the CWA provides for the National Pollutant Discharge Elimination System (NPDES), in which discharges into navigable waters, are prohibited except in compliance with specified requirements and authorizations. Under this system, municipal and industrial facilities are required to obtain a NPDES permit that specifies allowable limits based on available wastewater treatment technologies for pollutant levels in their effluent. In California, the EPA has delegated the implementation of this program to the State Board and to the Regional Boards. Storm water discharges are regulated somewhat differently.

Storm water runoff from construction areas of one acre or more require either an individual permit or coverage under the statewide General Construction Storm Water Permit. In addition, specific

industries, including wastewater treatment plants that have direct storm water discharges to navigable waters are required to obtain either an individual permit issued by the Regional Board, or obtain coverage under the statewide General Industrial Storm Water Permit for storm water discharges.

A non-point source is a diffused source, such as land runoff, precipitation, deposit from the atmosphere, or percolation. Major non-point sources of water pollution are agriculture, mining, oil and gas extraction, pastureland and feedlots, land disposal, and urban runoff. For non-point sources, the Basin Plan outlines the approach that the Regional Board has taken to control non-point source pollution in its Urban Runoff Management scheme. Part of the strategy involves the permitting of storm water discharges from all facilities associated with industrial activities and from all construction activities that result in the disturbance of land totaling one acre or more.

3.1.2 Federal Emergency Management Agency

Under Executive Order 11988, FEMA is responsible for the management and mapping of areas subject to flooding during a 100-year flood event (i.e., one percent chance of occurring in a given year). FEMA requires that local governments covered by federal flood insurance pass and enforce a floodplain management ordinance that specifies minimum requirements for any construction within the 100-year flood plain, as depicted on FEMA maps.

3.2 State Plans, Policies, Regulations, and Laws

3.2.1 State Water Resources Control Board

SWRCB, located in Sacramento, is the agency with jurisdiction over water quality issues in the State of California. The SWRCB is governed by the Porter-Cologne Water Quality Act (Division 7 of the California Water Code), which establishes the legal framework for water quality control activities by the SWRCB. The intent of the Porter-Cologne Act is to regulate factors which may affect the quality of waters of the State to attain the highest quality which is reasonable, considering a full range of demands and values. Much of the implementation of the SWRCB's responsibilities is delegated to its nine Regional Boards. The project area is located within the Central Valley Region.

3.2.2 Regional Water Quality Control Board, Central Valley Region

The Central Valley RWQCB Basin Plan (Third Edition, May 2018) was referenced to determine existing and potential beneficial uses of groundwater in the project area, which is located in Detailed Analysis Unit 260. Per State Waters Resources Control Board (SWRCB) Resolution No. 88-63, groundwater is designated for municipal and industrial groundwater beneficial uses (RWQCB 2018; SWRCB 2006). However, as defined in the Aquifer Exemption application and

supporting materials, groundwater supply is not sufficient quantity or quality to serve these potential uses (EPA 2018b). Additionally, this is within WKWDs Western Watch Area, which is described as predominantly made up of barren land or oil fields (WKWD 2022). Depth to water in the Spring of 2022 ranged between 122 to 148 feet and shows a gradient to the east-southeast. However, depth to groundwater is estimated at over 500 feet below ground surface in the project area. A groundwater assessment conducted in 1987 encountered no groundwater to a depth of 420 feet. In addition, a 1000-foot soil boring was drilled in 1991 at the nearby and no groundwater was encountered (Soils Engineering Inc. 2022). Lastly, any groundwater that is encountered in this area is generally unusable due to high salinity levels.

3.2.3 NPDES Construction General Permit

Construction associated with the project would disturb more than one acre of land surface affecting the quality of stormwater discharges. Therefore, the project would be subject to the NPDES General Permit for Stormwater Discharges Associated with Construction and Land Disturbance Activities (Order 2009-0009-DWQ, NPDES No. CAS000002, as amended by Orders 2010-0014-DWQ and 2012-006-DWQ). The Construction General Permit regulates discharges of pollutants in stormwater associated with construction activity to Waters of the United States from construction sites that disturb one acre or more of land surface, or that are part of a common plan of development or sale that disturbs more than one acre of land surface. The permit regulates stormwater discharges associated with construction or demolition activities, such as clearing and excavation, construction of buildings, and linear underground projects, including installation of water pipelines and other utility lines. The Construction General Permit requires that construction sites be assigned a Risk Level of 1 (low), 2 (medium), or 3 (high), based both on the sediment transport risk at the site and the receiving waters risk during periods of soil exposure (e.g., grading and site stabilization). The sediment risk level reflects the relative amount of sediment that could potentially be discharged to receiving water bodies and is based on the nature of the construction activities and the location of the site relative to receiving water bodies. The receiving waters risk level reflects the risk to the receiving waters from the sediment discharge. Depending on the risk level, the construction projects could be subject to the following requirements:

- Effluent standards; Good site management “housekeeping”
- Non-stormwater management
- Erosion and sediment controls
- Run-on and runoff controls
- Inspection, maintenance, and repair
- Monitoring and reporting requirements

The Construction General Permit requires the development and implementation of a Stormwater Pollution Prevention Plan (SWPPP) that includes specific best management practices (BMPs) designed to prevent sediment and pollutants from contacting stormwater from moving offsite into receiving waters. The BMPs fall into several categories, including erosion control, sediment control, waste management, and good housekeeping, and are intended to protect surface water quality by preventing the off-site migration of eroded soil and construction-related pollutants from the construction area. Routine inspection of all BMPs is required under the provisions of the Construction General Permit. In addition, the SWPPP is required to contain a visual monitoring program, a chemical monitoring program for non-visible pollutants, and a sediment monitoring plan if the site discharges directly to a water body listed on the 303(d) list for sediment.

The SWPPP must be prepared before the construction begins. The SWPPP must contain a site map(s) that delineates the construction work area, existing and proposed buildings, parcel boundaries, roadways, stormwater collection and discharge points, general topography both before and after construction, and drainage patterns across the project area. The SWPPP must list BMPs and the placement of those BMPs that the applicant would use to protect stormwater runoff. Additionally, the SWPPP must contain a visual monitoring program, a chemical monitoring program for "non-visible" pollutants to be implemented if there is a failure of BMPs, and a sediment monitoring plan if the site discharges directly to a water body listed on the 303(d) list for sediment. Examples of typical construction BMPs include scheduling or limiting certain activities to dry periods, installing sediment barriers, such as silt fence and fiber rolls, and maintaining equipment and vehicles used for construction. Non-stormwater management measures include installing specific discharge controls during certain activities, such as paving operations, vehicle and equipment washing and fueling. The Construction General Permit also sets post-construction standards (i.e., implementation of BMPs to reduce pollutants in stormwater discharges from the site following construction).

In the project area, the Construction General Permit is implemented and enforced by the Central Valley RWQCB, which administers the stormwater permitting program. Dischargers must electronically submit a notice of intent and permit registration documents to obtain coverage under this Construction General Permit. Dischargers are to notify the Central Valley RWQCB of violations or incidents of noncompliance and submit annual reports identifying deficiencies in the BMPs and explaining how the deficiencies were corrected. The risk assessment and SWPPP must be prepared by a State Qualified SWPPP Developer, and implementation of the SWPPP must be overseen by a State Qualified SWPPP Practitioner. A legally responsible person, who is legally authorized to sign and certify permit registration documents, is responsible for obtaining coverage under the permit.

3.2.4 California State Nondegradation Policy

In 1968, as required under the Federal antidegradation policy, SWRCB adopted a nondegradation policy aimed at maintaining a high quality of waters in California. The nondegradation policy

states that the disposal of wastes into State waters shall be regulated to achieve the highest water quality consistent with maximum benefit to the people of the State and to promote the peace, health, safety, and welfare of the people of the State. Any discharges associated with the project would be required to comply with this policy.

3.2.5 Sustainable Groundwater Management Act

The Sustainable Groundwater Management Act of 2014 (SGMA), effective January 1, 2015, authorizes local agencies to manage groundwater in a sustainable manner and allows limited state intervention when necessary to protect groundwater resources. SGMA requires the creation of a Groundwater Sustainability Agency (GSA) that would develop and implement a Groundwater Sustainability Plan (GSP) to manage and use groundwater in a manner that can be maintained during the planning and implementation horizon without undesirable results, defined as follows:

1) Chronic lowering of groundwater levels, indicating a significant and unreasonable depletion of supply

2) Significant and unreasonable reduction of groundwater storage

3) Significant and unreasonable seawater intrusion

4) Significant and unreasonable degraded water quality, including the migration of contaminant plumes that impair water supplies

5) Significant and unreasonable land subsidence that substantially interferes with surface land uses

6) Depletions of interconnected surface water that have significant and unreasonable adverse impacts on beneficial uses of the surface water

The WKWD GSA was created June 28, 2016 when WKWD's Board of Directors adopted Resolution 16.03, electing to become a GSA in the Subbasin and included the WKWD service area (WKWD 2022). The WKWD is a member of the Kern Groundwater Authority, and has a Management Area Plan within the KGAs GSP for the project area. The WKWD GSA jurisdictional area is defined by the WKWD service boundary with some addition proximal parcels owned and operated by oil production companies and other private landowners (such as the project area). The WKWD GSA is located along the western edge of the Subbasin and is comprised of 299 square miles. WKWD GSA formed two management areas named the North Project and South Project management areas, and three watch areas that include the Lake Watch Area, Little Santa Maria Valley Watch Area, and the Western Watch Area. The project area is located in the Western Watch Area because "the only known pumping in the area are considered de minimis; in general, yields of water in this area are unsuitable for domestic or industrial use" (WKWD 2022). Subsequently, no management or monitoring actions have been established in the Western Water Area.

3.3 Regional/Local Plans, Policies, Regulations, and Ordinances

3.3.1 Kern County General Plan

The Kern County General Plan includes elements to protect the groundwater and surface water resources of the County through various goals and policies. The following policies would apply to the project:

Chapter 1: Land Use, Open Space, and Conservation Element

Physical and Environmental Constraints

Policy 6. Regardless of percentage of slope, development on hillsides will be sited in the least obtrusive fashion, thereby, minimizing the extent of topographic alteration required and reducing soil erosion while maintaining soil stability.

Policy 11: Protect and maintain watershed integrity within Kern County

> Measure N: Applicants for new discretionary development should consult with the appropriate Resource Conservation District and the California Regional Water Quality Control Board regarding soil disturbances issues.

Resources

Policy 10. To encourage effective groundwater resource management for the long-term economic benefit of the County the following shall be considered:

(a) Promote groundwater recharge activities in various zone districts.

(b) Support for the development of Urban Water Management Plans and promote Department of Water Resources grant funding for all water providers.

(c) Support the development of groundwater management plans.

(d) Support the development of future sources of additional surface water and groundwater, including conjunctive use, recycled water, conservation, additional storage of surface water and groundwater and desalination.

Policy 11: Minimize the alteration of natural drainage areas. Require development plans to include necessary mitigation to stabilize runoff and silt deposition through utilization of grading and flood protection ordinances.

Policy 12. Areas identified by the Natural Resource Conservation Service (formerly Soil Conservation Service) as having high range-site value should be conserved for Extensive Agriculture uses or as Resource Reserve, if located within a county water district.

> Implementation Measure C. The County Planning Department will seek review and comment from the County Public Works Department, Engineering and Survey Services Division on the implementation of the National Pollution Discharge Elimination System for all discretionary projects.

Surface Water and Groundwater

Policy 34: Ensure that water quality standards are met for existing users and future development.

Policy 39. Encourage the development of the County's groundwater supply to sustain and ensure water quality and quantity for existing users, planned growth, and maintenance of the natural environment.

Policy 43: Drainage shall conform to the Kern County Development Standards and the Grading Ordinance.

Policy 44: Discretionary projects shall analyze watershed impacts and mitigate for construction related and urban pollutants, as well as alterations of flow patterns and introduction of impervious surfaces as required by CEQA, to prevent the degradation of the watershed to the extent practical.

Chapter 8: Safety Element

Storm Drainage

Goal 1. Ensure the provision of adequate storm drainage facilities to protect planning area residents from flooding resulting from storm water excess.

3.3.2 Kern County Code of Building Regulations

Kern County Grading Ordinance (17.28)

Chapter 17.28 Kern County Grading Code. Requirements of the Kern County Grading Code will be implemented. A grading permit will be obtained prior to commencement of construction activities. Of particular note with respect to hydrology and water quality is Section 17.28.140, Erosion Control, which addresses the following:

> **Slopes.** The faces of cut and fill slopes shall be prepared and maintained to control against erosion. This control may consist of effective planting. The protection for the slopes shall be installed as soon as practicable and prior to calling for final approval. Where cut slopes

are not subject to erosion due to the erosion-resistant character of the materials, such protection may be omitted.

Other Devices. Where necessary, check dams, cribbing, riprap or other devices or methods shall be employed to control erosion and provide safety.

Temporary Devices. Temporary drainage and erosion control shall be provided as needed at the end of each workday during grading operations, such that existing drainage channels would not be blocked. Dust control shall be applied to all graded areas and materials and shall consist of applying water or another approved dust palliative for the alleviation or prevention of dust nuisance. Deposition of rocks, earth materials or debris onto adjacent property, public roads or drainage channels shall not be allowed.

3.3.3 Kern County Development Standards

The Kern County Development Standards apply to all developments within Kern County that are outside of incorporated cities. These standards establish minimum design and construction requirements that will result in improvements that are economical to maintain and will adequately serve the general public. The requirements set forth in these standards are considered minimum design standards and will require the approval of the entity that will maintain the facilities to be constructed prior to approval by the County.

3.3.4 Kern County Water Quality Control Plan

Refer to NPDES Construction General Permit, above. The Kern County Engineering and Survey Services Department requires the completion of an NPDES applicability form for all construction projects disturbing one or more acre within Kern County. This form requires the Project Proponent to provide background information on construction activities. Project Proponents must apply for the permit under one of the following four conditions:

1) All stormwater is retained on site and no stormwater runoff, sediment, or pollutants from on-site construction activity can discharge directly or indirectly off site or to a river, lake, stream, municipal storm drain, or off-site drainage facilities.

2) All stormwater runoff is not retained on site but does not discharge to a Water of the United States (i.e., drains to a terminal drainage facility). Therefore, a SWPPP has been developed and BMPs must be implemented.

3) All stormwater runoff is not retained on site, and the discharge is to a Water of the United States. Therefore, a Notice of Intent must be filed with the State Regional Water Resources Control Board prior to issuance of the building permit. Also, a SWPPP has been developed and BMPs must be implemented.

4) Construction activity is between 1 to 5 acres and an Erosivity Waiver was granted by the SWRCB. BMPs must be implemented.

Chapter 4. Environmental Impacts

This chapter analyzes potential impacts of the project related to hydrology and water quality from project construction and operation.

4.1 Methodology

This environmental analysis of the potential impacts related to hydrology and water quality is based on a review of the following information: the description of the project; a review of available literature and maps; and review of the existing conditions of the project area, as described in Chapter 2, "Environmental Setting."

The project would be regulated by the various laws, regulations, and policies summarized in Chapter 3, "Regulatory Setting." Compliance by the project with applicable Federal, State, and local laws and regulations is assumed in this analysis and local and State agencies would be expected to continue to enforce applicable requirements to the extent that they do so now. Note that compliance with some regulations is a condition of permit and project approval.

After considering the implementation of the project, and compliance with the required regulatory requirements, the environmental analysis below identifies if the defined significance thresholds are exceeded and, therefore, a significant impact would occur. For those impacts considered to be significant (if any), environmental commitments are proposed to the extent feasible to reduce the identified impacts.

4.2 Thresholds of Significance

The thresholds for determining the significance of impacts for this analysis are based on the environmental checklist in Appendix G of the State CEQA Guidelines. Implementing the project would result in a significant impact related to hydrology and water quality if it would:

- Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or ground water quality.
- Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin.
- Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river or through the addition of impervious surfaces, in a manner which would.
    - Result in substantial erosion or siltation on- or offsite.

- Substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or offsite.
- Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff.
- Impede or redirect flood flows.

- In flood hazard, tsunami, or seiche zones, risk release of pollutants due to project inundation.
- Conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan.

4.2.1 Project Impacts

Impact 1: The project would not violate water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality.

Construction

Construction of the project would require excavation, grading, and recontouring of soil at the project area. During these activities, soils could be become exposed to high winds or heavy precipitation causing a substantial increase in sedimentation in storm water run-off. In addition, construction activities would require the use of hazardous materials including but not limited to petroleum products (e.g., gasoline, diesel, and motor oil) and automotive fluids (e.g., antifreeze and hydraulic fluids). The mobilization of sediment or inadvertent spills or leaks of such pollutants could affect the quality of runoff water from the construction sites. However, because the project would disturb more than one acre, construction would be subject to the NPDES General Permit for Discharges of Storm Water Runoff Associated with Construction Activity (Construction General Permit). As part of this process, the CRC would be required to comply with the NPDES Construction General Permit. Compliance with this permit would require the preparation and implementation of a SWPPP that would identify pollutant sources that may affect the quality of storm water discharge and implement BMPs, such as erosion control and pollution prevention measures, to be used during construction. The project SWPPP would include BMPs to minimize the impacts of construction activities to water quality. With implementation of the BMP requirements required by the state Construction General Permit, the potential for pollutants and sediment to affect the water quality of runoff from construction sites would be minimized to less-than-significant levels.

Operation

Project operation involves a carbon capture and sequestration field, associated injection wells, and related improvements for storage of CO_2. The project would take local industrial sources of CO_2 that are transported by a combination of truck, pipeline and/or rail to the dedicated injection wells that are constructed through geologically confined reservoirs for storage in perpetuity. The Elk

Hills Oil Field area has been identified as a location suitable for such storage due to the faults and folds that serve as restrictive structures combined with the thick confining layers of the Tulare Formation and Amnicola Clay that form geologic barriers to usable groundwater sources. Geotechnical studies and modeling within the project area (Aquifer Exemption Request for the Elk Hills Oil Feld, Phase II Area) demonstrates lateral confinement from underground sources of drinking water is primarily achieved through pressure containment. Injected fluids are expected to flow towards low-pressure areas and into the currently unsaturated zones in both the Upper and Lower Tulare Formations (EPA 2018b). Injection of CO_2 into the ground via injection well would not mix with or contaminate groundwater. Therefore, operation of the project would not violate water quality standards, waste discharge requirements, or degrade surface or water quality in the area.

Level of Significance

Less-than-significant impact

Impact 2: The project would not substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin.

Construction

The project would require water for dust suppression, fire protection, and pipeline hydrotesting. Water usage during construction, primarily for dust-suppression purposes, is not anticipated to exceed 75 acre-feet over the 18-month construction phase. The water would be trucked and stored on-site and would not substantially decrease groundwater supplies within the Subbasin. Impacts would be less than significant.

Operation

The project would include the addition of new impervious surfaces within the project area due to the implementation of concrete foundations, resurfacing (concrete) of existing dirt roads, development of new access roads, implementation of the proposed CO_2 compression and pumping facility, which includes the Control Room and Parking Area, injection wells, and aboveground pipelines. The proposed facilities would not have the scale or massing to interfere with groundwater recharge in the area. Much of the project area would be implemented on slopes, and surface water from precipitation events is unlikely to infiltrate the ground in areas on the slopes. Therefore, implementation of impervious surfaces and facilities would not impede groundwater management of the Subbasin.

Project operation would not rely on local groundwater since there is not sufficient quantity or quality. The western anticline in the Elk Hills is believed to divert the movement of groundwater south through the Buena Vista Valley toward Buena Vista Lake. WKWD describes the project area as predominantly made up of barren land or oil fields. The only known pumping in the area are considered de minimis; in general, yields of water in this area are unsuitable for domestic or

industrial use" (WKWD 2022). For the same reasons there is no groundwater use, the project area is also not suitable for groundwater recharge.

Implementation of the project does not propose uses that would require removal of groundwater, such as extraction and recovery wells. Therefore, it would not decrease groundwater supplies or impede sustainable management of the Subbasin. Impacts would be less than significant.

Level of Significance

Less-than-significant impact

Impact 3: The project would not substantially alter the existing drainage pattern of the project area but would not result in: substantial erosion, siltation, or flooding on-or offsite; create or contribute runoff water that would exceed the capacity of existing or planned stormwater drainage; or impede or redirect flood flows.

Construction

Construction of the project would require excavation, grading, and recontouring of soils in the project area. During these activities, soils could be become exposed to high winds or heavy precipitation causing erosion. As discussed above in Impact 1, the project would disturb more than one acre. Therefore, the project would be required to comply with the NPDES Construction General Permit, which would require the preparation and implementation of a SWPPP. The SWPPP would describe BMPs describing erosion control and pollution prevention measures to be used during construction. The project SWPPP would include BMPs to minimize the impacts of construction to a less than significant level. Erosion control BMPs have been proven effective at minimizing erosion during construction and associated earthwork activities. With implementation of the SWPPP, the project would minimize the potential for erosion or siltation to occur during construction, and the impact would be less than significant.

Operation

Storm water runoff would be captured onsite and therefore would not cause or exacerbate any potential flooding on- or off-site.

The new pipeline would be installed primarily above ground, with the exception of road crossings, which would be trenched using traditional cut-and-cover techniques. Most of the new pipeline would be collocated with existing pipelines along established rights-of-way. In sections that would not be collocated, new existing sleepers will be installed prior to pipe placement. Drainages intersecting the pipeline route would be spanned. Pipeline facilities would not have the scale or massing to significantly alter surface flows within the project area, which could result in erosion or flooding. Additionally, new or modified injection wells would have a minimal footprint surrounded by pervious soil into which precipitation would infiltrate, as it does now. Therefore, there would be no impact regarding flooding due to altering the existing drainage pattern of the project area.

The project would not create or contribute new sources of runoff. The proposed CO_2 compression and pumping facility would be designed to capture storm water runoff onsite. No new drainage system would be necessary for storm water capture. The project would consist of pipelines which would not require the use of any drainage system. Therefore, there would be a no impact regarding exceeding the capacity of drainage systems within the project area.

Although the drainage pattern would be altered in the immediate location of the proposed facilities, the proposed CO_2 compression and pumping facility and injection wells and pipelines would not cause substantial erosion or siltation on- or off-site because the project facilities would have relatively small footprints. Precipitation falling on the proposed facilities would flow off to the surrounding unpaved soils and infiltrate into the ground, as under current conditions. Therefore, implementation of the project would not substantially alter the existing drainage pattern of the project area and would not result in substantial erosion or siltation on- or off-site, resulting in a less than significant impact.

Level of Significance

Less-than-significant impact

Impact 4: The project would not risk the release of pollutants due to project inundation in a flood hazard, tsunami, seiche or dam failure flood zone.

Construction and Operation

The project is not located within a FEMA-designated 100-year flood zone and does not include the construction or renovation of any housing units. Therefore, there would be no impact to people or structures related to potential risk of loss, injury or death involving inundation in a flood hazard zone. The project area is not located in an area that is susceptible to the effects of a seiche or tsunami. Therefore, there would be no impact to people or structures related to potential risk of loss, injury or death involving inundation by a seiche or tsunami. Furthermore, there would be no potential for inundation from Lake Isabella Dam failure due to distance and existing topography. No impacts would occur.

Level of Significance

No impact

Impact 5: The project would not conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan.

Construction

Until the project is constructed, there would be no conflicts or obstructions to the Basin Plan or other sustainable groundwater management plan, and there would be no impact.

Operation

As defined the Chapter 3 of this report, operation of the CO_2 capture and storage facilities would not conflict with or obstruct implementation of the CWA or Basin Plan because there is no significant surface drainage, no surface water beneficial uses associated with the project area, and the Aquifer Exemption process determined the groundwater cannot serve as a current or future source of drinking water. Therefore, operation of the project would not conflict with or obstruct implementation of a water quality control or groundwater management plan.

Level of Significance

Less-than-significant impact

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G.2 Water Supply Assessment

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WATER SUPPLY ASSESSMENT

KERN COUNTY

CARBON TERRAVAULT 1



SEPTEMBER 2023

WATER SUPPLY ASSESSMENT

CARBON TERRAVAULT 1

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Project #220067

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SECTION 1 - INTRODUCTION

1.1 - Regulatory Requirement

Senate Bill 610 (Chapter 643, Statutes of 2001) amended State law, effective January 1, 2002, to improve the link between information on water supply availability and land use decisions made by cities and counties. The statute requires detailed information regarding water availability to be provided to city and county decision-makers before approval of specified large development projects subject to CEQA (the California Environmental Quality Act) approval. These include carbon sequestration projects as an industrial use. The statute also requires this detailed information to be included in the administrative record that serves as the evidentiary basis for an entitlement action by the city or county on such projects. The statute-required Water Supply Assessment (WSA) must examine the availability and sufficiency of an identified water supply under normal year, single-dry year, and multiple-dry year conditions over a 20-year projection, accounting for the projected water demand of the project in addition to other existing and planned future uses of the identified water supply.

The State Department of Water Resources "Guidebook for Implementation of Senate Bill 610 and Senate Bill 221 of 2001" (Guidebook) and the sample format presented in the Guidebook were used as guides in preparing this Water Supply Assessment. Pertinent excerpts from the law stipulating Water Supply Assessment requirements precede this report's sections. The full text of Chapter 643, Statutes of 2001 (SB 610) is included in Appendix A.

1.2 - Project Description and Location

The Carbon TerraVault 1 (CTV-1) Project, is being proposed by Carbon TerraVault, LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC). The Project would establish a carbon dioxide (CO_2) capture and storage network in the Elk Hills Oil Field in western Kern County that will remove CO_2 from natural gas produced from the Greater Elk Hills Area (GEHA) prior to processing at CRC's Cryogenic Gas Plant One (CGP-1). The captured CO_2 would then be transported through a network of onsite pipelines to CO_2 injection wells into geologically distinct depleted oil and gas reservoirs for permanent storage. The network will eventually take CO_2 from other onsite projects to maximize the full extent and capacity of the world class storage reservoirs within the field.

The proposed Project would include two identical capture, compression and pumping facilities located adjacent to the CGP-1, as well as the construction and modifications of a combination of new and existing injection and monitoring wells, and installation of approximately 15 miles of associated pipelines to complete the permanent storage network. The extensive existing oilfield infrastructure will be utilized to the maximum extent possible during the full life cycle of this project.

The proposed storage network would include six injection wells into two separate reservoirs and associated infrastructure, capable of storing a combined approximately 48 million metric tons of CO_2. The two reservoirs known as "26R" and "A1/A2" are geologically distinct

depleted oil and gas reservoirs. These reservoirs have confining qualities that make them ideal for permanent carbon dioxide storage including no connection or proximity to underground sources of drinking water (USDW). As proposed, the Project would inject up to 200,000 metric tons of concentrated CO2 per year (MMtpa) captured from natural gas produced at Elk Hills through dedicated Class VI injection wells, into identified geographically confined reservoirs for storage in perpetuity.

The Project also includes establishing and utilizing a temporary construction corridor and temporary storage and laydown areas. The temporary construction corridor right-of-way (ROW), of up to approximately 50 feet in width, will be established along areas of the pipeline route not accessible via established roads or other existing cleared areas to allow for off-road construction equipment and a travel path. Temporary storage and laydown areas outside of the ROW will be used to store equipment, pipe, and materials and to stage construction activities. Laydown areas are designed to minimize new disturbance by utilizing existing, cleared areas such as fields, parking lots, or other developed areas. After completion of construction, all laydown areas will be returned to pre-project contours and revegetated to native habitat conditions where applicable.

The two CO_2 compression and pumping facilities will be constructed in two consecutive phases over 18 months. Phase 1 is located within the CGP-1 facility and Phase 2 will be located within a fenced area measuring approximately 120 feet by 210 feet, an area of 0.55 acres. The facilities will be accessed via Skyline Drive within the Elk Hills Oil Field, west of Gate 4.

CO_2 captured at the sources described above would be sent for underground sequestration into one of more of the six (6) proposed Class VI UIC wells in compliance with the EPA UIC program Class VI geologic sequestration regulations. In addition, each reservoir will have a series of monitoring wells whose function will be to gather reservoir information and provide real-time feedback on USDW, reservoir fluids, pressure, and temperature. Any anomaly will be immediately detected, and appropriate actions will be taken to ensure no undesirable events occur. Monitoring of seismic activities will be conducted through an existing network of seismic monitoring wells located at Elk Hills.

This area has been identified as a location suitable for such storage and a potential to provide a significant contribution to the goals of California for carbon neutrality by 2045 by reducing industrial uses to no net contribution and supporting direct removal of CO_2 from the air. The proposed Project has the capacity for up to 48 million metric tons of estimated storage and capable of sequestrating up to 1.5 million metric tons of CO_2 per year.

The project would use the existing infrastructure, proven technology, suitable reservoirs, and an experienced and well-trained workforce to help meet CRC's industry leading climate goals, as well as those of the State of California.

The Project area is located generally within western Kern County, California (Figure 1-1). It is entirely within the boundary of the Elk Hills Oil Field, an approximately 75-square-mile complex with surface and mineral rights privately held by CRC in the San Joaquin Valley of

unincorporated Kern County. The Project area extends east of the intersection of Skyline Road and Elk Hills Road, approximately 0.50 miles, and west of the intersection, approximately 5.5 miles. The majority of the Project area follows existing and maintained pipeline rights-of-way. The Project area is approximately 12.75 miles west of Interstate 5 and five miles south of State Route 58. It can be accessed via CRC's gated and guarded entrance to the oil field located at the western intersection of Skyline Road and Elk Hills Road (Figure 1-2).

The Project area is bordered on all sides by existing oil and gas exploration and production. Existing land use outside of the Project area generally includes agricultural lands, current, past, and abandoned oil and gas exploration and production land, and undeveloped land owned by CRC and other oil and gas operators. The City of McKittrick is approximately four miles west of the Project area, and the City of Taft is approximately nine miles to the south.

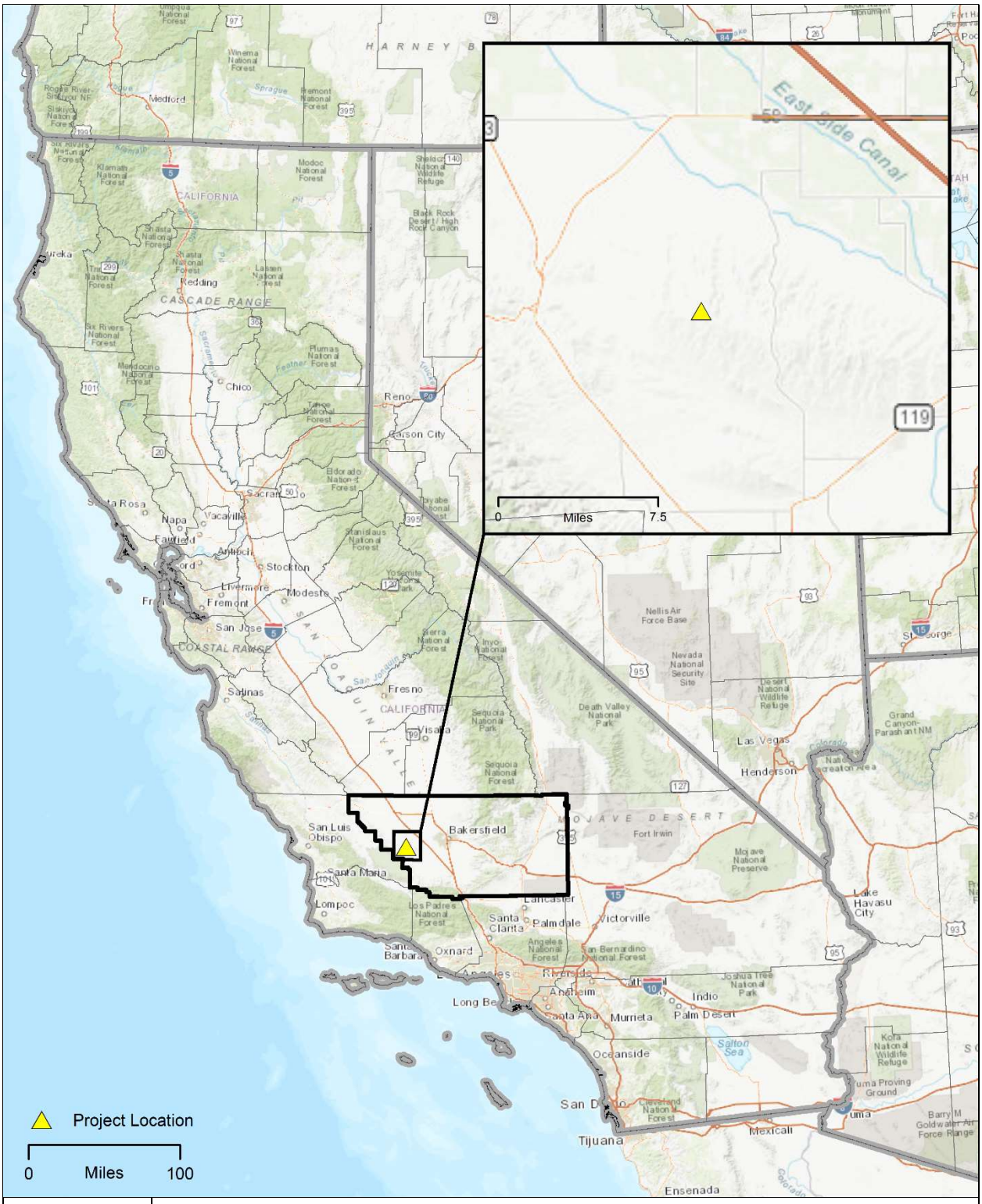


Figure 1-1
Regional Location

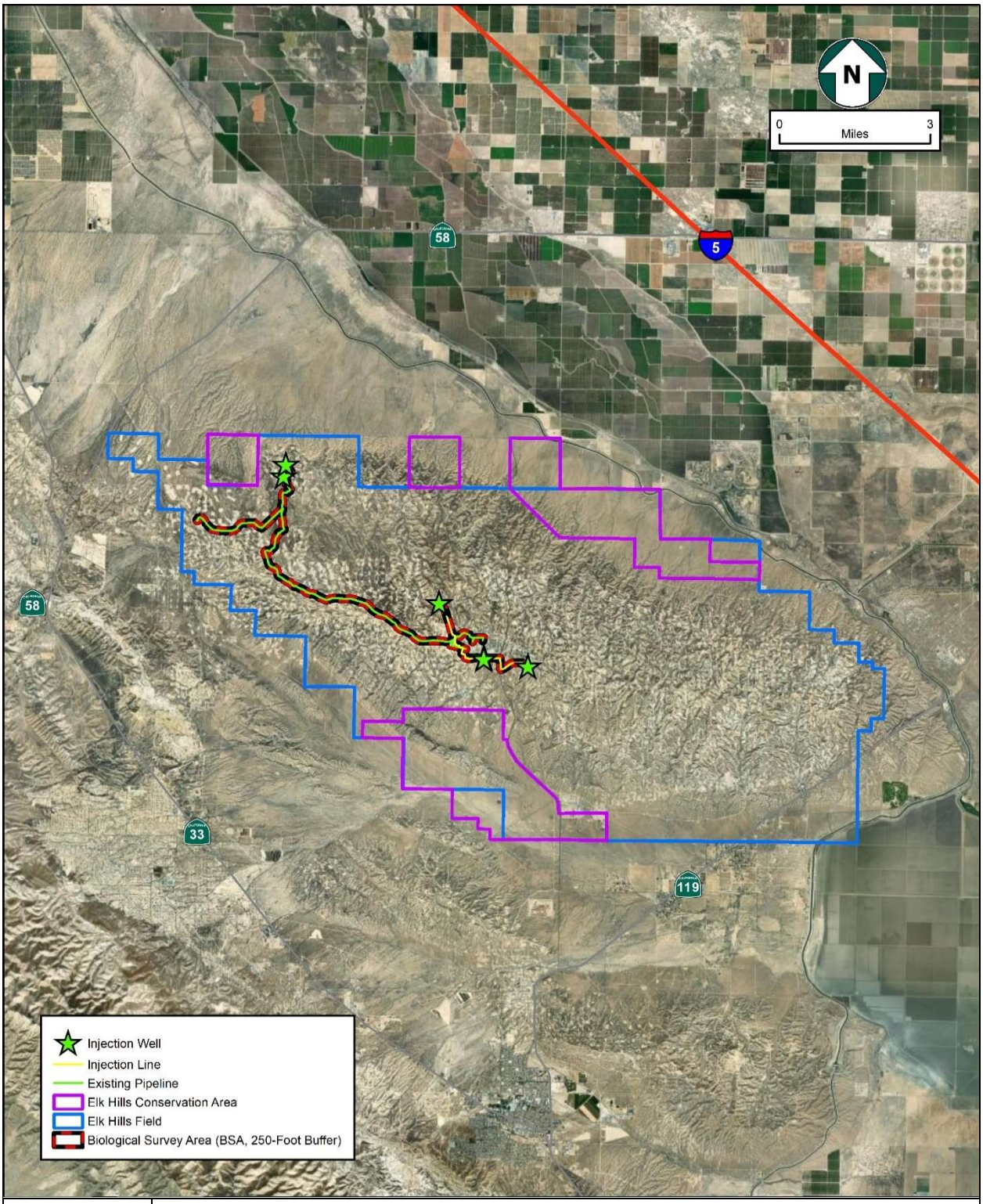


Figure 1-2
Project Site

1.3 - Project Water Requirements and Setting

Project construction is expected to take up to 18 months. Well activities, infrastructure work and facilities work may be conducted simultaneously as these activities are mostly geographically separated from each other. Construction duration may vary based on factors such as weather, seasonal environmental constraints, resource availability, or various site-specific conditions.

During construction, water will be used for dust suppression, fire protection, and pipeline hydrotesting. Construction activities will generally occur during daylight hours, but limited night work could potentially include, but are not limited to, pipeline tie-in connections, refuelling equipment, staging equipment and material for the following day's construction activities, quality assurance/control, and commissioning. All lighting utilized during night work will be situated to avoid lighting impacts on the surrounding area by directing lights down to the work area and only for durations necessary to complete the task safely. Traffic control will be provided for street encroachments and crossings as necessary.

Project construction will result in temporary disturbance associated with the pipeline construction corridor and temporary construction storage and laydown areas and limited permanent disturbance associated with new pipeline sleeper installation sites and the CO2 compression and pumping facility.

The construction period for the proposed project from site preparation through construction and testing is expected to commence in 2024 beginning with pipeline construction and facility construction to be initiated after procurement of new facilities equipment and pipe. Work on the project site would commence in mid-2024 and would extend for approximately 18 months.

Construction of the proposed project would include the following activities:

- Site preparation
- Construction of access and site internal roads
- Grading and earthwork
- Dust control
- Concrete foundations
- Major equipment installation
- Structural steel work
- Electrical/instrumentation work
- Storm water management facilities
- Architecture and landscaping

Approximately 80 workers would be involved, although numbers would fluctuate depending on the stage of construction. Bottled water would be provided to the construction workers for consumption.

During construction, water will be used for three primary uses: fugitive dust control, fire protection and pipeline hydrotesting. Approximately, 24.4 million gallons (75 acre-feet) of water may be required during the construction for all phases. Peak day demand for construction water usage could reach approximately 250,000 gallons per day. However, the actual amount of water applied daily for the pipeline is highly dependent on weather and varies between construction phases. The source of this water will be from the Elk Hills water system which is part of the West Kern Water District (WKWD). WKWD water is provided by surface water that is banked underground and recovered as necessary.

Assuming the construction process is to take approximately 18 months, the water demand is estimated to average 44,500 gallons per day (24.4 MG / (18 months * 30.5 days/month)).

During operation, water will be used in two AmiPur-PLUS units (amine units). AmiPur-PLUS uses an ion exchange process. Amine solution from a slip stream passes through a cartridge filter and ion exchange resin bed on the AmiPUR equipment skid. Heat Stable Salts (HSS) are removed from the amine solution and exchanged onto the resin, while the purified amine solution is returned to the circuit. After treating a fixed volume of solution, the unit automatically stops processing amine solution for a few minutes while it runs through a regeneration sequence during which water and caustic are passed through the resin bed to remove HSS from the resin and direct it to waste. The amine process is used in carbon sequestration processing for the removal of hydrogen sulfide and carbon dioxide (Figure 1-3).

Each AmiPur-PLUS unit will use 6 gallons per minute of water every day throughout the year. This would equate to 17,400 gallons (8,700 gallons per unit x 2 or 0.053 acre-feet) per day (6 gpm x 2 units x 60 min/hr x 24 hr/day) or 6.35 million gallons (19.49 acre-feet) per year.

Figures 1-4 illustrates the location of the Project site within the Tulare Lake Hydrologic Region, Kern County Groundwater Basin, and the borders of these water resource areas. Construction and operational water for the Project will be from sources pumping groundwater from this basin. The Kern County Groundwater Basin does not have any adjudicated areas.

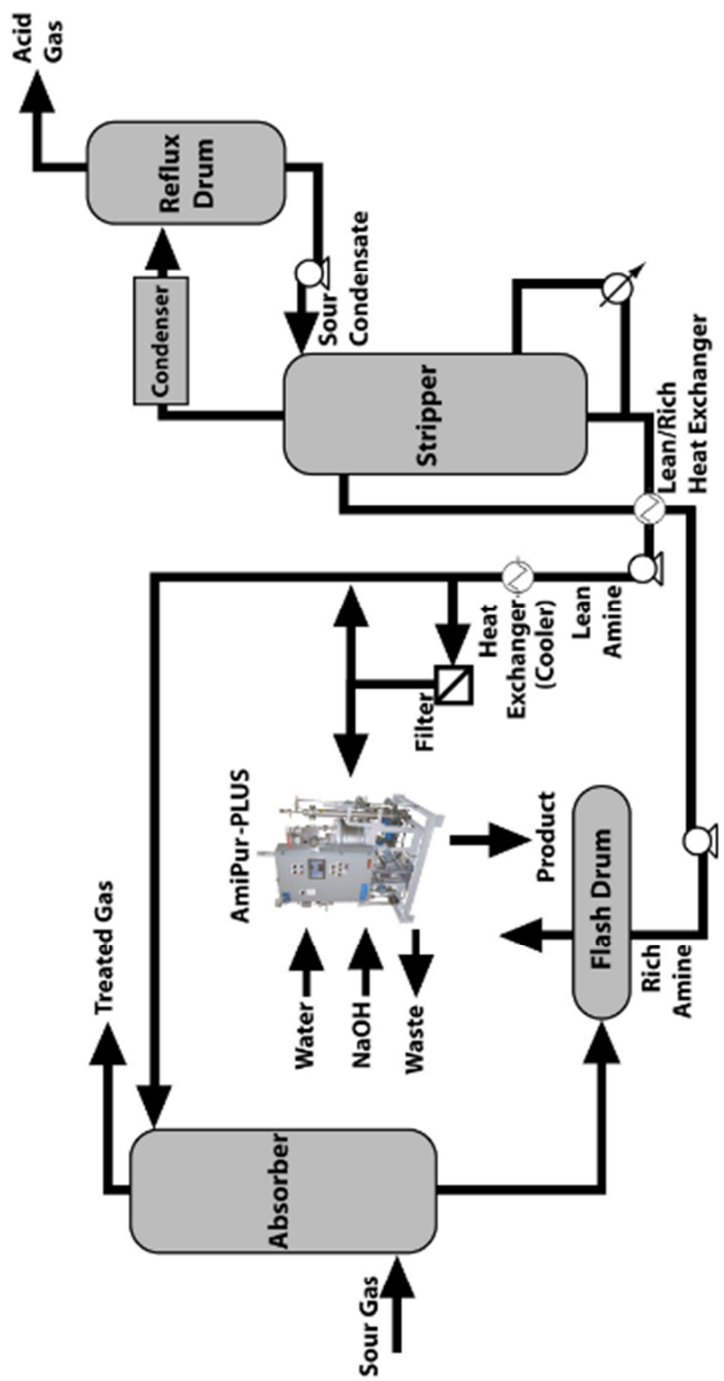


Figure 1-3
Project Water Use: AmiPUR-Plus Unit



Figure 1-4
Project Location: Tulare Lake Hydrologic Region

SECTION 2 - WATER RESOURCES/WATER SUPPLY

2.1 - Proposed Water Supply

The Project will not be served by a public water system, and therefore is preparing this Water Supply Assessment as required by Water Code Section 10910(b). The purpose of the Water Supply Assessment is to determine whether "the total projected water supplies, determined to be available by Kern County for the Project during normal, single-dry, and multiple-dry water years during a 20-year projection, will meet the projected water demand associated with the proposed Project, in addition to existing and planned future uses, including agricultural and manufacturing uses." Water Code Section 10910(c)(4).

In making the sufficiency determination, the County shall include an assessment of the following.

Water Code Section 10910

(d)(1) The assessment required by this section shall include an identification of any existing water supply entitlements, water rights, or water service contracts relevant to the identified water supply for the proposed project, and a description of the quantities of water received in prior years by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), under the existing water supply entitlements, water rights, or water service contracts.

(2) An identification of existing water supply entitlements, water rights, or water service contracts held by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), shall be demonstrated by providing information related to all of the following:

(A) Written contracts or other proof of entitlement to an identified water supply.

(B) Copies of a capital outlay program for financing the delivery of a water supply that has been adopted by the public water system.

(C) Federal, State, and local permits for construction of necessary infrastructure associated with delivering the water supply.

(D) Any necessary regulatory approvals that are required in order to be able to convey or deliver the water supply.

The Project area is bordered on all sides by existing oil and gas exploration and production. Existing land use outside of the Project area generally includes agricultural lands, current, past, and abandoned oil and gas exploration and production land, and undeveloped land owned by CRC and other oil and gas operators.

The Project area is located entirely within the boundary of the Elk Hills Oil Field, an approximately 75-square-mile complex with surface and mineral rights privately held by CRC in the San Joaquin Valley of unincorporated Kern County. As described in Section 1, the Project water supply is proposed to be trucked to the Project site from a nearby water provider.

2.2 - Hydrologic Region

The Water Supply Assessment evaluates the physical availability of and adequate groundwater supply, in all "water years" for a 20-year period.

This Assessment describes the relevant Hydrologic Region, and Basin, describes the principal groundwater agency serving and regulating Basin water planning and surface water importation, and lists water sufficiency and planning documents regarding the Basin. Section 3 includes the latest (July 2022) Kern Groundwater Authority projection of water availability (ground) for the Basin for a 20-year period under the normal, single dry and multiple dry year scenarios, as required by SB 610.

Water Code Section 10910

(f) If a water supply for a proposed project includes groundwater, the following additional information shall be included in the water assessment:

(1) A review of any information contained in the urban water management plan relevant to the identified water supply for the proposed project.

(2)(A) A description of any groundwater basin or basins from which the proposed project will be supplied.

(B) For those basins for which a court or the board has adjudicated the rights to pump groundwater, a copy of the order or decree adopted by the court or the board and a description of the amount of groundwater the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), has the legal right to pump under the order or decree.

(C) For a basin that has not been adjudicated that is a basin designated as high- or medium-priority pursuant to Section 10722.4 , information regarding the following:

(i) Whether the department has identified the basin as being subject to critical conditions of overdraft pursuant to Section 12924 .

(ii) If a groundwater sustainability agency has adopted a groundwater sustainability plan or has an approved alternative, a copy of that alternative or plan.

(D) For a basin that has not been adjudicated that is a basin designated as low- or very low priority pursuant to Section 10722.4 , information as to whether the department has identified the basin or basins as overdrafted or has projected that the

basin will become overdrafted if present management conditions continue, in the most current bulletin of the department that characterizes the condition of the groundwater basin, and a detailed description by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), of the efforts being undertaken in the basin or basins to eliminate the long-term overdraft condition.

2.2.1 - THE TULARE LAKE HYDROLOGIC REGION

The California Department of Water Resources, (DWR) has divided the State into 10 Hydrologic Regions. The Project site is located within the Tulare Lake Hydrologic Region in a Basin ranked as "high priority" in a statewide ranking of groundwater importance. Additionally, the Basin is listed as being in "critical overdraft". The Region encompasses approximately 16,800 square miles (see Figure 1-4).

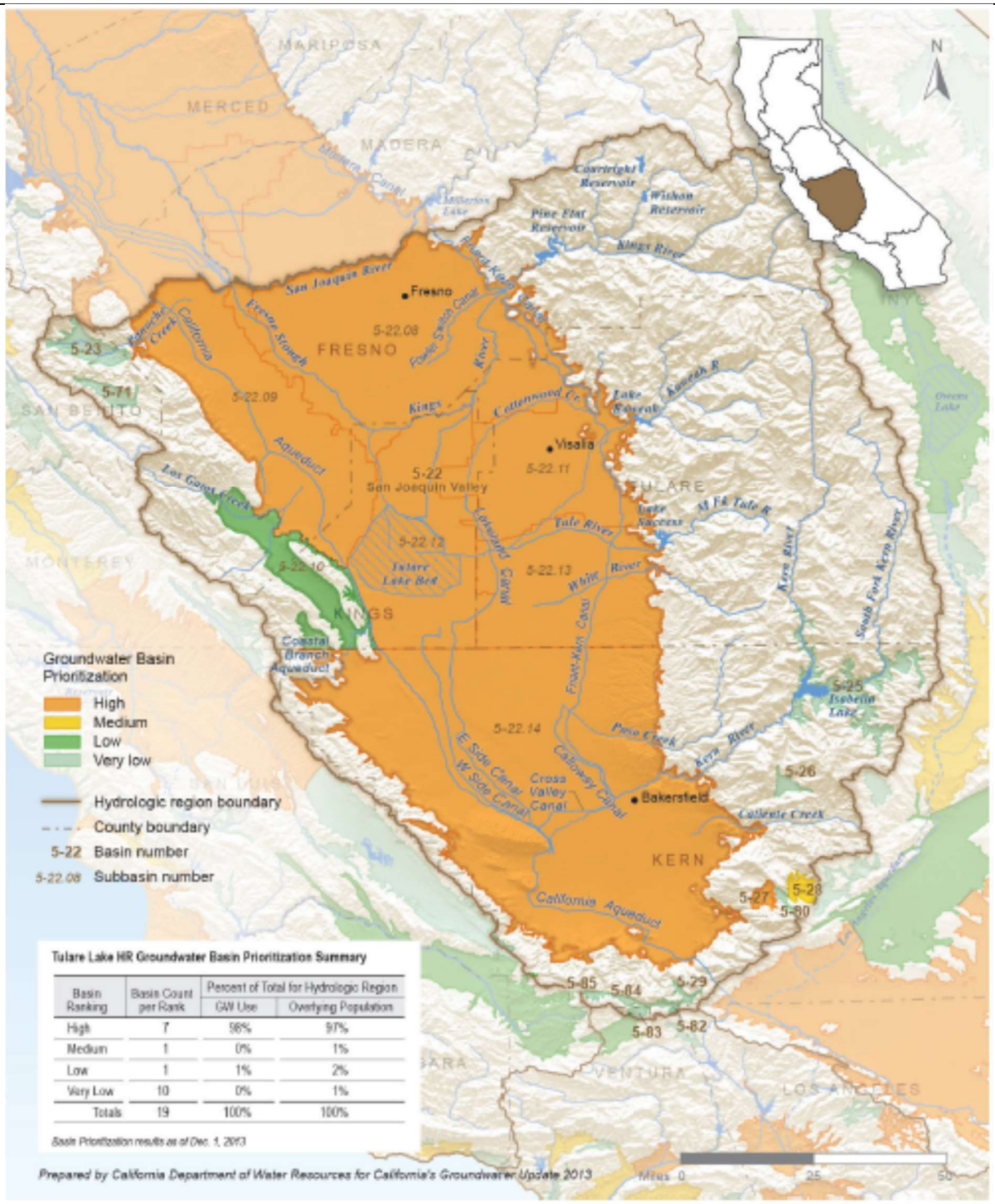
2.2.2 - THE KERN COUNTY GROUNDWATER SUBBASIN

The project site is located above the Kern County Hydrologic Region, for which the Kern Groundwater Authority (KGA) is the principal groundwater management agency. The Kern County subbasin is the specific groundwater subbasin in which the project resides and has a surface area of approximately 1,945,000 acres (see Figure 2-1 – Basin 5-22.14). It is bounded to the north by the Kern County line and the Tule Groundwater subbasin, on the east and southeast by granitic bedrock of the Sierra Nevada foothills and Tehachapi mountains, and on the southwest and west by the marine sediments of the San Emigdio Mountains and Coast Ranges; the subbasin has a surface area of approximately 3,040 square miles.

The Kern County Groundwater Subbasin is not an adjudicated groundwater basin. In characterizing the groundwater budget, the DWR has classified the subbasin as Type A, which means that enough data is available to complete the groundwater budget.

As of 2006, the DWR estimated the total water storage of the subbasin using an estimated specific yield of 11.8 percent and water levels collected by the DWR as well as other cooperators. Based on these calculations, the DWR estimates the total storage capacity of the subbasin to be 40,000,000 acre-feet.

Groundwater in the Basin will be used to supply water for the Project. The project is located within the West Kern Water District Groundwater Sustainability Agency (GSA), which is a member of the Kern Groundwater Authority.



Basin Ranking	Basin Count per Rank	Percent of Total for Hydrologic Region	
		GW Use	Overlying Population
High	7	98%	97%
Medium	1	0%	1%
Low	1	1%	2%
Very Low	10	0%	1%
Totals	19	100%	100%

Basin Prioritization results as of Dec. 1, 2013

Figure 2-1
Tulare Lake Groundwater Basin Prioritization

2.3 - The Kern Groundwater Authority

The proposed source to provide water for the Project is located within the Kern Groundwater Authority. As such, the Kern Groundwater Authority has detailed information regarding groundwater conditions in the vicinity of the proposed project site.

The Kern Groundwater Authority (KGA) Groundwater Sustainability Agency (GSA) covers approximately 1.2 million acres of the Kern County Subbasin's approximate 1.8 million acres, as defined by the California Department of Water Resources Bulletin 118. The Subbasin, as a whole, has an overdraft of 324,326 acre-feet per year over the baseline conditions of which the KGA is approximately 239,346 acre-feet of the deficit.

The KGA Members have sources of water supplies such as local streams (Caliente, Poso Creek), Kern River, State Water Project and Central Valley Project sources. Each member addresses their own individual water supply sources in greater detail in their individual management area plans along with how the beneficial users in their jurisdiction will participate in achieving sustainability.

The KGA Members have also identified more than 150 projects and management actions ranging from expansion of local and regional conveyance and recharge facilities to take advantage of surplus supplies; new conveyance and recharge projects; and participation in the California WaterFix or other thru-Delta improvement projects. Management actions range from implementing district level fee structures to incentive reduced groundwater pumping; participation in local, regional, and state-wide water markets; and setting allocation for groundwater use by landowner, based on the sustainable yield of management areas.

The coordinated modeling effort shows that implementation and completion of the identified projects and management actions during the implementation period of 2020 to 2040, as stated in the individual management area plans and GSPs from the other GSAs in the Subbasin, would result in an average surplus of 85,578 acre-feet per year over the projected baseline condition simulation.

2.4 - Kern Integrated Regional Water Management Plan

The Kern Region published an Integrated Regional Water Management Plan update in 2020. The 2020 Tulare Lake Basin Portion of Kern County Integrated Regional Water Management (IRWM) Plan Update (2020 Plan Update) includes new information as required by the California Department of Water Resources (DWR) 2016 Integrated Regional Water Management Proposition 1 Guidelines. IRWM is a collaborative effort to manage all aspects of water resources in a region. The State recognizes that there is a need to consider a broader range of resource management issues, competing water demands, new approaches to ensuring water supply reliability, and new ways of financing. The State's IRWM program was developed beginning with Senate Bill 1672, which created the Integrated Regional Water Management Act to encourage local agencies to work cooperatively to manage local and imported water supplies to improve water quality, quantity, and reliability.

The proposed source of water to provide water to the Project is located within the IRWM area. As such, the IRWM Plan has detailed information regarding groundwater conditions in the vicinity of the proposed project.

2.5 - West Kern Water District

The proposed source to provide water for the Project is the West Kern Water District within the Kern Groundwater Authority. As such, the West Kern Water District has detailed information regarding groundwater conditions in the vicinity of the proposed project site.

The West Kern Water District (WKWD) covers approximately 0.232 million acres of the Kern County Subbasin's approximately 1.8 million acres, as defined by the California Department of Water Resources Bulletin 118.

The WKWD primarily pumps groundwater but balances this extraction by recharging its State Water Project (SWP) water and other supplemental water supplies. The WKWD is allocated 31,500 acre-feet per year of SWP surface water at 100% allocation. Based on the WKWD 2020 Urban Water Management Plan (UWMP), the average water year supply is 18,600 acre-feet. According to the UWMP, when SWP water is restricted, the WKWD can meet water demand using banked groundwater supplies. Elk Hills and California Resources Corporation (CRC) are customers of WKWD. Elk Hills has an allocation of 3,000 acre-feet per year while California Resources Corporation has a 2,200 acre-feet per year allocation.

2.6 - The Planning Documents

The following documents were essential to the development of this report:

- The Kern Groundwater Authority (KGA) Groundwater Sustainability Plan (GSP) – July 2022
- Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan – 2020 Update
- The West Kern Water District (WKWD) Urban Water Management Plan (UWMP) – June 2021
- Department of Water Resources Bulletin 118

SECTION 3 - WATER SUPPLY SUFFICIENCY

Water Code Section 10910, Section 4.5

…(c)(3) If the projected water demand associated with the proposed project was not accounted for in the most recently adopted urban water management plan, or the public water system has no urban water management plan, the water supply assessment for the project shall include a discussion with regard to whether the public water system's total projected water supplies available during normal, single-dry, and multiple-dry water years during a 20-year projection will meet the projected water demand associated with the proposed project, in addition to the public water system's existing and planned future uses, including agricultural and manufacturing uses.

The sufficiency of the Project water supply is analyzed on three bases: the physical availability of the Project area aquifer, and wells drilled therein, to provide groundwater in the amounts required for Project construction and operation; the estimates (in the 2020 WKWD UWMP) of normal water years, single-dry water years, and multiple-dry water years, water supply and demand-related water availability; the availability of groundwater for the Project in compliance with SB610.

3.1 - Physical Availability

The available information regarding the physical availability of groundwater at and near to the Project site (Section 2.1, Appendix B and Appendix C) verifies that the groundwater aquifer and the well pumping history thereof are sufficient for both Project construction and Project operation. Based on the 2020 WKWD UWMP future water budget, approximately 18,600 (3,000 acre-feet per year for Elk Hills and 2,200 acre-feet per year for California Resources Corporation) are expected to be available. The 2022 water usage for Elk Hills and California Resources (based on the 2022 Electronic Annual Report (EAR)) was 167.5 MG (514.1 AF). With the Elk Hills and CRC allotment of 5,200 acre-feet year, only approximately 10% is being utilized. An additional demand of 75 acre-feet construction water demand would utilize 1.4% of the water allotment.

During construction, water will be used for two primary uses: fugitive dust control, fire protection and pipeline hydrotesting. Approximately, 24.4 million gallons (75 acre-feet) of water may be required during the construction season for dust control. Peak day demand for construction water usage could reach approximately 250,000 gallons per day. However, the actual amount of water applied daily for the pipeline is highly dependent on weather and varies between construction phases. Water would be delivered via truck from an off-site source(s) within the project vicinity. If water is trucked into the site, it is anticipated that an available local water source would be selected to minimize truck trips/lengths in transporting water to/from the site.

Assuming the construction process is to take approximately 18 months, the water demand is estimated to average 44,500 gallons per day (24.4 MG / (18 months * 30.5 days/month)).

During operation, water will be used in two AmiPur-PLUS units. AmiPur-PLUS uses an ion exchange process. Amine solution from a slip stream passes through a cartridge filter and ion exchange resin bed on the AmiPUR equipment skid. Heat Stable Salts (HSS) are removed from the amine solution and exchanged onto the resin, while the purified amine solution is returned to the circuit. After treating a fixed volume of solution, the unit automatically stops processing amine solution for a few minutes while it runs through a regeneration sequence during which water and caustic are passed through the resin bed to remove HSS from the resin and direct it to waste. The amine process is used in carbon sequestration processing for the removal of hydrogen sulfide and carbon dioxide (Figure 1-3).

Each AmiPur-PLUS unit will use 6 gallons per minute of water every day throughout the year. This would equate to 17,400 gallons (0.053 acre-feet) per day (6 gpm x 2 units x 60 min/hr x 24 hr/day) or 6.35 million gallons (19.49 acre-feet) per year.

The construction water for this Project is estimated at 75 acre-feet or 1.4 percent of the projected available supply. The ongoing operational demand for the Project is 6.35 million gallons per year (19.49 acre-feet per year), or 0.37 percent of projected available supply. The Project will have very little impact on groundwater use in the area.

3.2 - The 2020 WKWD UWMP – Water Years Adequacy Projections

The following is excerpted from the WKED UWMP illustrates the description of groundwater resources available to the West Kern Water District including Elk Hills and California Resources Corporation. The following table and text extracts (page 55 from the UWMP) explains the water availability during drought periods.

Year	Description	Water Use (AFY)					
		2020	2025	2030	2035	2040	2045
Year 1	Surface Water (19% of Normal)	3,500	3,500	3,500	3,500	3,500	3,500
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	10,650	10,650	10,650	10,650	10,000	10,000
	Total Demand	16,338	17,356	17,448	17,542	17,637	17,735
	Difference (from Banked Groundwater)	5,688	6,706	6,798	6,892	7,637	7,735
Year 2	Surface Water (78% of Normal)	14,500	14,500	14,500	14,500	14,500	14,500
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	21,650	21,650	21,650	21,650	21,000	21,000
	Total Demand	16,338	17,356	17,448	17,542	17,637	17,735
	Difference (from Banked Groundwater)	0	0	0	0	0	0
Year 3	Surface Water (24% of Normal)	4,400	4,400	4,400	4,400	4,400	4,400
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	11,550	11,550	11,550	11,550	10,900	10,900
	Total Demand	14,704	15,620	15,703	15,788	15,873	15,962
	Difference (from Banked Groundwater)	3,154	4,070	4,153	4,238	4,973	5,062
Year 4	Surface Water (42% of Normal)	7,900	7,900	7,900	7,900	7,900	7,900
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	15,050	15,050	15,050	15,050	14,400	14,400
	Total Demand	14,704	15,620	15,703	15,788	15,873	15,962
	Difference (from Banked Groundwater)	0	570	653	738	1,473	1,562
Year 5	Surface Water (29% of Normal)	5,400	5,400	5,400	5,400	5,400	5,400
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	12,550	12,550	12,550	12,550	11,900	11,900
	Total Demand	14,704	15,620	15,703	15,788	15,873	15,962
	Difference (from Banked Groundwater)	2,154	3,070	3,153	3,238	3,973	4,062

Summary of Comparisons

As shown in the analyses above, WKWD has adequate supplies to meet demands during normal, single-dry, and multiple-dry years throughout the 25-year planning period. WKWD will pump banked groundwater to meet demand when demand exceeds the surface water supply in single-dry and multiple-dry year periods. In times of excess, the water will be banked for use in the future. Currently, WKWD has about 247,545 AF in storage which represents about 10 years of full annual demands and helps to ensure reliability in dry periods. The groundwater storage often increases in wet and dry years from recharge efforts,

so the storage is expected to last for several decades. WKWD's water reliability is stable, largely due to the long history of banking groundwater for use in dry years.

The water to be used for the Project has been included in the above demand volumes in the UWMP since the water source for the Project existed at the time the UWMP was published.

SECTION 4 - CONCLUSIONS

This Water Supply Assessment has provided the data and analysis needed to verify that a sufficient Project water supply is physically available (Section 3.1) and that the Project water supply is in accord with SB 610's normal year/dry year/multiple-dry year requirements, sufficient (Section 3.2). This conclusion is based on the fact that the construction process is to take approximately 18 months with a water demand estimated to average 44,500 gallons per day (24.4 MG / (18 months * 30.5 days/month)). The construction water for this Project is estimated at 75 acre-feet or 1.4 percent of the projected available supply in the groundwater basin. The ongoing operational demand for the Project is 6.35 million gallons per year (19.49 acre-feet per year), or 0.37 percent of projected available supply. The Project will have very little impact on groundwater use in the area.

It is recommended that the County of Kern conclude that the proposed water supplies for the Project be found sufficient to meet the projected Project water demand.

SECTION 5 - REFERENCES

CalEPA (California Environmental Protection Agency), 2015. The Water Rights Process: Groundwater Rights. (online): http://www.swrcb.ca.gov/waterrights/board_info/water_rights_process.shtml#rights. Accessed December 2, 2015

2003. Guidebook for Implementation of Senate Bill 610 and Senate Bill 221 of 2001. (online): http://www.water.ca.gov/pubs/use/sb_610_sb_221_guidebook/guidebook.pdf. Accessed June 23, 2023

California Department of Water Resources (DWR). 2015. California's Groundwater Bulletin 118.135 p.

The Kern Groundwater Authority (KGA) Groundwater Sustainability Plan (GSP) – July 2022

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan – 2020 Update

West Kern Water District Urban Water Management Plan (2020) – June 2021

APPENDIX A

CHAPTER 643, STATUTES OF 2001 (SENATE BILL 610)

Senate Bill No. 610
CHAPTER 643

An act to amend Section 21151.9 of the Public Resources Code, and to amend Sections 10631, 10656, 10910, 10911, 10912, and 10915 of, to repeal Section 10913 of, and to add and repeal Section 10657 of, the Water Code, relating to water.

[Filed with Secretary of State October 09, 2001. Approved by Governor October 09, 2001.]

LEGISLATIVE COUNSEL'S DIGEST

SB 610, Costa. Water supply planning.

(1) Existing law requires every urban water supplier to identify, as part of its urban water management plan, the existing and planned sources of water available to the supplier over a prescribed 5-year period. Existing law prohibits an urban water supplier that fails to prepare or submit its urban water management plan to the Department of Water Resources from receiving drought assistance from the state until the plan is submitted.

This bill would require additional information to be included as part of an urban water management plan if groundwater is identified as a source of water available to the supplier. The bill would require an urban water supplier to include in the plan a description of all water supply projects and programs that may be undertaken to meet total projected water use. The bill would prohibit an urban water supplier that fails to prepare or submit the plan to the department from receiving funding made available from specified bond acts until the plan is submitted. The bill, until January 1, 2006, would require the department to take into consideration whether the urban water supplier has submitted an updated plan, as specified, in determining eligibility for funds made available pursuant to any program administered by the department.

(2) Existing law, under certain circumstances, requires a city or county that determines an environmental impact report is required in connection with a project, as defined, to request each public water system that may supply water for the project to assess, among other things, whether its total projected water supplies will meet the projected water demand associated with the proposed project. Existing law requires the public water system to submit the assessment to the city or county not later than 30 days from the date on which the request was received and, in the absence of the submittal of an assessment, provides that it shall be assumed that the public water system has no information to submit. Existing law makes legislative findings and declarations concerning "Proposition C," a measure approved by the voters of San Diego County relating to regional growth management, and provides that the procedures established by a specified review board established in connection with that measure are deemed to comply with the requirements described above relating to water supply planning by a city or county.

This bill would revise those provisions. The bill, instead, would require a city or county that determines a project is subject to the California Environmental Quality Act to identify any public water system that may supply water for the project and to request those public water systems to

prepare a specified water supply assessment, except as otherwise specified. The bill would require the assessment to include, among other information, an identification of existing water supply entitlements, water rights, or water service contracts relevant to the identified water supply for the proposed project and water received in prior years pursuant to those entitlements, rights, and contracts. The bill would require the city or county, if it is not able to identify any public water system that may supply water for the project, to prepare the water supply assessment after a prescribed consultation. The bill would revise the definition of "project," for the purposes of these provisions, and make related changes.

The bill would prescribe a timeframe within which a public water system is required to submit the assessment to the city or county and would authorize the city or county to seek a writ of mandamus to compel the public water system to comply with requirements relating to the submission of the assessment.

The bill would require the public water system, or the city or county, as applicable, if that entity concludes that water supplies are, or will be, insufficient, to submit the plans for acquiring additional water supplies.

The bill would require the city or county to include the water supply assessment and certain other information in any environmental document prepared for the project pursuant to the act. By establishing duties for counties and cities, the bill would impose a state-mandated local program.

The bill would provide that the County of San Diego is deemed to comply with these water supply planning requirements if the Office of Planning and Research determines that certain requirements have been met in connection with the implementation of "Proposition C."

(3) The bill would incorporate additional changes in Section 10631 of the Water Code proposed by AB 901, to be operative only if this bill and AB 901 are enacted and become effective on or before January 1, 2002, each bill amends Section 10631 of the Water Code, and this bill is enacted last.
(4) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

DIGEST KEY

BILL TEXT

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1.

(a) The Legislature finds and declares all of the following:

(1) The length and severity of droughts in California cannot be predicted with any accuracy.

(2) There are various factors that affect the ability to ensure that adequate water supplies are available to meet all of California's water demands, now and in the future.

(3) Because of these factors, it is not possible to guarantee a permanent water supply for all water users in California in the amounts requested.

(4) Therefore, it is critical that California's water agencies carefully assess the reliability of their water supply and delivery systems.

(5) Furthermore, California's overall water delivery system has become less reliable over the last 20 years because demand for water has continued to grow while new supplies have not been developed in amounts sufficient to meet the increased demand.

(6) There are a variety of measures for developing new water supplies including water reclamation, water conservation, conjunctive use, water transfers, seawater desalination, and surface water and groundwater storage.

(7) With increasing frequency, California's water agencies are required to impose water rationing on their residential and business customers during this state's frequent and severe periods of drought.

(8) The identification and development of water supplies needed during multiple-year droughts is vital to California's business climate, as well as to the health of the agricultural industry, environment, rural communities, and residents who continue to face the possibility of severe water cutbacks during water shortage periods.

(9) A recent study indicates that the water supply and land use planning linkage, established by Part 2.10 (commencing with Section 10910) of Division 6 of the Water Code, has not been implemented in a manner that ensures the appropriate level of communication between water agencies and planning agencies, and this act is intended to remedy that deficiency in communication.

(b) It is the intent of the Legislature to strengthen the process pursuant to which local agencies determine the adequacy of existing and planned future water supplies to meet existing and planned future demands on those water supplies.

SEC. 2.

Section 21151.9 of the Public Resources Code is amended to read:

21151.9.

Whenever a city or county determines that a project, as defined in Section 10912 of the Water Code, is subject to this division, it shall comply with Part 2.10 (commencing with Section 10910) of Division 6 of the Water Code.

SEC. 3.

Section 10631 of the Water Code is amended to read:

10631.

A plan shall be adopted in accordance with this chapter and shall do all of the following:

(a) Describe the service area of the supplier, including current and projected population, climate, and other demographic factors affecting the supplier's water management planning. The projected population estimates shall be based upon data from the state, regional, or local service agency population projections within the service area of the urban water supplier and shall be in five-year increments to 20 years or as far as data is available.

(b) Identify and quantify, to the extent practicable, the existing and planned sources of water available to the supplier over the same five-year increments as described in subdivision (a). If groundwater is identified as an existing or planned source of water available to the supplier, all of the following information shall be included in the plan:

(1) A copy of any groundwater management plan adopted by the urban water supplier, including plans adopted pursuant to Part 2.75 (commencing with Section 10750), or any other specific authorization for groundwater management.

(2) A description of any groundwater basin or basins from which the urban water supplier pumps groundwater. For those basins for which a court or the board has adjudicated the rights to pump groundwater, a copy of the order or decree adopted by the court or the board and a description of the amount of groundwater the urban water supplier has the legal right to pump under the order or decree. For basins that have not been adjudicated, information as to whether the department has identified the basin or basins as overdrafted or has projected that the basin will become overdrafted if present management conditions continue, in the most current official departmental bulletin that characterizes the condition of the groundwater basin, and a detailed description of the efforts being undertaken by the urban water supplier to eliminate the long-term overdraft condition.

(3) A detailed description and analysis of the amount and location of groundwater pumped by the urban water supplier for the past five years. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.

(4) A detailed description and analysis of the location, amount, and sufficiency of groundwater that is projected to be pumped by the urban water supplier. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.

(c) Describe the reliability of the water supply and vulnerability to seasonal or climatic shortage, to the extent practicable, and provide data for each of the following:

(1) An average water year.

(2) A single dry water year.

(3) Multiple dry water years.

For any water source that may not be available at a consistent level of use, given specific legal, environmental, water quality, or climatic factors, describe plans to replace that source with alternative sources or water demand management measures, to the extent practicable.

(d) Describe the opportunities for exchanges or transfers of water on a short-term or long-term basis.

(e) (1) Quantify, to the extent records are available, past and current water use, over the same five-year increments described in subdivision (a), and projected water use, identifying the uses among water use sectors, including, but not necessarily limited to, all of the following uses:

(A) Single-family residential.

(B) Multifamily.

(C) Commercial.

(D) Industrial.

(E) Institutional and governmental.

(F) Landscape.

(G) Sales to other agencies.

(H) Saline water intrusion barriers, groundwater recharge, or conjunctive use, or any combination thereof.

(I) Agricultural.

(2) The water use projections shall be in the same five-year increments as described in subdivision (a).

(f) Provide a description of the supplier's water demand management measures. This description shall include all of the following:

(1) A description of each water demand management measure that is currently being implemented, or scheduled for implementation, including the steps necessary to implement any proposed measures, including, but not limited to, all of the following:

(A) Water survey programs for single-family residential and multifamily residential customers.

(B) Residential plumbing retrofit.

(C) System water audits, leak detection, and repair.

(D) Metering with commodity rates for all new connections and retrofit of existing connections.

(E) Large landscape conservation programs and incentives.

(F) High-efficiency washing machine rebate programs.

(G) Public information programs.

(H) School education programs.

(I) Conservation programs for commercial, industrial, and institutional accounts.

(J) Wholesale agency programs.

(K) Conservation pricing.

(L) Water conservation coordinator.

(M) Water waste prohibition.

(N) Residential ultra-low-flush toilet replacement programs.

(2) A schedule of implementation for all water demand management measures proposed or described in the plan.

(3) A description of the methods, if any, that the supplier will use to evaluate the effectiveness of water demand management measures implemented or described under the plan.

(4) An estimate, if available, of existing conservation savings on water use within the supplier's service area, and the effect of such savings on the supplier's ability to further reduce demand.

(g) An evaluation of each water demand management measure listed in paragraph (1) of subdivision (f) that is not currently being implemented or scheduled for implementation. In the course of the evaluation, first consideration shall be given to water demand management measures, or combination of measures, that offer lower incremental costs than expanded or additional water supplies. This evaluation shall do all of the following:

(1) Take into account economic and noneconomic factors, including environmental, social, health, customer impact, and technological factors.

(2) Include a cost-benefit analysis, identifying total benefits and total costs.

(3) Include a description of funding available to implement any planned water supply project that would provide water at a higher unit cost.

(4) Include a description of the water supplier's legal authority to implement the measure and efforts to work with other relevant agencies to ensure the implementation of the measure and to share the cost of implementation.

(h) Include a description of all water supply projects and water supply programs that may be undertaken by the urban water supplier to meet the total projected water use as established pursuant to subdivision (a) of Section 10635. The urban water supplier shall include a detailed description of expected future projects and programs, other than the demand management programs identified pursuant to paragraph (1) of subdivision (f), that the urban water supplier may implement to increase the amount of the water supply available to the urban water supplier in average, single dry, and multiple dry water years. The description shall identify specific projects and include a description of the increase in water supply that is expected to be available from each project. The description shall include an estimate with regard to the implementation timeline for each project or program.

(i) Urban water suppliers that are members of the California Urban Water Conservation Council and submit annual reports to that council in accordance with the "Memorandum of Understanding Regarding Urban Water Conservation in California," dated September 1991, may submit the annual reports identifying water demand management measures currently being implemented, or scheduled for implementation, to satisfy the requirements of subdivisions (f) and (g).

SEC. 3.5.

Section 10631 of the Water Code is amended to read:

10631.

A plan shall be adopted in accordance with this chapter and shall do all of the following:

(a) Describe the service area of the supplier, including current and projected population, climate, and other demographic factors affecting the supplier's water management planning. The projected population estimates shall be based upon data from the state, regional, or local service agency population projections within the service area of the urban water supplier and shall be in five-year increments to 20 years or as far as data is available.

(b) Identify and quantify, to the extent practicable, the existing and planned sources of water available to the supplier over the same five-year increments as described in subdivision (a). If groundwater is identified as an existing or planned source of water available to the supplier, all of the following information shall be included in the plan:

(1) A copy of any groundwater management plan adopted by the urban water supplier, including plans adopted pursuant to Part 2.75 (commencing with Section 10750), or any other specific authorization for groundwater management.

(2) A description of any groundwater basin or basins from which the urban water supplier pumps groundwater. For those basins for which a court or the board has adjudicated the rights to pump groundwater, a copy of the order or decree adopted by the court or the board and a description of the amount of groundwater the urban water supplier has the legal right to pump under the order or decree. For basins that have not been adjudicated, information as to whether the department has identified the basin or basins as overdrafted or has projected that the basin will become overdrafted if present management conditions continue, in the most current official departmental bulletin that

characterizes the condition of the groundwater basin, and a detailed description of the efforts being undertaken by the urban water supplier to eliminate the long-term overdraft condition.

(3) A detailed description and analysis of the location, amount, and sufficiency of groundwater pumped by the urban water supplier for the past five years. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.

(4) A detailed description and analysis of the amount and location of groundwater that is projected to be pumped by the urban water supplier. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.

(c) Describe the reliability of the water supply and vulnerability to seasonal or climatic shortage, to the extent practicable, and provide data for each of the following:

(1) An average water year.

(2) A single dry water year.

(3) Multiple dry water years.

For any water source that may not be available at a consistent level of use, given specific legal, environmental, water quality, or climatic factors, describe plans to supplement or replace that source with alternative sources or water demand management measures, to the extent practicable.

(d) Describe the opportunities for exchanges or transfers of water on a short-term or long-term basis.

(e) (1) Quantify, to the extent records are available, past and current water use, over the same five-year increments described in subdivision (a), and projected water use, identifying the uses among water use sectors, including, but not necessarily limited to, all of the following uses:

(A) Single-family residential.

(B) Multifamily.

(C) Commercial.

(D) Industrial.

(E) Institutional and governmental.

(F) Landscape.

(G) Sales to other agencies.

(H) Saline water intrusion barriers, groundwater recharge, or conjunctive use, or any combination thereof.

(I) Agricultural.

(2) The water use projections shall be in the same five-year increments as described in subdivision (a).

(f) Provide a description of the supplier's water demand management measures. This description shall include all of the following:

(1) A description of each water demand management measure that is currently being implemented, or scheduled for implementation, including the steps necessary to implement any proposed measures, including, but not limited to, all of the following:

(A) Water survey programs for single-family residential and multifamily residential customers.

(B) Residential plumbing retrofit.

(C) System water audits, leak detection, and repair.

(D) Metering with commodity rates for all new connections and retrofit of existing connections.

(E) Large landscape conservation programs and incentives.

(F) High-efficiency washing machine rebate programs.

(G) Public information programs.

(H) School education programs.

(I) Conservation programs for commercial, industrial, and institutional accounts.

(J) Wholesale agency programs.

(K) Conservation pricing.

(L) Water conservation coordinator.

(M) Water waste prohibition.

(N) Residential ultra-low-flush toilet replacement programs.

(2) A schedule of implementation for all water demand management measures proposed or described in the plan.

(3) A description of the methods, if any, that the supplier will use to evaluate the effectiveness of water demand management measures implemented or described under the plan.

(4) An estimate, if available, of existing conservation savings on water use within the supplier's service area, and the effect of the savings on the supplier's ability to further reduce demand.

(g) An evaluation of each water demand management measure listed in paragraph (1) of subdivision (f) that is not currently being implemented or scheduled for implementation. In the course of the evaluation, first consideration shall be given to water demand management measures, or combination of measures, that offer lower incremental costs than expanded or additional water supplies. This evaluation shall do all of the following:

(1) Take into account economic and noneconomic factors, including environmental, social, health, customer impact, and technological factors.

(2) Include a cost-benefit analysis, identifying total benefits and total costs.

(3) Include a description of funding available to implement any planned water supply project that would provide water at a higher unit cost.

(4) Include a description of the water supplier's legal authority to implement the measure and efforts to work with other relevant agencies to ensure the implementation of the measure and to share the cost of implementation.

(h) Include a description of all water supply projects and water supply programs that may be undertaken by the urban water supplier to meet the total projected water use as established pursuant to subdivision (a) of Section 10635. The urban water supplier shall include a detailed

description of expected future projects and programs, other than the demand management programs identified pursuant to paragraph (1) of subdivision (f), that the urban water supplier may implement to increase the amount of the water supply available to the urban water supplier in average, single dry, and multiple dry water years. The description shall identify specific projects and include a description of the increase in water supply that is expected to be available from each project. The description shall include an estimate with regard to the implementation timeline for each project or program.

(i) Urban water suppliers that are members of the California Urban Water Conservation Council and submit annual reports to that council in accordance with the "Memorandum of Understanding Regarding Urban Water Conservation in California," dated September 1991, may submit the annual reports identifying water demand management measures currently being implemented, or scheduled for implementation, to satisfy the requirements of subdivisions (f) and (g).

SEC. 4.

Section 10656 of the Water Code is amended to read:

10656.

An urban water supplier that does not prepare, adopt, and submit its urban water management plan to the department in accordance with this part, is ineligible to receive funding pursuant to Division 24 (commencing with Section 78500) or Division 26 (commencing with Section 79000), or receive drought assistance from the state until the urban water management plan is submitted pursuant to this article.

SEC. 4.3.

Section 10657 is added to the Water Code, to read:

10657.

(a) The department shall take into consideration whether the urban water supplier has submitted an updated urban water management plan that is consistent with Section 10631, as amended by the act that adds this section, in determining whether the urban water supplier is eligible for funds made available pursuant to any program administered by the department.

(b) This section shall remain in effect only until January 1, 2006, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2006, deletes or extends that date.

SEC. 4.5.

Section 10910 of the Water Code is amended to read:

10910.

(a) Any city or county that determines that a project, as defined in Section 10912, is subject to the California Environmental Quality Act (Division 13 (commencing with Section 21000) of the Public Resources Code) under Section 21080 of the Public Resources Code shall comply with this part.

(b) The city or county, at the time that it determines whether an environmental impact report, a negative declaration, or a mitigated negative declaration is required for any project subject to the California Environmental Quality Act pursuant to Section 21080.1 of the Public Resources Code, shall identify any water system that is, or may become as a result of supplying water to the project identified pursuant to this subdivision, a public water system, as defined in Section 10912, that may supply water for the project. If the city or county is not able to identify any public water system that may supply water for the project, the city or county shall prepare the water assessment required by this part after consulting with any entity serving domestic water supplies whose service area includes the project site, the local agency formation commission, and any public water system adjacent to the project site.

(c) (1) The city or county, at the time it makes the determination required under Section 21080.1 of the Public Resources Code, shall request each public water system identified pursuant to subdivision (b) to determine whether the projected water demand associated with a proposed project was included as part of the most recently adopted urban water management plan adopted pursuant to Part 2.6 (commencing with Section 10610).

(2) If the projected water demand associated with the proposed project was accounted for in the most recently adopted urban water management plan, the public water system may incorporate the requested information from the urban water management plan in preparing the elements of the assessment required to comply with subdivisions (d), (e), (f), and (g).

(3) If the projected water demand associated with the proposed project was not accounted for in the most recently adopted urban water management plan, or the public water system has no urban water management plan, the water supply assessment for the project shall include a discussion with regard to whether the public water system's total projected water supplies available during normal, single dry, and multiple dry water years during a 20-year projection will meet the projected water demand associated with the proposed project, in addition to the public water system's existing and planned future uses, including agricultural and manufacturing uses.

(4) If the city or county is required to comply with this part pursuant to subdivision (b), the water supply assessment for the project shall include a discussion with regard to whether the total projected water supplies, determined to be available by the city or county for the project during normal, single dry, and multiple dry water years during a 20-year projection, will meet the projected water demand associated with the proposed project, in addition to existing and planned future uses, including agricultural and manufacturing uses.

(d) (1) The assessment required by this section shall include an identification of any existing water supply entitlements, water rights, or water service contracts relevant to the identified water supply for the proposed project, and a description of the quantities of water received in prior years by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), under the existing water supply entitlements, water rights, or water service contracts.

(2) An identification of existing water supply entitlements, water rights, or water service contracts held by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), shall be demonstrated by providing information related to all of the following:

(A) Written contracts or other proof of entitlement to an identified water supply.

(B) Copies of a capital outlay program for financing the delivery of a water supply that has been adopted by the public water system.

(C) Federal, state, and local permits for construction of necessary infrastructure associated with delivering the water supply.

(D) Any necessary regulatory approvals that are required in order to be able to convey or deliver the water supply.

(e) If no water has been received in prior years by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), under the existing water supply entitlements, water rights, or water service contracts, the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), shall also include in its water supply assessment pursuant to subdivision (c), an identification of the other public water

systems or water service contractholders that receive a water supply or have existing water supply entitlements, water rights, or water service contracts, to the same source of water as the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), has identified as a source of water supply within its water supply assessments.

(f) If a water supply for a proposed project includes groundwater, the following additional information shall be included in the water supply assessment:

(1) A review of any information contained in the urban water management plan relevant to the identified water supply for the proposed project.

(2) A description of any groundwater basin or basins from which the proposed project will be supplied. For those basins for which a court or the board has adjudicated the rights to pump groundwater, a copy of the order or decree adopted by the court or the board and a description of the amount of groundwater the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), has the legal right to pump under the order or decree. For basins that have not been adjudicated, information as to whether the department has identified the basin or basins as overdrafted or has projected that the basin will become overdrafted if present management conditions continue, in the most current bulletin of the department that characterizes the condition of the groundwater basin, and a detailed description by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), of the efforts being undertaken in the basin or basins to eliminate the long-term overdraft condition.

(3) A detailed description and analysis of the amount and location of groundwater pumped by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), for the past five years from any groundwater basin from which the proposed project will be supplied. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.

(4) A detailed description and analysis of the amount and location of groundwater that is projected to be pumped by the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), from any basin from which the proposed project will be supplied. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.

(5) An analysis of the sufficiency of the groundwater from the basin or basins from which the proposed project will be supplied to meet the projected water demand associated with the proposed project. A water supply assessment shall not be required to include the information required by this paragraph if the public water system determines, as part of the review required by paragraph (1), that the sufficiency of groundwater necessary to meet the initial and projected water demand associated with the project was addressed in the description and analysis required by paragraph (4) of subdivision (b) of Section 10631.

(g) (1) Subject to paragraph (2), the governing body of each public water system shall submit the assessment to the city or county not later than 90 days from the date on which the request was received. The governing body of each public water system, or the city or county if either is required to comply with this act pursuant to subdivision (b), shall approve the assessment prepared pursuant to this section at a regular or special meeting.

(2) Prior to the expiration of the 90-day period, if the public water system intends to request an extension of time to prepare and adopt the assessment, the public water system shall meet with the city or county to request an extension of time, which shall not exceed 30 days, to prepare and adopt the assessment.

(3) If the public water system fails to request an extension of time, or fails to submit the assessment notwithstanding the extension of time granted pursuant to paragraph (2), the city or county may seek a writ of mandamus to compel the governing body of the public water system to comply with the requirements of this part relating to the submission of the water supply assessment.

(h) Notwithstanding any other provision of this part, if a project has been the subject of a water supply assessment that complies with the requirements of this part, no additional water supply assessment shall be required for subsequent projects that were part of a larger project for which a water supply assessment was completed and that has complied with the requirements of this part and for which the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), has concluded that its water supplies are sufficient to meet the projected water demand associated with the proposed project, in addition to the existing and planned future uses, including, but not limited to, agricultural and industrial uses, unless one or more of the following changes occurs:

(1) Changes in the project that result in a substantial increase in water demand for the project.

(2) Changes in the circumstances or conditions substantially affecting the ability of the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), to provide a sufficient supply of water for the project.

(3) Significant new information becomes available which was not known and could not have been known at the time when the assessment was prepared.

SEC. 5.

Section 10911 of the Water Code is amended to read:

10911.

(a) If, as a result of its assessment, the public water system concludes that its water supplies are, or will be, insufficient, the public water system shall provide to the city or county its plans for acquiring additional water supplies, setting forth the measures that are being undertaken to acquire and develop those water supplies. If the city or county, if either is required to comply with this part pursuant to subdivision (b), concludes as a result of its assessment, that water supplies are, or will be, insufficient, the city or county shall include in its water supply assessment its plans for acquiring additional water supplies, setting forth the measures that are being undertaken to acquire and develop those water supplies. Those plans may include, but are not limited to, information concerning all of the following:

(1) The estimated total costs, and the proposed method of financing the costs, associated with acquiring the additional water supplies.

(2) All federal, state, and local permits, approvals, or entitlements that are anticipated to be required in order to acquire and develop the additional water supplies.

(3) Based on the considerations set forth in paragraphs (1) and (2), the estimated timeframes within which the public water system, or the city or county if either is required to comply with this part pursuant to subdivision (b), expects to be able to acquire additional water supplies.

(b) The city or county shall include the water supply assessment provided pursuant to Section 10910, and any information provided pursuant to subdivision (a), in any environmental document prepared for the project pursuant to Division 13 (commencing with Section 21000) of the Public Resources Code.

(c) The city or county may include in any environmental document an evaluation of any information included in that environmental document provided pursuant to subdivision (b). The city or county shall determine, based on the entire record, whether projected water supplies will be sufficient to satisfy the demands of the project, in addition to existing and planned future uses. If the city or county determines that water supplies will not be sufficient, the city or county shall include that determination in its findings for the project.

SEC. 6.

Section 10912 of the Water Code is amended to read:

10912.

For the purposes of this part, the following terms have the following meanings:

(a) "Project" means any of the following:

(1) A proposed residential development of more than 500 dwelling units.

(2) A proposed shopping center or business establishment employing more than 1,000 persons or having more than 500,000 square feet of floor space.

(3) A proposed commercial office building employing more than 1,000 persons or having more than 250,000 square feet of floor space.

(4) A proposed hotel or motel, or both, having more than 500 rooms.

(5) A proposed industrial, manufacturing, or processing plant, or industrial park planned to house more than 1,000 persons, occupying more than 40 acres of land, or having more than 650,000 square feet of floor area.

(6) A mixed-use project that includes one or more of the projects specified in this subdivision.

(7) A project that would demand an amount of water equivalent to, or greater than, the amount of water required by a 500 dwelling unit project.

(b) If a public water system has fewer than 5,000 service connections, then "project" means any proposed residential, business, commercial, hotel or motel, or industrial development that would account for an increase of 10 percent or more in the number of the public water system's existing service connections, or a mixed-use project that would demand an amount of water equivalent to, or greater than, the amount of water required by residential development that would represent an increase of 10 percent or more in the number of the public water system's existing service connections.

(c) "Public water system" means a system for the provision of piped water to the public for human consumption that has 3000 or more service connections. A public water system includes all of the following:

(1) Any collection, treatment, storage, and distribution facility under control of the operator of the system which is used primarily in connection with the system.

(2) Any collection or pretreatment storage facility not under the control of the operator that is used primarily in connection with the system.

(3) Any person who treats water on behalf of one or more public water systems for the purpose of rendering it safe for human consumption.

SEC. 7.

Section 10913 of the Water Code is repealed.

SEC. 8.

Section 10915 of the Water Code is amended to read:

10915.

The County of San Diego is deemed to comply with this part if the Office of Planning and Research determines that all of the following conditions have been met:

(a) Proposition C, as approved by the voters of the County of San Diego in November 1988, requires the development of a regional growth management plan and directs the establishment of a regional planning and growth management review board.

(b) The County of San Diego and the cities in the county, by agreement, designate the San Diego Association of Governments as that review board.

(c) A regional growth management strategy that provides for a comprehensive regional strategy and a coordinated economic development and growth management program has been developed pursuant to Proposition C.

(d) The regional growth management strategy includes a water element to coordinate planning for water that is consistent with the requirements of this part.

(e) The San Diego County Water Authority, by agreement with the San Diego Association of Governments in its capacity as the review board, uses the association's most recent regional growth forecasts for planning purposes and to implement the water element of the strategy.

(f) The procedures established by the review board for the development and approval of the regional growth management strategy, including the water element and any certification process established to ensure that a project is consistent with that element, comply with the requirements of this part.

(g) The environmental documents for a project located in the County of San Diego include information that accomplishes the same purposes as a water supply assessment that is prepared pursuant to Section 10910.

SEC. 9.

Section 3.5 of this bill incorporates amendments to Section 10631 of the Water Code proposed by both this bill and AB 901. It shall only become operative if (1) both bills are enacted and become effective on or before January 1, 2002, (2) each bill amends Section 10631 of the Water Code, and (3) this bill is enacted after AB 901, in which case Section 3 of this bill shall not become operative.

SEC. 10.

No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because a local agency or school district has the authority to levy service charges, fees, or assessments sufficient to pay for the program or level of service mandated by this act, within the meaning of Section 17556 of the Government Code.

APPENDIX B

2022 GROUNDWATER SUSTAINABILITY PLAN – KERN GROUNDWATER AUTHORITY

2020 INTEGRATED WATER MANAGEMENT PLAN – TULARE LAKE BASIN PORTION OF KERN COUNTY

KERN

GROUNDWATER AUTHORITY



Groundwater Sustainability Plan

Kern County, CA

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Response to DWR Determination Letter

July 27, 2022

Mr. Paul Gosselin, Deputy Director
Department of Water Resources
Sustainable Groundwater Management Office
PO Box 942836
Sacramento, CA 94236-0001

RE: Submittal of Amended KGA Groundwater Sustainability Plan (GSP)

In response to the Statement of Findings regarding the Determination of Incomplete Status of the San Joaquin Valley – Kern County Subbasin Groundwater Sustainability Plans, State of California, Department of Water Resources, January 28, 2022

The Kern Groundwater Authority (KGA) Groundwater Sustainability Agency (GSA) is pleased to submit this Amended KGA Groundwater Sustainability Plan to the Department of Water Resources (DWR) for review. Amendments have been developed in response to the incomplete determination letter received on January 28, 2022, for the Kern Subbasin GSA pertaining to the 2020 Groundwater Sustainability Plans submitted for the Kern County Subbasin. DWR reviewed the Kern Subbasin GSPs as one plan including the Coordination Agreement (Water Code 10727), and as such all the Kern Subbasin GSAs coordinated and contributed to the responses and solutions as generally described herein with more detail that is relevant to the KGA as presented in this amended GSP as submitted.

Upon receipt of the determination letter, the Kern Subbasin GSAs including all members of the KGA, participated in weekly coordination meetings, along with coordination meetings between adjacent GSAs and KGA members, coordination meetings between adjacent KGA members, monthly Coordination Committee meetings, and monthly KGA Board meetings. At the monthly KGA board meetings, updates were provided to the stakeholders, beneficial users, and public as well as final draft documents that were provided in the board packages for review seeking input and comments. The KGA board meetings were/are available to attend either in-person or via Zoom. The KGA members also held their monthly board meetings with open public discussions on the status of how the response to the DWR determination letter was being developed and coordinated.

Another opportunity presented to assist in this process, DWR staff held several consultation meetings with the Kern Subbasin GSAs, which included the KGA is and was greatly appreciated by all participants. From those meetings and working collaboratively with all the Kern Subbasin GSAs, the KGA believes that the amended GSP along with all the other amended GSPs in the Kern Subbasin, will achieve and address the deficiencies identified in the determination letter. As stated in the DWR determination letter, the Kern Subbasin is the “largest and arguably most complicated Subbasin in terms of entities involved and demands placed on the Subbasin” (page 11). DWR’s understanding of the Kern Subbasin being the most complicated is quite the understatement considering that each water district has access to different surface water supply portfolios, which may include water from either the State Water Project, the Friant Water Project, the Central Valley

Project, the Kern River, or combination of these supplies. Then you take into consideration the largest subbasin and you then have different beneficial users in different areas with no two water districts having the same ration of beneficial users by management area. With having submitted the original GSPs in 2020 and now with two years of submitting annual reports and implementation of the GSPs moving forward, the DWR determination letter shed light on those areas back in 2018 & 2019, that the Kern Subbasin was struggling with however now, with the coordinated efforts along with better understanding, the KGA sees this as an opportunity to improve on their GSP and prepare for the 2025 update.

The DWR determination letter focused on three primary deficiencies and provided Corrective Actions for the Kern Subbasin GSAs to consider, coordinate and focus on:

1. *The GSPs do not establish undesirable results that are consistent for the entire Subbasin. Key issues include:*
    a) *The Coordination Agreement should be revised to explain how the undesirable results definitions are consistent with the requirements of SGMA and the GSP regulations, which specify that the undesirable results represent effects caused by groundwater conditions occurring throughout the Subbasin.*
    b) *The GSAs must commit to comprehensively reporting on the status of minimum thresholds exceedances by area in the annual reports and impacts to the beneficial users.*
    c) *The GSAs must adopt clear and consistent terminology to ensure various plans are comparable and reviewable by the GSAs, interested parties and DWR staff.*
2. *The GSAs must adopt clear and consistent terminology to ensure various plans are comparable and reviewable by the GSAs, interested parties and DWR staff. The Plan does not set minimum thresholds for chronic lowering of groundwater levels in a manner consistent with the requirements of SGMA and the GSP Regulations.*
    a) *For deficiency 2, DWR staff provided Table 2 that provided individual and helpful specific concerns and suggestive corrective actions for the GSAs and their members to address.*
    b) *All the GSPs must demonstrate the relationship between the minimum thresholds for each sustainability indicator.*
3. *The Plan's land subsidence sustainable management criteria do not satisfy the requirement of SGMA and the GSP regulations.*

    a) *The Subbasin's GSAs should coordinate and collectively satisfy the requirements of SGMA and the GSP regulations to develop the sustainable management criteria for land subsidence.*

Deficiency 1 - The GSPs Do Not Establish Undesirable Results that are Consistent for the Entire Basin

DWR indicated that this deficiency relates to the Plan's lack of an explanation of the specific effects, occurring throughout the Subbasin, that, when significant and unreasonable would be an undesirable result. DWR continues to state that this should be reflected in the framework of the Coordination Agreement thus the recommended corrective actions.

> *a) The Plan's Coordination Agreement should be revised to explain how the undesirable results definitions are consistent with the requirements of SGMA and the GSP Regulations, which specify that undesirable results represent effects caused by groundwater conditions occurring throughout the Subbasin.*

During the weekly coordinated GSA/KGA managers meeting, the following definitions were clarified and adjusted to be used by all GSA/KGA covering the entire basin. These definitions took into consideration the vast differences in the distribution of beneficial users between management areas, water right holders, hydrology, and day to day operations. These weekly meetings also accomplished confirming that all are using the same definitions to prevent further confusion as well as revising the monitoring protocols, and specifically addressing the process for determination of an undesirable result. The Coordination Agreement is reflective of these coordinated efforts in Appendix 3 and for ease, the definitions are listed below as well:

Kern Subbasin Definitions

Management Area: management Areas are areas that will be considered against the determination of an undesirable result at the basin level.

Watch Areas: areas with no significant groundwater use and no planned groundwater use as documented in the MAP. Watch areas will be monitored for land use changes and groundwater conditions that could change its designation to a "management area" with specified SMCs.

Monitoring Areas: areas that have significance within a Management Area for monitoring groundwater conditions or impacts to certain beneficial users but are not considered towards the determination of an Undesirable Result.

MT Exceedance: where a single representative monitoring well exceeds its minimum threshold.

MT Trigger: a management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events (Definition for Chronic Lowering of Groundwater).

Management Area Exceedance: exceeding the MT Trigger (i.e., 40% of wells) with a management area is a "management area exceedance", not an Undesirable Result which is defined at the basin level.

Undesirable Result: the basin-wide definition of unreasonable impacts to beneficial uses and users of groundwater. Should only be referred to as a basin-wide conditions and not a management area

condition. The equivalent designation at the management area is a "Management Area Exceedance."

Urban Management Area Exceedance*: A* management area exceedance is triggered when groundwater levels decline below established MTs in any RMW for more than three conservative months.

b) The GSAs must commit to comprehensively reporting on the status of minimum threshold exceedances by area in the annual reports and describe how groundwater conditions at or below the minimum thresholds may impact beneficial uses and users prior to the occurrence of a formal undesirable result.

The Kern Subbasin GSAs/KGA already are committed to comprehensively reporting on the status of minimum threshold exceedances by area in the annual report and to further describe how groundwater conditions may impact beneficial users and uses as well as providing in the annual report management actions/projects being implemented to correct or contain the exceedance. The Kern Subbasin GSAs/KGA have already submitted three annual reports with the exceedances addressed in the last two reports along with corrective actions to address. The Kern Subbasin/KGA's annual reports cover the entire basin and utilize a common methodology for determining demand and supply to update the C2VSim model use the same demand methodologies, water supply, and update the C2VSim model to provide an update basin wide status to assess how the basin is progressing towards sustainability.

The Kern Subbasin GSAs/KGA have also developed, designed, and released a data management system (DMS) that provides current seasonal data reflective by monitoring well locations for groundwater levels. This DMS also sends alerts when any GSA/KGA enters any seasonal data that exceeds the minimum thresholds so to alert all to the exceedance. The KGA has also developed an exceedance policy that prescribes immediate attention to an exceedance at a monitoring location (one exceedance triggers the KGA call to action process). Refer to the *KGA Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater* inserted into this letter on page 6.

c) The GSAs must adopt clear and consistent terminology to ensure the various plans are comparable and reviewable by the GSAs, interested parties, and Department staff. Department staff recommend the revisions should include, at a minimum:

- A map of the entire Subbasin showing each of the GSP areas, including management areas and the management areas within the management area plans, associated monitoring zones, etc. that have a locally defined "undesirable result" that can contribute to the Subbasin's undesirable result area-based definitions described in the Coordination Agreement.
- A comprehensive table or another organized form of identifying each of the areas, the land coverage – both absolutely and as a percentage – of each of those listed areas in comparison to the Subbasin in total, and a clear and concise description of the conditions that would cause the area to trigger a localized undesirable result (i.e., watch

area, etc.). These materials should demonstrate that 100 percent of the Subbasin area is being managed under the various GSPs with reasonable definitions for undesirable results.

In addition to the graphical and tabular representation of the definition of the Subbasin-wide undesirable results, and if the GSAs elect to maintain the percentage of land area definition for undesirable results, the GSAs need to provide a comprehensive description of the groundwater conditions that would lead to localized undesirable results in the GSAs and other management areas which ultimately contribute to the 15 percent or 30 percent of land area criteria.

Accomplished at the weekly coordination meetings, KGA developed the matrix below reflecting the triggers of an undesirable result as it relates to groundwater level exceedances and the process associated to handling an exceedance in management areas and how the basin enters an undesirable result for the entire basin. The KGA decided to take this process one step further by the development of an exceedance policy for just one exceedance and thus setting a "call to action" to avert beneficial uses and users impacts. The KGA developed sustainable management criteria that meets the GSP Regulations and enhances the process by including additional steps to better manage political, operational, and diverse demographic of beneficial user conditions found across the Kern Subbasin. This process is proactive in identifying individual MT Exceedances and intervenes before a Management Area Exceedance occurs and/or progresses to an undesirable result condition.

The complexity of groundwater management in the Kern Subbasin required that the KGA and other Subbasin GSAs coordinate this process that recognizes the diversity found across the Subbasin. The core of this process is the identification of key beneficial users within each management area and the conditions that create significant and unreasonable impacts to those beneficial users from groundwater operations in that management area.

KGA Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater

The Groundwater Sustainability Plans (GSPs) in the Kern County Subbasin (Subbasin) define sustainability under the Sustainable Groundwater Management Act (SGMA) as the avoidance of undesirable results. Undesirable results for the chronic lowering of groundwater occur when a certain number of minimum thresholds are exceeded at representative monitoring well sites. While a single or isolated exceedance of a minimum threshold will not, by itself, cause an undesirable result, such an exceedance may be indicative of future or trending exceedances which could result in undesirable results for chronic lowering of groundwater.

The Kern Groundwater Authority (KGA) GSP defines undesirable results within each Management Area Plan (MAP) developed by respective KGA members. Each KGA member is responsible for monitoring groundwater conditions, complying with GSP requirements and coordinating with other agencies and entities (cities, small systems, etc.) within their respective MAPs. The KGA also coordinates with its member agencies to facilitate SGMA compliance. As part of this coordination, the KGA works with other groundwater sustainability agencies (GSAs) in the Subbasin to compile an annual report and submit that report to the Department of Water Resources (DWR) each year on April 1. Information that reflects compliance with or exceedance of minimum thresholds is included in each annual report, if present.

It is important to monitor compliance with minimum thresholds over time to understand the Subbasin's likelihood of achieving sustainability. The following five-step action plan is proposed to address a minimum threshold exceedance for the chronic lowering of groundwater levels at a single representative monitoring well, including coordination between KGA member districts.

1. Identify Exceedance and Investigate the RMW Area

After each annual report, the KGA managers team will review data and identify any exceedances of minimum thresholds for each RMW and will compile a summary of minimum threshold exceedances, as noted in the annual report, for review by the KGA Board.

Various conditions surrounding the RMW will be considered. For example: Are water levels declining in nearby wells? If so, how large of an area is affected? Has a new well been installed nearby or localized groundwater extraction increased? Is the problem related to area-wide drought conditions? Has local demand increased? If increased demand is responsible for the exceedance, then is a sustainable water budget needed and/or being adhered to in the area?

2. Evaluate Outside MAP Contributing Factors

Provided the aquifer connectivity between MAP areas and groundwater impacts crossing MAP boundaries, declining groundwater levels in an area may be the result of operations in an adjacent MAP and/or an adjacent GSA. In this situation, the KGA member may not be able to resolve any

exceedances unilaterally. KGA members in adjacent MAPs agree to coordinate. Updates or proposals shall be reported back to the KGA.

3. Consider Developing Management Actions and/or Projects

Any KGA member with a minimum threshold exceedance may develop or modify existing management actions or projects to mitigate a minimum threshold exceedance and avoid undesirable results ("mitigation plan"). Any mitigation plan should be submitted to the KGA managers team for review. The mitigation plan along with any KGA managers team comments shall be submitted to the KGA Board. To the extent the mitigation plan includes any new management actions, any proposed modifications to an existing management action or new projects, the KGA will consider how those changes will be incorporated into any update to the KGA GSP.

4. Consider Enforcement Plan

In the event of a management area exceedance the KGA member or contributing member(s) will consider developing and/or implementing policies and programs intended to eliminate or mitigate the exceedance (enforcement plan). The enforcement plan(s) must be submitted to the KGA and the KGA will have 90 days to determine whether the enforcement plan is sufficient to demonstrate the avoidance of undesirable results. If no enforcement plan is submitted to KGA, the KGA Board may recommend policies or programs to the member(s) that could, in its discretion, take to remedy the existence of a management area exceedance(s) and to avoid undesirable results.

KGA Member Agencies are committed to managing groundwater levels at or above the MO. Groundwater elevations between the MO and MT provide operational flexibility that balances short-term water level declines due to drought conditions, while allowing access to previously banked surface water that provides a critical supply when local and imported surface waters are limited. To avoid undesirable results, each KGA Member Agency has committed to the following actions:

1. Manage groundwater levels in their respective management areas at or above the MO set for their Regional Monitoring Wells (RMW).
2. Manage to a water budget that will collectively eliminate the KGA Member Agencies deficit of 239,346 AFY by 2040 (see Section 2.4),
3. Implement projects and management actions identified in Section 4.0 of the KGA Umbrella GSP and further described in each MAP.

As described above and demonstrated in Figure 1, in the Kern Subbasin, Sustainable Management Criteria are more robust than the SGMA prescribed Undesirable Results, MO and MT. Sustainable management begins with early identification of potential minimum threshold exceedances and coordinated actions to address those early exceedances.

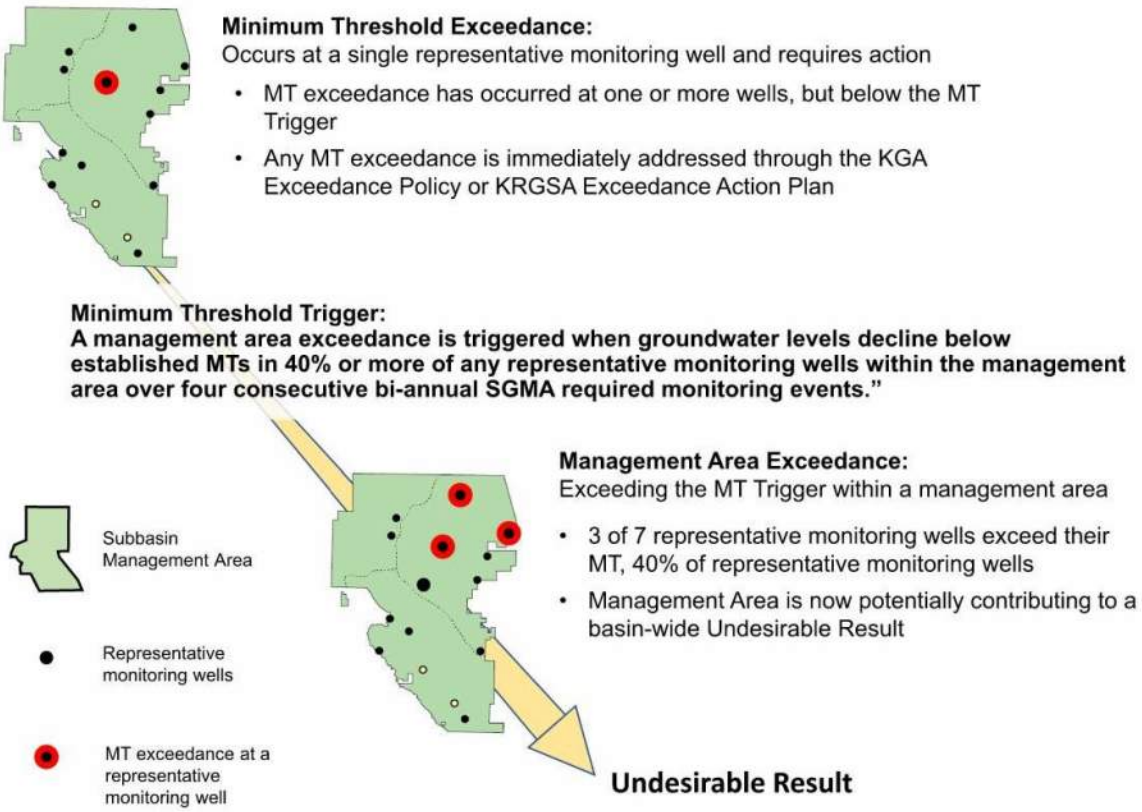


Figure 1. Process of Minimum Threshold Trigger to Undesirable Result

An undesirable result is a condition that occurs throughout the Subbasin, demonstrating that the Subbasin is not sustainably managing groundwater conditions in the aggregate and that impacts to beneficial users are occurring on a scale (spatially and temporally) that is significant and unreasonable to beneficial users and groundwater managers alike. However, the KGA recognizes that as groundwater approaches an undesirable result condition, exceedances of minimum thresholds will likely progressively occur in the absence of intervention, beginning with isolated exceedances which could impact beneficial users. Table 1 lists the KGA management areas and data used to calculate a management area exceedance and undesirable result which accounts for approximately 55% of the basin and does not include the management areas of the other GSAs; however, Figures 2 and 3 include all the management areas including the other GSAs.

Table 1. Number of Monitoring Wells that Trigger A Management Area Exceedance

KGA Management Area	# of Representative Wells	# of Well Exceedances to Trigger Management Area Exceedance Criteria	Acres in Management Area	Percentage of Subbasin
Cawelo GSA	7	3	62,616	3.5
Eastside Water Management Agency	6	2	38,222	2.1
Kern-Tulare Water District (in Kern)	6	2	11,219	0.6
North Kern WSD				
MA-1 (Old District)	8	4	61,741	3.4
MA-2 (RRID)	2	1	5,802	0.3
KCWA-Pioneer GSA	5	2	2,233	0.1
Kern Water Bank Authority	0	0	20,490	1.1
Rosedale-Rio Bravo WSD	19	8	48,610	2.7
Southern San Joaquin MUD	10	4	65,693	3.7
Shafter-Wasco Irrigation District	7	3	39,980	2.2
7th Standard Annex	3	2	10,045	0.6
Semitropic GSA				
MA-1 (Pond Poso)	6	2	82,638	4.6
MA-2 (Buttonwillow)	5	2	92,633	5.2
MA-3 (Undeveloped)	2	1	49,140	2.7
West Kern GSA				
North Project MA	6	2	521	0.0
South Project MA	17	7	889	0.0
Western Watch Area [1]	n/a	n/a	183,128	10.2
Lake Watch Area [1]	n/a	n/a	653	0.0
LSMV Watch Area [1]	n/a	n/a	1,947	0.1
Westside Districts Water Authority				
Westside District MA	3	1	195,263	10.9
Lost Hills Watch Area [1]	n/a	n/a	33,191	1.9
Southwest Watch Area [1]	n/a	n/a	48,739	2.7
Non-District White Lands Watch Areas [1]	n/a	n/a	210,034	11.7

1. "Watch Areas" are areas with no significant groundwater use and no planned groundwater use as documented by the management area member agency. Water areas will be monitored for land use changes and groundwater conditions which could change its designation to a "management area" with specified SMCs.

Defining the point of a Subbasin level undesirable result begins with a defined level of significant and unreasonable impacts to beneficial users, both spatially and temporally, within each management area of the Subbasin. The accumulation of impacts to beneficial users throughout the Subbasin, and across multiple management areas, representing a persistent and prevalent occurrence of impacts to beneficial users is considered an undesirable result.

For Chronic Lowering of Groundwater Levels, the Kern Subbasin has defined the occurrence of an undesirable result as the level of impacts affecting either:

- 15% of the Subbasin area, measured as the combined acres of three adjacent management areas with Management Area Exceedances, or
- 30% of the Subbasin area, measured as the combined acres of any management area with Management Area Exceedances.

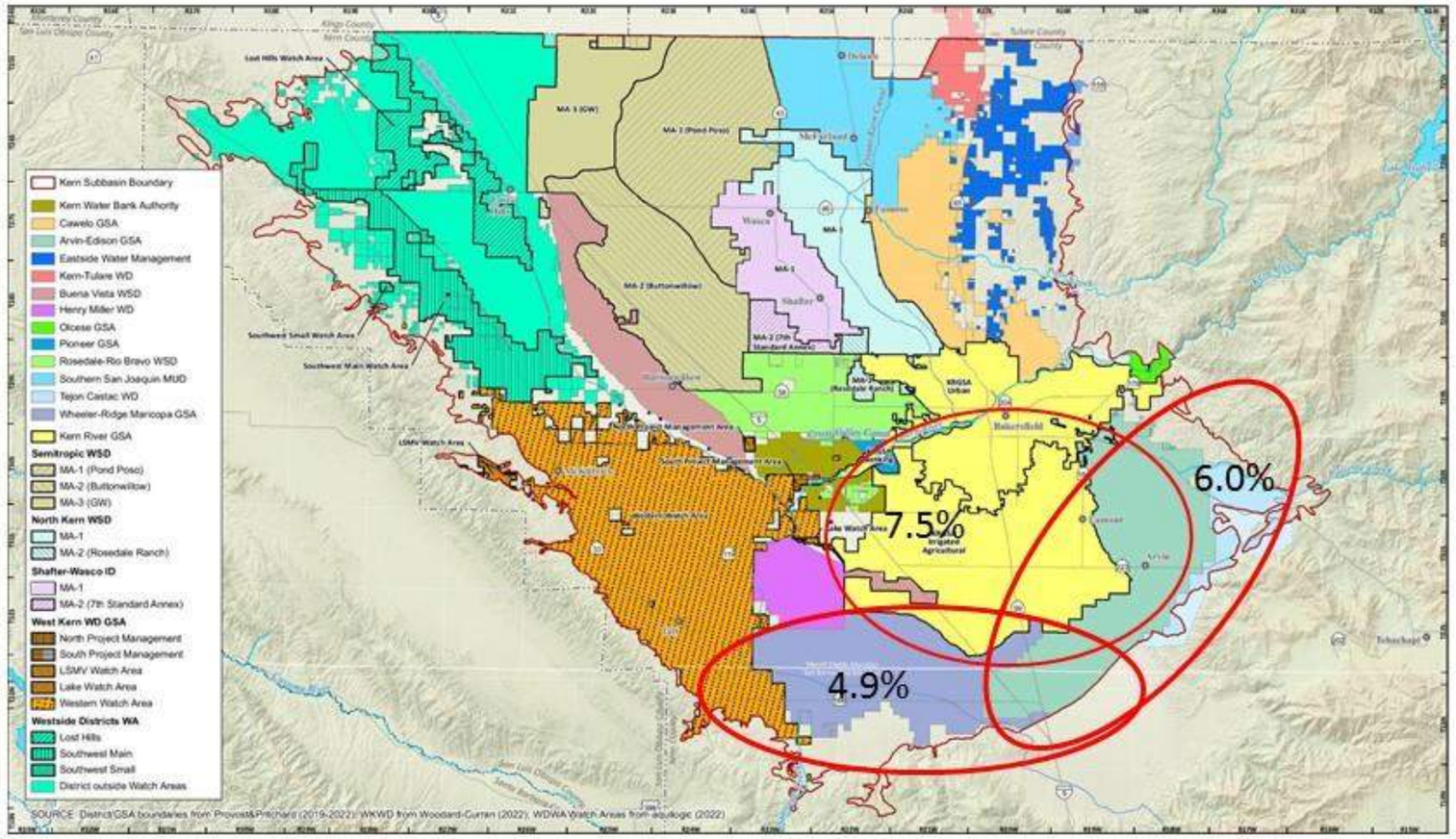
The criterion of three adjacent management areas of at least 15% of the Subbasin was developed to recognize a condition where degrading groundwater conditions from one management area spreads to adjacent management areas. This criterion recognizes that even the lesser percentage of the Subbasin (15%) as a contiguous area is significant with regards to the potential for further degradation of groundwater conditions across the Subbasin. The criterion of 30% of the Subbasin (generally non-contiguous management areas) recognizes a condition of widespread degradation of groundwater conditions across the whole of the Subbasin and across a diverse demographic of beneficial users, operational and geologic landscape.

Figure 2 provides an example of the occurrence of an undesirable result when Management Area Exceedances have occurred in at least three (3) adjacent management areas that represent at least 15% of the Subbasin (as measured by the acreage of each management area). In this example, Management Area Exceedances have occurred in three adjacent areas where the acreage totals more than 15% of the Subbasin total (defined in Section 3.3).

Figure 3 provides an example of the occurrence of the undesirable result criteria when Management Area Exceedances have occurred in greater than 30% of the Subbasin (as measured by the acreage of each management area). In this illustrative example, Management Area Exceedances have occurred in seven (7) separate management areas where the acreage totals more than 30% of the Subbasin total (defined in Section 3.3). This criterion recognizes a widespread occurrence of groundwater conditions across the whole of the Subbasin and across a diverse demographic of beneficial users, operational and geologic landscape.

Management Area	Acres	Percent of Subbasin
Cawelo GSA	62,616	3.5%
Eastside Water Management Area	38,222	2.1%
Kern-Tulare WD *(in Kern County)*	11,219	0.6%
North Kern WSD		
MA-1	61,741	3.4%
MA-2 (Rosedale Ranch)	5,802	0.3%
KCWA - Pioneer GSA	2,233	0.1%
Kern Water Bank Authority	20,490	1.1%
Rosedale-Rio Bravo WSD	48,610	2.7%
Southern San Joaquin MUD	65,693	3.7%
Shafter-Wasco ID		
MA-1	39,980	2.2%
MA-2 (7th Standard Annex)	10,045	0.6%
Semitropic GSA		
MA-1 (Pond Poso)	82,638	4.6%
MA-2 (Buttonwillow)	92,633	5.2%
MA-3 (Undeveloped)	49,140	2.7%
West Kern WD GSA		
North Project Management Area	521	0.0%
South Project Management Area	889	0.0%
Western Watch Area	183,128	10.2%
Lake Watch Area	653	0.0%
LSMV Watch Area	1,947	0.1%
Westside District WA		
Westside District WA	195,263	10.9%
Lost Hills Watch Area	33,191	1.9%
Southwest Watch Area	48,739	2.7%
Non-District White Lands Watch Areas	210,034	11.7%
South of Kern River Districts		
Arvin Edison WSD GSA	107,728	6.0%
Tejon Castac WD GSA	19,280	1.1%
Wheeler Ridge-Maricopa WSD GSA	87,391	4.9%
Kern River GSA		
KRGSA - AG	134,104	7.5%
KRGSA - Banking	5,045	0.3%
KRGSA - Urban	93,350	5.2%
Buena Vista GSA	50,414	2.8%
Henry Miller GSA	26,055	1.5%
Olcese GSA	3,206	0.2%
TOTALS:	1,792,000	100.00%

"..least three (3) adjacent management areas that represent at least 15% of the Subbasin ..."

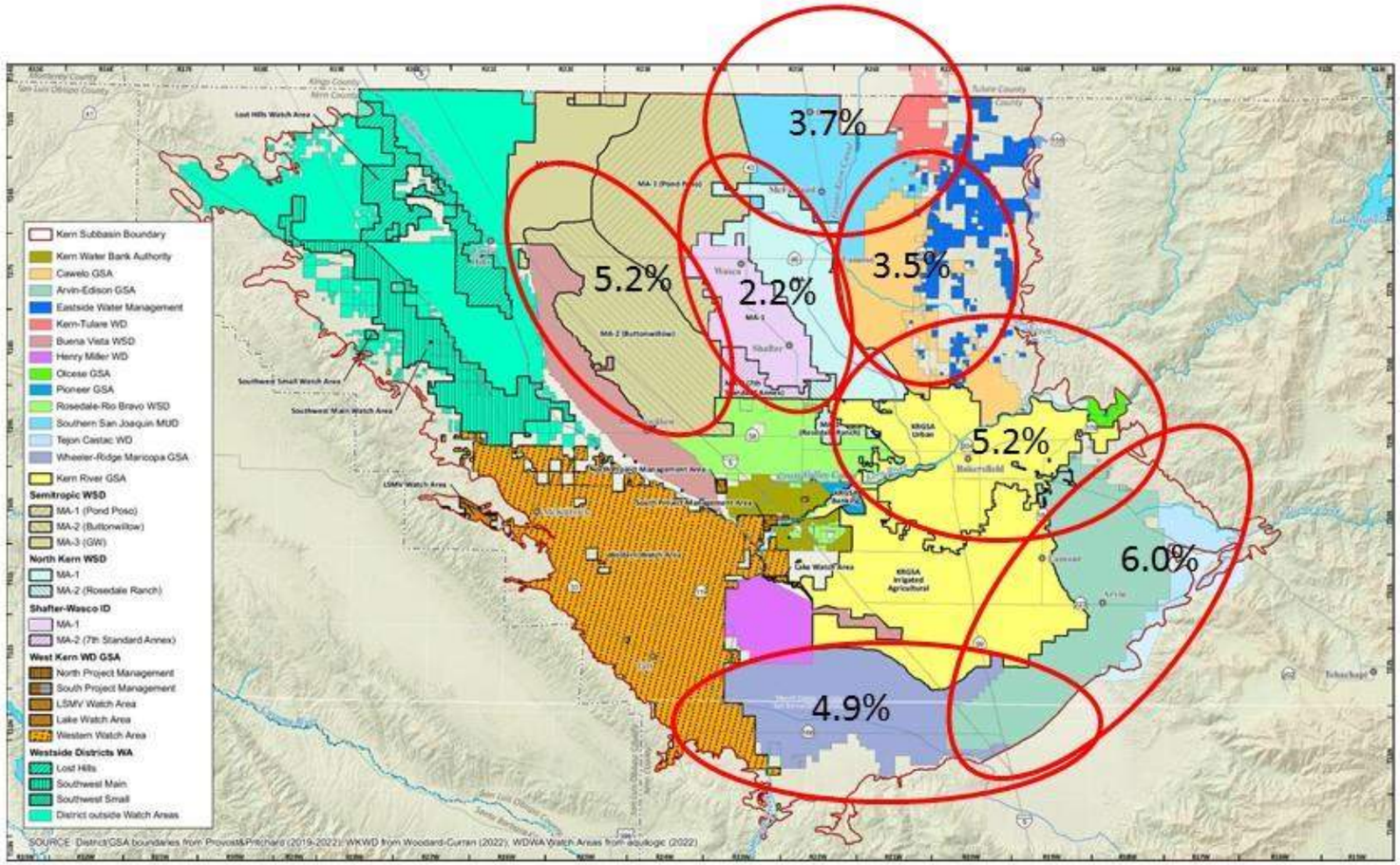


18.4 % of the Subbasin

Figure 2. Example of Undesirable Results Criteria for 15% of Adjacent Management Areas

Management Area	Acres	Percent of Subbasin
Cawelo GSA	62,616	3.5%
Eastside Water Management Area	38,222	2.1%
Kern-Tulare WD *(in Kern County)*	11,219	0.6%
North Kern WSD		
MA-1	61,741	3.4%
MA-2 (Rosedale Ranch)	5,802	0.3%
KCWA - Pioneer GSA	2,233	0.1%
Kern Water Bank Authority	20,490	1.1%
Rosedale-Rio Bravo WSD	48,610	2.7%
Southern San Joaquin MUD	65,693	3.7%
Shafter-Wasco ID		
MA-1	39,980	2.2%
MA-2 (7th Standard Annex)	10,045	0.6%
Semitropic GSA		
MA-1 (Pond Poso)	82,638	4.6%
MA-2 (Buttonwillow)	92,633	5.2%
MA-3 (Undeveloped)	49,140	2.7%
West Kern WD GSA		
North Project Management Area	521	0.0%
South Project Management Area	889	0.0%
Western Watch Area	183,128	10.2%
Lake Watch Area	653	0.0%
LSMV Watch Area	1,947	0.1%
Westside District WA		
Westside District WA	195,263	10.9%
Lost Hills Watch Area	33,191	1.9%
Southwest Watch Area	48,739	2.7%
Non-District White Lands Watch Areas	210,034	11.7%
South of Kern River Districts		
Arvin Edison WSD GSA	107,728	6.0%
Tejon Castac WD GSA	19,280	1.1%
Wheeler Ridge-Maricopa WSD GSA	87,391	4.9%
Kern River GSA		
KRGSA - AG	134,104	7.5%
KRGSA - Banking	5,045	0.3%
KRGSA - Urban	93,350	5.2%
Buena Vista GSA	50,414	2.8%
Henry Miller GSA	26,055	1.5%
Olcese GSA	3,206	0.2%
TOTALS:	1,792,000	100.00%

"... greater than 30% of the Subbasin (as measured by each management area)."



30.7 % of the Subbasin

Figure 3. Example of Undesirable Results Criteria for 30% of Subbasin

Deficiency 2 – The Plan does not set minimum thresholds for chronic lowering of groundwater levels in a manner consistent with the requirements of SGMA and the GSP regulations

DWR staff's review of the Plan indicated that the approaches used and the level of analysis to support those approaches, is disparate across the various management area plans. Thus, DWR staff developed Table 2.

a) For deficiency 2, DWR staff provided Table 2 that provided individual and helpful specific concerns and suggestive corrective actions for the GSAs and their management areas to address.

The Kern Subbasin GSAs held the weekly meetings to coordinate responses to the deficiencies identified in Table 2. During one of the consultation meetings, a matrix which generally describes each entities response to the specific deficiencies identified was presented, DWR staff indicated that the Kern Subbasin was moving in the right direction however needed to explore impacts to all beneficial users and uses as well as addressing what was being avoided by the actions. Please see the table presented below but note that the information in the table below is only a summary of the discussion and response to the DWR Table 2 and to understand more specific information, the management area plans provide greater details.

The KGA moved forward in exploring the impacts to their beneficial users and uses as well as considering the impacts to those adjacent GSAs. The KGA also explored what was being avoided by their actions of managing to the measurable objectives. The members of the KGA all agreed that they were and are working to avoid the impacts or unmitigated dewatering of municipal and domestic wells while balancing the impact to the agricultural beneficial users in their respective management areas since most, if not all, of the KGA members have more agricultural users than municipal and domestic users. They continued by analyzing water wells depths which was the original justification for the setting of their SMCs. See table 3 for the breakdown of beneficial users and uses in each KGA management area as well as how or if any impacts will occur with the current SMCs set. If there is an impact, see the note about how each KGA member will or has developed a mitigation plan/strategy for impacts.

The KGA members also have agreed that they are managing to their measurable objectives and are managing to their water budgets (checkbook). They have also agreed that if there is more than a 5% of dewatering of wells in their management area, a mitigation plan will or is already developed. This is also explained in great detail in their individual management area plans.

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Table 2a. KGA Management Area Responses to Deficiency 2, Table 2

KGA Management Area	Summary of DWR Plan Interpretation	DWR Suggested Corrective Action	Proposed Response	Coordination with Neighboring Districts
Areas Outside of Management Areas	The KGA GSP provides little information on the characteristics of non-management-area portions of its GSP area and does not appear to set any sustainable management criteria for these areas. The table of page 297 of the Coordination Agreement indicates that non-districted lands account for 18,013 acre-feet per year of total demand, which Department Staff note is a larger volume than occurs in many of the areas covered by the management area plans.	Provide a comprehensive discussion of areas covered by the KGA GSP, but that are not contained within the various management area plans. Among other items, provide maps of these areas, describe the uses and users or groundwater in these areas, and either set sustainable management criteria for these areas or include robust discussions justifying why sustainable management area are not required.	The KGA Umbrella already has a description of the non-districted lands in the Umbrella with maps of those areas however at the time of the GSP submittal, the KGA Board's approach was to remove those lands from the GSA if the landowner was not or had not signed on with a management area (KGA member). Now the direction provided by the KGA Board is to retain all lands and continue to monitor (watch) those lands. Since the very first submittal of the annual reports, the non-districted lands have been included and that will continue. Most of the non-districted lands have oil and grazing activities and those irrigated acres have been reduced with the annexation of the 7th Standard area into the Shafter-Wasco Irrigation District, the establishment of the Eastside Water Management Area and landowners signing agreements with KGA members to be covered by their MAP. The Umbrella will be updated to reflect the direction of the KGA Board, updating of the map reflecting the only those non-districted lands left as well as a map reflecting the lack of water wells in the area of activities of oil and grazing. The Umbrella will also have a "robust" discussion as to the justification of having the non-districted area as a "watch area" which will be also with maps reflecting oil field locations and water quality not conducive to irrigation of crops.	KGA members that are adjacent to those non-districted lands where there exists beneficial uses and users, which are very limited areas, considered them as they were setting their SMC and continue to consider as they manage under SGMA.
Cawelo GSA	The KGA GSP Cawelo management area established minimum thresholds for chronic lowering of groundwater levels based on the conditions experienced over the past 10 years. The minimum threshold is set 80 feet below the historic low between 2007 and 2016. Cawelo states that most wells have been drilled deeper and undesirable results associated with drought are unlikely. While it appears during a meeting held in 2019, Cawelo received a presentation on impacts to wells given various minimum thresholds, a discussion of impacts to beneficial uses and users of the adopted minimum thresholds is not provided.	The KGA GSP must describe how the minimum thresholds in the Cawelo management area may affect the interests of beneficial uses and users of groundwater or land uses and property interests.	The Cawelo MAP is attempting to avoid significant and unreasonable impacts to a significant number of private, agricultural, industrial, domestic and/or small water system wells due to the management and use of groundwater under SGMA that would cause these wells to either be unable to continue to supply water for their intended beneficial use or incur significant economic impacts to continue operation of the well. The Cawelo MAP identified 76 small water system or private groundwater wells and 197 agricultural and industrial water supply wells. Five community and 12 non-community small water systems were identified that provide water for residential or institutional use. The largest of these is the Kern County Sheriff's Lerdo Detention Facility which houses up to 2,300 inmates and up to 500 employees. A well completion analysis was conducted that compared the MT from the nearest RMW to the well screen interval and saturated thickness for 290 water supply wells. The analysis indicates that most wells in the Cawelo MAP are constructed sufficiently deep to accommodate the MTs in all but 3 (3%) of the domestic and small water system wells and 1 (<1%) of the agricultural and industrial wells being potentially vulnerable. The four community water systems were considered to be completed sufficiently deep so as to accommodate the MTs in their areas. Furthermore, to address DWR's comment "cc" in Table 2 of the Final Determination Letter, the Cawelo MAP will develop a summary table identifying for each sustainability indicator, the respective beneficial users / uses considered, potential effects to beneficial users / uses, summary of undesirable result causes, local undesirable result criteria / definition, justification for the local undesirable result criteria / definition, minimum threshold(s) definition, justification for the minimum threshold(s), and measurable object definition. The minimum threshold(s) definition will include a summary of how the conditions will avoid undesirable results for the other sustainability indicators.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s). Cawelo GSA coordinated the Cawelo MAP RMW MTs with neighboring MAP RMW MTs. During the coordination no recommended MT adjustments were identified. Cawelo GSA will continue to coordinate with neighboring GSAs / MAPs to identify potential future issues. Other Cawelo MAP revisions that demonstrate coordination will include: • Addition of the KGA Exceedance Policy as the first Management Action in the MAP, to be implemented immediately. • Documenting the well impact analysis was used to identify potential impacts to beneficial users / uses consistent with KGA MAPs. Addition of a Domestic Well Mitigation Program to be considered by the Cawelo GSA Board, if deemed necessary and appropriate, to assist in offsetting costs for domestic well issues related to dewatering of pumps and/or well screens to the point of significant reduction in production.

Eastside Water Management Area	While it appears that Eastside is protective of dewatering wells, all the minimum thresholds are below historical lows and the impacts of the established minimum thresholds for chronic lowering of groundwater levels on beneficial uses and users are not discussed. Eastside is aware that there are domestic wells within the management area; however, "the full extent and distribution of active domestic wells within the Management Area is currently unknown".	The KGA GSP must describe how the minimum thresholds in the Eastside management area may affect the interests of beneficial uses and users of groundwater or land uses and property interests.	The EWMA will perform a well impact analysis to describe potential impacts to beneficial users. The analysis will artificially drop water levels to the minimum thresholds for RMWs and review potential impacts to ag and domestic wells in an area of influence at each RMW. The EWMA's beneficial users consist primarily of ag/production wells, a number of domestic wells and one municipal well. The EWMA will ensure well information in the analysis includes all current, publicly available data.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s).
Kern Water Bank Management Area	The KGA GSP Kern Water Bank management area can only recover groundwater that has previously been stored minus losses that have been applied. The Kern Water Bank states that "[a]n extensive Mitigation Monitoring Reporting Program (MMRP) has been developed by DWR for the KWB Storage Project that reduces impacts from operations to less-than significant, and undesirable results are not present or are not likely to occur." It is acknowledged that pumping operations can cause lowering of groundwater levels in adjacent areas and threshold water levels have been established in the Joint Operation Plan. The threshold water levels in the Joint Operation Plan are based on DWR KWB Model and a model developed by Rosedale-Rio Bravo Water Storage District. "When the With-Project conditions are fifteen (15) or forty-five (45) feet deeper than the Without-Project conditions at any operative domestic or agricultural well, respectively, and mechanical failure or other operational problems have occurred or are reasonably likely to occur due to declining water levels, mitigation will be provided …" The 15-foot threshold is essentially the point when the projects have had a discernable influence on Domestic/Small Community users. The 45-foot threshold for Agricultural users recognizes the significant economic benefits resulting from higher groundwater elevations provided by the projects through time, and that agricultural wells in the area are completed to greater depths.	While the Department understands the unique circumstances with the Kern Water Bank, compliance with SGMA and the GSP Regulations is still a requirement and while the thresholds established in the Joint Operation Plan are being utilized to meet these requirements, all parts of the GSP Regulations related to the sustainable management criteria must be addressed. The KGS GSP must provide an explanation of how the Join Operation Plan meets the requirements of SGMA and the GSP Regulations. It is also noted that the Joint Operation Plan expired on January 31, 2019. Provide an updated explanation if these thresholds have changes and the latest Joint Operation Plan if applicable.7th	The Joint Operations Plan protects beneficial users impacted by lowered water levels resulting from KWB operations with the 15- and 45-foot triggers. The Plan has been renewed through 2023 and thresholds have not changed. If the Joint Plan is not renewed at some point in the future, the KWB Long-term Plan will take precedence. The KWB can only recover water stored previously, so KWB operations cannot cause a reduction of native groundwater supplies. Therefore, the "threshold" for a reduction of native groundwater supplies for the KWBA is when stored water accounts (less prescribed losses) are zero. The objective of the water quality measures in the KWB MOU is to export more salt than is imported by storage operations and the threshold is to maintain a positive salt balance. The objective of the mitigation measures in the DWR MMRP is to identify and mitigate as necessary potential threats to water quality that may be discovered on KWB lands such that potential impacts will be less-than-significant. The objective of the Pump-in Policy and Improvement District 4 standards is to minimize impacts to water quality in the Cross Valley Canal and Aqueduct and the threshold is to meet these requirements through modifications to recovery pumping if necessary. InSAR and extensometer data indicates inelastic subsidence has not occurred during 27 years of operations. KWBA will continue to monitor both InSAR data and extensometer data and develop thresholds and management actions should inelastic subsidence develop in the Kern Fan area.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s). In addition, the Kern Water Bank MOU, which has been negotiated with adjoining groundwater stakeholders, prescribes groundwater quality thresholds.

Kern-Tulare Water District	The management area plan states that chronic lowering of groundwater levels is the major cause of undesirable results for reduction in groundwater storage and land subsidence. Kern-Tulare management area plan utilized historical groundwater level data from 2006 to 2018 for wells perforated at the Santa Margarita Formation and projected out the trendline to 2040. These values ranged from -120 to -190 feet mean sea level. The district then selected -150 feet msl as the minimum threshold for each of the well sites. The lowest groundwater level the management area has experienced is -51.8 feet. The Kern-Tulare management area plan states that "water users within the District are the predominant users of the Santa Margarita Formation" and that minimum thresholds may impact groundwater users within the management area by requiring an overall reduction in groundwater pumping to ensure the minimum threshold is met; however, no discussion is provided describing the impacts to beneficial uses and users.	The KGA GSP must provide an explanation of how minimum thresholds within the Kern-Tulare management area at the monitoring sites are consistent with the requirement to be based on a groundwater elevation indicating a significant and unreasonable depletion of supply at a given location. If the minimum thresholds were not set consistent with levels indicating an undesirable depletion of supply, the thresholds should be revised accordingly. Provide a discussion identifying how the minimum thresholds may affect the interests of beneficial uses and users of groundwater or land uses and property interests.	In order to develop the minimum threshold, the District initially started with the lowest water surface elevation experienced historically in the Santa Margarita Formation (SMF) which occurred during the peak of the drought in August 2015 at -52 ft msl. Landowners did not have any significant or unreasonable impacts occur at this level. Next, the District discussed SMCs with the Eastside Water Management Area (EWMA) who are adjacent to and upslope of the District and also rely upon the SMF. EWMA wells are shallower and will go dry before wells in the District. EWMA established minimum thresholds at each individual well site based on the allowance of drawdown to 20% of the saturated water column height above the bottom of the well and was increased on a well-by-well basis to take into account the amount of head above the existing pump intake. EWMA had determined that the minimum threshold required in a representative monitoring well on the eastern border of the District (Well 04) that extracts groundwater out of the SMF should be set at -133 ft msl. Based on landowner feedback and coordination with EWMA, the minimum threshold for groundwater elevation in wells perforated to the SMF was set at -150 ft msl which ranges as a depth to water from about 600 to 830 ft. At this elevation, no agricultural wells perforated to the SMF will go dry. Agricultural users are the only beneficial users of the SMF. The minimum threshold prevents continued lowering of groundwater elevations which may impact agricultural users that do not have access to water supplies other than groundwater. All domestic wells within the District are drilled to depths of less than 700 ft and do not reach the SMF (1800-2400 ft bgs). As shown in Figure 2-17 of the KTWD MAP Basin Setting, groundwater levels in the upper aquifer that supplies the domestic wells are either stable or rising.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s).
North Kern WSD/ Shafter-Wasco ID	The KGA GSP North Kern/Shafter-Wasco management area plan identifies three management areas, two managed by North Kern WSD and the third managed by Shafter-Wasco ID. In looking at Figure 3-2, management area NKWSD-MA-2 does not have minimum thresholds established. A well impact analysis of the equivalent minimum threshold average values (represented as depth to groundwater) for each HZ was used to determine that a portion of the existing wells are impacted to varying extents. Based on results of the well impact analysis, the management area plan states that is can be assumed many wells will remain operational and that water levels can drop without causing undesirable results which cannot be mitigated. Agricultural wells would be mitigated by landowners. While the management area plan states that mitigation to domestic wells would be necessary, there is no mention of who would implement the mitigation effort.	The KGA GSP must establish sustainable management criteria for management area NKWSD-MA-2. The KGA GSP must be revised to explain how minimum thresholds within the North Kern Water Storage District/Shafter-Wasco Irrigation District management area at the monitoring sites are consistent with the requirement to be based on a groundwater elevation indicating a significant and unreasonable depletion of supply at a given location. If the minimum thresholds were not set consistent with levels indicating an undesirable depletion of supply, the thresholds should be revised accordingly. Verify how the subset of wells used in the well impact analysis is representative of wells in the management area. Provide an explanation of the mitigation plan for domestic wells.	North Kern Water Storage District has identified two representative monitoring wells for MA-2 (Rosedale Ranch). A well impact analysis was conducted, MOs and MT were established with consideration for potential impacts to beneficial users and coordination with surrounding RMWs. A description will be provided to explain how the quantity above fresh water is so substantial that depletion of supply is not a significant issue in the Kern County Subbasin and that groundwater levels at the MT are protective of groundwater in storage. In each management area, the quantity of water that exists between March 2020 water levels and MT's will also be calculated, to show the correlation between the water budget and the MT depths. An updated Well Impact Analysis was conducted using DWRs Well Completion Report database. The MAP will be updated with the current analysis that is consistent with assumptions and methodology used by neighboring districts and demonstrate how wells are representative. The Well Impact Analysis was used to determine MOs and MTs for RMWs avoiding significant and unreasonable impacts to municipal wells and mitigated domestic wells. MOs and MTs could be further to reduce the number of other beneficial users impacted and/or better coordinate with surrounding RMWs.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s). In addition to using the well impact analysis, setting SMCs for the two new RMWs in RRID included interpolating a coordinated level based on RMW's along a north-south and east-west line. This method included wells from KRGSA, RRB, SWID, and CWD. A coordinated MO and MT was selected. MTs for wells in the southern portion of NKWSD and SWID were raised 50 ft to reduce impacts to beneficial users and to coordinate with neighboring districts. Corresponding MOs were also raised. Through coordination meetings, it was recommended that KRGSA lower the MT by 30 ft. at their nearby wells. Other changes that demonstrate coordination will include: – Adding KGA Exceedance Action Plan as a Management Action – Documenting the methodology used for the Well Impact Analysis is consistent with KGA Member Agencies – Implementing a Domestic Well Mitigation Program as a Management Action

Kern County Water Agency Pioneer GSA Management Area	The Pioneer management area minimum thresholds are "calculated for each representative well by using the difference between the historical maximum and minimum values, calculating 20 percent of that range and subtracting the 20 percent value from the historical minimum value." However, the management area provides no further information or description (e.g., details of the well and pump information) for beneficial uses and users. Based on Table 7-1, it appears the minimum threshold represents a substantial reduction in groundwater levels relative to recent (i.e., 2011-2019) levels, which, at their lowest point, appear to be just over 250 feet below ground surface. Without any further description provided in the management area plan, Department Staff cannot assess whether the minimum thresholds are reasonable and substantially comply with GSP Regulations.	The KGA GSP must explain the selection of groundwater level minimum thresholds for the Pioneer management area, including how they represent site-specific levels of depletion that could cause undesirable results, how they may affect the interests of beneficial uses and users of groundwater, and the relationship between this sustainability indicator and other sustainability indicators such as degradation of groundwater quality and subsidence, both of which can be exacerbated by lowering groundwater levels.	1. The Pioneer GSA has calculated and set thresholds to provide operational flexibility and maintain long-term sustainability for the beneficial uses and users of groundwater within its MAP Area. As the sole beneficial user of groundwater in the MAP, the Pioneer Participants were consulted during the GSP development process to ensure thresholds and undesirable results criteria accurately represented the quantitative and qualitative conditions as directed by SGMA regulations. The Pioneer Participants have determined that groundwater level and groundwater storage conditions that would be expected at a MT Trigger would represent undesirable conditions for their normal and sustainable banking operations. These conditions include increased operation costs due to increased energy requirements for pumping deeper water, lowering pumps, and additional operational maintenance requirements. 2. MTs were set in the Pioneer Management Area to allow for an appropriate margin of operational flexibility for the sustainable operation of the Pioneer Project (the sole beneficial use). Through coordination efforts, neighboring GSAs' MTs and MOs were also taken into consideration to ensure protection of nearby beneficial uses and users outside of the Pioneer Management Area (as discussed further in Section 1.5, Existing Water Management Programs). In addition, a spatial analysis of MTs and water level trends was performed to ensure relative consistency between the MTs of the Pioneer Management Area and those set in adjacent management areas, and no conflicts or issues between Pioneer and its neighbors were identified. 3. An analysis of historical groundwater quality and groundwater level data was performed to estimate groundwater quality if groundwater level minimum thresholds were to be reached. Results of the analysis show that no groundwater quality thresholds are expected to be exceeded at the minimum thresholds. This analysis demonstrates that the minimum thresholds will not negatively impact groundwater quality in the Pioneer MAP Area and will not negatively impact Pioneer Project operations (the sole beneficial use). The Pioneer GSA will continue to monitor groundwater levels and groundwater quality to ensure the historically observed trend does not change under future conditions. MTs were set to mitigate the potential for land subsidence by relying on the Pioneer Project's current and historical sustainable management of groundwater levels, noting that no undesirable results with respect to land subsidence have been identified historically and that subsidence elastically responds to groundwater banking operations in the Pioneer Project GSA Area.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s). The Pioneer GSA has coordinated with neighboring GSAs (Rosedale-Rio Bravo Water Storage District and the Kern Water Bank Authority) regarding the thresholds; no conflicts or issues were identified. Ongoing coordination with both agencies will continue through the Joint Operating Plan and the Kern Fan Monitoring Committee MOUs (as described in Section 1.5, Existing Water Management Programs). The Pioneer GSA has coordinated with Kern River GSA (KRGSA) regarding the thresholds; no conflict or issues were identified. Ongoing coordination with the KRGSA will continue as described in Section 1.5, Existing Water Management Programs.

Rosedale-Rio Bravo Management Area	Rosedale Rio Bravo conducted an analysis of the economic impacts of continued groundwater lowering, examining the costs for each 25-foot increment of lowering, and concluded that any "additional reinvestment in groundwater facilities [beyond those already experienced] …would be deemed an undesirable result." Therefore, groundwater level thresholds are set at the low point of the last drought. The management area plan states that they would consider an undesirable result to occur if two of either the North, Central, or South of the River Zones exceed their thresholds, or if the threshold was exceeded in any of the South or East Zones. Why thresholds are allowed to be exceeded in one of the North, Central, or South of the River zones without agency considering that to trigger an undesirable result was not adequately explained. Adequate explanation is also lacking regarding whether the triggering of an undesirable result in any of these zones trigger the entire Rosedale Rio Bravo management area to become an undesirable result watch area, or if only the area of the triggering monitoring zone(s) would contribute to the Subbasin-wide tracking of undesirable results.	The KGA GSP must provide clarification regarding why minimum threshold exceedances are allowed to occur in one of the North, Central, or South of the River zones for this management area (i.e., why it takes two of those zones to exceed their threshold before the management area plan considers an undesirable result to have occurred). Describe any projects or management actions that may be implemented if the minimum threshold is exceeded in one of those areas and users are impacted but an undesirable result is not triggered.	RRBMA will include all the monitoring areas into one singular Management Area. While the monitoring areas will remain the **KGA coordinated triggers will be applied to the whole of the RRBMA (MA)**. The monitoring areas are strictly geographical areas that will be utilized to provide the RRBMA with data and information pertaining to each sustainability criteria and the corresponding to unique beneficial uses within each monitoring area. RRBMA conducted additional well impact analysis analyzing the number, percentage, age, and type of wells that would be impacted at a revised MT of 50' and 75' below the low point of the last drought. The MT was revised to approximately 50' below the historical low point considering the number of domestic wells that may require replacement (less than 3). These wells would be mitigated by existing mitigation requirements with the RRBMA or by proposed adaptive management actions (see section 7.5).	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and that maintain groundwater elevations at or above the measurable objectives in each member agency's Management Area. To provide clarity and to better coordinate with neighboring MA's, RRBMA prepared multiple groundwater level and MT cross-sections in the general direction of groundwater flow and crossing multiple MA's. MT's and MO's were compared and adjusted to the projected water levels for consistency across the coordinating MA's. RRBMA coordinated groundwater level MO's and MT's with the following GSA's and MA's: 1. Buena Vista WSD GSA 2. Kern Groundwater Authority GSA a. North Kern Water Storage District b. Shafter Wasco Irrigation District c. 7th Standard Annex d. West Kern Water District e. Pioneer Project 3. Kern River GSA a. Improvement District No. 4
Semitropic GSA	The KGA GSP Semitropic Water Storage District management are plan further divides the management area into three management areas. In comparing the map of the monitoring well sites (Figure 3-1) and Table 3-1 which summarizes the minimum thresholds, Department staff were not able to correlate the two. The management area plan states that there are thresholds for the upper zone wells in Appendix B-3; however, Department staff could not locate this appendix and it is not clear how these thresholds were established, and the location of the monitoring sites assigned these minimum thresholds. A well impact analysis of the equivalent minimum threshold average values (represented as depth to water values) for each HZ was used to determine that a portion of the existing wells are impacted to varying degrees. Based on results of the well impact analysis, the management area plan states that is can be assumed many wells will remain operational and that water levels can drop without causing undesirable results which cannot be mitigated. Agricultural wells would be mitigated by landowners. While the management area plan states that mitigation to domestic wells would be necessary, there is no mention of who would implement the mitigation effort.	The KGA GSP must explain the selection of groundwater level minimum thresholds for the Semitropic Water Storage District management area, including how they represent site-specific levels of depletion that could cause undesirable results and the relationship between this sustainability indicator and other sustainability indicators such as degradation of groundwater quality and subsidence, both of which can be exacerbated by lowering groundwater levels. If minimum thresholds were not set consistent with levels indicating a depletion of supply, the minimum thresholds should be revised accordingly. Reconcile Figure 3-1 and Table 3-1 to utilize the same well naming convention so that Department staff and other interested parties may correlate the two. Verify how the subset of wells used in the well impact analysis is representative of wells in the management area. Provide an explanation of the mitigation plan for domestic wells.	The SWSD MAP utilized a well impact analysis for determination of impacts to beneficial users present in its three management areas for the lowering of groundwater levels. This analysis included the level of impacts at various levels of performance above the MT, including the MO. Additional description and analysis will be presented in the MAP to clearly show levels of impacts to beneficial users from current water levels down through the MO and MT levels. While the SWSD MAP included a thorough analysis of water quality, additional descriptions will be included to show the relationship between water quality and groundwater levels. While the linkage is not as well defined for subsidence, the SWSD MAP will include an expanded discussion, which will also be consistent with the Subbasin wide approach to subsidence. Figure 3-1 and Table 3-1 will be updated as appropriate. Additional descriptions of the well impact analysis will be included to describe the wells used for the well impact analysis and their representation of the wells within the three SWSD GSA management areas. The SWSD GSA is developing a mitigation program, and a complimentary funding program, for the appropriate mitigation of impacts to domestic wells. These will be described in the SWSD MAP.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s). RRB: Incorporated comments from RRB as noted: - Edits to Management Action 2 to more closely align with RRB's water budget and charges program - Added additional RMW's to management area adjacent to RRB - Added KGA Exceedance Policy as Management Action - Added Domestic Well Mitigation as Management Action SWID/NK: Discussions regarding beneficial users and well impact analysis BV, Westside, Wheeler, Henry Miller: Coordination regarding development of SMC for subsidence relative to California Aqueduct

SWID 7th Standard Annex	The KGA GSP Shafter-Wasco Irrigation District management area calculates the minimum thresholds for chronic lowering of groundwater levels by "projecting a theoretical future water groundwater elevation based on the assumption that the conditions experienced over the ten-year period 2006-2016 (Spring measurements) continue through 2016 to 2040" at each of the three well sites. The management area plan claims this is done to be consistent with what is being used by surrounding management areas. The management area plan examined the impacts of the minimum thresholds and measurable objectives on wells within the area and determined that there they would potentially experience "excessive dewatering, [but] the impacts would not be unreasonable and would be mitigated through an Impacted Well Mitigation Program." It's unclear if all the wells in the management area were included in this impact analysis.	The KGA GSP must explain the selection of groundwater level minimum thresholds for the Shafter-Wasco Irrigation District Management Area, including how they represent site-specific levels of depletion that could cause undesirable results and the relationship between this sustainability indicator and other sustainability indicators such as degradation of groundwater quality and subsidence, both of which can be exacerbated by lowering groundwater levels. If minimum thresholds were not set consistent with levels indicating a depletion of supply, the minimum thresholds should be revised accordingly.	SWID 7th Standard Annex Management Area will raise the MTs for Chronic Lowering of Groundwater Levels by 50 feet based on coordination with adjacent Management Areas to maintain the MT gradient to be similar to the current groundwater elevation gradient and to reduce risk of creating Undesirable results. The SMC section of the SWID 7th Standard Annex Map ("the MAP") will be reorganized to make it more consistent with the DWR BMPs and Determination Letter. More explicit section headers will be added, including Relationship with Other Sustainability Indicators, Impact to Adjacent Management Areas and Basins, Impact to Beneficial Users, State/Federal/Local Standards, and Measurement of MTs. Some sections will be expanded to better address DWR's comments on the MAP in its Determination Letter. Refinements will be made to standardize language and triggers to match Basin-wide definitions. The MAP will clarify that MTs for Chronic Lowering of Groundwater Levels were set at levels that would avoid depletion of supply that would lead to Undesirable Results. Local Undesirable Results criteria justification will be updated with a well age analysis and an expanded well impact analysis by beneficial user category. The MAP will clarify that the well impact analysis includes all wells within the Management Area, including wells compiled from the stakeholder survey and domestic well information from the DWR database. The Impacted Well Mitigation Program that was considered by SWID landowners and funded in the Proposition 218 in 2019 will be explained to include more details.	The SWID 7th Standard Annex MAP (Section 4.5.2 Public Meetings Summary) documents the direct outreach and coordination efforts with neighboring districts that addressed identified potential conflicts of MT and MT development processes. The MTs within the SWID 7th Standard Annex MAP have been developed in consideration of and in coordination with the MTs established in neighboring water agencies within the Kern Subbasin. The methodology used to develop the MTs is generally consistent with the approach taken in several surrounding Management Areas (i.e., Shafter-Wasco Irrigation District Management Area, Rosedale-Rio Brave Water Storage District, and North Kern Water Storage District Management Area), in that all of the approaches consider historical water level trends, well construction information, and projected groundwater levels. The SWID 7th Standard Annex Management Area raised the MTs and MOs for Chronic Lowering of Groundwater Levels by 50 feet to reduce impacts to beneficial users and to coordinate with adjacent management areas.
Southern San Joaquin MUD	The KGA GSP Southern San Joaquin Municipal Utility District management area, in establishing minimum thresholds for chronic lowering of groundwater levels, the management area was dived into hydrogeologic zones (HZ). A well impact analysis of the equivalent minimum threshold average values (represented as depth to groundwater) for each HZ was used to determine that a portion of the existing wells are impacted to varying extents. Based on results of the well impact analysis, the management area plan states that is can be assumed many wells will remain operational and that water levels can drop without causing undesirable results which cannot be mitigated. Agricultural wells would be mitigated by landowners. While the management area plan states that mitigation to domestic wells would be necessary, there is no mention of who would implement the mitigation effort.	The KGA GSP must explain the selection of groundwater level minimum thresholds for the Southern San Joaquin Municipal Utility District management area, including how they represent site-specific levels of depletion that could cause undesirable results and the relationship between this sustainability indicator and other sustainability indicators such as degradation of groundwater quality and subsidence, both of which can be exacerbated by lowering groundwater levels. If minimum thresholds were not set consistent with levels indicating a depletion of supply, the minimum thresholds should be revised accordingly. Verify how the subset of wells used in the well impact analysis is representative of the wells in the management area. Provide an explanation of the mitigation plan for domestic wells.	A description will be provided to explain how MTs represent site-specific levels of depletion that could cause undesirable results and the relationship between this sustainability indicator and other sustainability indicators such as degradation of groundwater quality and subsidence will be described. The total number of wells in each Management Area will be estimated using DWRs Well Completion Report database, then compared against the dataset used for the Well Impact Analysis. A statement will be added to explain that the subset of wells in the Well Impact Analysis only included wells with a complete record for construction details. The total number of known well details will be compared against the total well counts in DWR's database. A mitigation plan will be developed prior to submittal to DWR. A new Well Impact Analysis was conducted using DWRs Well Completion Report database, then compared against the dataset used for the original Analysis and Gailey model. There was significant discrepancy between each dataset due to assumptions made to filter data. The MAP will be updated with the current analysis that is consistent with assumptions and methodology used by neighboring districts.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s). To better coordinate with neighboring districts, the Southern San Joaquin Municipal Utility District evaluated their MTs with those of neighboring districts to ensure values were consistent. Coordination with neighboring districts determined no recommended MT adjustments. Other changes that demonstrate coordination will include: – Adding KGA Exceedance Policy as a Management Action – Documenting the methodology used for the Well Impact Analysis is consistent with KGA Member Agencies – Implementing a Domestic Well Mitigation Program as a Management Action. While previously listed in their 2020 plan, additional information will be added to provide an explanation of the mitigation plan for domestic wells.

West-Kern Water District	The KGA GSP West Kern Water District management area plan describes it being divided into four management areas (Lake, North Project, South Project, and Western). Department staff note that Figure 1-2 shows an additional management area (Little Santa Maria Valley), and Appendix H consists of a draft GSP for this additional management area. No sustainable management criteria were determined for the Lake management area because the District was unable to procure the groundwater level data for the production wells in the area. No sustainable management criteria were established for the western management area because there is no groundwater usage in the area; however, earlier parts of the management area plan describe groundwater usage in this area as de minimis without further explanation of the type of de minimis users in the area. Due to the draft nature of the material provided for Little Santa Maria Valley, Department staff is unable to review the sustainable management criteria for that portion of the KGA GSP.	The KGA GSP must provide sustainable management criteria for all identified management areas. The minimum thresholds must include a description of the selection of groundwater level minimum thresholds, including how they represent site-specific levels of significant and unreasonable depletion of supply that could cause undesirable results, how they may affect beneficial uses and users of groundwater, and the relationship between this sustainability indicator and other sustainability indicators such as degradation of groundwater quality and subsidence, both of which can be exacerbated by lowering groundwater levels.	1. WKWD has revised categorization of areas within the MAP to match the Subbasin definitions. The WKWD MAP will contain two management areas and three watch areas as follows: – North Project Management Area – South Project Management Area – Lake Watch Area – Western Watch Area – Little Santa Maria Valley Watch Area SMC were already provided for the two management areas. Watch areas have no significant current or planned groundwater use and, therefore, SMC will not be developed for the three watch areas. 2. a. WKWD has determined that groundwater level conditions that would be expected at a MT Trigger would represent undesirable conditions for their normal and sustainable operations. These conditions may include increased operation costs due to increased energy requirements for pumping deeper water, costs to lower pumps, costs to install treatment systems or seek alternate water supplies due to degraded water quality, costs to remedy land subsidence, and/or additional operational maintenance requirements and costs. b. WKWD is the primary beneficial user in the WKWD GSA area. WKWD is the only groundwater user to pump, treat, and distribute water from the WKWD MAP Management Areas. WKWD calculated and set sustainable management criteria to provide operational flexibility and maintain long-term sustainability for the beneficial uses and users of groundwater within its MAP Area. As the primary beneficial user of groundwater in the MAP, WKWD was consulted during the GSP development process to ensure the thresholds and undesirable results criteria accurately represented the quantitative and qualitative conditions as directed by SGMA regulations. Through coordination efforts, neighboring GSAs' MTs and MOs were also taken into consideration to ensure protection of nearby beneficial uses and users outside of the WKWD Management Area. In addition, a spatial analysis of MTs and water level trends was performed to ensure relative consistency between the MTs of the WKWD Management Area and those set in adjacent management areas. c. An analysis of historical groundwater quality and groundwater level data was performed to estimate groundwater quality if groundwater level minimum thresholds were to be reached. This analysis demonstrates that the minimum thresholds will not negatively impact groundwater quality in the WKWD MAP Area and will not negatively impact WKWD operations (the primary beneficial use). The WKWD GSA will continue to monitor groundwater levels and groundwater quality to ensure the historically observed trend does not change under future conditions. Furthermore, groundwater delivered by WKWD for domestic and industrial uses must meet Title 22 drinking water standards. Any groundwater in exceedance of drinking water standards is required to be treated and disinfected to meet such standards. Any degradation of groundwater quality will be identified during required routine water quality monitoring by WKWD would be considered an undesirable result by nature, regardless of groundwater levels.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s). The WKWD GSA has coordinated with neighboring GSAs regarding the thresholds; no conflicts or issues were identified. Ongoing coordination with the other agencies will continue as described in Section 1.5, Existing Water Management Programs.

			MTs in the WKWD MAP Area were set to mitigate the potential for land subsidence, noting that no undesirable results with respect to land subsidence have been identified historically and that subsidence elastically responds to groundwater banking operations in the Kern Fan aquifer. No infrastructure damage relating to land subsidence has been documented in the WKWD MAP area and the potential for future damage to critical infrastructure appears unlikely due to the elastic response of subsidence to groundwater banking operations. No long-term historical subsidence has been documented in the WKWD MAP area and ground surface elevation has risen approximately 0.8 feet over time.	
Westside Districts Water Authority	The KGA GSP Westside District Water Authority (WDWA) management area states that total groundwater demand is 3,000 acre-feet per year due to water quality; therefore, the potential for significant lowering of groundwater levels due to pumping is believed to be minimal. In establishing minimum thresholds, the management area first divided into two sentry coordination zones. There is one minimum threshold established for Sentry Zone #1 and three for Sentry Zone #2. These minimum thresholds are not explained or justified. The established minimum thresholds do not apply for the majority of the management area and the rest of the management area is not being monitoring for water levels. The management area plan states that minimal pumping takes place within the management area due to water quality; however, based on Figure 28a and Figure 28b, subsidence appears to be occurring within the middle of the management area. For this reason, sustainable management criteria must be applied to the entirety of the management area, including the establishment of thresholds and monitoring.	The KGA GSP must explain the selection of groundwater level minimum thresholds for the WDWA management area, including how they represent site-specific levels of depletion that could cause undesirable results, how they may affect the interests of beneficial uses and users of groundwater, and the relationship between this sustainability indicator and other sustainability indicators such as the degradation of groundwater quality and subsidence, both of which can be exacerbated by lowering groundwater levels. If minimum thresholds were not set consistent with levels indicating depletion of supply, the minimum thresholds should be revised accordingly. The larger portion of the management area must establish sustainable management criteria, including the establishment of minimum thresholds and monitoring; otherwise, further evaluation and justification is needed to negate management criteria in this portion of the management area.	Due to naturally occurring poor groundwater quality, groundwater demand is largely limited to use for blending with surface water from the Aqueduct. Further, much of the WDWA is undeveloped range land or is used for oil and gas production with no significant current or planned SGMA related groundwater uses. Based on CV2Sim modeling the most significant change in groundwater levels/storage is attributed to natural under flow from the WDWA towards the axis of the Valley. The WDWA does not control this natural phenomenon. The WDWA has revised categorization of areas within the MAP to coordinate with adjacent Management Areas and match the Subbasin definitions. The revised WDWA MAP will contain a single management area and two Watch Areas as follows: – Lost Hills Watch Area – Southwest Watch Area An Additional Watch Area comprised of KGA Undistricted Lands, that are interspersed within the two aforementioned Watch Areas, will also be included in the revised MAP. Once approved by the KGA Board, the revised SMC will initially include up to three additional monitoring wells (total of six) in the WDWA Management Area. Watch Areas have no significant current or planned SGMA related groundwater use at this time and, therefore, SMC will not be developed for the three Watch Areas (two WDWA, and one Undistricted Lands) unless conditions change. In addition, the MO/MT for RMW 7106-03 which was originally set using only CV2Sim modeling simulations due to a lack of actual groundwater level data. The MO/MT adjusted to reflect recently acquired actual groundwater level data. Prior to making this change the WDWA coordinated with the adjacent water district, Buena Vista Water Storage District and the KGA Board. Two of the new RMWs are the Lerdo Well 7 (35.528925,-119.629831) and the Starrh Well 3-8 (35.419371,-119.633266). This brings the number of RMWs in the WDWA to a total of 5, with a projected sixth RMW under review for inclusion. Potential impacts to beneficial users were assessed through the use of historical WDWA pumping volumes, land use, CASGEM well construction and groundwater level data, the WDWA estimated water budget, and modeling using the CV2Sim hydrogeologic model. Taken together this information indicates that under current and projected conditions impacts to the principal beneficial user should be within planned MOs/MTs and therefore impacts to other users would be de minimis as expected groundwater levels would not constitute an undesirable result. Subsidence was assessed by the WDWA, and the findings were presented to the DWR (CASP) staff on three occasions (January & April 2020 and June 2022). These studies concluded that causes other than agricultural withdrawals, such as oil field activities, are a substantive contributor to subsidence in the WDWA.	KGA Member Agencies have committed to managing groundwater condition using water budgets that avoid groundwater overdraft, where present, and maintains groundwater elevation at or above the measurable objectives in each member agencies management area(s).

Table 2b. KGA Management Area Responses to Deficiency 2, Comment CC to all GSPs

KGA Management Area	Response to Table 2 "cc" groundwater level relationship to each sustainability threshold
DWR Corrective Action (cc): All the GSPs must demonstrate the relationship between the minimum thresholds for each sustainability indicator, including an explanation of how the GSA has determined that basin conditions at each minimum threshold will avoid undesirable results for each of the sustainability indicators.	
Cawelo GSA	• The chronic lowering of groundwater levels MTs are used as a proxy for groundwater storage for the respective RMW. • Based on available data, there is no direct correlation between water levels and trends in water quality within the Cawelo MAP. Therefore, water quality is used as a MT for the degraded water quality SMC to protect beneficial users and uses. • Groundwater level MTs for land subsidence were determined to be lower than the MT for chronic lowering of groundwater level. Therefore, the chronic lowering of groundwater level MTs are protective for land subsidence. • Interconnected surface water and seawater intrusion are not applicable to the Cawelo MAP.
Eastside Water Management Area	• **Groundwater Storage:** The EWMA is using groundwater levels as a proxy for reduction in groundwater storage. Due to data gaps of the deeper aquifers not modeled in the original model and production wells perforated in multiple zones, levels are being used until the basin-wide hydrologic study is completed and will be evaluated for the 2025 GSP update. • **Groundwater Quality:** TDS was selected as a constituent of concern due to the potential to be affected by groundwater pumping increases or decreases in the EWMA. The Santa Margarita Formation and the Olcese Sand contain higher-TDS groundwater at more western locations and at greater depths. Continued pumping potentially could move the "fresh/saline" groundwater interface if not monitored and managed, as necessary. Therefore, the MT was set at 750 mg/L and the MO at 500 mg/L. • **Land Subsidence**: Minimum thresholds for Regional Critical Infrastructure have been established at the subbasin level. No regional critical infrastructure is located within the EWMA, therefore, no Undesirable Results are defined. The EWMA has not proposed any local minimum threshold for management area critical infrastructure. The only critical infrastructure within EMWA are roads, pipelines, and wells and the EWMA is unaware of any costs incurred to replace or repair infrastructure due to subsidence within the EWMA.
Kern Water Bank Management Area	Groundwater levels are not used as a proxy for sustainability thresholds.
Kern-Tulare Water District	• **Groundwater Storage:** The District is using groundwater levels as a proxy for reduction in groundwater storage. The groundwater level minimum thresholds were selected to avoid dewatering the SMF and the District's management actions are focused on pumping at or less than the sustainable yield. The minimum threshold selected ensures the District balances average annual inflows and outflows of groundwater so that a negative change in storage that results in lower groundwater levels does not occur. • **Groundwater Quality:** The District's main groundwater quality concern is that immediately west of the District the SMF becomes saline. Recharge has fed fresh water from the east at a sufficient elevation to exert a westward hydraulic gradient in the SMF maintaining the fresh-saltwater interface along the western border of the District. Over pumping of groundwater beneath the District has the potential to reverse the gradient so that saline water begins to move eastward. Since the groundwater level minimum threshold has been placed below what has historically been experienced and the District knows changes in groundwater elevation differences has the capability to change the groundwater gradient, the District has selected to establish a separate minimum threshold for groundwater quality as TDS < 750 mg/L. The District's management actions aim to balance average annual inflows and outflows of water which reduces the potential for changing the groundwater gradient. • **Land Subsidence**: Minimum thresholds for Regional Critical Infrastructure have been established at the subbasin level. The District has not proposed any local minimum threshold for management area critical infrastructure. The only critical infrastructure on the land surface within the District are roads, pipelines, and wells. Within the District, groundwater elevations have declined historically without creating a loss of functionality due to subsidence. The District is unaware of any costs incurred to replace or repair infrastructure due to subsidence within the District. Even though significant impacts to infrastructure is not anticipated, the District's management actions aim to balance average annual inflows and outflows of water which reduces the potential for additional subsidence related to groundwater production.
North Kern WSD/ Shafter-Wasco ID	Groundwater levels are used as a proxy for groundwater in storage and water quality. Regional Interim SMCs are used land subsidence. • **Groundwater storage** is determined at the Subbasin level. NK-SWID demonstrated that their MTs are set at a depth that is protective of groundwater storage by presenting a summary of average 2020 water levels, median well depth, MO, MT, and base of fresh water. This data is also graphically displayed with the well impact study results. • **Quality** constituents of concern for the Subbasin were evaluated. Effects of water levels declining to the MT were evaluated based on historical data. Trend analysis indicates: o Arsenic is released from pyrites bound in the E-clay, which is prevalent in SWID MA. Highest observed concentrations were 20 ppb between 2010-11, which represents hydrologically wet years and higher water levels. When water levels declined to historic low (2018-19), arsenic levels declined. This is likely because less of the pumped water is in direct contact with the E-clay. o Nitrate in shallow wells increased when water levels reach historic low. While there is a direct correlation, no projects or management actions are proposed through SGMA. The districts intend to coordinate with the Nitrate Management Zone mitigation programs. o TCP is prevalent throughout both Management Areas. There is no relevant correction between water level and contaminant concentration. No SGMA-associated projects are proposed. o Salinity is found to be increasing in most areas. Where recharge basin is present, groundwater downgradient of the basins generally has lower salinity levels than wells that are upgradient. The high-quality source of recharge available to NKWSD and SWID appear to be freshening groundwater. o Throughout the SGMA implementation period, evaluation of groundwater levels and water quality trends will be routinely monitored. If a correlation develops indicating that declining water levels are causing unmitigated impacts to beneficial users, stakeholders will be consulted, and appropriate corrective actions or mitigation will be considered. • **Subsidence** is expected to occur if water levels decline to the MT, estimates indicate that an additional -0.9 to -1.1 feet of subsidence could occur. This estimate is well within the extent value of -3.6 feet during the SGMA implementation period (2040).

Table 2b. KGA Management Area Responses to Deficiency 2, Comment CC to all GSPs

KGA Management Area	Response to Table 2 "cc" groundwater level relationship to each sustainability threshold
DWR Corrective Action (cc): All the GSPs must demonstrate the relationship between the minimum thresholds for each sustainability indicator, including an explanation of how the GSA has determined that basin conditions at each minimum threshold will avoid undesirable results for each of the sustainability indicators.	
Kern County Water Agency Pioneer GSA Management Area	An analysis of historical groundwater quality and groundwater level data was performed to estimate groundwater quality if groundwater level minimum thresholds were to be reached. Results of the analysis show that no groundwater quality thresholds are expected to be exceeded at the minimum thresholds. This analysis demonstrates that the minimum thresholds will not negatively impact groundwater quality in the Pioneer MAP Area and will not negatively impact Pioneer Project operations (the sole beneficial use). The Pioneer GSA will continue to monitor groundwater levels and groundwater quality to ensure the historically observed trend does not change under future conditions. MTs were set to mitigate the potential for land subsidence by relying on the Pioneer Project's current and historical sustainable management of groundwater levels, noting that no undesirable results with respect to land subsidence have been identified historically and that subsidence elastically responds to groundwater banking operations in the Pioneer Project GSA Area.
Rosedale-Rio Bravo Management Area	**Chronic Lowering of Groundwater Levels.** Minimum Thresholds set for monitoring of groundwater levels within the RRBMA are based on historical groundwater conditions less 50 feet as expressed by hydrographs at representative monitoring wells, which levels are coordinated with most of the neighboring Management Areas. The RRBMA seeks to avoid unmitigated impacts that require the replacement of wells caused by chronic lowering of groundwater levels. A detailed well impact analysis was performed to confirm that undesirable results will be avoided. All wells in the RRBMA were evaluated in terms of well depths, screened intervals, age, and drawdown requirements, etc. Should impacts occur, an adaptive management action was developed to repair or replace impacted domestic wells and emergency water supplies will be provided. **Reduction in Groundwater Storage.** The KGA has opted to use water level Minimum Thresholds and Measurable Objectives as a "proxies" for reduction in groundwater storage. The RRBMA Minimum Thresholds set for monitoring of groundwater levels are based on historical groundwater conditions less 50 feet as expressed by hydrographs at representative monitoring wells. The RRBMA seeks to avoid an imbalanced water supply. The RRBMA will coordinate with the water level method until such time as a basin study can be completed and volumetric methodologies adopted. However, RRBMA will also calculate annually the amount of groundwater in storage above the Minimum Threshold using its groundwater model for planning purposes. The RRBMA will calculate annual numerical model generated volumes in storage within the groundwater basin and a check-book balance, and will seek to keep both above 0 acre-feet in storage. **Degraded Water Quality**. Minimum Thresholds for degradation of water quality are based on water quality MCL's for KGA identified Constituents of Concern (COC's) for beneficial user groups. The Minimum Thresholds were set at greater than the current MCL, or an observed increase of 10% over the 2015-2020 value. The RRBMA seeks to avoid operations that cause KGA identified COC's to rise above the MCL thus limiting beneficial use or requiring well head treatment by domestic, municipal, and banking wells. COC's such as Nitrate and Arsenic appear to be somewhat connected to water levels, therefore water levels do somewhat provide a secondary proxy for degraded water quality. The RRBMA chose not to rely solely on water levels as the primary evaluation metric and opted to assign actual Minimum Thresholds for each COC at several representative monitoring wells. This method will help the RRBMA to ensure that groundwater level MTs are appropriate for degraded water quality. **Land Subsidence**. A Subbasin-wide approach is now being developed to set Minimum Thresholds for regional land subsidence. This approach is intended to be protective of regional critical infrastructure throughout the Subbasin, which the Subbasin has determined to be the California Aqueduct and the Friant-Kern Canal in areas outside of the RRBMA. The RRBMA seeks to avoid groundwater recovery created subsidence that will impact Management Area critical infrastructure requiring unscheduled retrofitting or replacement within and adjacent to the RBMA. The interim Minimum Threshold set for RRBMA subsidence, is 0.1 ft/year over a five-year rolling average. This was based on historical trends that did not result in impacts to critical infrastructure within the RRBMA, as expressed at several locations in proximity to groundwater pumping and other identified critical infrastructure within the RRBMA. Recent rates of subsidence within the RRBMA (2015-2021) were unaffected by large variations in depths to groundwater during that time. The RRBMA chose specific Minimum Thresholds for land subsidence in order to monitor subsidence independent of groundwater levels in order to help ensure that groundwater level MTs are appropriate measurements for subsidence.
Semitropic GSA	The primary minimum threshold for the SWSD GSA, based upon the well impact analysis and consultation with SWSD GSA Beneficial Users, is Chronic Lowering of Groundwater Levels. In accordance with §354.28 (d), the SWSD GSA minimum thresholds for chronic lowering of groundwater levels are used as a proxy for reduction of groundwater storage, and degraded groundwater water quality. **Relationship of Groundwater Levels and Reduction of Groundwater Storage:** Although groundwater storage and capacity in the Subbasin is plentiful, it becomes uneconomical to obtain groundwater at certain depths. Therefore, the SWSD GSA has elected to maintain approximately 10-years of groundwater storage (by volume) above the minimum threshold for groundwater elevation to manage a 10-year operational drought, similar to the 2006-2016 historical period. **Relationship of Groundwater Levels and Degraded Water Quality:** With respect to water quality, changes in groundwater levels can cause changes in water quality. However, as discussed in Section 2.3.5 water quality within the SWSD GSA is not significantly affected by changes in groundwater levels above the minimum thresholds for chronic lower of groundwater levels. And since there are no anticipated changes in water quality from fluctuations of groundwater levels above the minimum threshold values, groundwater elevation minimum thresholds serve as the appropriate proxy for water quality.
SWID 7th Standard Annex	MTs for Chronic Lowering of Groundwater Levels are set at levels that would avoid a depletion of supply that may lead to URs. MTs consider historical groundwater level trends based on the assumption that the conditions experienced over the ten-year period 2006-2016 continue from 2016 through 2040. A well impact analysis of all wells within the Management Area was conducted that showed that the proposed MTs could potentially cause bottom of well screen dewatered in 26% of wells within the Management Area (including 12% of agricultural and industrial wells, 56% of domestic wells, and 0% of municipal wells). A Well Dewatering Mitigation Program (Section 17.1.6 of the MAP) addresses wells impacted by Chronic Lowering of Groundwater Levels before water levels reach MO or MT, including agricultural and domestic supply wells. Groundwater levels will be measured in each of the three RMWs semiannually and will be analyzed for trends. Chronic Lowering of Groundwater Levels and Reduction of Groundwater Storage are directly, if not linearly, related. To demonstrate that the Minimum Thresholds for Chronic Lowering of Groundwater Levels are sufficiently protective, a calculation was performed to determine the fraction of total usable groundwater storage that would be removed from the Principal Aquifer if groundwater levels were to decline from current (Spring 2016) levels to their respective Minimum Thresholds for Chronic Lowering of Groundwater Level. This volume is then compared to the volume of usable storage, and it is shown that the usable storage is substantially greater, and therefore the Minimum Thresholds for Chronic Lowering of Groundwater Levels are protective for the Reduction of Groundwater Storage Sustainability Indicator. Because hydrogeologic storage properties and the MA Plan area are constant when looking at the change in storage (Change in Storage = MA Plan Area * Storage Coefficient * Change in Saturated Thickness), the following analysis is presented in terms of saturated thickness, which is mathematically equivalent to storage volume. The change in saturated thickness from current (Spring 2016) groundwater elevations (13.7 ft msl) to the Chronic Lowering of Groundwater Levels MTs (-87 ft msl) is approximately 101 ft. The total usable groundwater storage is calculated to be 624 ft of saturated thickness within the Management Area based on current groundwater elevations and the deepest groundwater extractions from well construction information (-710 ft msl) within the MA Plan Area plus 100 ft reserve for well pumping operations. Therefore, the reduction in usable storage volume if groundwater levels were to decline to the MTs amounts to 16%. As described in detail in Section 13.2, because volume of usable groundwater storage can be represented by changes in groundwater elevations and the amount of recoverable storage is substantially greater than the volume associated with a reduction in groundwater levels to the MTs for Chronic Lowering of Groundwater Levels, those MTs are considered protective for the Reduction of Groundwater Storage Sustainability Indicator.

Table 2b. KGA Management Area Responses to Deficiency 2, Comment CC to all GSPs

KGA Management Area	Response to Table 2 "cc" groundwater level relationship to each sustainability threshold
DWR Corrective Action (cc): All the GSPs must demonstrate the relationship between the minimum thresholds for each sustainability indicator, including an explanation of how the GSA has determined that basin conditions at each minimum threshold will avoid undesirable results for each of the sustainability indicators.	
	There is no apparent correlation between groundwater elevations and water quality measurements based on the historical data, with the exception of a suspected correlation between groundwater levels and arsenic concentration and at the base of fresh water defined by Page (1973). The base of fresh water is well below the MT for Chronic Lowering of Groundwater Levels. The storage associated with the MT is approximately 4.5% of the storage associated with the base of fresh water. Therefore, the MT for Chronic Lowering of Groundwater Levels is conservative and protective to water quality within the Management Area, and the MTs are not expected to exacerbate water quality issues. No direct correlation can be discerned between water levels and Land Subsidence measurements within the Management Area at this time as little to no subsidence has occurred within the Management Area based on available data and the lack of Corcoran clay suggests that the risk continues to be small. It should be noted that there is no Regional Critical Infrastructure within the 7th Standard Annex Management Area. Both Seawater Intrusion and Interconnected Surface Water are not applicable to the Management Area.
Southern San Joaquin MUD	Groundwater levels are used as a proxy for groundwater in storage, water quality, and subsidence. • **Groundwater storage** is determined at the Subbasin level. SSJMUD demonstrated that their MTs are set at a depth that is protective of groundwater storage by presenting a summary of average 2020 water levels, median well depth, MO, MT, and base of fresh water. This data is also graphically displayed with the well impact study results. • **Quality** constituents of concern for the Subbasin were evaluated. Effects of water levels declining to the MT were evaluated based on historical data. Trend analysis indicates: o Arsenic is released from pyrites bound in the E-clay, which is prevalent in the SSJMUD management area. Prevalence is largely correlated to well construction. When wells are constructed in an area without E-clay, results show moderate, stable arsenic concentrations and are not impacted by fluctuating water level. o Nitrate in shallow wells increased when water levels reach historic low. While there is a direct correlation, no projects or management actions are proposed through SGMA. The districts intend to coordinate with the Nitrate Management Zone mitigation programs. o TCP is prevalent throughout the SSJMUD Management Area. There is no relevant correlation between water level and contaminant concentration. o Salinity is found to be increasing in most areas. Although there are no spreading grounds currently in SSJMUD Management Areas, evaluation of sodium levels in other parts of the Subbasin have shown wells located downstream of spreading show lower sodium levels and decreasing trends. This indicates spreading grounds are diluting salinity in portions of the basin with higher sodium levels. SSJMUD is actively construction recharge basin, which are expected to be fully implemented in early 2023. Salinity management will be further addressed through the Salt Control Program, which began collecting fees in 2021 to support the Prioritization and Optimization Study that began in 2022. o Throughout the SGMA implementation period, evaluation of groundwater levels and water quality trends will be routinely monitored. If a correlation develops indicating that declining water levels are causing unmitigated impacts to beneficial users, stakeholders will be consulted, and appropriate corrective actions or mitigation will be considered. • **Subsidence** is expected to occur if water levels decline to the MT. Work is still in-progress to estimate the inches of inelastic subsidence that could be caused by water levels intermittently declining to the MT.
West-Kern Water District	An analysis of historical groundwater quality and groundwater level data was performed to estimate groundwater quality if groundwater level minimum thresholds were to be reached. Results of the analysis show that no groundwater quality thresholds are expected to be exceeded at the minimum thresholds. This analysis demonstrates that the minimum thresholds will not negatively impact groundwater quality in the WKWD MAP Area and will not negatively impact WKWD operations (the sole beneficial use). The WKWD GSA will continue to monitor groundwater levels and groundwater quality to ensure the historically observed trend does not change under future conditions. MTs were set to mitigate the potential for land subsidence by relying on the WKWD's current and historical sustainable management of groundwater levels, noting that no undesirable results with respect to land subsidence have been identified historically and that subsidence elastically responds to groundwater banking operations in the WKWD GSA Area in areas where groundwater production occur.
Westside Districts Water Authority	**Chronic Lowering of Groundwater Levels.** Due to naturally occurring poor groundwater quality, groundwater demand (i.e., 3,000-5,000 AFY) is largely limited to use for blending with surface water from the aqueduct. Further, much of the WDWA is undeveloped rangeland, or is used for oil and gas production with no significant current or planned groundwater uses. The WDWA has no control over oil and gas activities. The WDWA has revised categorization of areas within its management area to coordinate with adjacent management areas and match subbasin definitions. The revised WDWA will contain a single management area and two watch areas as follows. Lost Hills Watch Area (approximately 33,191 acres) and Southwest Watch Area (approximately 48,739 acres). The watch areas include non-cultivated lands, areas adjacent to former or active oilfields and open rangeland. **Reduction in Groundwater Storage.** Due to naturally occurring poor groundwater quality, groundwater demand (i.e., 3,000-5,000 AFY) is largely limited to use for blending with surface water from the aqueduct. SGMA-related groundwater extraction de minimis when compared to natural underflow. Based on CV2Sim modeling, the principal factor (approximately 111,000 AFY) affecting change in groundwater storage is natural underflow toward the axis of the valley. To further monitor for changes in groundwater storage, the WDWA will utilize data from representative monitoring wells and the planned update to the CV2Sim model. Representative monitoring well Minimum Thresholds are set above historic low groundwater levels. **Degraded Water Quality.** An analysis of historical groundwater quality has determined that groundwater quality within the WDWA is naturally degraded due to the presence of marine sediments and saline connate water. The WDWA therefore relies on surface water as its primary water source. As a result, the WDWA typically utilizes groundwater (i.e., 3,000-5,000 AFY) for the purpose of blending when surface water deliveries are low. **Subsidence.** Two recent studies conducted by the WDWA and KGA indicate that current rates of subsidence within the WDWA and adjacent to Regional Critical Infrastructure are attributable to oilfield activities. The WDWA has no control over oil and gas activities.

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To identify beneficial users, all KGA Management Areas used a Well Impact Study to identify beneficial uses and users within each management area that reflects the types of users that actively rely on local groundwater resources and those that can be directly affected by groundwater management, impacts of operating at proposed Measurable Objectives (MO), and impacts of exceeding Minimum Thresholds (MT). Each MAP provides the details of the data and methodology applied to the Well Impact Study specific to that management area and identifies an estimate of potential impacts to beneficial users (in terms of dewatered wells) if groundwater elevations reach the MO and MT in the management area. Table 3a provides a tabular summary and Figure 4a shows a graphic summary of the number of wells for each beneficial use category (M-municipal, D-domestic, A-agricultural) and the potential impact to each category as a percent of wells that could be dewatered at the measurable objective. Table 3b shows a tabular summary of Figure 4b shows a graphic summary of the percent of wells that could be dewatered at the minimum threshold.

Table 3a. Tabular Summary of Wells Potentially Dewatered at the Measurable Objective

	Number of Wells				Number of Dewatered Wells			
	M	D	A	% M/D Wells	M	D	A	% M/D Wells
CWD	0	93	197	32%	0	0	0	0%
EWMA	2	11	41	24%	0	0	0	0%
NK	1	22	161	13%	0	0	2	0%
KTWD	0	18	94	16%	0	0	0	0%
RRB	24	149	156	53%	0	0	0	0%
SWID	16	68	118	42%	0	8	7	10%
SSJMUD	19	67	243	26%	0	13	11	15%
SWSD	4	138	763	16%	0	10	4	7%
WDWA	0	2	35	5%	0	0	0	0%
WKWD	13	0	0	100%	0	0	0	0%
7th Standard	2	9	19	37%	0	2	0	18%
Total	**81**	**577**	**1827**	**26%**	**0**	**33**	**24**	**5%**

0 Municipal wells going dry at the MT's
Anyone over 5% of Domestic wells dewatered required to put together a mitigation plan

M= Municipal, D= Domestic, and A=Agricultural

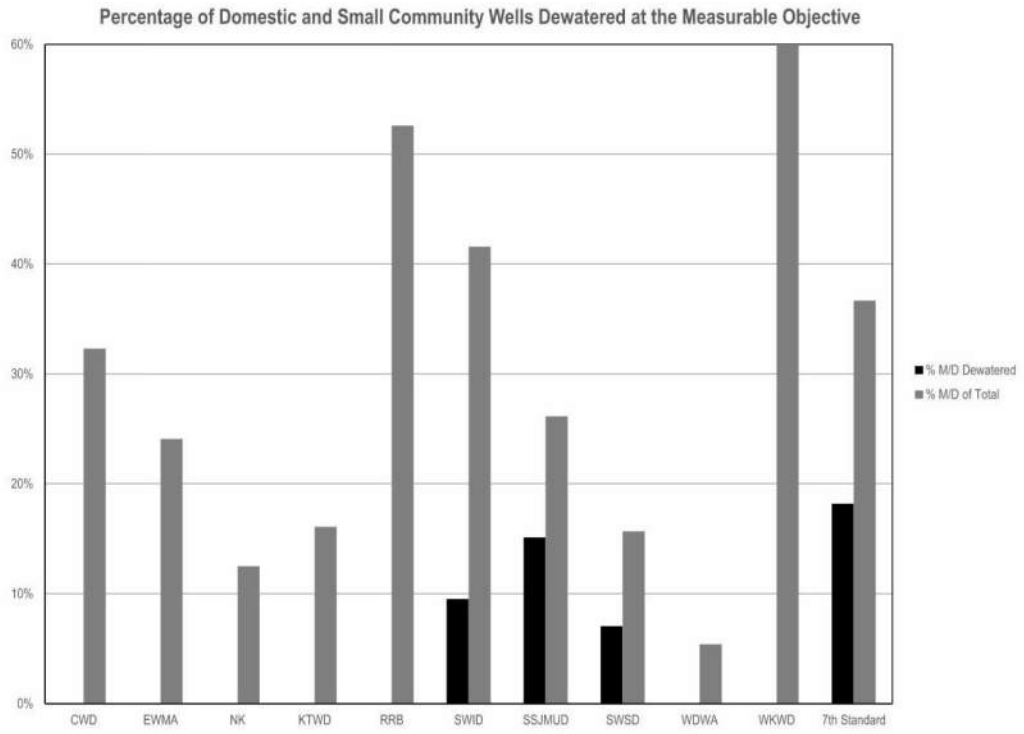

Figure 4a. Graphic Summary of Wells Potentially Dewatered at the Measurable Objective

Table 3b. Tabular Summary of Wells Potentially Dewatered at the Minimum Threshold

	Number of Wells				Number of Dewatered Wells			
	M	D	A	% M/D Wells	M	D	A	% M/D Wells
CWD	0	93	197	32%	0	3	1	3%
EWMA	2	11	41	24%	0	3	0	23%
NK	1	22	161	13%	0	2	5	9%
KTWD	0	18	94	16%	0	0	0	0%
RRB	24	149	156	53%	0	21	0	12%
SWID	16	68	118	42%	0	22	13	26%
SSJMUD	19	67	243	26%	0	29	25	34%
SWSD	4	138	763	16%	0	41	52	29%
WDWA	0	2	35	5%	0	0	0	0%
WKWD	13	0	0	100%	0	0	0	0%
7th Standard	2	9	19	37%	0	5	2	45%
Total	**81**	**577**	**1827**	**26%**	**0**	**126**	**98**	**19%**

0 Municipal wells going dry at the MT's
Anyone over 5% of Domestic wells dewatered required to put together a mitigation plan

M= Municipal, D= Domestic, and A=Agricultural

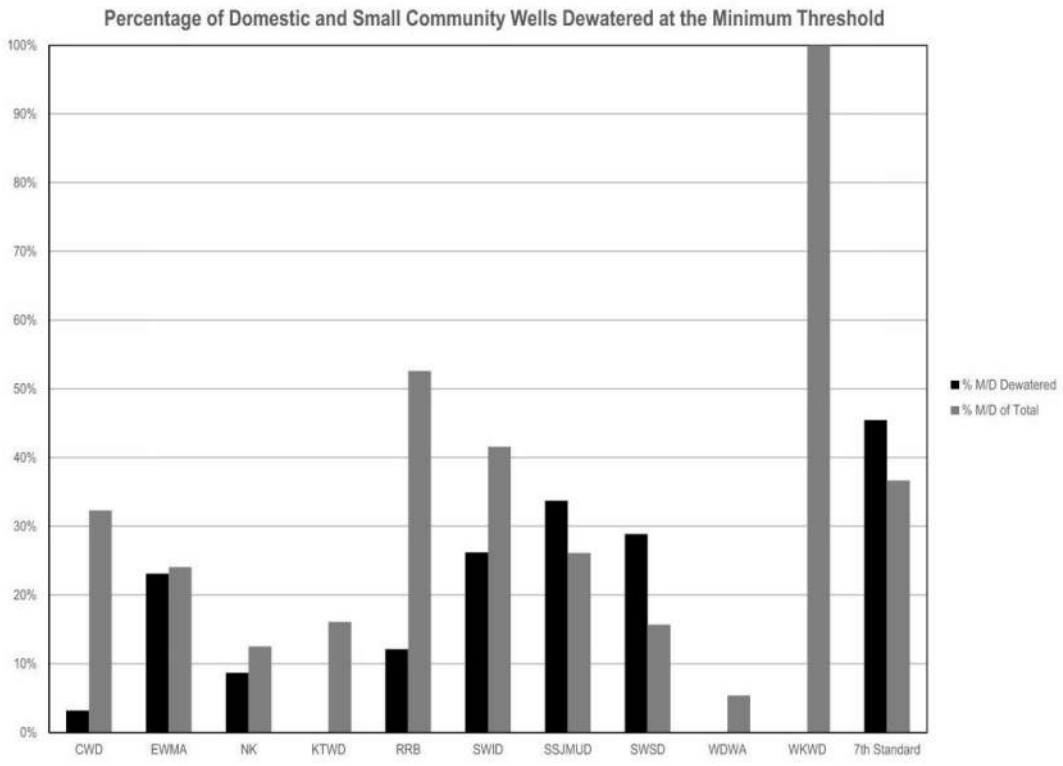

Figure 4b. Graphic Summary of Wells Potentially Dewatered at the Minimum Threshold

Interests of Beneficial Uses and Users

Effects caused by groundwater management are defined in Section 3.4, Undesirable Results. The Subbasin is trying to avoid widespread occurrence of groundwater levels declining below the minimum thresholds, which indicates the Subbasin is not sustainably managing groundwater conditions in the aggregate and that beneficial users could be affected on a spatial and temporal scale that it too substantial to mitigate. If groundwater levels approach the minimum threshold, isolated exceedances will likely occur and is expected to progressively occur in multiple wells if there is no intervention. To avoid a widespread occurrence of MT exceedances, the KGA established an *Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater*, which is a proactive approach to identifying and working with management areas to address a single, isolated exceedance. If intervention at a single MT exceedance is unsuccessful, a Management Area Exceedance may be triggered, which could trigger a Subbasin-wide undesirable result.

The minimum thresholds established for Chronic Lowering of Groundwater Levels are used by many management areas as a proxy for Reduction in Groundwater Storage and Degraded Water Quality (where applicable), and in a few instances Land Subsidence. Table 4 shows the measurable objective and minimum threshold for each KGA regional monitoring wells, indicates whether the groundwater elevation is used as a proxy for other sustainability indicators, and defines the trigger for a management area exceedance for each sustainability indicator. This table also shows the

management area trigger reported in the 2020 GSP submittal and the changes that have been made to better coordinate and make consistent management area triggers. Note that the table below is a summary of the management area triggers and detailed information about the analysis to set those triggers are located in the management area plans.

Table 4. Summary of KGA RMWs with SMCs and Trigger to a Management Area Exceedance

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
Cawelo GSA		Well 12H	RMW-167	25	ft msl	103	ft msl	X		X	~~The undesirable result will be triggered when 30 percent or more of the monitoring wells in the Cawelo GSA fall below the MT during three (3) successive spring measurements.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The undesirable result will be triggered when 30 percent or more of the monitoring wells in the Cawelo GSA fall below the MT during three (3) successive spring measurements.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The undesirable result will be triggered when 30 percent or more of the monitoring wells in the Cawelo GSA have TDS concentrations rising above the MT for two continuous years.~~ A management area exceedance is considered to occur when more than 40% of representative monitoring wells used to monitor TDS concentrations exceed their minimum thresholds for two consecutive annual monitoring periods.	Since groundwater elevations below historical lows may lead to localized land subsidence undesirable results, the exceedance of the land subsidence MT at a single representative monitoring well will be considered a management area exceedance.
		Well 24R	RMW-170	-43	ft msl	35	ft msl	X		X				
		Well 11M	RMW-171	-81	ft msl	3	ft msl	X		X				
		Well 6C	RMW-172	-85	ft msl	-1	ft msl	X		X				
		Well 33C	RMW-173	-64	ft msl	20	ft msl	X		X				
		Well 28L	RMW-169	26	ft msl	110	ft msl	X		X				
		Well 4R	RMW-168	-24	ft msl	60	ft msl	X		X				
Eastside Water Management Authority		EWMA #04 *(added July 2020)*	RMW-283	-133.21	ft msl	87.79	ft msl	X			~~Measurement of water levels below minimum thresholds, in four (4) consecutive semiannual monitoring periods, in no less than 50% of the Representative monitoring network wells, rounded down to the nearest whole number, i.e., four (4) wells. (Sec 12.1.2)~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Same as GW levels criteria (Sec 12.2.2)~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	Chronic lowering of groundwater levels or changes in storage may potentially draw saline water into the area of groundwater production in these units in the EWMA, thus monitoring for TDS will be necessary to foresee and avoid Undesirable Results related to degradation of groundwater quality. (Sec 12.4).	There have been no known occurrences of significant (i.e., magnitude more than one foot) land subsidence within the EWMA (Figure GWC-4) and no observed negative effects. Since no "critical infrastructure" are located within the EWMA, no Undesirable Results are defined within the EWMA.. (Sec 12.5.3)
		EWMA #21	RMW-185	-110	ft msl	136	ft msl	X						
		EWMA #23	RMW-278	-71	ft msl	132	ft msl	X						
		EWMA #30	RMW-187	-228	ft msl	-71	ft msl	X						
		EWMA #10 *(added July 2020)*	RMW-280	-43	ft msl	175.8	ft msl	X						
		EWMA #41	RMW-189	-41	ft msl	230	ft msl	X						
		EWMA #49 *(added April 2022)*	RMW-	312.0	ft msl	381.9	ft msl	X						
Kern-Tulare Water District		Well 4P1	RMW-175	-150	ft msl	20	ft msl	X			~~An Undesirable Result for the KTWD would be lowering the groundwater levels to the extent that the minimum threshold for groundwater levels are exceeded in 30% of the monitoring wells located within the District. The 30% criteria was chosen to be consistent with criteria uses throughout the Kern Subbasin.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The Undesirable Result and Minimum Threshold for reduction of groundwater storage shall be the same threshold associated with chronic lowering of groundwater levels.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	A management area exceedance is triggered when the MT for groundwater quality is exceeded in 40% or more of any representative monitoring wells within the management area. KTWD believes that the main constituent of concern associated with the chronic lowering of groundwater levels is TDS. Immediately west of the District, the Santa Margarita Formation becomes saline. The District has established a minimum threshold for TDS as 750 mg/L.	KTWD has not established any management area critical infrastructure. The District is unaware of any loss of functionality or incurred costs to replace or repair infrastructure due to subsidence within the Dsitrict.
		Well 20C1	RMW-176	-150	ft msl	20	ft msl	X						
		Well 15P1	RMW-177	-150	ft msl	20	ft msl	X						
		Well 24Q1	RMW-178	-150	ft msl	20	ft msl	X						
		Well 32M1	RMW-179	-150	ft msl	20	ft msl	X						
		Well 8L1	RMW-180	-150	ft msl	20	ft msl	X						

Table 4. Summary of KGA RMWs with SMCs and Trigger to a Management Area Exceedance

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
Rosedale-Rio Bravo Management Area		1 Bushnell	RMW-050	-33.1	ft msl	48	ft msl	X			~~The RBMA will seek to maintain at least two water level monitoring points for each monitoring zone. To the extent that average water levels in of designated monitoring points has exceeded the minimum threshold of the monitoring zone, it will be considered an undesirable result. To the extent that two of the North, Central, and South of River zones exceed this criterion, the RBMA will consider it an undesirable result to the extent that either the South or East zones exceed this criterion, the RBMA will consider it an undesirable result.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The Minimum Threshold for the RRB MA groundwater storage as calculated by its cumulative balance (Appendix D) will be 0 AF and its Measurable Objective is 663,000 AF. The storage level with respect to the calculated water surface calculations will assume the level Minimum Threshold to be 0.~~ The RRBMA will coordinate with the other KGA MAP's and utilize groundwater levels as a proxy until such time as a basin study can be completed and volumetric metholodogies are adopted. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The Measurable Objective will be any applicable beneficial use COC value that is less than the MCL and a value increase less than 10 percent of the 2015-2020 value. An undesirable result will exist if any applicable beneficial use COC value that is greater that the current MCL and value increase of greater than 10 percent from the 2015-2020 value.~~ A Management Area exceedance is triggered when groundwater quality rises above the established minimum threshold in 40% or more of any representative monitoring wells within the respective Management Area over two-consecutive annual SGMA required monitoring events.	~~Until a regional program is developed, a threshold of 2 feet will be assigned given that there is not a history of subsidence in the RBMA. A measurable objective of less than 1 foot will be assigned and a 2030 milestone of less than 1.5 feet will be assigned.~~ A Management Area exceedance is triggered when the average measured subsidence rate at the representative monitoring sites exceeds the established minimum threshold over a six-year roiling average.
		3 L.R. Stout	RMW-052	-2.7	ft msl	78	ft msl	X						
		5 RBG School	RMW-053	3.5	ft msl	85	ft msl	X						
		18 Cauzza	RMW-057	8.3	ft msl	82	ft msl	X						
		6 P. Enns Domestic	RMW-054	41.9	ft msl	116	ft msl	X						
		16 Section 18	RMW-055	16.0	ft msl	90	ft msl	X						
		17 Blacco HQ	RMW-056	9.0	ft msl	83	ft msl	X						
		19 Parsons	RMW-058	28.3	ft msl	127	ft msl	X						
		20 West I-5	RMW-059	44.0	ft msl	143	ft msl	X						
		22 Virgil Bussell	RMW-060	49.0	ft msl	148	ft msl	X						
		27N_Mayer	RMW-061a	55.0	ft msl	154	ft msl	X						
		30 Enos	RMW-062a	69.0	ft msl	168	ft msl	X						
		9 Chet Reed	RMW-063	101.0	ft msl	209	ft msl	X						
		13 Home Place	RMW-064	88.4	ft msl	196	ft msl	X						
		32 Greeley	RMW-065a	84.0	ft msl	192	ft msl	X						
		36 Harvest Ranch	RMW-066	91.0	ft msl	199	ft msl	X						
		37 RRBWSD Shop	RMW-067a	107.0	ft msl	215	ft msl	X						
		28J Triple	RMW-069b	129.0	ft msl	196	ft msl	X						
		32N Triple	RMW-068a	127.0	ft msl	189	ft msl	X						
		Frito Lay	RMW-?						X					
		Brock South	RMW-?						X					
		Nord Road Water	RMW-?						X					
		I-5 and Stockdale Hwy	RMP-?					X		X				
		Stockdale Hwy and Hwy 43	RMP-?					X		X				
		Allen Road and Hwy 58	RMP-?					X		X				
		Hwy 58 and Hwy 43	RMP-?					X		X				
		Hwy 43 and 7th Standard Rd	RMP-?					X		X				

Table 4. Summary of KGA RMWs with SMCs and Trigger to a Management Area Exceedance

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
				Minimum Threshold		Measurable Objective								
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Value	Unit	Value	Unit	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
Semitropic WSD GSA	MA-2 Buttonwillow	S-02	RMW-119	-200	ft msl	-127	ft msl	X	X		~~Within the Semitropic GSA, a management area will be considered an undesirable result watch area when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Within the Semitropic GSA, a management area will be considered an undesirable result watch area for reduction in groundwater storage when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels, since water elevations serve as a proxy for reduction of groundwater storage.~~ Groundwater levels are used as a proxy for storage. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Within the Semitropic GSA, a management area will be considered an undesirable result watch area for degraded water quality when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels, since groundwater levels serve as a proxy for degraded water quality.~~ Groundwater levels are used as a proxy for water quality. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	Semitropic has identified land subsidence as a data gap. The SWSD GSA has not historically experienced impacts to local infrastructure from the levels of subsidence historically experienced. As such no minimum thresholds for local infrastructure are established for land subsidence at this time.
		S-04	RMW-121	-144	ft msl	-76	ft msl	X	X					
		S-05	RMW-122	-242	ft msl	-161	ft msl	X	X					
		S-1 *(added February 2020)*	RMW-277	-165	ft msl	-80	ft msl	X	X					
		948L02 Cluster 1 of 2	RMW-139	-180	ft msl	-101	ft msl	X	X					
	MA-3 Undeveloped	S-11	RMW-130	-258	ft msl	-195	ft msl	X	X					
		S-12	RMW-131	-264	ft msl	-194	ft msl	X	X					
	MA-1 Pond-Poso	S-06	RMW-123	-306	ft msl	-209	ft msl	X	X					
		S-09A Cluster 1 of 2	RMW-128	-227	ft msl	-146	ft msl	X	X					
		S-13A Cluster 1 of 2	RMW-132	-371	ft msl	-269	ft msl	X	X					
		S-14B Cluster 2 of 2	RMW-135	-335	ft msl	-233	ft msl	X	X					
		26S-23E-15A1	RMW-137	-345	ft msl	-244	ft msl	X	X					
		S-8A Cluster 1 of 2	RMW-126	-331	ft msl	-229	ft msl	X	X					
Westside Districts Water Authority		S#14 *(added November 2020)*	RMW-279	150	ft msl	200	ft msl	X			~~There has been little historical pumping for irrigation in the interior areas of the WDWA due to naturally degrade ground water. The WDWA maintains two sentry coordination zones with adjacent groundwater management areas to the east and will expand its network of monitor wells as part of PMA #1. An undesirable result is identified if a sentry zone records a measured GW level falls below its MT over three consecutive monitor events.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~See response to Lowering of GW Levels.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	Water quality in the WDWA is known to be naturally degraded due to local geology. As a result over 95% of water used in the WDWA is surface water.	Land subsidence is an identified data gap, as such interim MOs/ MTs have been identified for regional critical infrastructure and associated management area infrastructure pursuant to the Basin-wide coordinated GSP subsidence plan. The interim MOs/MTs are valid until 2025 at which time they may be updated based on additional data. Areas of InSAR identified subsidence in the WDWA include the Lost Hills and Belridge oilfields. Recent subsidence studies by the WDWA to assess impacts to the Aqueduct (MP 195-215) have identified sources other than agricultural pumping as the likely primary cause. This material was shared with the subsidence experts within the DWR in early 2020 subsequent to GSP submittal. The WDWA is coordinating with adjacent water districts to assess interim MOs/MTs pending acquiring additional subsidence data as described in the KGA GSP Subsidence Management Plan.
		7108-66 *(added March 2020)*	RMW-275	-115	ft msl	-62	ft msl	X						
		7106-63	RMW-203	59	ft msl	101	ft msl	X						

Deficiency 3 The Plan's Land Subsidence Sustainable Management Criteria do not Satisfy the Requirements of SGMA and the GSP Regulations

In the review of the Plan, DWR staff indicated as deficiency #3 that the Subbasin does not have a "basin wide coordinated GSP subsidence monitoring plan" nor any coordinated Subbasin wide subsidence sustainable management criteria or assessment of critical infrastructure that would be susceptible to substantial interference from future subsidence. The DWR staff is correct that when the original Plan was developed the Subbasin realized that the data gaps to establish and set a monitoring plan for subsidence would not have been based on scientific and defensible data and submitted the Plan indicating just that. Since then, the Subbasin has been very active in having studies completed to assist in having the scientific and defensible data in preparation for the 2025 update but since DWR now has indicated subsidence as a deficiency, the Subbasin has been engaged to achieve the setting of interim sustainable management criteria.

DWR staff recommended the following corrective actions:

1. *The Subbasin's GSAs should coordinate and collectively satisfy the requirements of SGMA and the GSP Regulations to develop the sustainable management criteria for land subsidence.*
2. *The Plan should identify the rate and extent of subsidence corresponding with substantial interference that will serve as the minimum threshold or should thoroughly demonstrate that another metric can serve as a proxy for that rate and extent.*
3. *If land subsidence is not applicable to parts of the Subbasin, the GSP must provide supported justification of such. The supporting information must be sufficiently detailed and the analyses sufficiently thorough and reasonable and must be supported by the best available information and best available science.*

In the 2020 GSPs submittals, the Kern Subbasin coordinated definition for a basin-wide undesirable result for land subsidence is:

> *The point at which significant and unreasonable impacts, as determined by a subsidence rate and extent in the basin, that affects the surface land uses or critical infrastructure.*
>
> *This is determined when subsidence results in significant and unreasonable impacts to critical infrastructure as indicated by monitoring points established by a basin wide coordinated GSP subsidence monitoring plan.*

From the weekly GSA/KGA meetings, the Kern Subbasin worked collaboratively to respond to the DWR deficiency as it relates to subsidence but maintaining the definition of the basin-wide undesirable results due to the diverse and complexity of the subbasin. However, the Kern Subbasin did further identify the occurrence of a single minimum threshold exceedance along either the Aqueduct or the Friant-Kern Canal as an undesirable result with a call-to action for the GSAs/KGA to investigate the exceedance and to address the causation of the exceedance.

Due to the size, diverse and complexity of the subbasin, the Kern Subbasin coordinated and collectively defined infrastructure as:

Regional Critical Infrastructure is defined as infrastructure located within the Subbasin that serves multiple areas of the Subbasin and whose loss of significant functionality due to inelastic subsidence, if caused by SGMA related Subbasin groundwater extractions, would have significant impacts to beneficial users. The Subbasin has collectively determined that the only infrastructure that meets the definition for Regional Critical Infrastructure are the California Aqueduct and the Friant-Kern Canal, refer to Figure 5.

Management Area Critical Infrastructure is defined as infrastructure located within a particular Subbasin Management Area whose loss of significant functionality due to inelastic subsidence if caused by SGMA related Subbasin groundwater extractions would have significant impacts to beneficial users within that Subbasin Management Area. Each Subbasin Management Area has identified their respective Management Area Critical Infrastructure in their Management Area Plan or individual GSP.

Relying on the studies that were completed after the submittal of the Plan on January 31, 2020, but before the deadline per the DWR determination letter of July 27, 2022, the Subbasin was able to work with the California Aqueduct Subsidence Project team (CASP) and presented those results of those studies as well as having an opportunity to present to the DWR SGMA staff. From both of those meetings, the Subbasin developed and finalized two white papers, one for the California Aqueduct and one for the Friant-Kern Canal. Both white papers provided methodology used to set interim sustainable management criteria for the two Regional Critical infrastructure that will be revised in the 2025 update of the Plan. The Subbasin is committed to continue to explore scientific and defensible data to achieve a comprehensive understanding of the root causation of subsidence in the Subbasin.

In the meeting with DWR SGMA staff, they understood the data that was provided by the Kern Subbasin and appreciated the challenge of setting sustainable management criteria in the face of the existing data gaps. However, DWR stated that substantial compliance with the requirements of SGMA requires the development of sustainable management criteria however DWR staff stated that the setting of the sustainable management criteria can include caveats while the Kern Subbasin continues to move forward on studies that will provide scientific and defensible data to include in the 2025 update. Those caveats suggested were:

- The sustainable management criteria can be interim, will only be valid until 2025, and will be updated in the 2025 Plan update
- Due to the complexity of the Kern Subbasin, setting an interim SMC for subsidence, does not require GSAs take responsibility, manage, regulate or otherwise be liable for impacts resulting from actions outside the authority of the GSA or outside the GSA’s ability to manage sustainability under SGMA: and
- That the Kern Subbasin GSAs are not responsible for addressing subsidence caused by activities outside of the jurisdiction of SGMA i.e., extractions from exempt aquifers, or

caused by activities other than extraction of water on behalf of the beneficial users under the purview of SGMA

From the meeting with DWR SGMA staff the Kern Subbasin GSAs collaborated on a "white paper" for the California aqueduct. The "white paper" on the CA aqueduct was developed with basin-wide agreed upon methodology and data. The data that was used, was the little amount of data obtained from the KGA study of 2021 and the Westside study that provided additional information about other activities adjacent to the Ca aqueduct. Upon completion of the draft "white paper", the Kern Subbasin worked to set-up two meeting with the CASP team, however the paragraph below provides more details into those two meetings and the history of the previous meetings. In the last meeting with the CASP team, they indicated their commitment to continue to work collaboratively on establishing a monitoring system (CASP is looking to add one more monitoring well in the Kern subbasin) as well as to develop data-based management objectives and future sustainable management criteria.

Prior to COVID, the Kern subbasin had been meeting with the DWR CASP team to share KGA findings related to non-SGMA related sources of subsidence (e.g., oil field, geotechnical etc.) on the Aqueduct. These studies had been shared with DWR SGMA on a separate occasion. Knowing that DWR SGMA and DWR CASP do not directly communicate on a staff level, the Subbasin recently held two additional meetings (July 8th and June 3rd) to bring new DWR CASP staff up to speed on the findings of KGA subsidence work conducted between 2020 and 2022. At the July 8th meeting, the CASP team expressed that they are still analyzing data for their 2022 Precise Survey Report on the California Aqueduct and as such, they were unable to provide any concrete findings or direction on potential subsidence rates for comparison to the KGA studies. The Kern Subbasin presented an Aqueduct "white paper" to the CASP that details the proposed methodology for evaluating future subsidence rates, and the need to set interim (i.e., through 2025) MO/MTs per the direction of DWR SGMA staff. The Subbasin and DWR CASP also explored mutually beneficial studies that could be implemented between 2022 and 2025 that would address identified data gaps for both the Subbasin and DWR CASP. The CASP team indicated that they understood the white paper approach and were also evaluating non-SGMA related sources of subsidence. As an initial step, DWR CASP had held a meeting with CA Department of Conservation – Geologic Energy Management Division (CAL GEM)to discuss how to account for those activities in their evaluations. The CASP team stated that they believe themselves to be similar to the GSAs as an infrastructure owner, and thus a participant of SGMA not a regulator.

After reviewing the draft white paper, the CASP team followed up with a letter dated 7-10-2022. In their letter the CASP team identified topics where more study and discussion are necessary. For example, methodology on averaging pool subsidence and monitoring corridor details as well as sharing studies that provide information on soluble soils and natural differential compaction. The Kern Subbasin has already completed a preliminary assessment of native soils in parts of the westside of the Subbasin and has plans to expand those studies as part of the assessment of subsidence for the 2025 SGMA update. Further, the Kern Subbasin will also assess the subsidence rates by Aqueduct pool as requested by the CASP. These topics and others will be discussed during a series of monthly technical coordination meetings with CASP. The first monthly technical meeting has been proposed for August 2022.

As the Kern subbasin moves forward, we believe significant data gaps pertaining to the various causes and rates of subsidence in the KCS still exist and, that if addressed, will lead to better defined management objectives for the Aqueduct and help focus planned and future monitoring resources where they will be most effective. We also believe that working jointly and in close consultation with the DWR-California Aqueduct Subsidence Project (CASP) team would multiply the respective expertise and resources of both parties to the benefit of all those dependent on the Aqueduct. The process and methods for establishing interim sustainable management criteria is provided in Section 3.5.3.1, California Aqueduct.

As for the Friant-Kern Canal, the Kern Subbasin is working towards the same relationship as with the CASP team. However, the Friant-Kern Canal does have a more complicated situation to it, with the activities north of the Kern Subbasin and the current subsidence in the northern area. The KGA has engaged Lawrence Berkeley Livermore Lab to assist in both critical infrastructure subsidence assessments to assist in understanding the causation of subsidence in the subbasin and one area will be to understand how the activities to the north impact the Kern Subbasin's ability to become sustainable under the subsidence component. The KGA and its members recognize InSAR is a valuable tool, in conjunction with ground-based geodetic technology, for assessing subsidence in relation to KGA identified critical infrastructure. To ensure the best suite of technologies and methodology are brought to bear on subsidence affecting Subbasin critical infrastructure, the KGA will reassess both the methodology for determining the current interim MOs/MTs and the infrastructure specific MO/MT levels in 2025.The process and methods for establishing interim sustainable management criteria is provided in Section 3.5.3, Friant-Kern Canal.

Pertaining to the management area critical infrastructure, each individual management area plan has addressed and analyzed subsidence as it relates to critical infrastructure in their management areas.

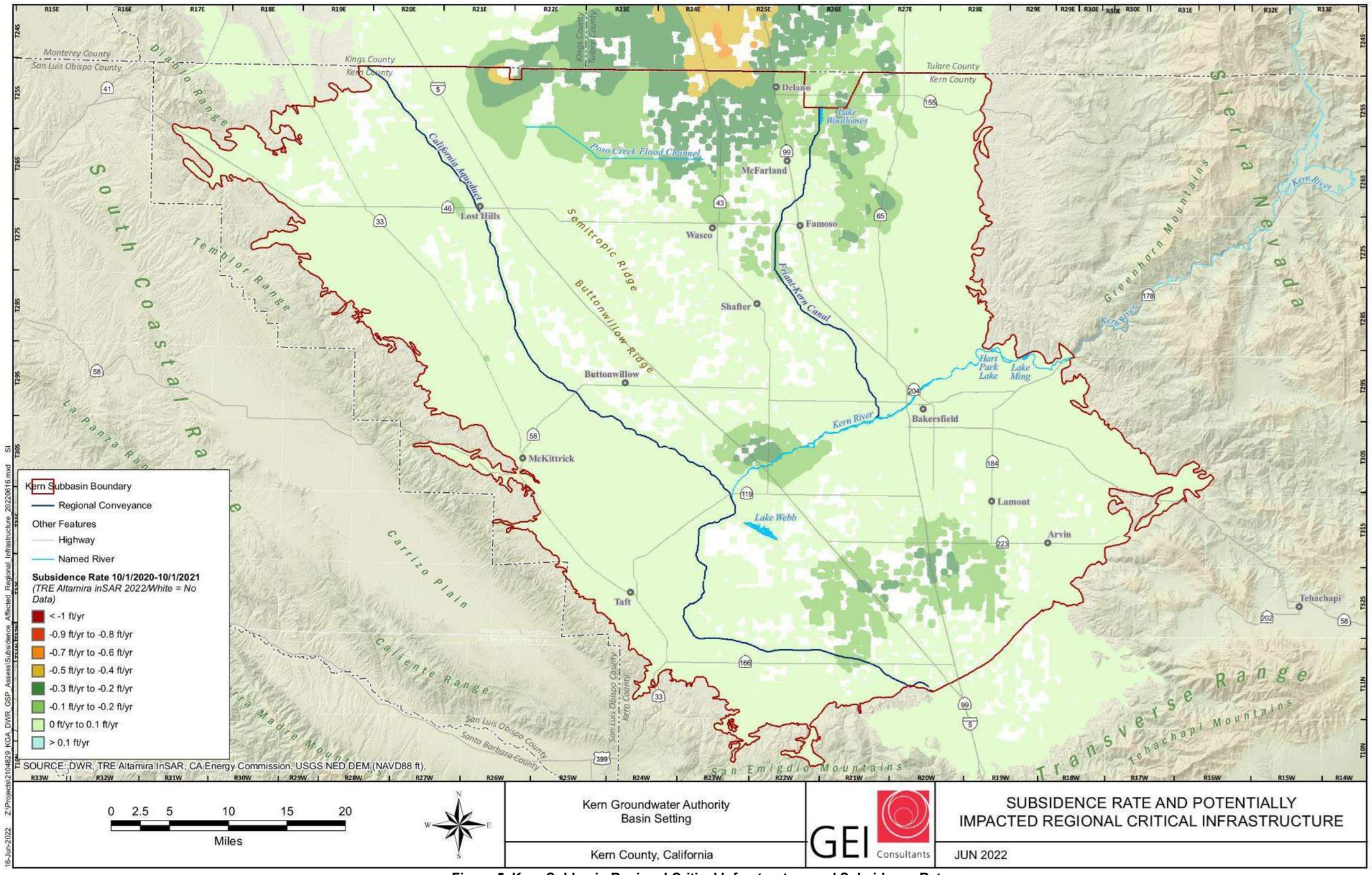

Figure 5. Kern Subbasin Regional Critical Infrastructure and Subsidence Rate

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Kern Groundwater Authority

Groundwater Sustainability Plan

Kern County, CA

Amended July 2022

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List of Abbreviations

µmhos/cm	micromhos per centimeter
µS/cm	microsiemens per centimeter
AB	Assembly Bill
AF	Acre-Feet
Al/Fe-	Aluminum- and Iron-Bearing
AOI	Area of Interest
BGS	Below Ground Surface
BMP	Best Management Practices
BMSL	Below Mean Sea Level
BVARA	Buena Vista Aquatic Recreation Area
C&E	Communications and Engagement Plan
CASGEM	California Statewide Groundwater Elevation Monitoring Program
CDFW	California Department of Fish and Wildlife
CGPS	Continuous Global Positioning System
CIWQS	California Integrated Water Quality System
Cr3	Trivalent Chromium
Cr6+	Hexavalent Chromium
CUP	Conditional Use Permit
CVP	Central Valley Project
CVPIA	Central Valley Improvement Act of 1992
CVRWQCB	Central Valley Regional Water Quality Control Board
CWC	California Water Code
DBCP	Dibromochloropropane
DDW	Division of Drinking Water
DOGGR	Division of Oil, Gas, and Geothermal Resources
DTSC	Department of Toxic Substances
DTW	Depth to Water
DWR	California Department of Water Resources
ESA	European Space Agency
GAMA	Groundwater Ambient Monitoring and Assessment Program
GDE	Groundwater Dependent Ecosystems
GPM	Gallons per Minute
GPS	Global Positioning System
GSA	Groundwater Sustainability Agency
GSP	Groundwater Sustainability Plan
GWE	Groundwater Elevation
HCM	Hydrogeologic Conceptual Model

HMWD	Henry Miller Water District
HR2W	Human Right to Water
ID4	Improvement District 4
ILRP	Irrigated Lands Regulatory Program
InSAR	Inferometric Synthetic-Aperture Radar
IRWM	Integrated Regional Water Management Plan
JPA	Joint Powers Agreement
JPL	Jet Propulsion Laboratory
KCWA	Kern County Water Agency
KDWD	Kern Delta Water District
Kern Fan	Kern Alluvial Fan
KGA	Kern Groundwater Authority
KGET	Kern Golden Empire Television
KRGSA	Kern River Groundwater Sustainability Agency
KRWCA	Kern River Watershed Coalition Authority
LANDSAT	Land Remote-Sensing Satellite
LSCE	Luhdorff & Scalmanini Consulting Engineers
LUST	Leaking Underground Storage Tank
MA	Management Area
Mc	Fanglomerate
MCL	Maximum Contaminant Level
mg/l	Milligrams Per Liter
MGSA	McFarland Groundwater Sustainability Agency
MIT	Mechanical Integrity Test
msl	Mean Sea Level
NASA	National Aeronautics and Space Administration
NCCAG	Natural Communities Commonly Associated with Groundwater
NHD	National Hydrography Dataset
NHI	Nitrate Hazard Index
NKWSD	North Kern Water Storage District
PALSAR	Phased Array type L-band Synthetic Aperture Radar
PPB	Parts per Billion
PPT	Parts per Trillion
RPE	Reference Point Elevation
RWQCB	Regional Water Quality Control Board
SAGBI	Soil Agricultural Groundwater Banking Index
SB	Senate Bill
SDWIS	State Drinking Water Information System
SGMA	Sustainable Groundwater Management Act

SMCL	Secondary Maximum Contaminant Level
SOPAC	Scripps Orbit and Permanent Array Center
SpC	Specific Conductance
SSJMUD	Southern San Joaquin Municipal Utility District
SSURGO	Soil Survey Geographical Database
Subbasin	Kern County Subbasin
SWP	State Water Project
SWRCB	State Water Resources Control Board
TCP	1,2,3-trichloropropane
TDS	Total Dissolved Solids
TNC	The Nature Conservancy
UAVSAR	Unmanned Aerial Vehicle Synthetic Aperture Radar
UIC	Underground Injection Control
UNAVCO	Unmanned Aerial Vehicle Synthetic Aperture Radar
USDA	United States Department of Agriculture
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
UST	Underground Storage Tank
WDR	Waste Discharge Requirements

List of Kern Subbasin Definitions

Management Area	Areas that will be considered against the determination of an undesirable result at the basin level.
Watch Area	Areas with no significant groundwater use and no planned groundwater use as documented in the MAP. Watch areas will be monitored for land use changes and groundwater conditions that could change its designation to a "management area" with specified Sustainable Management Criteria.
Monitoring Area	Areas that have significance within a Management Area for monitoring groundwater conditions or impacts to certain beneficial users but are not considered towards the determination of an Undesirable Result.
MT Exceedance	A single representative monitoring well exceeds its minimum threshold.
MT Trigger	A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events (Definition for Chronic Lowering of Groundwater).
Management Area Exceedance	Exceeding the MT Trigger (i.e., 40% of wells) with a management area is a “Management Area Exceedance,” not an Undesirable Result which is defined at the basin level.
Undesirable Result	The basin-wide definition of unreasonable impacts to beneficial uses and users of groundwater. Should only be referred to as a basin-wide conditions and not a management area condition. The equivalent designation at the management area is a “Management Area Exceedance.”
Urban Management Area Exceedance	A management area exceedance is triggered when groundwater levels decline below established Minimum Thresholds (MT) in any Regional Monitoring Well (RMW) for more than three conservative months.

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Executive Summary

The Kern Groundwater Authority (KGA) Groundwater Sustainability Agency (GSA) covers approximately 1.2 million acres of the Kern County Subbasin's (Subbasin) approximate 1.8 million acres, as defined by the California Department of Water Resources (DWR) Bulletin 118 (see Figure E-1). DWR has identified the Kern Subbasin as a "critically overdrafted basin." The Kern Groundwater Authority includes 12 member entities made up of water districts/agencies, groundwater banking projects, and organized nondistricted lands. The 12 member entities also constitute the KGA Board, with one representative from each member entity. Its boundary stretches along the northwest, northeast, and southern parts of the Subbasin. The KGA was formed for the purpose of:

- Coordinating groundwater management programs and activities;
- Identifying and addressing issues pertaining to sustainable groundwater management;
- Establishing a framework for local groundwater management; and
- Coordinating with other GSAs in the Subbasin.

The KGA provides, through a Joint Powers Agreement, each member the sole right and responsibility to implement SGMA within its respective boundaries and/or management areas, in a manner determined by the member. However, the implementation actions can not interfere with the surrounding members or GSAs in their ability to comply with SGMA. The KGA, as such, provides the critical mechanism for coordination of SGMA related activities between its members as well as with the other GSAs in the Subbasin.

The Subbasin includes 14 organized GSAs. Of these, five GSAs have elected to be included in the Groundwater Sustainability Plan (GSP) of the KGA and two are included in the Kern River Groundwater Sustainability Agency GSP, and three are included in the South of Kern River GSP. Three additional specific GSPs have been prepared in the Subbasin by Buena Vista Water Storage District GSA, Henry Miller Water District GSA, and Olcese Groundwater Sustainability Agency. The six GSAs submitting GSPs have coordinated throughout the development of the GSPs in the Subbasin as indicated in the executed Coordination Agreement and will continue through the implementation of the GSPs.

Kern County produces a wide variety of crops on approximately 900,000 acres, making it a major contributor to California's agricultural economy. One important honor that Kern County is known for is its agricultural industry ranking. Kern County is currently ranked the #1 agricultural producing county in the United States and has been for the last three years with gross value of all agricultural commodities produced in 2017 estimated at $7.25 billion. The top five commodities are grapes, almonds, citrus, milk, and pistachios, which make up more than $4.5 billion (63 percent) of the total value. With this, Kern County agriculture is the largest employer in the region with 1 in every 5 jobs related to agriculture. The communities, economy, and local governments are and have been reliant on Kern County agriculture and are dedicated to preserving the viability of agriculture into the future.

As stated, all the GSAs in the Subbasin have coordinated and collaborated on the development of water modeling budgets (historical, baseline and projected) in the Subbasin. Considerable effort and resources were expended to update the C2VSim model with local data to better represent Subbasin conditions, as described in this GSP. Subbasin-wide water budget results from the numerical model-based water budget show the Subbasin, as a whole, has an overdraft of 324,326 acre-feet per year over the baseline conditions of which the KGA is approximately 239,346 of the deficit.

In response to this level of overdraft the KGA members, in coordination with the other GSAs in the Subbasin, have developed Subbasin-wide Sustainable Management Criteria. This includes required Measurable Objectives and Minimum Thresholds for the Sustainability Indicators relevant to the specific management areas of the Subbasin to protect against the occurrence of Undesirable Results that would cause unreasonable impacts the beneficial users and uses of groundwater in the Subbasin.

The KGA Members have sources of water supplies such as local streams (Caliente, Poso Creek), Kern River, State Water Project and Central Valley Project sources. Each member addresses their own individual water supply sources in greater detail in their individual management area plans along with how the beneficial users in their jurisdiction will participate in achieving sustainability.

The KGA Members have also identified more than 150 projects and management actions ranging from expansion of local and regional conveyance and recharge facilities to take advantage of surplus supplies; new conveyance and recharge projects; and participation in the California WaterFix or other thru-Delta improvement projects. Management actions range from implementing district level fee structures to incentive reduced groundwater pumping; participation in local, regional, and state-wide water markets; and setting allocation for groundwater use by landowner, based on the sustainable yield of management areas.

The coordinated modeling effort shows that implementation and completion of the identified projects and management actions during the implementation period of 2020 to 2040, as stated in the individual management area plans and GSPs from the other GSAs in the Subbasin, would result in an average surplus of 85,578 acre-feet per year over the projected baseline condition simulation.

1 Introduction

The Kern County Subbasin is located at the southern end of the San Joaquin Valley and is known for its rich soil and Mediterranean-like climate, which has made Kern County one of the top producing agriculture regions in the nation. The Kern County Subbasin (Subbasin) is bounded by the Kern County Line and the Tule Groundwater Subbasin on the north; the granitic bedrock of the Sierra Nevada foothills on the east; the Tehachapi mountains on the southeast; and by the marine sediments of the San Emigdio Mountains and Coast Ranges on the southwest and west (DWR, 2006).

California is the nation's largest agricultural producer and is the nation's sole exporter of many agricultural commodities, supplying nearly 99 percent of the almonds, artichokes, and garlic. Recent study by the University of California (November 2019) highlighted the contribution of agriculture to California's economy. Agricultural production, agricultural support, agricultural distribution, and agricultural processing employ nearly 1.2 million people and generated approximately $264 billion in sales in 2018. The San Joaquin Valley is the major contributor to California agricultural economy as can be shown in Table 1-1.

Table 1-1: San Joaquin Valley Contribution to California's Agricultural Economy (2018)

	Agricultural Production	Agricultural Support	Agricultural Distribution	Agricultural Processing
San Joaquin Valley				
Jobs	131,700	116,900	33,700	62,900
Earnings ($ billion)	$6.5	$4.2	$1.9	$4.0
Sales ($ billion)	$24.0	$7.7	$6.4	$31.7
California				
Jobs	325,200	320,000	304,00	245,000
Earnings ($ billion)	$16.2	$18.0	$17.8	$16.0
Sales ($ billion)	$61.0	$32.0	$57.4	$113.0

Sources: California's Working Landscapes, University of California, November 2019

In Kern County a wide variety of crops are produced on approximately 900,000 acres, making it a major contributor to California's agricultural economy. One important honor that Kern County is known for is its agricultural industry ranking. Kern County currently is ranked the #1 agricultural producing county in the United States and has been for the last three years with gross value of all agricultural commodities produced in 2017 estimated at $7.25 billion (Kern County Department of Agriculture and Measurement Standards, 2018). The top five commodities are grapes, almonds, citrus, milk, and pistachios, which make up more than $4.5 billion (63 percent) of the total value. With this, Kern County agriculture is the largest employer in the region with 1 in every 5 jobs related to agriculture. The communities, economy, and local governments are and have been reliant on Kern County agriculture and are dedicated to preserving the viability of agriculture into the future.

Bulletin 118 published by California Department of Water Resources (DWR) in January 1980 states that "The Kern County Water Agency, which covers the Kern County Basin, presently receives about half of its maximum annual entitlement from the State Water Project. If no new lands were to go into production, and the full entitlement from the State Water Project were delivered today, there would be no overdraft in Kern County as a whole." Harvested acres in Kern County have remained relatively steady at an average of 858,000 acres a year with only a 10 percent annual fluctuation from that average between 1980 and 2017.

Since the operation of the State Water Project (SWP) in 1968 until 2007, SWP contractors received on average 86 percent of their entitlement. However, in May 2007, Federal Judge Oliver Wagner overturned a federal scientific study that aimed to protect Delta Smelt in the Sacramento-San Joaquin Delta (Delta) resulting in curtailing Delta export pumping operations to protect the continued existence of the fish. In addition, the State of California experienced a historic extended drought from 2012 to 2016. As a result, SWP contractors received on an average only 48 percent of their entitlement from 2008 to 2016.

Despite the reduction in SWP deliveries, the groundwater overdraft in the entire Subbasin declined from 600,000 acre-feet per year in 1980 (Bulletin 118-80) to a current estimate of 324,300 acre-feet in 2015 (Todd, 2019). This decrease in amount of overdraft per year was achieved through change in crop patterns; increase in agriculture efficiency; and increase in conjunctive use and banking projects throughout the Subbasin.

The current baseline condition estimates that the Subbasin has an average annual overdraft of 324,326 acre-feet per year (Todd, 2019 projected water model). However, with the proposed projects and management actions slated for development and implementation in the Subbasin, it is forecasted that the Subbasin will achieve sustainability by 2040 with an estimated 42,144 acre-feet of annual surplus (see Attachment H). The projects and management actions are described in this Groundwater Sustainability Plan (GSP) and the individual management area plans, attached to this GSP, and the 4 other GSPs prepared within the Subbasin. Collectively, the projects and management actions currently proposed provide a reasonable approach for sustainable management of the groundwater Subbasin and can be adaptively managed to meet future challenges as necessary.

1.1 Sustainable Groundwater Management Act

During the height of the last drought in 2014, the State Legislature passed the Sustainable Groundwater Management Act (SGMA), which consists of a three-bill package of Assembly Bill (AB) 1739 (Dickinson), Senate Bill (SB) 1168 (Pavley) and SB 1319 (Pavley). SGMA as it is called, provides for the local control of groundwater resources while requiring the sustainable management of that groundwater resource. One of the first requirements under the SGMA law was to form/establish a local governance body called a Groundwater Sustainability Agency (GSA) with the local authority to develop, adopt, and implement a GSP. GSPs must document monitoring conditions and establish management criteria to avoid undesirable results and identify potential actions which either maintain and/or achieve sustainable groundwater management by 2040 or 20 years from the date of the adoption of the GSP. The KGA, through a

Joint Powers Agreement, is a recognized GSA in the Subbasin for the purpose of developing a GSP.

Sustainable management of groundwater is defined under SGMA as the "management and use of groundwater in a manner that can be maintained during the planning and implementation horizon without causing undesirable results" (California Water Code (CWC) Section 10721(v)). The undesirable results under SGMA include the significant and unreasonable lowering of groundwater levels; loss of groundwater storage and supply; degradation of water quality; land subsidence; surface water depletion; and sea water intrusion.

Further, under the SGMA law, water basins throughout California were determined or classified to be of "high" or "medium" priority by DWR. The Subbasin was determined or classified to be a "high" priority basin, which triggers the requirement of submittal of its GSP by January 31, 2020.

1.2 Purpose of the Groundwater Sustainability Plan

The purpose of this GSP is to comply with SGMA and serve as a comprehensive foundation for groundwater management within areas of the Subbasin covered by the Kern Groundwater Authority (KGA) by providing information on the current groundwater conditions; establishing the sustainability goals to be achieved through the implementation of management actions and projects; and demonstrating how sustainability will be achieved through the 20-year implementation period.

In the Subbasin, there are five other established GSA groups who are submitting GSPs: the Kern River Groundwater Sustainability Agency (KRGSA), Buena Vista Water Storage District (BVGSA), Henry Miller Water District (HMGSA), Olcese Groundwater Sustainability Agency (Olcese GSA), and South of Kern River (SOKR) group.

Throughout the development process for this Amended GSP, the KGA has considered and coordinated with the other five GSA groups in the Subbasin to comply with the requirement of developing and utilizing consistent data and methodologies throughout the Subbasin, especially the development of a basin-wide basin setting, water model, the setting of sustainable management criteria and water budget allocations, to mention a few of the coordinated efforts. To truly coordinate during the development of the Kern Subbasin GSPs, the water district managers met each Friday to discuss, explore concepts, and engage in robust discussions on methodologies before coming to a consensus. Additionally, the GSAs within the Subbasin coordinated the respective elements of their GSPs necessary for achieving the sustainability goals for the Subbasin as well as Management Actions and Projects. In addition to the weekly meetings with all the GSAs, the KGA held weekly meetings to coordinate and collaborate on the responses to the DWR determination letter as well as at the KGA board meetings, held open discussions providing updates to the responses and how the KGA would be amending their submitted GSP seeking inputs from the public, stakeholders and beneficial users. Also, the KGA members held their board meetings with open discussions to their individual beneficial users in seeking input. A summary of KGA member communications and stakeholder engagement efforts are provided in Table 1-2

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Table 1-2. Summary of Communication and Stakeholder Engagement in Response to DWR's Determination Letter

Management Area	Summary of Communications and Stakeholder Engagement in response to DWR's Determination Letter
KGA	• Weekly meetings for KGA Member Agencies and their Consultants from February 1 through July 25, 2022 to coordinate response to DWR comments • Weekly meetings for Kern Subbasin GSAs and their Consultants from February 1 through July 25, 2022 to coordinate response to DWR comments • Monthly: KGA Executive Director provides informational updates on Determination Letter, and work in progress to address the deficiencies at the KGA Board meetings from February 23 to June 28, 2022 • Monthly Presentations at the Kern County Farm Bureau meetings to discuss updates to the response to DWR comments and SGMA • April 27, 2022: KGA Board meeting – Discussion and adoption of the KGA Exceedance Action Plan during Executive Director public meeting items • May 25, 2022: KGA Board meeting – Discussion and approval of Lawrence Berkeley Livermore Lab proposal on subsidence during Executive Director public meeting items • June 3, 2022: Meeting with CA Aqueduct Subsidence Program Team (CASP) to continue the discussions on subsidence as it relates to the CA Aqueduct. New CASP team members • June 20, 2022: Presentation to the Greater Kern Hispanic Chamber of Commerce on SGMA and DWR comments • June 22, 2022: KGA Board meeting – Discussion and adoption of Kern County Subbasin Sustainability Goals during Executive Director public meeting items. • July 8, 2022: DWR/CASP Team meeting to update on Kern Subbasin subsidence studies and consideration for setting interim SMCs for the CA Aqueduct. • July 12, 2022: Presentation to Teachers Ag Seminar on SGMA and DWR comments.
Cawelo GSA	• Weekly meetings for KGA Member Agencies and their Consultants from February 1 through July 25, 2022 • Weekly meetings for Kern Subbasin GSAs and their Consultants from February 1 through July 25, 2022 • Monthly: Cawelo GSA Board Packages included Progress Reports describing work completed and work in progress to address deficiencies in the DWR Determination Letter. • Monthly: Staff provided updates on the Cawelo GSA and KGA activities and Cawelo GSA coordination activities with other Management Areas during each monthly Cawelo GSA Special Board Meeting. • April 2022: Cawelo GSA coordination meetings with Eastside Water Management Area and North Kern Water Storage District • July 14, 2022: Cawelo GSA Special Board Meeting and Public Hearing for Adoption of Cawelo GSA Groundwater Sustainability Plan, as Revised.
Eastside Water Management Area	• Monthly: Meetings with Eastside Water Management Area (EWMA) Directors and Members to address deficiencies in the DWR Determination Letter • Monthly: Direct email communication with EWMA landowners regarding response to deficiencies in the DWR Determination Letter • March 25, 2022: Coordination with Kern Tulare Water District on addressing deficiencies in the DWR Determination Letter • April 14, 2022: Coordination with Kern Tulare Water District on addressing deficiencies in the DWR Determination Letter • April 19, 2022: Coordination with Cawelo Water District on addressing deficiencies in the DWR Determination Letter • July 7, 2022: EWMA Special Board to approve amended Management Area Plan.
Kern County Water Agency – Pioneer GSA	• Monthly meetings with Pioneer Participants • As needed Joint Operations Committee meetings for coordination which included RRBWSD, KWB, and Pioneer • April 22, 2022: Pioneer met with KRGSA to coordinate Measurable Objectives and Minimum Thresholds • May 12, 2022: Electronic communication included Draft GSP for review • June 23, 2022: Kern County Water Agency Board meeting to approve the Pioneer GSA GSP to provide to the KGA for submittal • As a member of the KGA, all coordination included in the KGA section above is also included.
Kern-Tulare Water District	• Monthly: Provided SGMA updates at each monthly KTWD Board Meeting. • January 14, 2022: Sent SGMA Update flyer to all landowners within the District summarizing KTWD's GSP and implementation of management actions.

Management Area	Summary of Communications and Stakeholder Engagement in response to DWR's Determination Letter
	• March 25, 2022: Coordination meeting with Eastside Water Management Area. • April 14, 2022: Coordination meeting with Eastside Water Management Area. • May 12, 2022: Staff Engineer gave a presentation at the KTWD Board Meeting on KGA's approach to address DWR's deficiencies and summarized the SWRCB May Board Meeting regarding SGMA. • June 9, 2022: Draft Amended KTWD GSP was included in June Board Packet and presented at the KTWD Board Meeting. • July 14, 2022: Amended KTWD GSP was discussed and approved with revisions at the KTWD Board Meeting.
Kern Water Bank Authority	• Participation in weekly meetings with adjoining GSA managers. • Participation in KGA workshops and meetings listed above. • February 11, 2022: Meeting and KWB tour with Paul Gossellin, DWR, Ann Hayden, Environmental Defense Fund, and adjoining GSA directors. • March 22, 2022: Presentation and tour with Hancock College. • April 21, 2022: Presentation and tour with the Water Education Foundation. Attendees from, Bureau of Reclamation, Delta Stewardship Council, DWR, CA State Water Board, UC ANR/Cooperative Extension, US Geological Survey, Valley Water. • May 10, 2022: Teleconference with UC Extension, Sustainable Agriculture and Land Conservation Program, regarding conservation of agricultural lands. • May 26, 2022, May 17, 2022, and June 28, 2022: Meeting with Kern Subbasin CA Aqueduct Subsidence Committee, including adjoining GSA's. • June 14, 2022: KWBA Board meeting (open session) to discuss revisions to KGA GSP chapter report. • July 12, 2022: KWBA Board meeting (open session) to approve Revised KGA GSP chapter report and submittal.
North Kern Water Storage District and Shafter-Wasco Irrigation District	• Weekly meetings for KGA Member Agencies and their Consultants from February 1 through July 25, 2022 • Weekly meetings for Kern Subbasin GSAs and their Consultants from February 1 through July 25, 2022 • Monthly: NKWSD Board Packages included Progress Reports describing work in progress to address deficiencies in the DWR Determination Letter. • Monthly: General Manager's provided updates on KGA activities and District coordination with adjacent management areas during each monthly Board Meeting. • March 9, 2022: NKWSD RMW coordination meeting with KRGSA • March 31, 2022: NKWSD RMW coordination meeting with Cawelo WD • April 7, 2022: Management area coordination meeting with Shafter-Wasco, North Kern, Rosedale-Rio Bravo, and 7th Standard Annex. • April 18, 2022: NKWSD RMW coordination meeting with KRGSA • April 27, 2022: Meeting with Cities of Shafter and Wasco Staff to discuss DWR Determination Letter and work in progress to resolve the deficiencies. • May 20, 2022: NKWSD SGMA Landowner Committee meeting, presentation on Determination Letter and work in progress to resolve deficiencies. • July 12, 2022: NKWSD SGMA Landowner Committee meeting, present Amended Management Area Plan. • July 13, 2022: SWID Special Board Meeting to approve the Amended Management Area Plan. • July 15, 2022: NKWSD Special Board Meeting to approve the Amended Management Area Plan. • As a member of the KGA, all coordination included in the KGA section above is also included.
Rosedale-Rio Bravo Water Storage District	• Monthly: RRBWSD Board Packages included Progress Reports describing work in progress to address deficiencies in the DWR Determination Letter. • February 22, 2022: RRBMA Stakeholder Workshop #11 • March 9, 2022: ID4, NKWSD, SWID and 7th Standard Annex, SWSD Coordination Meetings • March 14, 2022: SWSD Coordination Meeting • April 7, 2022: NKWSD, SWID and 7th Standard Annex, SWSD Coordination Meeting

Management Area	Summary of Communications and Stakeholder Engagement in response to DWR's Determination Letter
	• April 12, 2022: RRBMA Stakeholder Workshop #12 • April 13, 2022: NKWSD Coordination Meeting • April 29, 2022: RRBMA Stakeholder Workshop #13 • June 14, 2022: RRBMA Stakeholder Workshop #14 • June 28, 2022: RRBMA Stakeholder Workshop #15 • July 12, 2022: RRBMA Stakeholder 2020 Revised Plan Hearing #2
Semitropic GSA	• February 9, 2022: GSA Board Meeting MA2 update and review of DWR Comments on GSP • February 11, 2022: Workshop with DWR regarding DWR Determination Letter • February 17, 2022: Coordination Meeting (SWID, North Kern WSD, South San Joaquin MUD) • February 28, 2022: Coordination Meeting (RRB) • March 9, 2022: Coordination Meeting (RRB) • March 9, 2022: GSA Board Meeting Review of DWR comments on GSP • March 25, 2022: Coordination Meeting (SWID) • April 5, 2022: Coordination Meeting (Lost Hills Utility District) • April 13,2022: GSA Board Meeting Review of Beneficial Uses and Users, Draft SGMA Mitigation Plan, MA2, Deficiency 1 and 2 items • May 11, 2022: GSA Board Meeting Review approach to responses to DWR comment, Basin coordination and updates • May 25, 2022: Special GSA Board Meeting Review draft revisions to Management Area Plan, Domestic Well Mitigation Program • June 8, 2022: GSA Board Meeting Review draft revisions to Management Area Plan • June 21, 2022: GSA Board Meeting Review draft revisions to Management Area Plan • July 13, 2022: GSA Board Meeting Adopt Revised Management Area Plan
Shafter-Wasco Irrigation District 7th Standard Annexation	• Monthly: SWID MA2 Landowner meetings for discussions to address DWR deficiencies and planning for revisions to MAP. • Monthly: SWID MA2 Manager provided updates on KGA activities and coordination with adjacent management areas during each monthly Board Meeting. • March 9, 2022: SWID coordination meeting with Rosedale-Rio Bravo Water Storage District and other MAs. • April 7, 2022: SWID coordination meeting with Rosedale-Rio Bravo Water Storage District and other MAs. • July 6, 2022: SWID MA2 Landowner Workshop. • July 13, 2022: SWID Board Meeting to consider approval of the MA2 Amended Management Area Plan.
Southern San Joaquin Municipal Utility District	• Monthly: SSJMUD Board Meetings included a review of Progress Reports describing work in progress to address deficiencies in the DWR Determination Letter. • Monthly: SSJMUD Board Meetings included an overview of KGA activities and District coordination. • February 9, 2022: SSJMUD Board Meeting Review of DWR Comments on Management Area Plan • February 11, 2022: Workshop with DWR regarding DWR Determination Letter • March 9, 2022: SSJMUD Board Meetings review of DWR Determination Letter and identified deficiencies • April 12, 2022: SSJMUD Board Meeting Review of Proposed Revisions to Address Deficiency 1 and Deficiency 2; Approval of KGA Exceedance Policy

Management Area	Summary of Communications and Stakeholder Engagement in response to DWR's Determination Letter
	• May 11, 2022: SSJMUD Board Meeting Review of proposed responses to DWR Determination Letter • June 8, 2022: SSJMUD Board Meeting Review of Beneficial Uses and Users, Revised Well Impact Analysis, and Domestic Well Mitigation Program. • June 20, 2022: SSJMUD Special Board Meeting to approve the Amended Management Area Plan • As a member of the KGA, all coordination included in the KGA section above is also included.
West-Kern Water District	• Weekly meetings for KGA Member Agencies and their Consultants from February 1 through July 25, 2022 • Weekly meetings for Kern Subbasin GSAs and their Consultants from February 1 through July 25, 2022 • Monthly: WKWD Board Packages included updates describing work in progress to address deficiencies in the DWR Determination Letter. • Monthly: During regular board meeting, General Manager's report provided updates on KGA activities and any coordination discussions with adjacent management areas. • July 13, 2022, Special Board meeting to approve Revises Management Area Plan
Westside District Water Authority	• Weekly meetings with Board Director, General Manager, and lead consultant to provide updates on work in progress to resolve deficiencies. • April 19, 2022: WDWA Special Board Meeting to approve SMC's and Exceedance Policy. • June 2, 2022: Coordination meeting with neighboring GSA's to update groundwater level SMC's. • July 13, 2022: WDWA Special Board Meeting to approve Amended Management Area Plan.

1.3 Sustainability Goal

Under Section 354.24 of the GSP emergency regulations, each agency shall establish in its GSP a sustainability goal for the basin that culminates in the absence of undesirable results within 20-years of the applicable statutory deadline. This GSP and the GSPs of the other GSAs in the Subbasin have collaborated on the development of the following sustainability goal for the Kern County Subbasin.

The sustainability goal of the Kern County Subbasin is to:

- *Collectively bring the Subbasin into sustainability and to maintain sustainability over the implementation and planning horizon.*
- *Achieve sustainable groundwater management in the Kern County Subbasin through the implementation of projects and management actions at the member agency level of each GSA.*
- *Maintain its groundwater use within the sustainable yield of the basin as demonstrated by monitoring and reporting groundwater conditions.*
- *Operate within the established sustainable management criteria, which are based on the collective technical information presented in the GSPs in the Subbasin.*
- *Protect beneficial users for municipal and domestic drinking water supply wells*

In addition, sustainability within the KGA will focus on maintaining the economic viability of agriculture while also balancing the needs of all beneficial users that rely on groundwater resources. To achieve this, KGA members manage to checkbook water budgets as well as implement projects and management actions within their respective management areas to sustain water levels at or above the measurable objectives to mitigate impacts to beneficial users. Through the coordinated meetings regarding beneficial uses and users, all KGA members have agreed that their groundwater management objective is to avoid dewatering municipal wells and any unmitigated domestic wells. Table 1-3 and Figure 1-1 provides a summary of the number of wells for each beneficial use category and the potential impact to each category as a percent of wells that could be dewatered at the measurable objectives. Table 1-4 and Figure 1-2 provides the summary of potential impact at the minimum thresholds. Wells impacted at the measurable objectives or minimum thresholds are expected to be mitigated through well mitigation programs developed at the management area plan level.

Table 1-3. NEW Expected Well Impacts at the Measurable Objective

	Number of Wells				Number of Dewatered Wells			
	M	D	A	% M/D Wells	M	D	A	% M/D Wells
CWD	0	93	197	32%	0	0	0	0%
EWMA	2	11	41	24%	0	0	0	0%
NK	1	22	161	13%	0	0	2	0%
KTWD	0	18	94	16%	0	0	0	0%
RRB	24	149	156	53%	0	0	0	0%
SWID	16	68	118	42%	0	8	7	10%
SSJMUD	19	67	243	26%	0	13	11	15%
SWSD	4	138	763	16%	0	10	4	7%
WDWA	0	2	35	5%	0	0	0	0%
WKWD	13	0	0	100%	0	0	0	0%
7th Standard	2	9	19	37%	0	2	0	18%
Total	81	577	1827	26%	0	33	24	5%

0 Municipal wells going dry at the MT's
Anyone over 5% of Domestic wells dewatered required to put together a mitigation plan

M=Municipal, D=Domestic and Small Community, A= Agircultural and Industrial

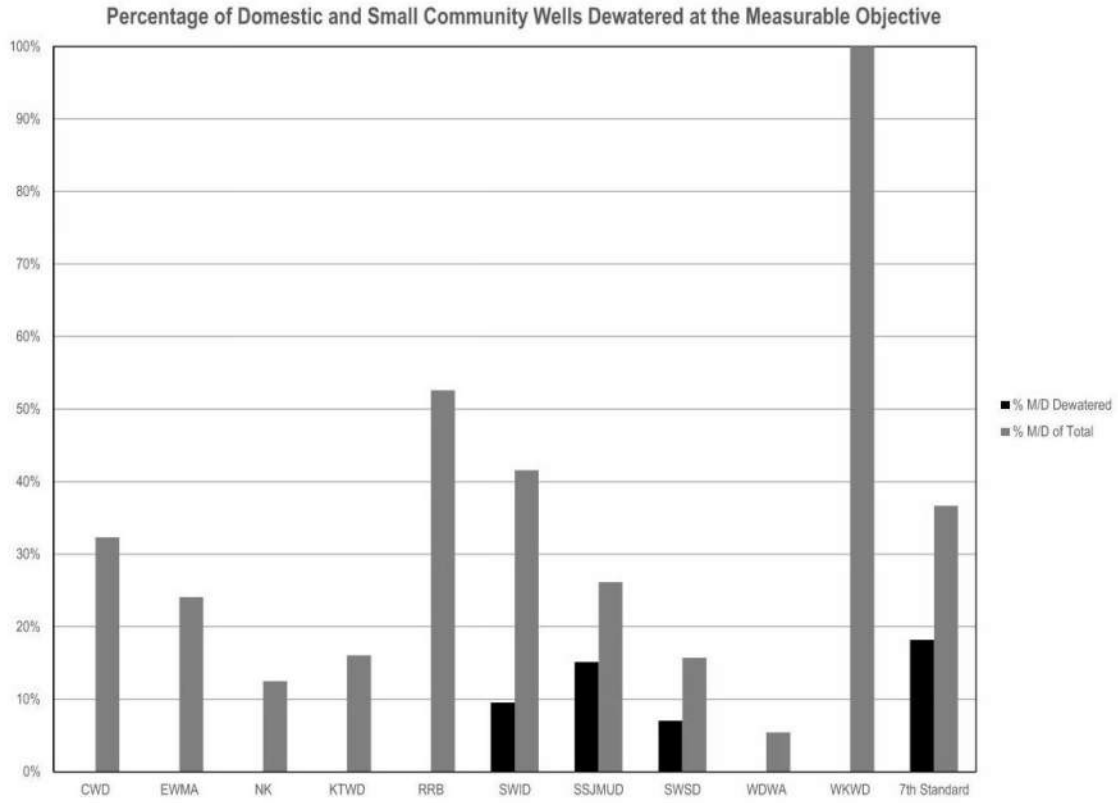

Figure 1-1. NEW Percentage of Domestic and Small Community Wells Dewatered at the Measurable Objective

Table 1-4. NEW Expected Well Impacts at the Minimum Threshold

	Number of Wells				Number of Dewatered Wells			
	M	D	A	% M/D Wells	M	D	A	% M/D Wells
CWD	0	93	197	32%	0	3	1	3%
EWMA	2	11	41	24%	0	3	0	23%
NK	1	22	161	13%	0	2	5	9%
KTWD	0	18	94	16%	0	0	0	0%
RRB	24	149	156	53%	0	21	0	12%
SWID	16	68	118	42%	0	22	13	26%
SSJMUD	19	67	243	26%	0	29	25	34%
SWSD	4	138	763	16%	0	41	52	29%
WDWA	0	2	35	5%	0	0	0	0%
WKWD	13	0	0	100%	0	0	0	0%
7th Standard	2	9	19	37%	0	5	2	45%
Total	**81**	**577**	**1827**	**26%**	**0**	**126**	**98**	**19%**

0 Municipal wells going dry at the MT's
Anyone over 5% of Domesiic wells dewatered required to put together a mitigetion plan

M=Municipal, D=Domestic and Small Community, A= Agircultural and Industrial

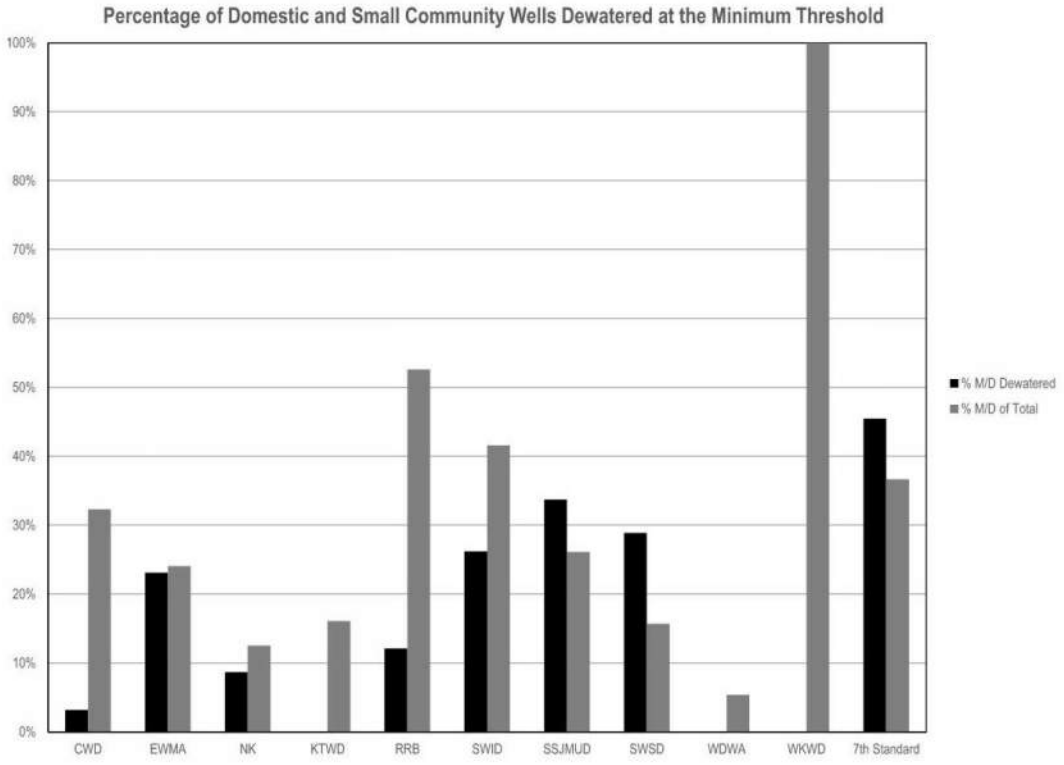

Figure 1-2. NEW Percentage of Domestic and Small Community Wells Dewatered at the Minimum Threshold

1.4 Agency Information

In complying with Section 354.6 of the GSP emergency regulations, the following section provides agency information, legal authority, and estimated cost of plan implementation for the KGA and its members in the Subbasin.

Agency's Name:	Kern Groundwater Authority
Agency's Address:	1800 30th Street, Suite 280
Agency's Phone Number:	(661) 479-7171
Agency's Website:	http://www.kerngwa.com/index.html
Contact Person:	Patty Poire
Contact Person's Title:	Executive Director, KGA

1.4.1 Organization and Management Structure of the KGA GSA

The Subbasin includes 14 organized GSAs, as shown in Figure 1-3. Table 1-5 indicates if the GSA have elected to prepare an independent GSP. In total, 14 GSAs in the Subbasin are developing six GSPs.

Table 1-5: Groundwater Sustainability Agencies in Kern County Subbasin

GSA Name	Independent GSP	GSP Name
Buena Vista Water Storage District GSA	Yes	BVGSA GSP
Henry Miller Water District GSA	Yes	HMWD GSA GSP
Cawelo Water District GSA	No	KGA GSP
Kern Groundwater Authority GSA	Yes	KGA GSP
City of McFarland GSA	No	KGA GSP
Pioneer GSA	No	KGA GSP
Semitropic Water Storage District GSA	No	KGA GSP
West Kern Water District GSA	No	KGA GSP
Greenfield County Water District GSA	No	KRGSA GSP
Kern River GSA	Yes	KRGSA GSP
Olcese Water District GSA	Yes	OGSA GSP
Arvin Groundwater Sustainability Agency	Yes	SOKR GSP
Wheeler Ridge-Maricopa GSA	Yes	SOKR GSP
Tejon-Castac Water District GSA	Yes	SOKR GSP

The KGA, as a Subbasin coordination group, was created prior to the enactment of SGMA with the intent of establishing a framework for the coordinated management of the groundwater basin underlying the San Joaquin Valley portion of Kern County, including the preservation and maintenance of local control over groundwater resources and to provide future certainty for basin users. With the passage of SGMA, the KGA elected to form a GSA under a Joint Powers Agreement (JPA) (Attachment A), thereby assuming responsibility for development of a comprehensive GSP for an area which includes agricultural lands, urban and industrial development as well as oil fields.

The KGA GSA covers approximately 1.3 million acres of the Subbasin's approximate 1.8 million acres and includes 12 member agencies and non-districted lands (Table 1-6 and Figure 1-4). The 12 member agencies also constitute the KGA Board, with one representative from each agency. The KGA also includes a single associate member, the Eastside Water Management Authority, who consistent with SGMA, is a non-voting member of the GSA and represents lands outside of a KGA member agency boundary. The Eastside Water Management Authority was formed by landowners who are non-districted and are working towards becoming a public agency in the future.

Table 1-6: Kern Groundwater Authority Member Agencies

Member Agencies	
Cawelo Water District[1]	Rosedale-Rio Bravo Water Storage District
City of Shafter	Semitropic Water Storage District[1]
Kern County Water Agency - Pioneer Project[1]	Shafter-Wasco Irrigation District
Kern-Tulare Water District	Southern San Joaquin Municipal Utility District
Kern Water Bank Authority	West Kern Water District[1]
North Kern Water Storage District	Westside District Water Authority
Associate Members	
Eastside Water Management Area	

1 – Groundwater Sustainability Agency

1.4.2 SOKR GSA Formation

The KGA submitted the KGA GSP to DWR in January 2020 on behalf of its members. The structure of the 2020 KGA GSP included an overarching or umbrella section and specific management area plan ("MAP") chapters for each of its member districts. After receiving an incomplete assessment from DWR, the KGA immediately began working diligently with its members and Kern Subbasin partners to address the DWR recommendations and deficiencies.

On April 21, 2022, three KGA members – Wheeler Ridge-Maricopa Water Storage District, Tejon-Castac Water District, Arvin-Edison Water Storage District – provided the KGA notice they planned to develop their own GSP as part of the revision in response to the DWR incomplete assessment. These members are geographically similar and plan to revise each of their respective MAPs and submit these sections together as the South of Kern River ("SOKR") GSP. On May 20, 2022, the SOKR members requested the KGA amend its GSP to exclude the SOKR GSAs from the revised KGA GSP. In addition to the removal, this request asked that the SOKR members be allowed to continue KGA membership until they adopted the SOKR GSP, in late July of 2022.

The KGA had significant concerns with the timing of the SOKR withdrawal and the ability of the KGA to both respond to the DWR incomplete assessment and achieve the changes necessary to facilitate the SOKR withdrawal. Despite these concerns, the KGA members have been dedicated to working with the SOKR GSAs to ensure the Kern Subbasin remains compliant with the requirements of SGMA. Specifically, the KGA has worked diligently to ensure the SOKR withdrawal will not disrupt its procedural compliance with SGMA, ensure the Subbasin remains

entirely managed, and develop comprehensive responses to DWR in response to its assessment. The KGA and the SOKR GSAs met with DWR to propose that the KGA submit the revised KGA GSP in response to the DWR assessment in two parts: the revised KGA GSP and the SOKR GSP.

On May 20, 2022, DWR provided a confirmation that, although it would prefer a single GSP for the subbasin, it would not be precluded from accepting the KGA GSP in two parts, from the KGA and SOKR respectively. DWR did not provide this guidance without reservation, but rather, provided the explicit cautions, noting this approach must:

- Ensure that there is no lapse in GSP coverage for the Subbasin; a lapse in coverage would result in an inadequate determination;
- Provide a uniform, basin-wide response to the deficiencies identified in the Incomplete Determination; if the SOKR withdrawal hinders, confuses, or creates additional deficiencies the subbasin would be determined inadequate;
- Amend the Coordination Agreement and ensure all parties sign the amended coordination agreement; if the Coordination Agreement does not include all parties, the revised GSPs cannot be submitted to DWR;
- Ensure the SOKR GSP is complete and contains all the necessary information of an individual GSP; an incomplete SOKR GSP would result in an Inadequate Determination for the entire Kern County Subbasin.

The KGA has been working diligently to achieve the above requirements and protect its members from exposure to an inadequate determination. From a technical perspective, the KGA revised its GSP to remove the SOKR MAPs from its GSP. In addition, all KGA technical materials have been amended to ensure the KGA does not include or otherwise exercise jurisdiction over the SOKR member district areas. On June 22, 2022, the KGA was briefed and understood that the Provision of Jurisdiction Agreements with SOKR districts would expire upon the SOKR districts no longer being members of the KGA. This Provision of Jurisdiction Agreement provided to Wheeler and Arvin with jurisdiction that allowed the districts include out of district lands in their GSAs to ensure the SOKR GSAs are able to obtain valid jurisdiction for management outside of their service area boundaries. The termination of jurisdiction was coordinated to ensure the KGA continued to provide jurisdiction for as long as possible through KGA membership to avoid any lapse in coverage. The KGA amended the Coordination Agreement to include the SOKR agencies, amend all appendices to be consistent with the amendments in the Kern Subbasin GSPs and account for added SOKR GSA membership. The KGA presented the revised Coordination Agreement to the Kern Subbasin Coordination committee in June of 2022 to ensure all the Subbasin Coordination Committee members were able to review, adopt, and execute by the respective Boards by late July 2022. At the June 22, 2022, KGA meeting, the Board approved the revised Coordination Agreement.

1.4.3 Non-Districted Lands

At the inception of the KGA, Kern County was a member of the KGA to represent lands within the Subbasin and outside of the jurisdiction of a local agency participating in a GSA in the

Subbasin – non-districted lands. However, in December 2018, Kern County supervisors elected to withdrawal from the KGA as well as SGMA, and from that action, approximately 440,950 acres of non-districted lands became not covered by a GSA (Figure 1-5A). At the December 19, 2018 KGA Board meeting and after several meetings with staff from both the State Water Board and DWR regarding Kern County's departure, the direction provided by the KGA Board was to reach out to the non-districted landowners and extend coverage; however, those non-districted landowners who are not wanting to participate will be eventually removed from the KGA GSA boundary and will then be required to report directly to the State Water Resources Control Board (State Water Board). The KGA reached out to those landowners via a mass mail-out to advise of the County's decision and extended the opportunity to participate in SGMA through the member agencies of the KGA. The coverage to the non-districted lands was handled by the landowners entering into agreements with the KGA member agencies, including associate members, for SGMA coverage under the KGA members' respective management area plans. Assistance from Kern County Water Agency made this coverage possible by lending its jurisdiction under SGMA to the KGA members' who have agreements with those non-districted landowners. Through the efforts by the member agencies of the KGA, approximately 242,180 acres of the non-districted lands will be covered and will be compliant with SGMA. The remaining 198,770 acres not covered are typically grazing lands or lands associated with oil production where minimal or no groundwater usage exists. The decision to extend SGMA coverage and to revise the KGA GSA boundary to remove non-districted lands not participating with KGA member agencies has been presented and discussed openly at public KGA board meetings since the initial discussion at the December 2018 board meeting. Since the December 2018 Board meeting decision, the KGA has continued to oversee approximately 198,770 acres of non-districted lands that did not have agreements with its members. In 2022 the KGA retained those acres within its GSA boundary. The decision to retain the non-districted lands was made to provide the Kern Subbasin complete coverage in compliance with SGMA and stemmed from follow-up meetings with State Water Board and DWR Staff. Following decision, the KGA stepped up to cover non-irrigated and irrigated lands under their GSP. Other GSAs also extended coverage to landowner lands within or adjacent to their GSA.

For those non-districted lands not covered by a member of the KGA, the six Subbasin GSAs have coordinated to cover all those non-districted lands in the water modeling effort for the historic, baseline, and future projections. Today, the future projection water modeling results demonstrate that the entire Kern Subbasin (including the non-districted lands) will be sustainable with implementation of proposed projects and management actions activities by 2040. Also, the Kern Subbasin GSAs have agreed to continue to coordinate on the monitoring of those non-districted lands going forward and to include the monitoring data in the annual reporting requirements of the Subbasin, thus covering the entire basin in the GSP. Figure 1-5A reflects the data obtained through the development of the Subbasin's annual reports showing little to no consumptive use (measured as evapotranspiration (Et)) over the non-district lands. Figure 1-5B shows 2021 consumptive use in the Subbasin, which generally shows there is little to no consumptive use in the non-district lands. Figure 1-6A reflects water well locations within the non-districted area that supports the annual report data that little to no consumptive use occurs. Additionally, Figure 1-6B shows all representative monitoring wells in the Kern Subbasin in

proximity to the non-districted lands. One important requirement under SGMA is to consider all beneficial users in the setting of sustainable management criteria and to monitor those activities related to groundwater extraction. With almost no water wells in most of the non-districted lands thus no beneficial users to consider, these areas are considered as “management area watch areas”. The low consumptive use values on these non-districted lands demonstrates the lack of groundwater extractions in these areas and justification for consideration as “management area watch areas” Figure 1-5A is the result of satellite imagery for the entire Kern Subbasin generated for use in the annual report and updating the water model (C2VSim) for the entire Kern Subbasin. The lack or even no use of groundwater in these non-districted lands justifies the designation of these areas as “watch areas,” where no significant groundwater use currently exists or is planned consistent with current land use zoning. These watch areas will be monitored for land use changes and groundwater conditions that could change its designation and then at that time, the KGA will develop sustainable management criteria for the area. Prior to the 2025 GSP update, the KGA and the Kern Subbasin will be working on a Basin Study that will ultimately provide the native yield of native groundwater for the Subbasin. This will allow the GSAs to determine native sustainable yield allocations for each acre and process for the allocation of groundwater resources to non-districted lands. This process will provide water extraction limit for those lands that don’t have other water sources such as State Water Project, Friant Water Project, Kern River, or other surface water sources through the remaining implementation horizon and beyond.

Figure 1-5A reflects some irrigated non-districted lands located in the middle of the Kern Subbasin. Those irrigated non-districted lands are lands owned by the City of Los Angeles where they bring in their “sludge” to comply with their wastewater discharge requirements. These lands and the wastewater are used for the production of forage crops. There is one well located within the property to assist in the activities necessary to comply. The City of Los Angeles also has an agreement with the City of Bakersfield to accept their wastewater from their plant #3 (Order No. R5-2009-0087). The City of Bakersfield’s wastewater permit reflects that about 49-acre feet per day of treated effluent is delivered to the City of Los Angeles property. Between the delivery of wastewater sludge, deliveries from the City of Bakersfield and the one well, the City of Los Angeles has been able to comply with their discharge permit. To monitor these activities under SGMA, there are several monitoring wells of the Kern subbasin monitoring network to obtain seasonal water levels. Figure 3-4 in Section 3 provides the location of each monitoring well. The City of Los Angeles has also been very involved in that they attend meetings and understand the SGMA process.

Other small, irrigated lands shown in Figure 1-6 are also monitored through the Kern subbasin monitoring network (Figure 3-4, Section 3). Most of those lands are located adjacent to other GSAs or water districts and the landowners have properties in both the non-districted area and/or the adjacent GSA or water district.

As indicated above, the non-districted lands are monitored through the Kern Subbasin monitoring network or have no beneficial users or uses on the lands. For those lands that are irrigated, they are covered by the sustainable management criteria of the neighboring monitoring

wells as well as the adjacent KGA member. For those lands with no beneficial users or uses which is 98% of the lands, those lands are considered management area watch areas because there are no groundwater extractions due to no existing water wells.

To facilitate the implementation of the KGA GSP, KGA's jurisdictional area is divided into management areas formed by the portion of the Subbasin that underlies the boundaries of each member agency and any associated non-districted lands. Each member agency of KGA has developed its own management area plan to support the development of this KGA Umbrella GSP and collectively are used as reference for details regarding the variances between management areas throughout this report.

KGA includes one disadvantaged community (DAC) that has been a full voting member agency from the beginning of the formation of the exclusive GSA – the City of Shafter. Sustainable management for the City of Shafter is covered in North Kern Water Storage District & Shafter-Wasco Irrigation management area plan. The City of Shafter has been actively engaged with the KGA and its respective management area plan development.

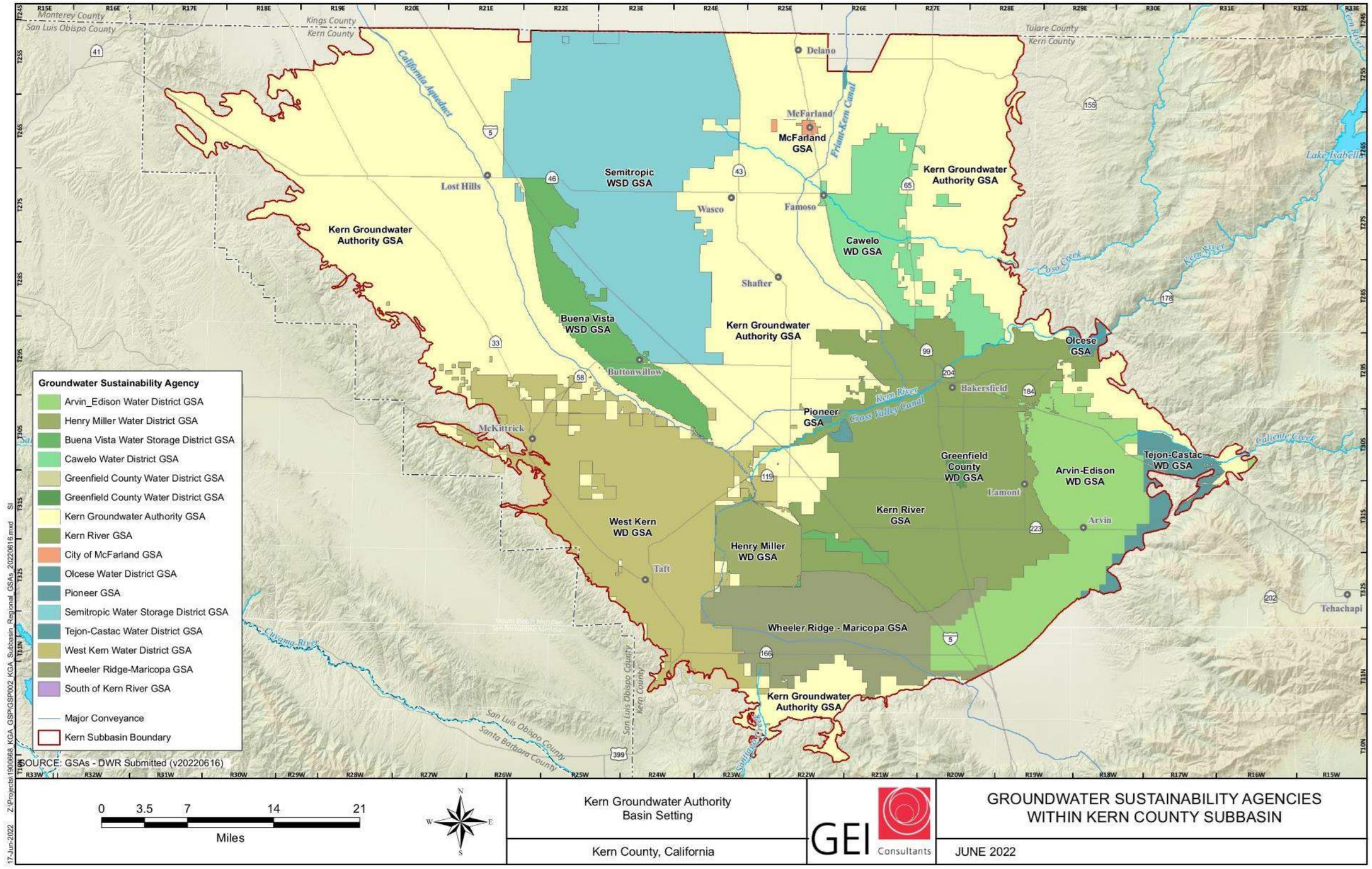

Figure 1-3. Groundwater Sustainability Agencies within Kern County Subbasin

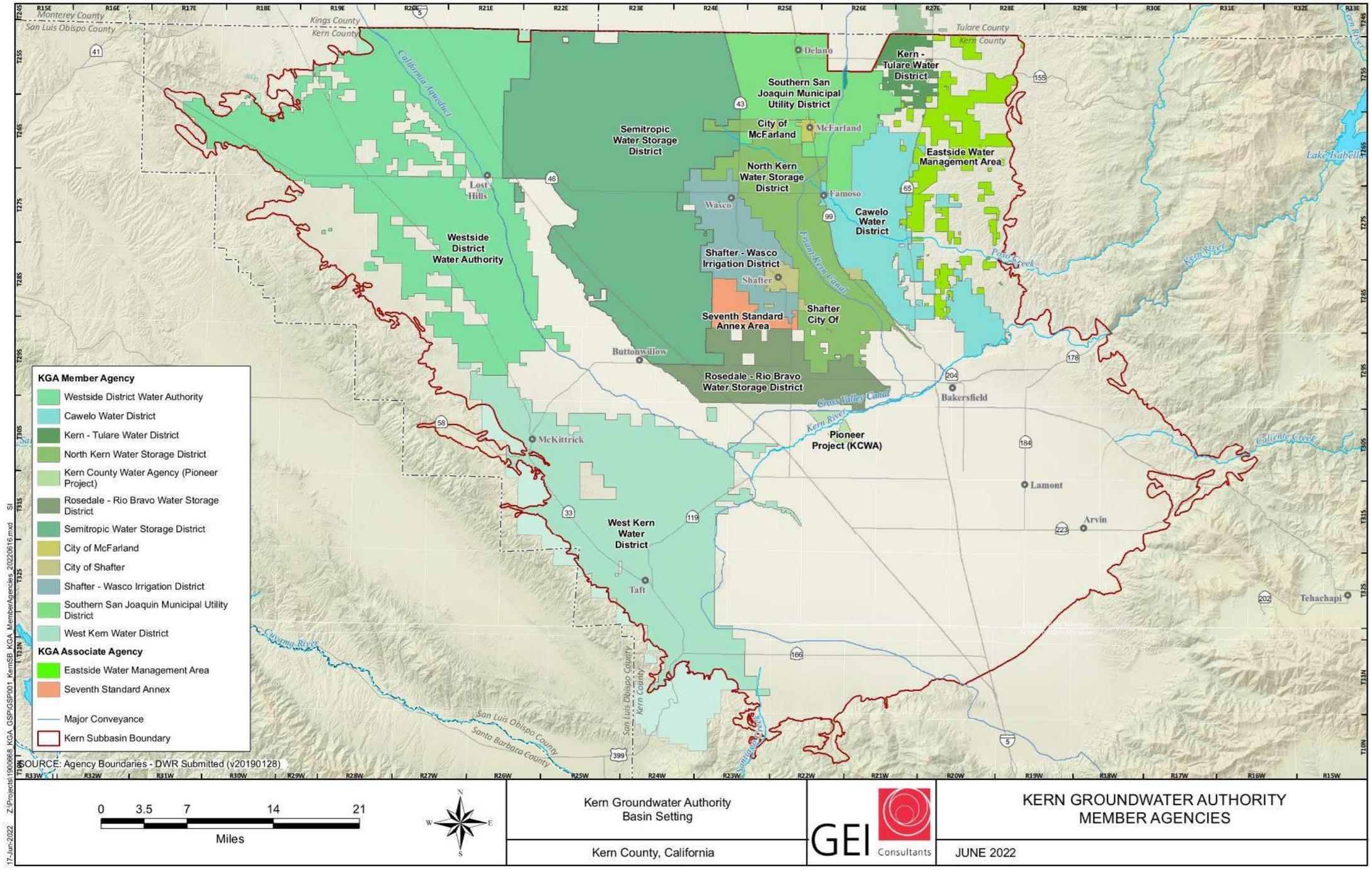

Figure 1-4. Member Agencies of the Kern Groundwater Authority

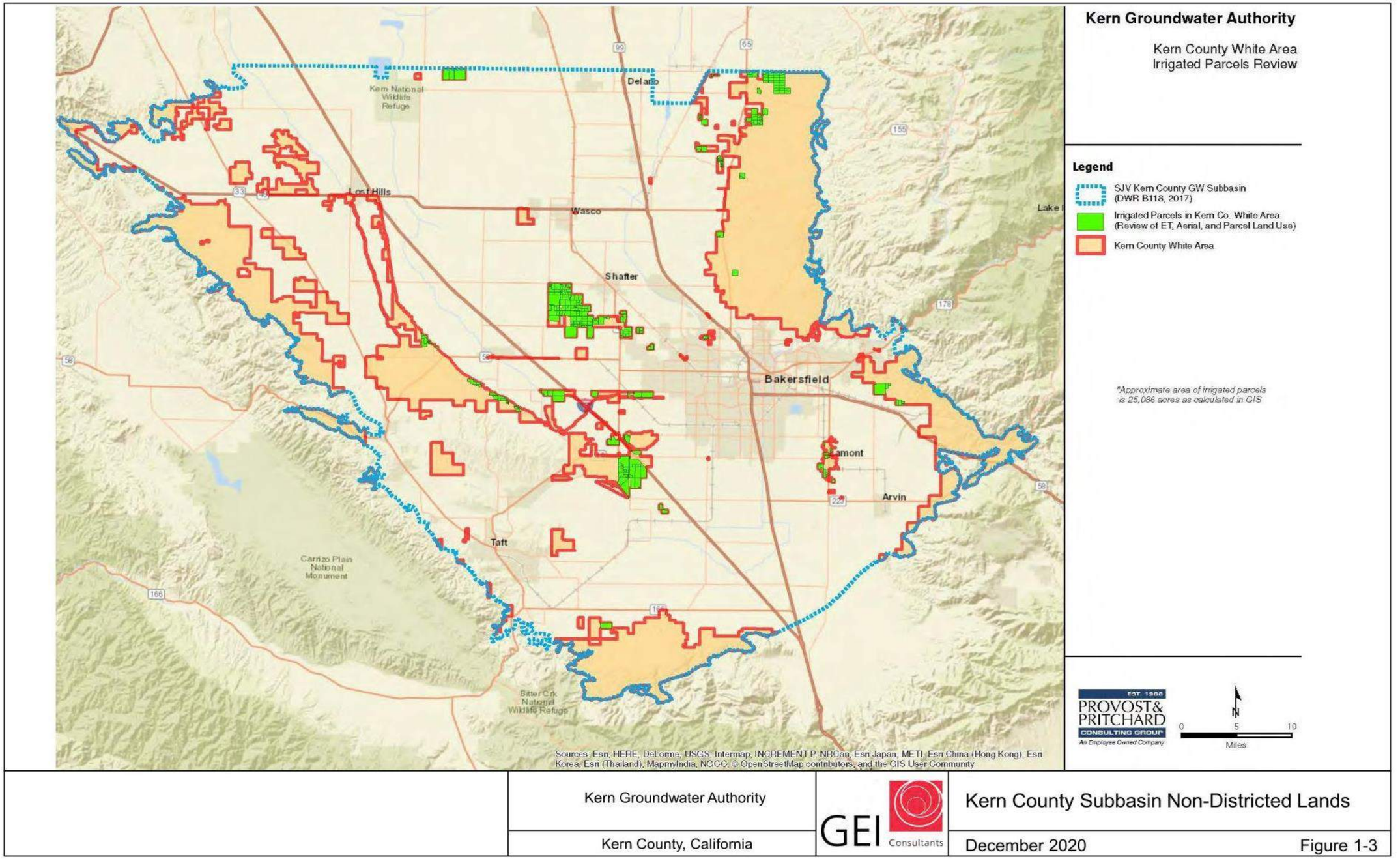

Figure 1-5. 2019 Kern County Subbasin Non-Districted Lands

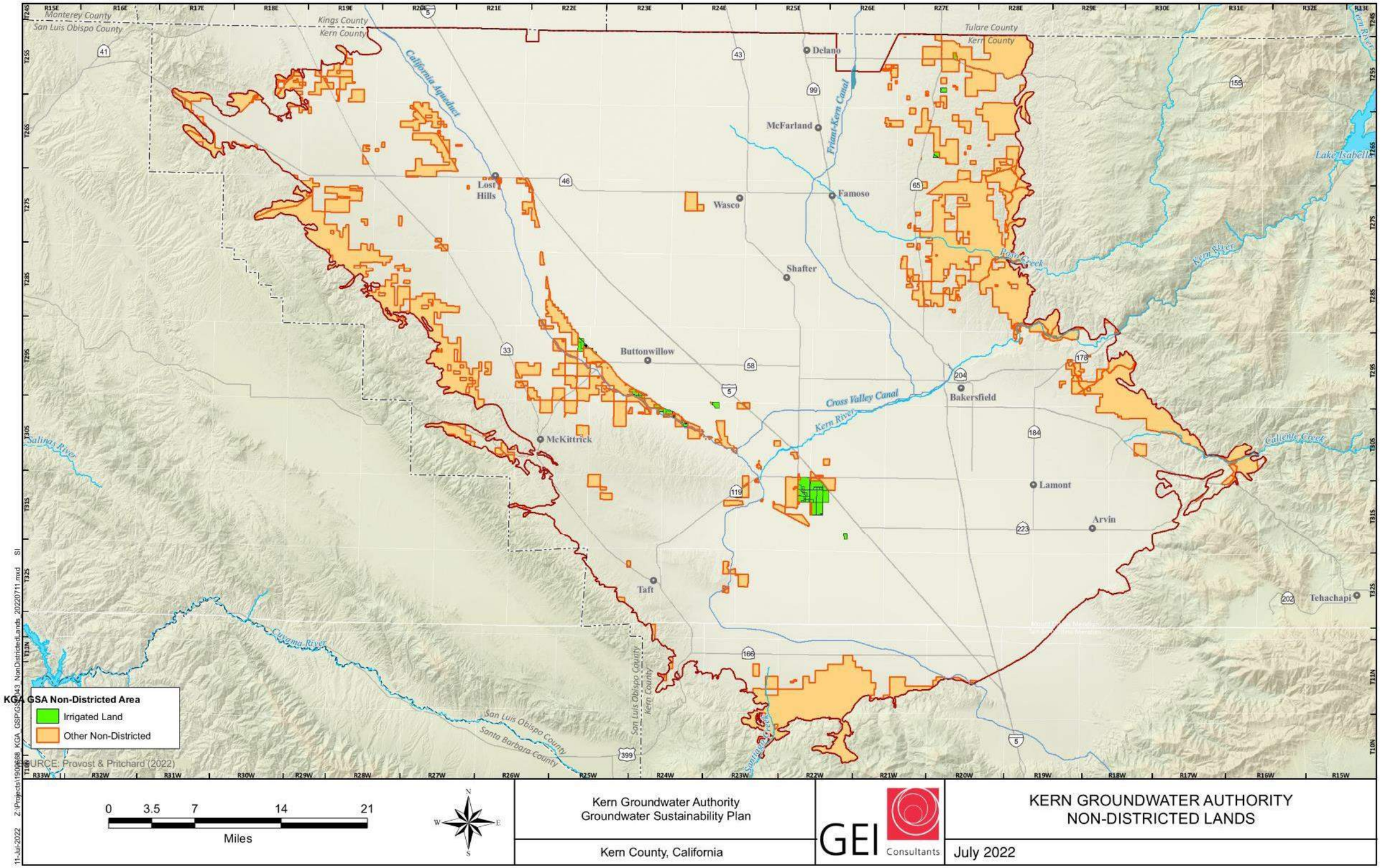

Figure 1-5a. REVISED Kern County Subbasin Non-Districted Lands

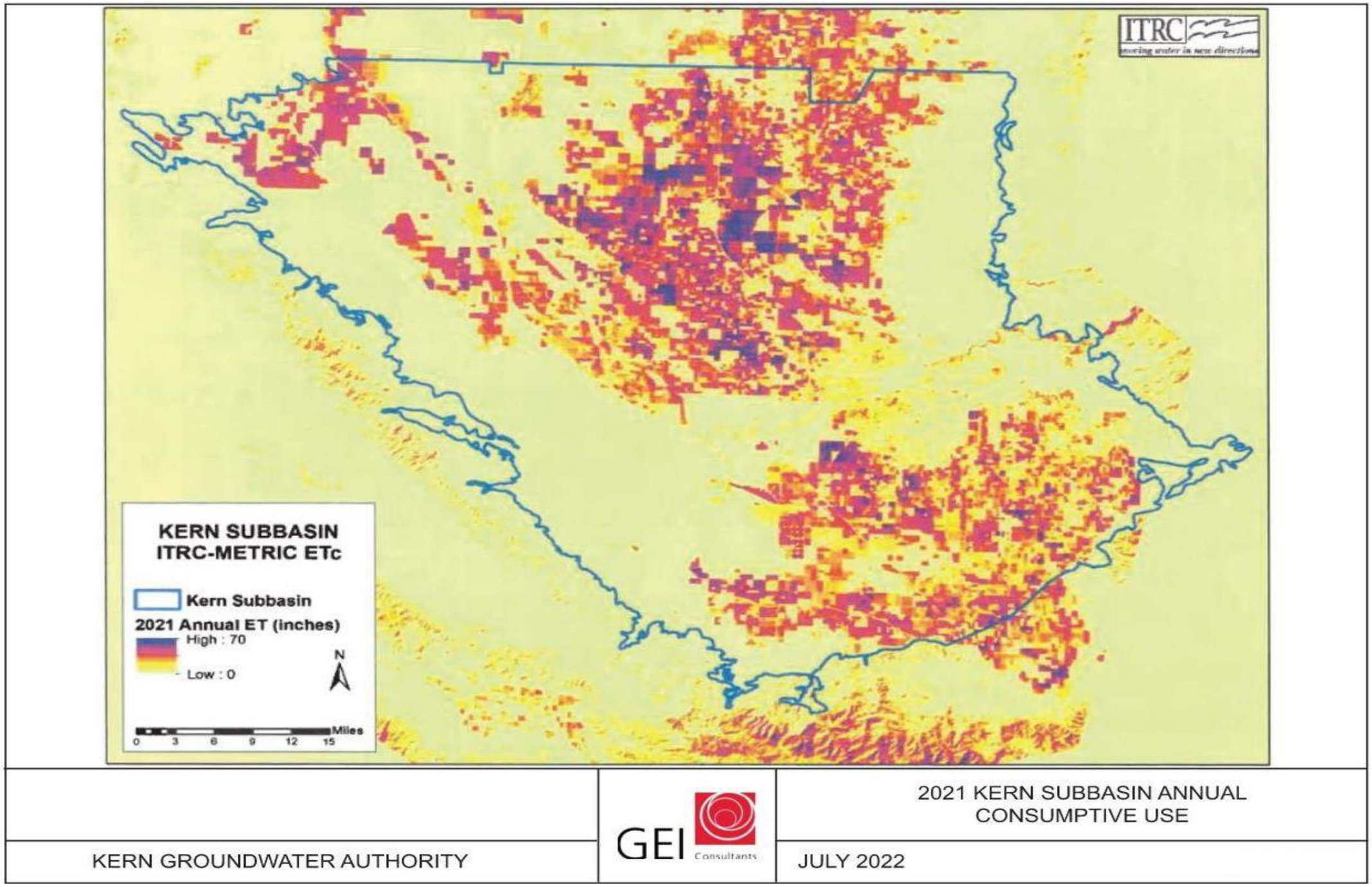

Figure 1-5b. NEW 2021 Kern Subbasin Annual Consumptive Use

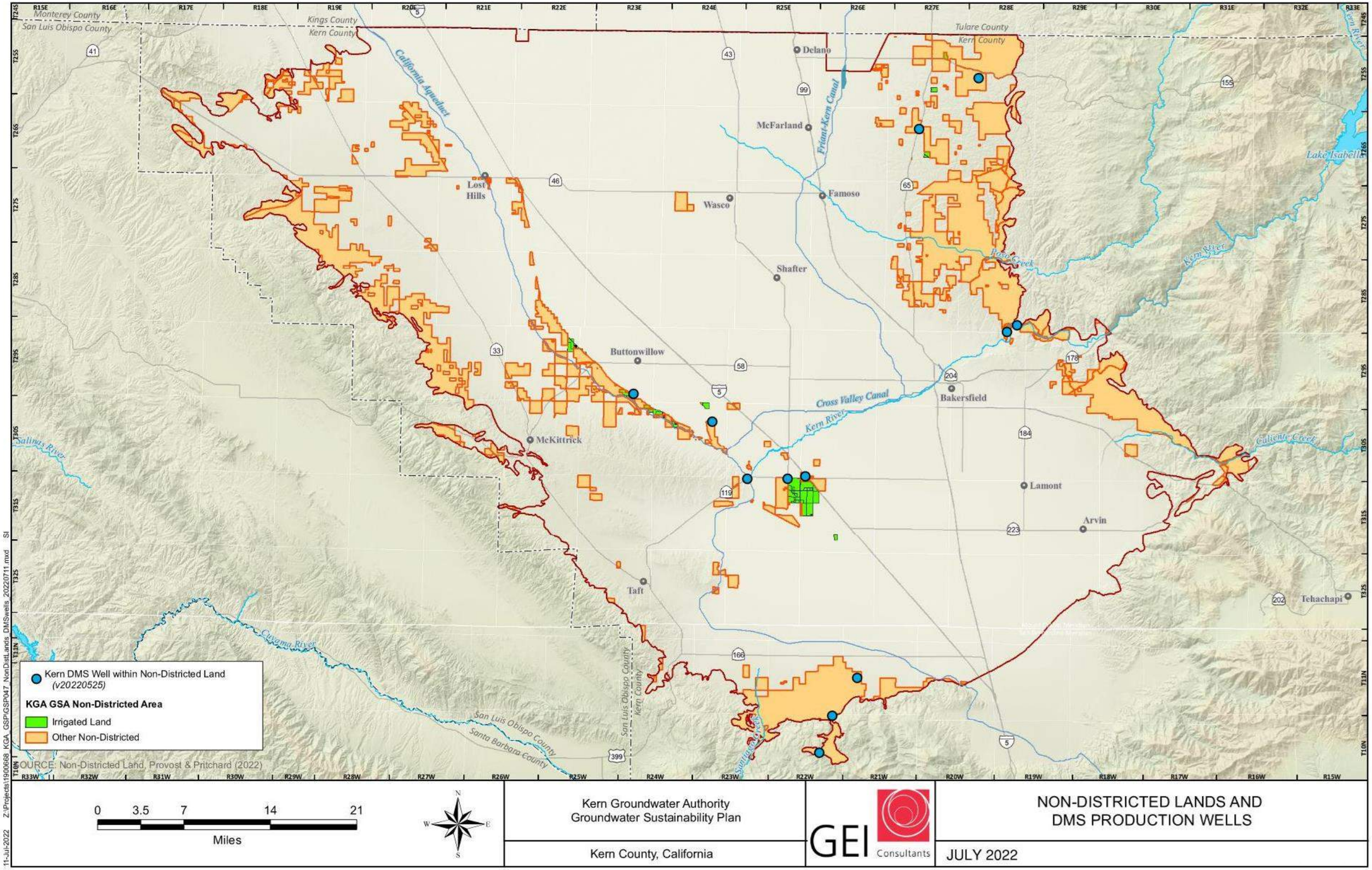

Figure 1-6a NEW. Kern County Subbasin Wells within Non-Districted Lands

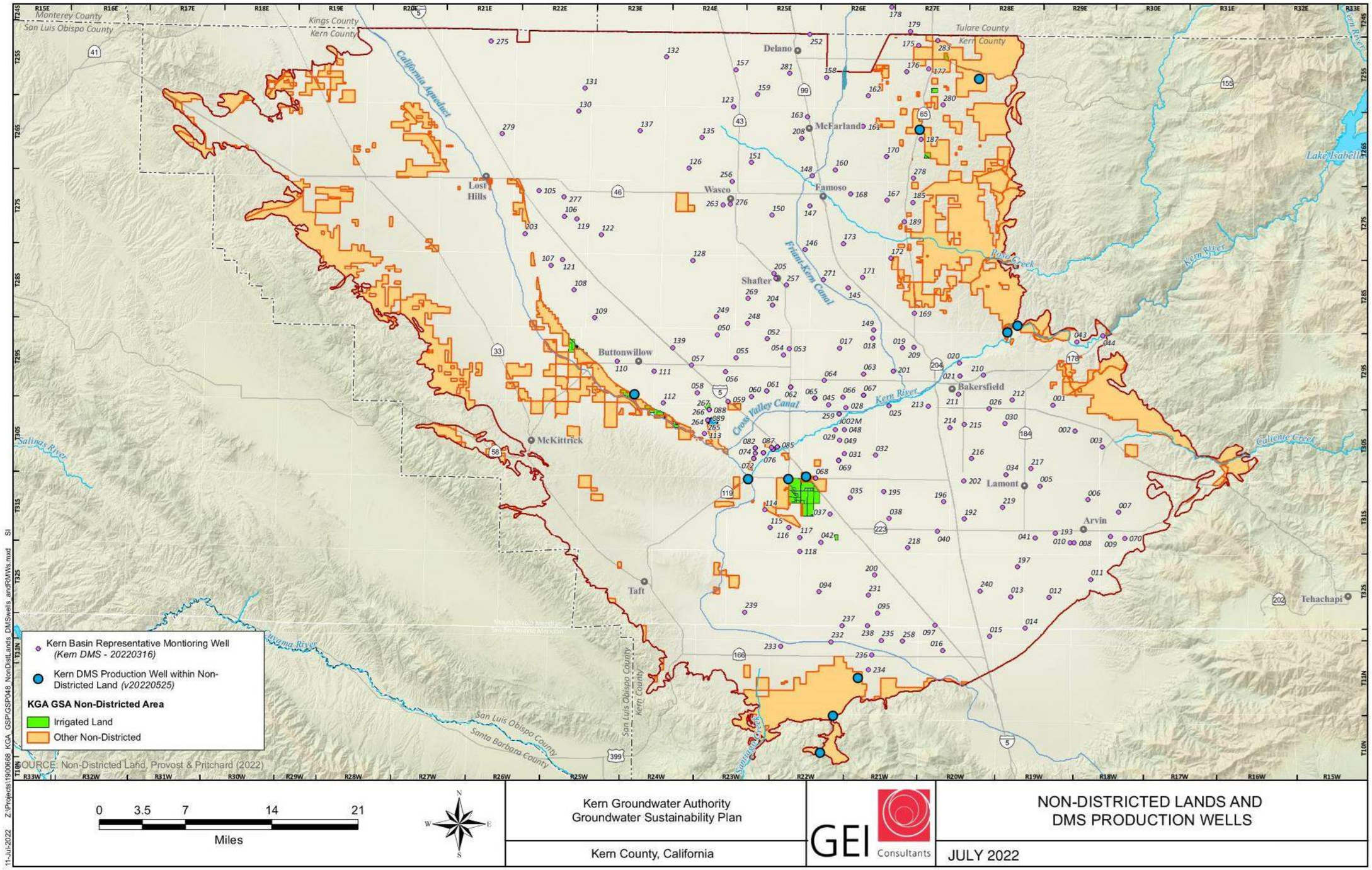

Figure 1-6b NEW. Non-Districted Lands and DMS Production Wells

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1.4.4 Legal Authority of the GSA

The KGA has been working proactively to coordinate with all GSAs and its associated GSP within the Subbasin to ensure that all GSPs developed within the Subbasin meet the requirements of the Kern County Subbasin Coordination Agreement. All the GSAs in the Subbasin have collaborated in the development and adoption of a Coordination Agreement, as required under SGMA, for the coordinated management and implementation of the five GSPs prepared in the Subbasin. Attachment B provides a copy of the Kern Subbasin Coordination Agreement. Table 1-7 provides the additional information of the six GSPs in the Subbasin.

Table 1-7: GSAs preparing GSPs within the Kern County Subbasin

GSA	Contact Person Title	Mailing Address	Phone Number	Website
Buena Vista Water Storage District	Tim Ashlock General Manager	PO Box 756 Buttonwillow, CA 93206	661-324-1101	www.bvh2o.com
Henry Miller Water District	Joef Wyrick President	101 W. Walnut Street Pasadena, CA 91103	626-583-3000	N/A
Kern Groundwater Authority	Patty Poire Executive Director	1800 30th Street Ste #280 Bakersfield, CA 93301	661-479-7171	www.kerngwa.com
Kern River Groundwater Sustainability Agency	Art Chianello Water Resources Manager	1600 Truxtun Avenue Bakersfield, CA 93301	661-326-3767	www.kernrivergsa.org
Olcese GSA	Brian Grant	P.O. Box 60679 Bakersfield, CA 93386-0679	661- 872-5050	www.olcesewaterdistrict.org
South of Kern River GSA	Jeevan Muhar	20401 Bear Mountain Blvd PO Box 175 Arvin CA 93202	661-854-5573	www.aewsd.org

The KGA was granted the legal authority of a GSA by complying with CWC Section 10723.8. The KGA held the required public hearings regarding the establishment of a GSA as stated in CWC Section 10723(b) and passed a resolution to form the KGA GSA. The authority granted to the KGA is to develop, adopt, and implement a GSP that would be available to those lands within the boundaries of the KGA members. KGA provided the required notification of intent to prepare a GSP to DWR on December 20, 2017. Under CWC Section 10723.2, the KGA within its boundaries shall consider the interests of all beneficial uses and users of groundwater, as well as those responsible for implementing GSPs.

The KGA was formed for the purpose of:

- Coordinating groundwater management programs and activities;
- Identifying and addressing issues pertaining to sustainable groundwater management; and
- Establishing a framework for local groundwater management.

The intent of the members under this JPA is to provide each member the sole right and responsibility to implement SGMA within its respective boundaries and/or management areas, in a manner determined by the member. Members expressly intend that the KGA will not have the authority to limit or interfere with the respective members rights and authorities over their own internal matters, including, but not limited to, a member's surface water supplies, groundwater supplies, facilities, operations, water management, and water supply matters.

1.4.5 GSP Implementation Costs & Funding

The KGA has developed the costs in Table 1-8 for its own administrative and coordination efforts as it serves as the coordination entity for the KGA member agencies. These costs will be funded through cost share agreement with the KGA member agencies.

The cost of implementing SGMA at the member agency level can be found in the management area plans attached to this GSP.

Table 1-8: Estimated Costs for GSP Implementation

Item	Description	Estimated Cost
Annual Administration	Administrative activities for ongoing coordination among Member Agencies and other GSA in the Subbasin and coordination with DWR.	$659,700
Sustainability Management and Coordination	KGA coordination with Member Agencies for coordinated implementation of sustainability management practices	$230,000
Coordinated Monitoring Activities	Basin-wide coordinated monitoring activities, such as, subsidence and evapotranspiration monitoring.	$200,000
Annual Report	Data collection and consolidation from Member Agencies to facilitate annual reporting to DWR	$350,000
5-Year GSP Update and Report	Data collection, consolidation and report generation of KGA 5-year update	$500,000

1.5 GSP Organization

The KGA Umbrella GSP provides SGMA coverage for all the Subbasin lands covered in the management areas of its member agencies. The members of the KGA have prepared management area plans that provide details for all GSP required elements, including the technical detail for setting sustainable management criteria specific for their respective management area. The KGA Umbrella GSP provides an overview and summary, a roll-up concept, of the GSP elements developed in the management area plans. There is a total of 12 management area plans attached to this GSP. This GSP is organized as follows:

1. Introduction
2. Plan Area and Basin Setting
3. Sustainable Management Criteria

4. Projects and Management Actions
5. Plan Implementation
6. References
7. Attachments
8. Management Area Plan Attachments
    1. Cawelo Water District
    2. Eastside Water Management Authority
    3. Kern County Water Agency – Pioneer Project
    4. Kern Tulare Water District
    5. Kern Water Bank Authority
    6. North Kern Water Storage District & Shafter-Wasco Irrigation District
    7. Rosedale-Rio Bravo Water Storage District
    8. Semitropic Water Storage District
    9. Shafter Wasco Irrigation District – 7th Standard Annexation Management Area
    10. Southern San Joaquin Municipal Utility District
    11. West Kern Water District
    12. Westside District Water Authority

2 Plan Area and Basin Setting

2.1 Description of Plan Area

KGA's jurisdictional boundary is entirely within the Subbasin, as defined in DWR Bulletin 118, South of the Tulare Lake Hydrologic Region of the San Joaquin Valley Groundwater Basin. The following section describes the area covered by the KGA GSP.

2.1.1 Summary of Jurisdictional Areas and other Features

The Subbasin is located within the southernmost portion of the Tulare Lake Hydrologic Region of the San Joaquin River Basin and is bounded by the Sierra Nevada on the east; by the Tehachapi Mountains, San Emigdio Mountains, and White Wolf Subbasin on the South; and the Coast Range (Temblor Range) on the west. As shown in Figure 2-1R, KGA's jurisdictional boundary represents 1,617 square miles or approximately 58 percent of the Subbasin. There are no Adjudicated Areas within the Kern County Subbasin.

Hydrologic systems in the Subbasin include numerous rivers, lakes, and canals, many of which are located in the KGA boundaries or are used to supply water to the entire Subbasin. The prominent natural surface water body in the Subbasin is the Kern River, which originates in the Sierra Nevada to the northeast of the Subbasin. Canals and conveyance systems within the Subbasin supply water for beneficial uses throughout the Subbasin. A detailed description of these hydrologic systems is included in Section 2.2 of the basin setting of this Umbrella GSP.

There are several incorporated cities within KGA's jurisdictional boundary as shown in Figure 2-1R. There are a number of de minimis domestic water users and multi-parcel water systems located within the KGA jurisdictional area, which will be covered under the management area GSPs.

2.1.2 Plan Area Setting

Land use designations within the KGA jurisdictional boundary are predominantly agricultural (Figure 2-2). Most urban and incorporated land use areas are in the eastern portion of the Subbasin while the agricultural lands dominate the northern, western, and southern portions. For lands covered by a water district, source of water is a combination of surface water and groundwater, as shown in Figure 2-3. Generally, all other lands not covered by a district are dependent on groundwater.

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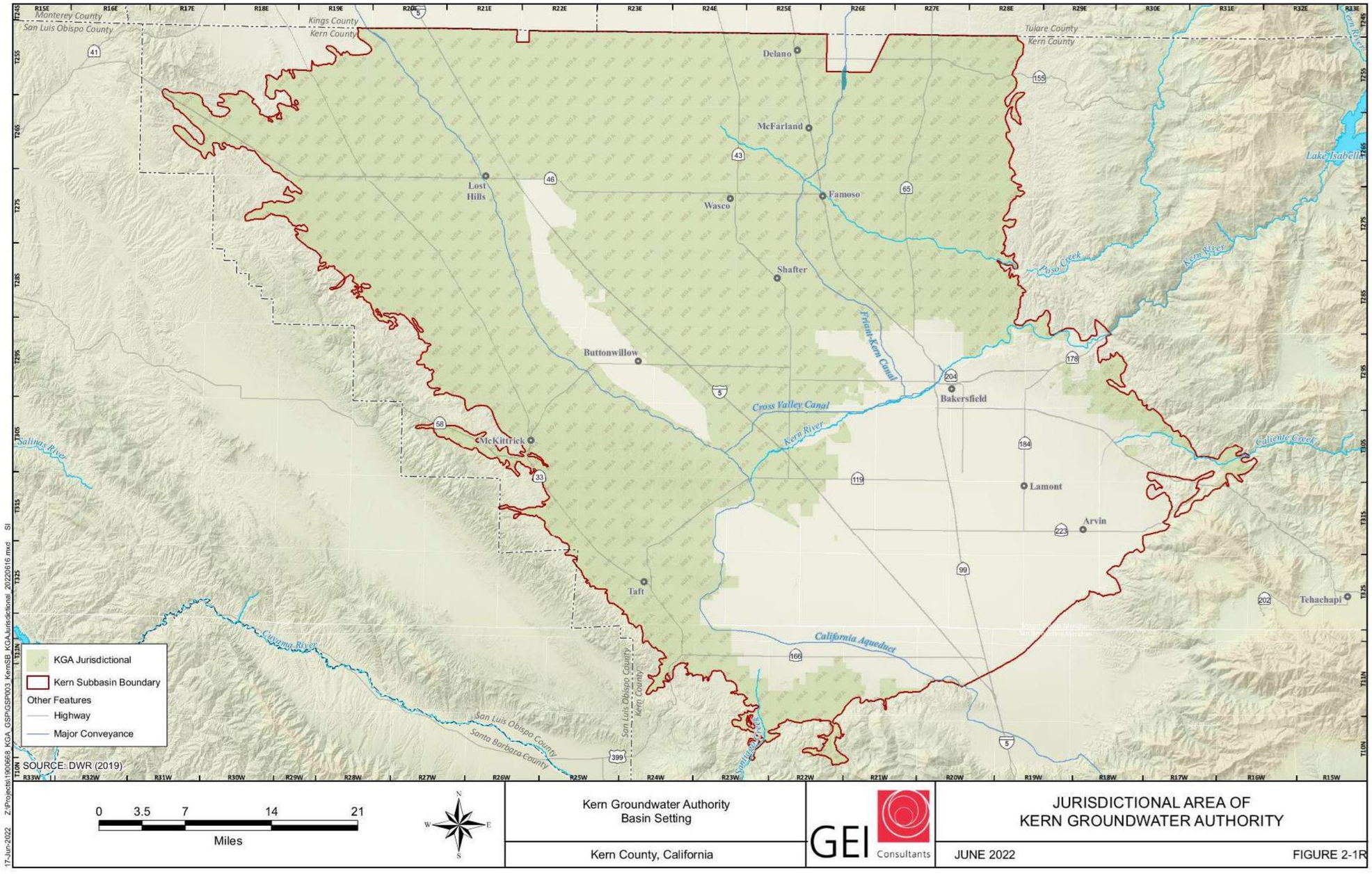

Figure 2-1R. REVISED Jurisdictional Area of Kern Groundwater Authority

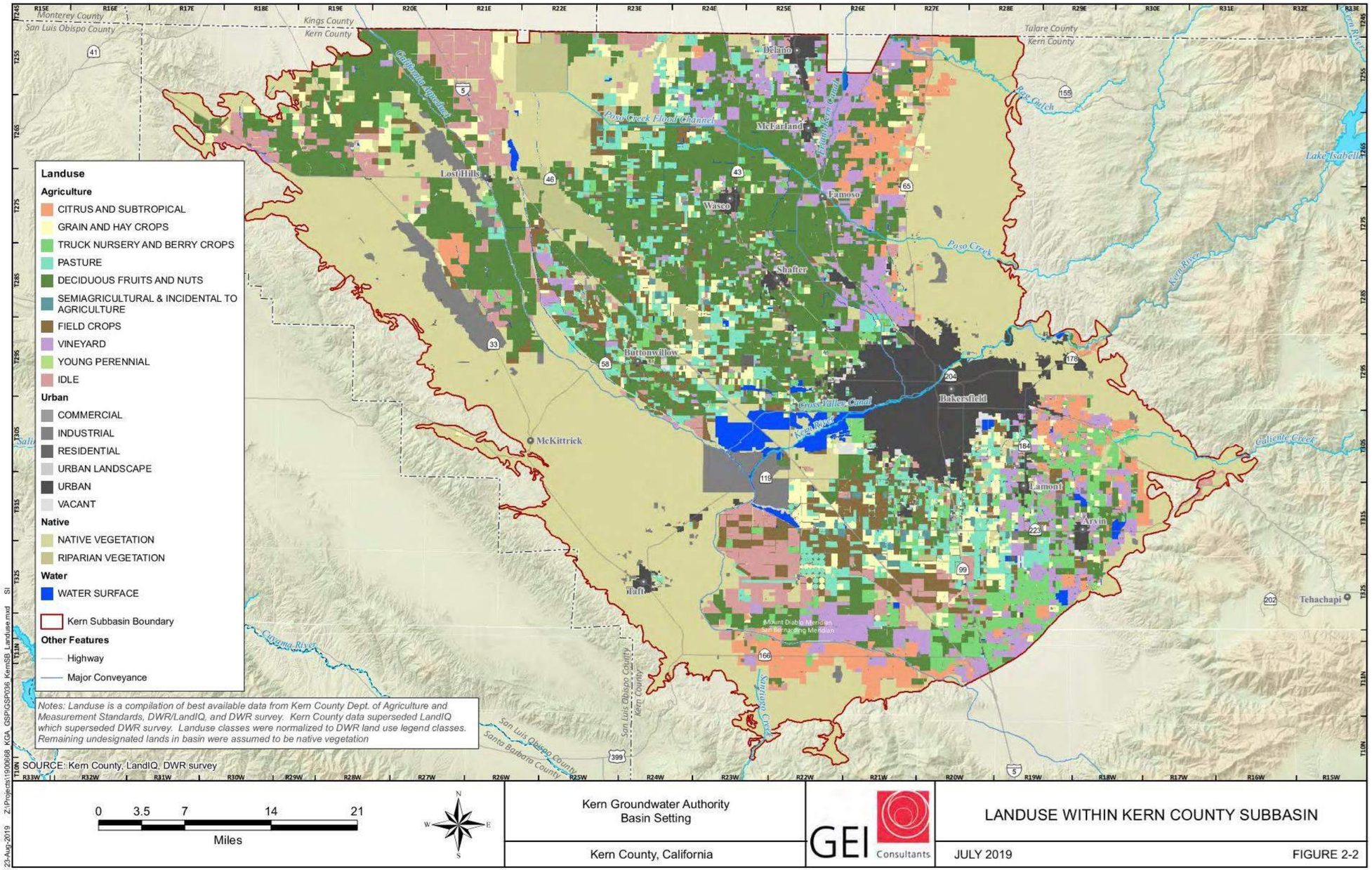

Figure 2-2. Land Use within Kern County Subbasin

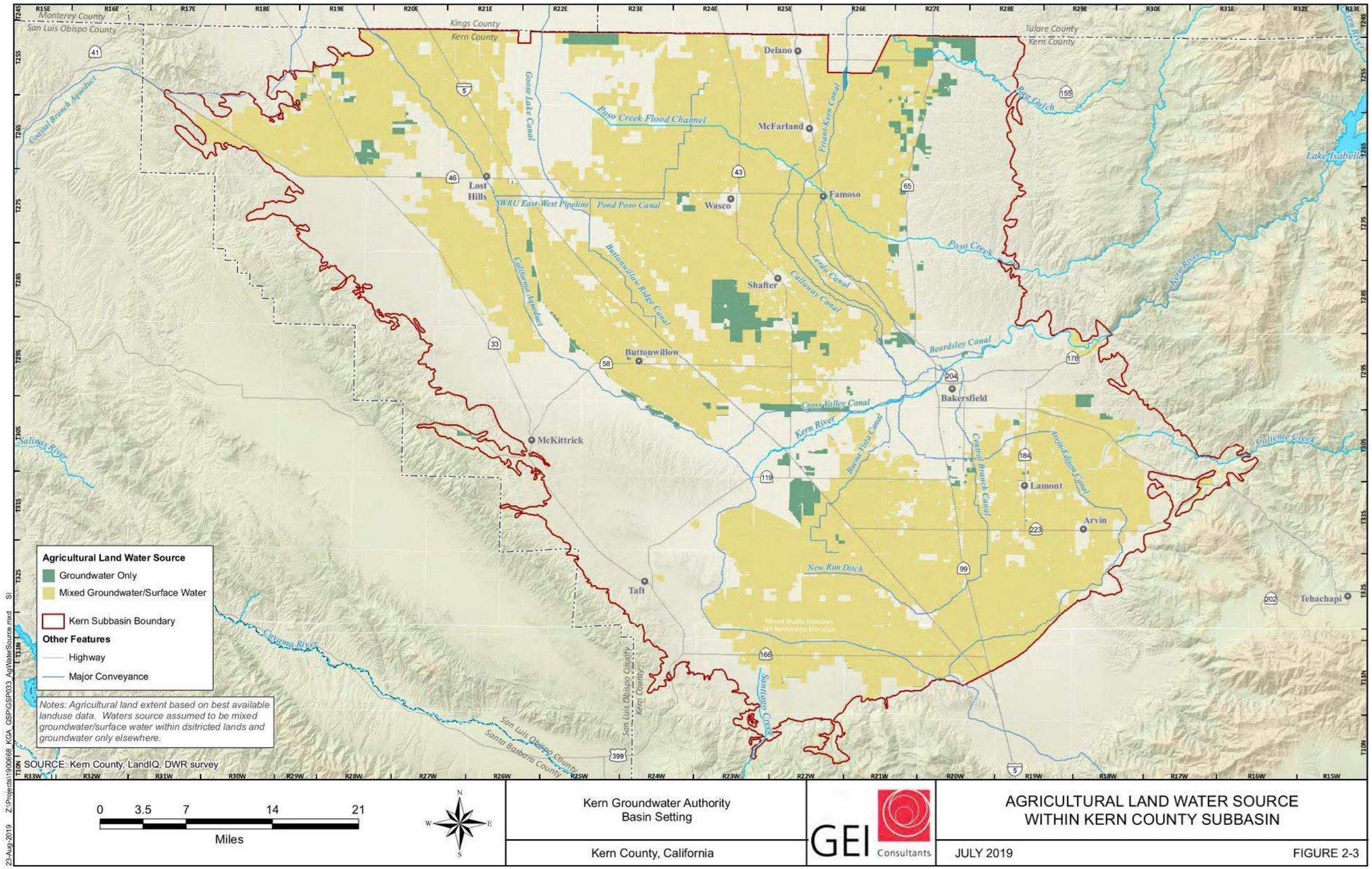

Figure 2-3. Agricultural Land Water Source within Kern County Subbasin

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Well densities for production, domestic, and public supply wells within the Subbasin are presented on Figures 2-4 through 2-6, respectively. This dataset is based on well statistics provided by DWR (2019) from the Online System for Well Completion Reports and is intended to be for qualitative informational purposes. Production wells include those described in completion reports as irrigation, municipal, public, or industrial wells. In summary, higher well densities can be found in the central portion of the Subbasin whereas moderate to lower densities are found in the north-east and south-east regions. The western region ranges in areas of low densities to no wells at all. For further information on well types and densities for each management area within the Subbasin, refer to the individual management area plans.

Under the KGA jurisdictional boundary, there are state, small multi-parcel water systems, and domestic water users that are groundwater dependent. In addition, there are incorporated cities within the KGA jurisdictional boundary as shown in Figure 2-7.

2.1.3 Existing Plans in the Plan Area

In general, the goals, policies, and implementation measures established by existing plans (e.g. the Kern County General Plan) are complementary to sustainable groundwater management of the local management areas relative to future land use development and conservation. The plan encourages development of the County's groundwater supply to ensure that existing users have access to high quality water, and states that future growth should be accommodated only while ensuring that adequate high-quality water supplies are available to existing and future users. Below is a list of all existing general plans within the Subbasin. The agencies that developed and adopted the general plans below have retained their jurisdiction over land use and zoning as well as the elements included into their respective general plans. The KGA nor its members have any jurisdiction over the development of general plans within the Subbasin, however, as general plans are being updated in the future, the KGA and its members will actively participate in the coordination of general plan update with the GSP implementation. The descriptions of plans associated with specific management areas are described in greater detail in the management area plans.

- **Kern County General Plan –** This plan was adopted in 2004 and is being updated through the year 2040. Its overall goal is to ensure the county can accommodate anticipated growth and development while maintaining a safe and healthful environment and a prosperous economy by preserving valuable natural resources and assuring the provision of adequate public services (Kern County, 2009).
- **Metropolitan Bakersfield General Plan –** The current plan was first adopted in 2002. This plan aims to achieve goals related to new development, protecting natural resources from environmental damage, as well as preserving agricultural land (City of Bakersfield, 2016) The Metropolitan Bakersfield General Plan is mostly located within the Kern River GSA. There also exists a Metropolitan Habitat Conservation Plan that is mostly located within the Kern River GSA jurisdiction.

- **City of Shafter General Plan –** This plan's goals include, but is not limited to, recognizing and retaining commercial agriculture as a desirable land use and as a major segment of the community's identity and economic base (City of Shafter, 2005).
- **City of Wasco General Plan –** This plan was adopted in 2002 and contains objectives, policies and standards specific to the protection of groundwater resources as well as soils and air quality within the City of Wasco and its planning area.
- **City of Delano General Plan –** This plan was adopted in 2005 and aims to protect natural resources, including groundwater, soils, and air quality.
- **City of McFarland General Plan –** This plan was adopted in 1991; however, current versions of the plan do not specifically address groundwater.
- **City of Taft General Plan –** This plan was adopted in 2010; however, the adopted version does not specifically address groundwater.

Successful implementation of this GSP will help to ensure that the Subbasin's groundwater supply is managed in a sustainable manner. Implementation of existing policies are expected to be compatible with management areas strategies in the Subbasin to achieve groundwater sustainability. It is anticipated that implementation of this GSP, while consistent with existing plans and policies to protect water resources, will alter the water supply assumptions and potentially land use plans over the planning horizon. Given that the existing plans are being updated concurrently with the development of this GSP, it is anticipated that future plans would take into account this GSP and utilize consistent water supply assumptions over the 2040 planning horizon.

Land use plans vary between each management area, as they implement policies which best fit their communities. Management area plans provide specific information regarding land use plans and effects of those plans in the individual management areas.

The implementation of land use plans outside of the Subbasin could potentially affect the ability of the KGA to achieve sustainable groundwater management, especially to the north of the Subbasin. However, at this stage, coordination with neighboring Subbasin's has been limited. Future activities of the KGA include increased coordination with neighboring groundwater Subbasins, which will be documented in future updates to this GSP.

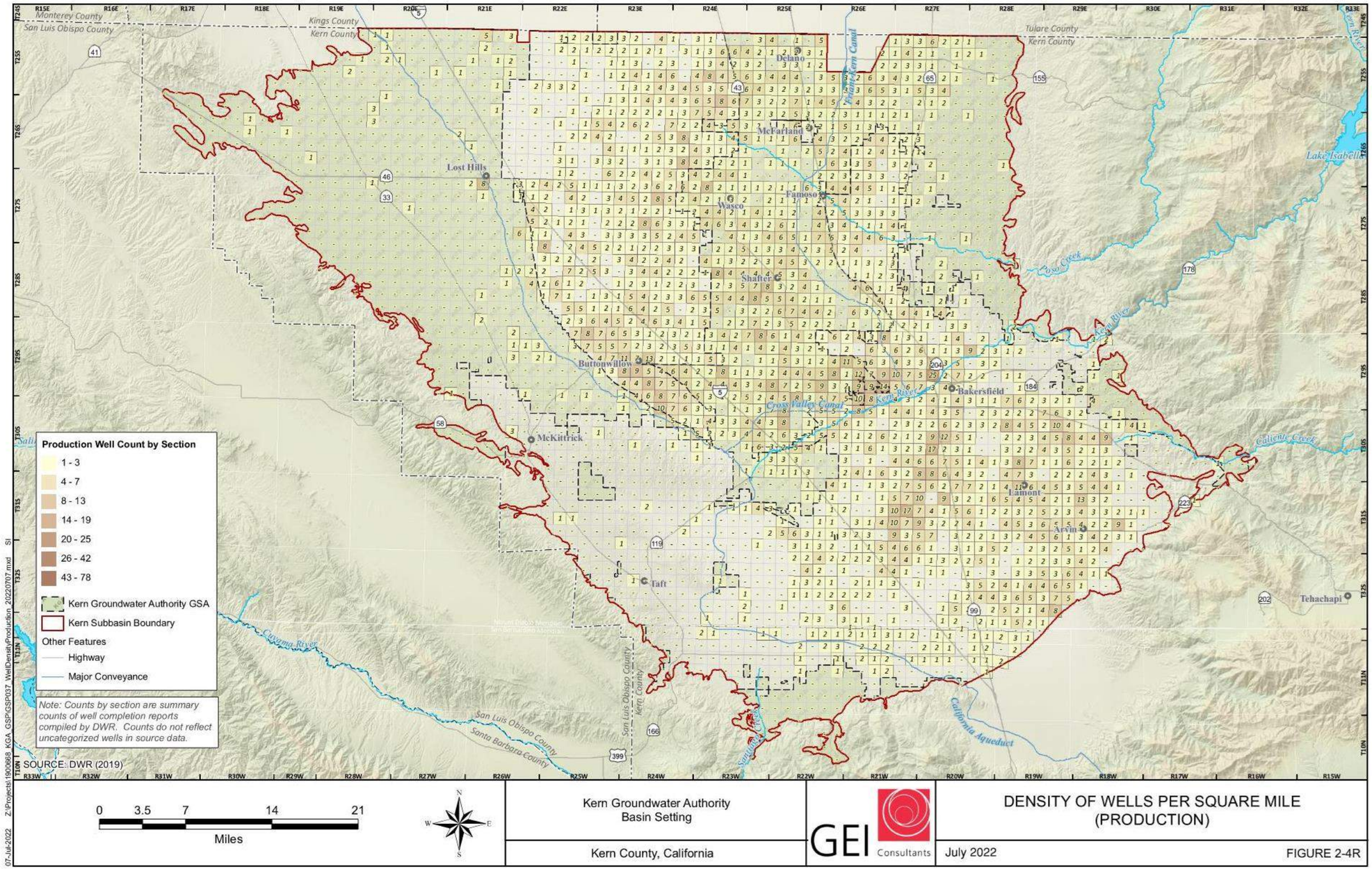

Figure 2-4R. REVISED Density of Well Per Square Mile (Production)

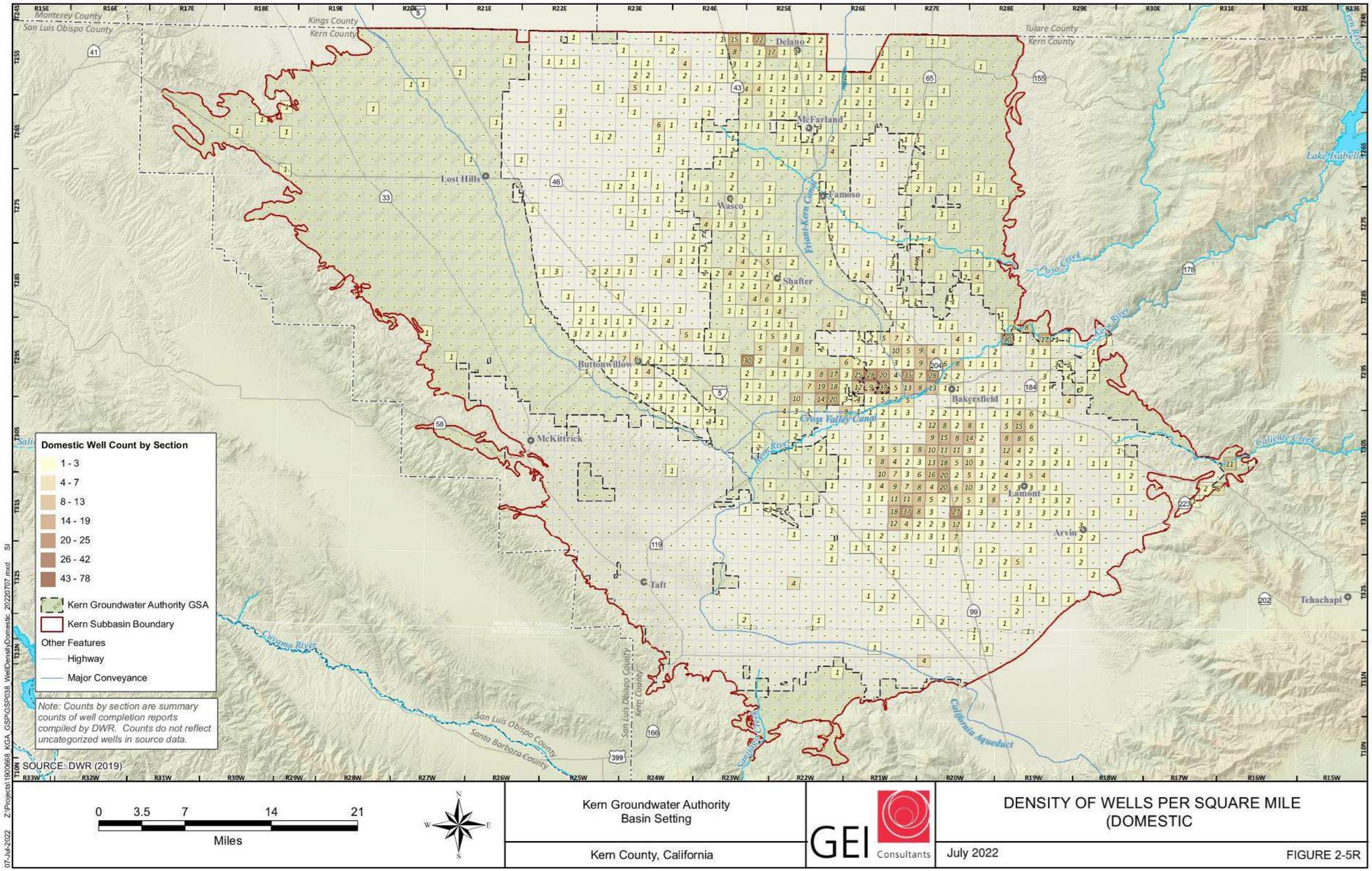

Figure 2-5R. REVISED Density of Well Per Square Mile (Domestic)

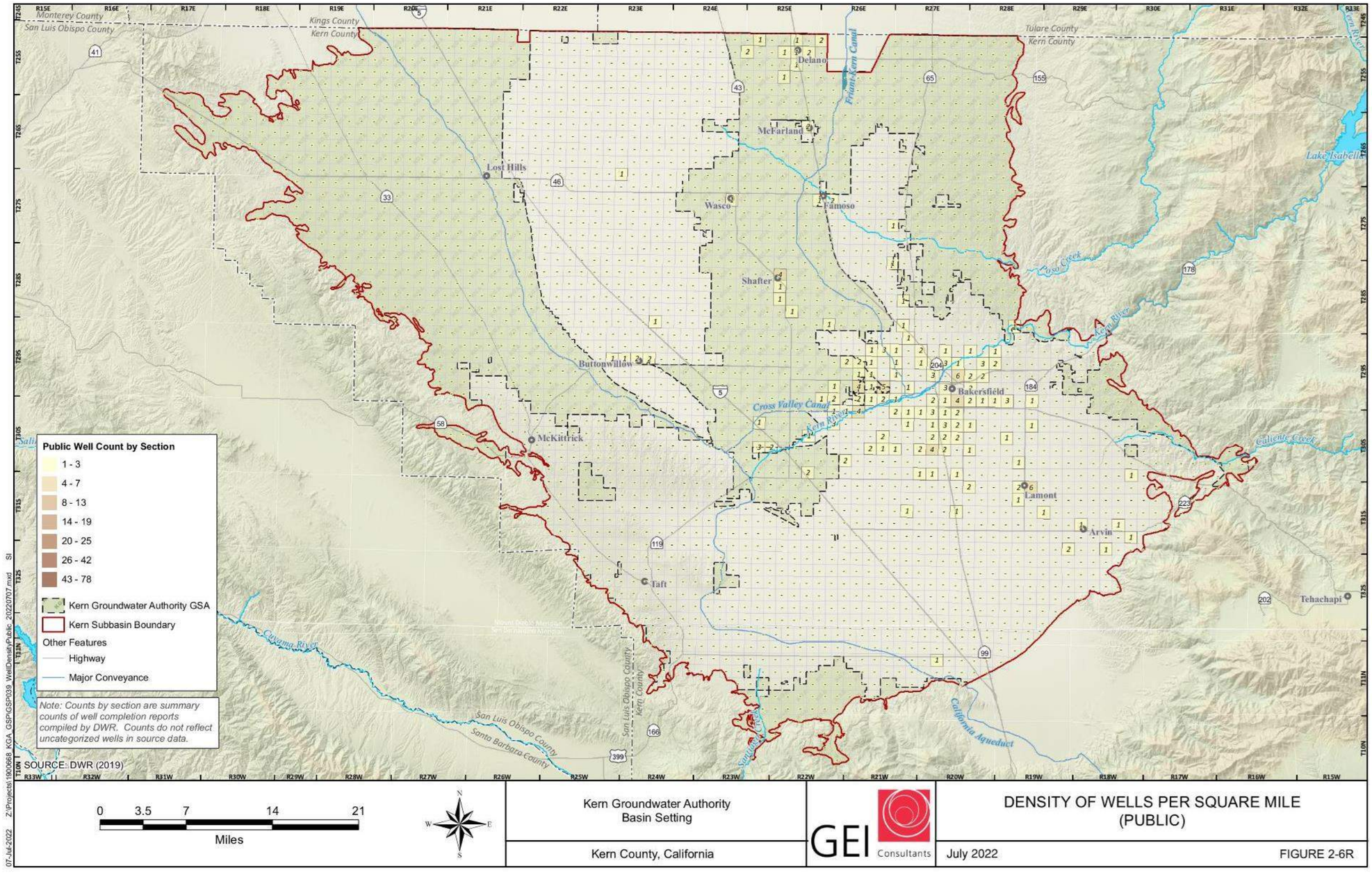

Figure 2-6R. REVISED Density of Well Per Square Mile (Public)

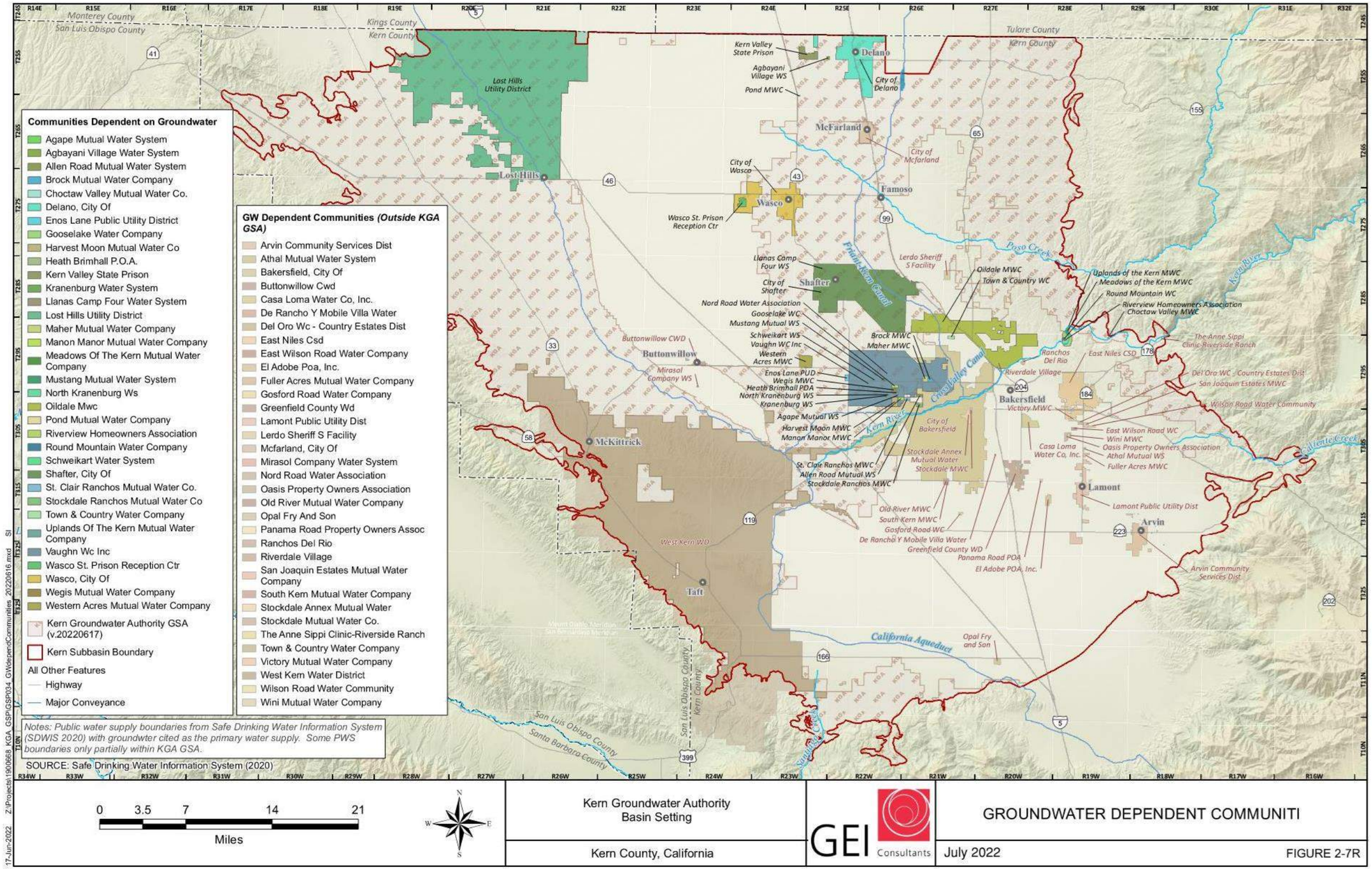

Figure 2-7R. Groundwater Dependent Communities

2.1.4 Existing and Ongoing Water Resource Programs

Per Section 354.8(c) of the GSP regulations, this section identifies and describes existing water resources programs in the KGA jurisdictional area. This section provides an overview of each program being implemented within the KGA. Table 2-1 provides a matrix showing which programs are being implemented within each management area. Additional details are provided in the individual management area plans.

2.1.4.1 Management Plans

The State of California has pre-SGMA programs for the management of groundwater supply and quality. These programs are managed at various levels of government by existing public agencies, either individually or collaboratively with neighboring agencies within the same groundwater basin. The following section provides an overview of these management programs and the elements addressed in each.

2.1.4.1.1 Groundwater Management Plans

In 1992, the State of California passed the Groundwater Management Act (AB 3030). This legislation provided guidelines for the agencies and districts to provide planned and coordinated monitoring, operation, and administration of groundwater basins with the goal of long-term sustainability. There are several types of Groundwater Management Plans, which are described below.

Pre-SB 1938 Plans: These plans, typically adopted before 2002, could be prepared by a local agency in a Bulletin 118-desginated basin on a voluntary basis. The voluntary components of these plans include:

- The control of saline water intrusion.
- Identification and management of wellhead protection areas and recharge areas.
- Regulation of the migration of contaminated groundwater.
- The administration of a well abandonment and well destruction program.
- Mitigation of conditions of overdraft.
- Replenishment of groundwater extracted by water producers.
- Monitoring of groundwater levels and storage.
- Facilitating conjunctive use operations.
- Identification of well construction policies.
- The construction and operation by the local agency of groundwater contamination cleanup, recharge, storage, conservation, water recycling, and extraction projects.
- The development of relationships with state and federal regulatory agencies.

- The review of land use plans and coordination with land use planning agencies to assess activities which create a reasonable risk of groundwater contamination.

SB 1938 Plans: These plans were generally adopted during or after 2002, incorporating the elements of the Pre-SB 1938 Plans. With the passage of SB 1938, the following components were required as part of any Groundwater Management Plan:

- Basin Management Objectives: The Groundwater Management Plan shall include Basin Management Objectives relating to the monitoring and management of groundwater levels within the groundwater basin, groundwater quality degradation, inelastic land surface subsidence, and changes in surface flow and surface water quality that directly affect groundwater levels or quality or are caused by groundwater pumping in the basin.
- Agency Cooperation: The local agency shall prepare a plan to involve other agencies that enables the local agency to work cooperatively with other public entities whose service area or boundary overlies the groundwater basin.
- Mapping: The local agency shall prepare a map that details the area of the groundwater basin, as defined in DWR's Bulletin 118, and the area of the local agency, that will be subject to the Groundwater Management Plan, as well as the boundaries of other local agencies that overlie the basin in which the agency is developing a Groundwater Management Plan.
- Monitoring Protocols: The local agency shall adopt monitoring protocols that are designed to detect changes in groundwater levels, groundwater quality, inelastic surface subsidence (in basins for which subsidence has been identified as a potential problem), and flow and quality of surface water that directly affect groundwater levels or quality or are caused by groundwater pumping in the basin.
- Located outside Bulletin 118 Groundwater Basins: Plans located outside DWR Bulletin 118 alluvial groundwater basins will incorporate the above components and shall use geologic and hydrologic principles appropriate to those areas.

Table 2-1: Summary of KGA Water Resources Programs

KGA Management Area Plan	Groundwater Management Plans			Water Management Programs						
	Pre-SB 1938 Plans	SB 1938 Plans	AB 359 Plans	Integrated Regional Water Management Plans	USBR Water Management Plans	Irrigated Lands Regulatory Program	Groundwater Export Ordinance	Title 22 Drinking Water Program	Urban Water Management Plans	Agricultural Water Management Plans
Cawelo Water District		X		X		X			X	X
Eastside Water Management Area						X				
Kern Water Bank										
Kern-Tulare Water District		X								
North Kern Water Storage District and Shafter-Wasco Irrigation District		X		X		X	X	X		X
		X		X		X	X	X	X	X
Pioneer				X					X	
Rosedale- Rio Bravo Water Storage District			X	X		X				
Semitropic Water Storage District		X		X		X	X	X		
Shafter-Wasco Irrigation District (7th Standard Rd.)										
Southern San Joaquin Municipal Utility District		X		X		X	X	X	X	X
West Kern Water District	X			X					X	
Westside District Authority				X		X				X

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AB 359 Plans: When AB 359 was enacted in 2013, it required additional technical components related to groundwater recharge areas and modification to several of the existing groundwater management plan adoption procedures in place as part of SB 1938. The additional technical components are as follows:

- The groundwater projects to which these requirements apply include projects that are part of an integrated regional water management program or plan.
- Groundwater projects require a description of how recharge areas identified in the plan substantially contribute to the replenishment of the groundwater basin and a map identifying the recharge areas, as defined, for the groundwater basin to be included in a groundwater management plan for purposes of the state funding requirements.
- Require the local agency to provide the map of the recharge areas to local planning agencies and notify the department and other interested persons when a map is submitted to those local planning agencies.

2.1.4.1.2 Integrated Regional Water Management Plans

In 2002, the Regional Water Management Planning Act (SB 1672) created the Integrated Regional Water Management (IRWM) Program. The IRWM Program is used as a collaborative effort to identify and implement water management solutions on a regional scale that increase regional self-reliance, reduce conflict between agencies and users, and manage water to concurrently achieve social, environmental, and economic objectives. By collaborating on projects, participants in the IRWM Program can provide these benefits and meet their water supply and quality goals. In the Kern County Subbasin, there are two IRWM Plans: the Poso Creek IRWM Plan and the Kern County IRWM Plan.

2.1.4.1.3 USBR Water Management Plans

The Central Valley Improvement Act of 1992 and Section 210(b) of the Reclamation Reform Act of 1982 requires certain entities to prepare and submit a Water Management Plan. Entities required are those that enter into a repayment contract or water service contract with the Bureau of Reclamation. Not all member agencies under KGA are required to have a plan under USBR. Refer to management area plans for specific details.

2.1.4.1.4 Irrigated Lands Regulatory Program

The Tulare Lake Basin General Order (Order R5-2013-0120) was passed by the Regional Water Quality Control Board (RWQCB) in 2006. This order requires that any irrigated land having the potential to discharge to surface water or groundwater must comply with the requirements set by the RWQCB. Compliance includes membership in a Coalition or obtaining coverage through an Individual Order from the RWQCB. Several districts in the KGA jurisdictional area are members of the Kern River Watershed Coalition Authority, which was formed in 2011.

2.1.4.1.5 Groundwater Export Ordinance

Kern County adopted a groundwater export ordinance in 1998, which requires a Conditional Use Permit for export of water to areas both outside the County and within watershed areas of

underlying aquifers in the County. The ordinance applies only to the southeastern drainage of the Sierra Nevada and Tehachapi mountains in the South Lahontan Hydrologic Region in eastern Kern County.

2.1.4.1.6 Title 22 Drinking Water Program

The Division of Drinking Water regulates public drinking water systems, which include municipal and state small water systems. These systems are required to comply with the standards set forth in Title 22 of the California Code of Regulations. For single parcel/single-connection systems, Kern County Environmental Health Services provides regulation and oversight to meet the requirements of Title 22.

2.1.4.2 Conjunctive Use Programs

Conjunctive use or "the coordinated use of surface water and groundwater" has been used for many years in Kern County, for the benefit of water users, to allow for flexibility in the way water is delivered, whether climatic conditions allow for imported surface water, or if groundwater is needed in any given year. Conjunctive use is further described by the Water Education Foundation with the following: "In its passive form, also called in-lieu conjunctive use, surface water is used in wet years and groundwater is used in dry years. In active conjunctive use, surface water is directly injected into aquifers and wells to be used as needed as part of groundwater banking" (Water Education Foundation, 2019).

In the Kern Subbasin, conjunctive use plays a vital role for all beneficial users to coordinate the use of surface water and groundwater to improve the overall reliability of water supply. Whether it be water used to irrigate crops or to service communities for drinking water purposes, all users benefit from conjunctive use programs throughout the Subbasin. Conjunctive use programs in the Subbasin have been developed to capture and transport wet year surface water for the purpose of groundwater recharge and offset use of groundwater pumping. In turn, this prepares the basin for dry periods when groundwater may be limited. Projects such as interties, pipelines, and recharge basins have been developed, financed, and implemented by districts within the Kern Subbasin to deliver, bank, and return surface water, as well as replenish aquifers to better prepare for and manage during times of dry periods when beneficial users are more reliant on groundwater. Many of these types of projects have been incorporated in other state programs, such as the IRWM program. In the Kern Subbasin, there are two IRWM regions including the Poso Creek IRWM Region and the Kern IRWM Region. Both regions have developed plans to manage water use and delivery as well as the development of water related projects. Further information on the types of conjunctive use programs in the Kern Subbasin can be found in each of these plans. Additionally, many of the projects captured in the IRWM plans are included in the management area plans as project and management actions to be implemented within the Kern Subbasin to achieve groundwater sustainability.

The majority of the KGA member agencies partake in groundwater banking and recharge programs. The purpose of these programs is to bring surface water into the Subbasin to recharge groundwater levels and better prepare for and manage water during times of dry periods or in wet periods where water is of excess. Groundwater banking refers to recharging specific amounts of

water in a groundwater basin that can later be withdrawn and used by the entity that deposited the water.

KGA member agencies have banking agreements amongst each other. For example, members of the Poso Creek IRWM such as Semitropic WSD and North Kern WSD, operate long-term water banking programs that allow banking partners, including districts outside of the Poso Creek IRWM Region, to store surplus water in another district and to recover their water when needed. These districts receive surface water from the banking partners in years of ample supplies and deliver it to their landowners for irrigation use in-lieu of groundwater pumping (*Poso Creek Integrated Regional Water Management Plan, 2019 Update*). Once banked, the entity depositing the water receives a credit and groundwater which otherwise would have been pumped remains in storage. In the Poso Creek IRWM Region alone, there is approximately 25,000 acre-feet per month of recharge capacity that can be used to bank imported surface water.

In addition to banking programs within the Poso Creek IRWM Region, other prominent groundwater banking facilities in the Kern Subbasin include the Kern Water Bank and Kern County Water Agency - Pioneer Project. These are facilities managed by the Kern Water Bank and the Kern County Water Agency, respectively. Kern Water Bank contains approximately 7,000 acres of recharge ponds, which can recharge up to 72,000 acre-feet per month. When water is available to the Kern Subbasin which cannot be absorbed, these water banking projects provide additional storage facility for otherwise potentially lost surplus surface supplies available during wet years. Most members of the KGA participate in banking and recharge programs in one way or another. For further explanation of banking and recharge programs as well as district involvement, refer to individual management area plans.

2.1.4.3 Well Permitting Process

Well permits within the Subbasin are issued by the Kern County Public Health Services Department Water Well Program and will continue under SGMA. Kern County will continue to retain jurisdiction over the water well permitting process. The Water Well Program issues permits to construct, reconstruct, and destroy water wells. All wells must be constructed in accordance with Kern County Ordinance Code, Section 14.08, and the State Department of Water Resources' Bulletin 74-81 and Bulletin 74-90, except as modified by subsequent revisions. The ordinance requires, among other things, that domestic and agricultural wells be installed a minimum distance from potential pollution and contaminant sources; water quality be tested for new and reconstructed wells; an NSF 61 approved flowmeter be installed; and the final well construction be inspected by Kern County staff.

Through a collaborated process, the Kern Subbasin GSAs, with the KGA taking the lead, worked with the Kern County Public Health Services Department to develop a supplemental well application for wells to be installed within the Kern Subbasin (Figure 2-8). This new form requires the applicant to provide additional information regarding construction of the well, proposed use, and amount of water to be pumped. If the applicant knows the water district and GSA in which the well will be located, it is indicated on the form. The application is completed and submitted to the Kern County Public Health Department where it is forwarded to the

ENVIRONMENTAL HEALTH DIVISION
2700 M Street, Suite 300, Bakersfield, CA 93301
Phone # (661) 862-8740 Fax (661) 862-8701
Email EH@kerncounty.com

Overdrafted Basin Supplemental Well Application

FOR OFFICE USE ONLY Corcoran Clay: ☐ Yes ☐ No WP _____

Assessor's Parcel Number: _____ Township/Range/Section: _____

GPS Coordinates: Lat _____ Long _____ Well Elevation (ft): _____

Water District/GSA: _____ Est Cumulative Extraction Volume (ac ft) by 12/31/19: _____

☐ Irrigation ☐ Livestock ☐ Domestic ☐ Municipal ☐ Industrial ☐ Other _____

PROPOSED WELL DESIGN INFORMATION	
Proposed Well Depth (ft):	
Proposed Well Capacity (gal):	
Estimated Pumping Rate (gal/day):	
Proposed Pumping Schedule:	
Est Annual Extraction Volume (ac ft):	

GEOLOGIC SITING INFORMATION PROPOSED WELL	
Water Table Depth (ft):	
Seasonal Fluctuations in Water Table:	
Recharge Area (Yes/No):	
Recharge Rate (if known):	
Area to be served by well (in acres):	

EXISTING ON SITE WELL INFORMATION	Well 1	Well 2	Well 3
Type/Use of Well:			
Depth (ft):			
Diameter (in):			
Screen Interval (ft):			
Pumping Rate (gal/day):			
Est. or Annual Extraction Volume (ac ft):			
Capacity or Pump Test (gal) (if available):			

In addition to the above information, the following information ***must be shown*** on a detailed site map and include actual measurements (to scale not necessary). If in the Corcoran Clay, you may include 2 maps to satisfy the requirements below.

☐ Distance to potential sources of pollution, including but not limited to, septic systems, sewer lines, wells (all types), animal/fowl enclosures, or transmission lines; either existing or proposed.

☐ Distance from lakes, ponds, streams within 300 ft of proposed well

☐ If in Corcoran Clay, location of canals, ditches, pipelines, utility corridors, and roads within 2 miles.

Submitted By _____ Title _____ Date _____

Figure 2-8. Kern County Public Health Services – Over-drafted Basin Supplemental Well Application

appropriate water district or GSA, through the KGA Planning Manager. The district in which the well is located is able to provide comments on the application advising the applicant of sustainability criteria that may impact the operation of the well. This process has been in place since January 2019 and demonstrates coordination between Kern County Public Health Services requirements and SGMA requirements concerning water well permitting processes.

2.1.4.4 Plan Elements from CWC Section 10727.4

Per Section 354.8(g) of the GSP regulations, each plan shall include a description of any additional GSP elements included in Water Code Section 10727.4 appropriate to the region. While management area plans provide full details for each element, this section provides a brief overview.

(a) Control of saline water intrusion.

- Because the Kern County Subbasin is located far from coastal areas, saline water intrusion is not considered to be an issue.

(b) Wellhead protection areas and recharge areas.

- Kern County Public Health Services Department Water Well Program issues permits to construct, reconstruct, and destroy water wells (see Section 2.1.4). Recharge areas are managed by individual water districts in the Subbasin to bring in surface water to recharge the groundwater aquifers. Many districts engage in banking programs and work conjunctively to exchange water to support the sustainability of the Subbasin.

(c) Migration of contaminated water.

- The mitigation, remediation, and management of groundwater contamination plumes is regulated in the Subbasin by the Central Valley Regional Water Quality Control Board (CVRWQCB) and the County of Kern. Groundwater contamination plumes have been identified by individual districts, which actively monitor groundwater sampling and work with the CVRWQCB to address groundwater contamination issues. Contamination plumes are not found in every district under KGA, refer to management area plans for specific information.

(d) A well abandonment and well destruction program.

- Kern County Public Health Services Department Water Well Program issues permits to construct, reconstruct, and destroy water wells (see Section 2.1.4).

(e) Replenishment of groundwater extractions.

- KGA member agencies actively manage the groundwater basin within their respective boundaries through conjunctive use and other programs. For specific details pertaining to each management area refer to their management area plan.

(f) Activities implementing, opportunities for, and removing impediments to, conjunctive use or underground storage.

- KGA member agencies actively manage the groundwater basin within their respective boundaries through conjunctive use and other programs. Refer to management area plans for specific details pertaining to each management area.

(g) Well construction policies.

- Kern County Public Health Services Department Water Well Program issues permits to construct, reconstruct, and destroy water wells. To see how this process is coordinated under SGMA with the Subbasin GSAs, see Section 2.1.4.3.

(h) Measures addressing groundwater contamination cleanup, groundwater recharge, in-lieu use, diversions to storage, conservation, water recycling, conveyance, and extraction projects.

- Oversight of groundwater contamination cleanup is provided by the CVRWQCB and the County of Kern.
- Recharge policies exist across the Subbasin that allows on-farm banking as well as banking and exchanges with other districts in the region.
- Conservation and irrigation efficiency practices have been encouraged and incorporated both at the district and grower level.
- In-lieu use, diversions to storage, water recycling, conveyance, and extraction projects on managed on a district level in the Kern Subbasin.

(i) Efficient water management practices, as defined in Section 10902, for the delivery of water and water conservation methods to improve the efficiency of water use.

- KGA Member Agencies are constantly pursuing efficiency with their water management practices through management plans as outlined in the management area plans.

(j) Efforts to develop relationships with state and federal regulatory agencies.

- Many of the member agencies under KGA hold state and federal water contracts as well as work closely with DWR on projects and management practices. Refer to management area plans for further details.

(k) Processes to review land use plans and efforts to coordinate with land use planning agencies to assess activities that potentially create risks to groundwater quality or quantity.

- There are a number of water use and land use programs member agencies are involved in within the Kern Subbasin that require land use plans. Refer to management area plans for further details.

(l) Impacts on groundwater dependent ecosystems.

- This element is covered in the KGA Umbrella Chapter, Section 2.3.8, as well as the individual management area plans.

2.1.5 Notice and Communication

SGMA requires that GSAs consider the interests of all beneficial uses and users of groundwater and to encourage and include them in the GSP development process. To capture the intent of SGMA, as legislation better served under local control, KGA member agencies played a vital role in the development of this GSP. This process included communication and outreach at the local level, with each KGA member agency engaging with its beneficial users to gather vital input, data, and feedback to ensure the success of this GSP and individual management area plans.

In May of 2018, the KGA initiated the development of a Communication and Engagement Plan (C&E Plan) (Attachment C) to facilitate and assist KGA member agencies in stakeholder engagement and outreach. KGA communication and outreach consisted of stakeholder meetings and workshops; maintaining an interested parties list for KGA events; and development of a Stakeholder Survey and Agricultural Survey for the benefit of KGA member agencies. In addition to outreach and communication through the KGA, each member agency was tasked with conducting their own communication and outreach to better capture the diverse needs of their beneficial users within their jurisdictional areas. By receiving information directly for member agencies using a local control approach, users greatly benefitted.

For more detailed information on KGA member agency communication and outreach efforts please see the member agencies' management area plans.

2.1.5.1 Description of Beneficial Uses and Users in the Subbasin

As was previously stated, as required by SGMA, GSAs must consider the interests of all beneficial uses and users of groundwater and include them in the GSP development process. For the KGA and its member agencies, beneficial users are stakeholders who have an interest or a need in groundwater use within the boundaries of the KGA. With the development of the C&E Plan the focus was to address the opportunities for engagement and to encourage participation by beneficial users. Located within the C&E Plan are lists of beneficial users as well as a stakeholder engagement timeline based on phases of the GSP development and implementation processes. The engagement timeline for the KGA are shown in the following figures; Figures 2-9, Phase 1: GSA Formation and Coordination; Figure 2-10, GSP Preparation and Submission; and Figure 2-11, GSP Review and Evaluation.

Another component of the C&E Plan was the development of the interest parties list. The interested parties list began development immediately and is constantly updated to include all interested parties who sign in/attend any of the monthly meetings held by the KGA and/or its member agencies.

The development of the Stakeholder Survey and Agricultural Survey was a vital instrument in the KGA outreach during the process of the development of the management area plans. To capture as many diverse beneficial users as possible, the Stakeholder Survey was developed in both English and Spanish and was available at workshops, stakeholder meetings, and both were accessible on the KGA website where they could be completed online. The information provided

by the beneficial user assisted the KGA member agencies in the development of their projects and management actions. These surveys are located on the KGA website and can be completed online anytime during the process of the development of the management area plans. Monthly, the KGA took the information provided from those surveys and provided a summary report to the KGA Board of Directors, the KGA member agency managers, and to the public for their consideration.

2.1.5.2 Communication

2.1.5.2.1 Decision-Making Process

KGA was formed by a JPA that stipulates that each member agency has the sole right and responsibility to develop and implement SGMA within its respective boundaries; however, the KGA Board is the final decision-maker for the KGA and its member agencies, except for the implementation of SGMA within a management area. Implementation of SGMA is to be governed by the member agency within its jurisdiction.

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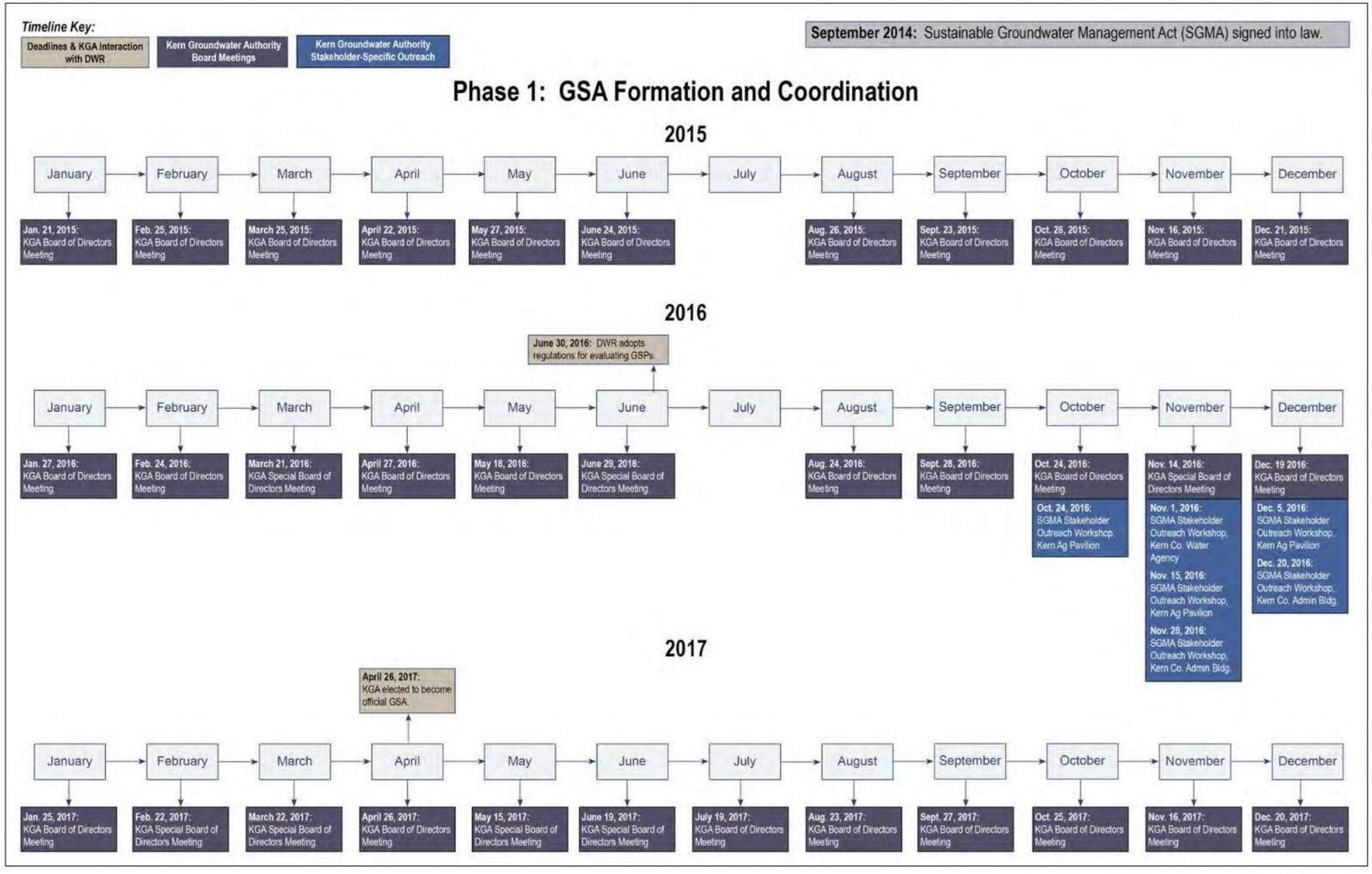

Figure 2-9. Kern Groundwater Authority's Communication & Engagement Timeline – Phase 1: GSA Formation and Coordination

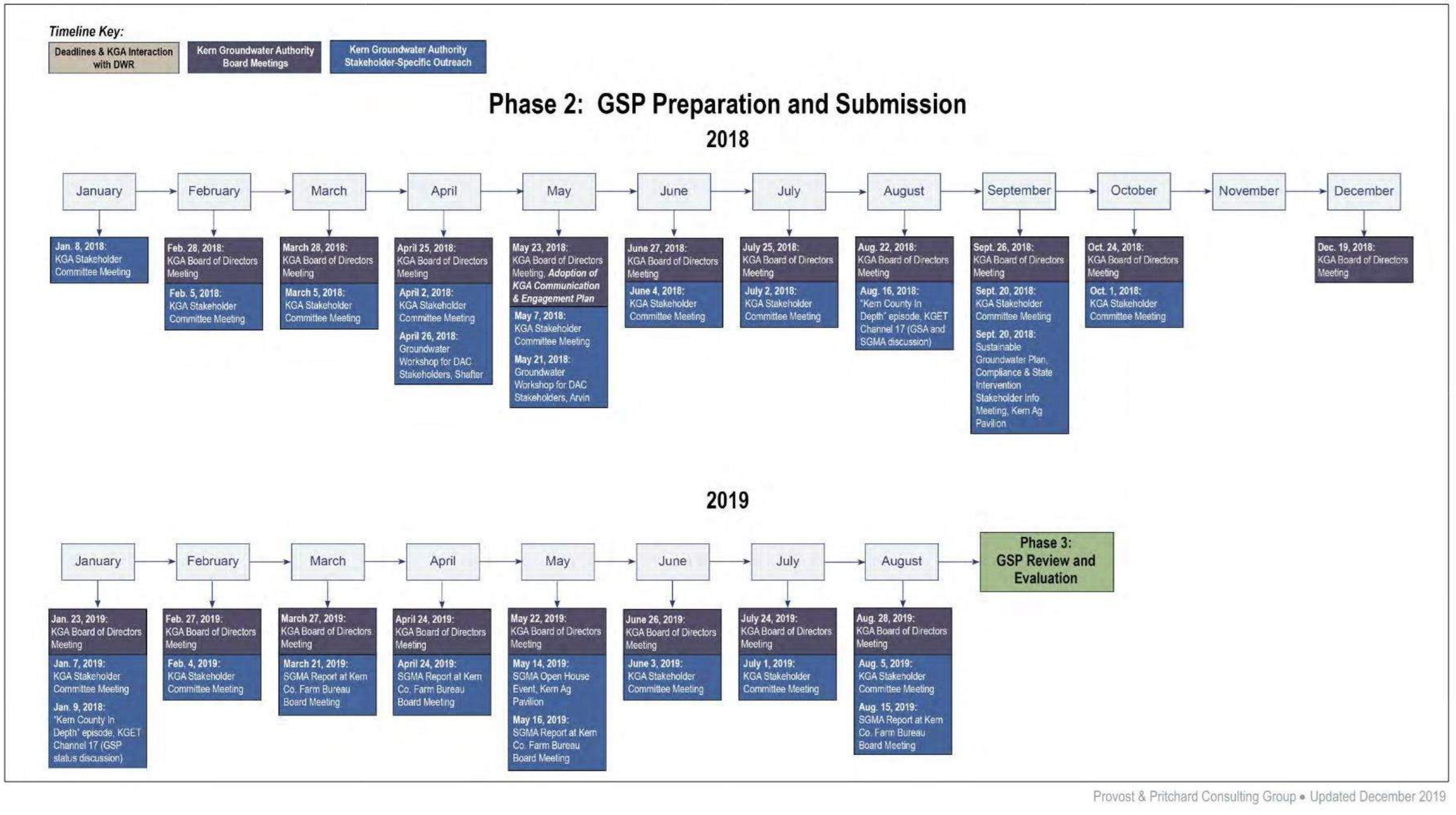

Figure 2-10. Kern Groundwater Authority's Communication & Engagement Timeline – Phase 2: GSP Preparation and Submission, and Phase 3: GSP Review and Evaluation

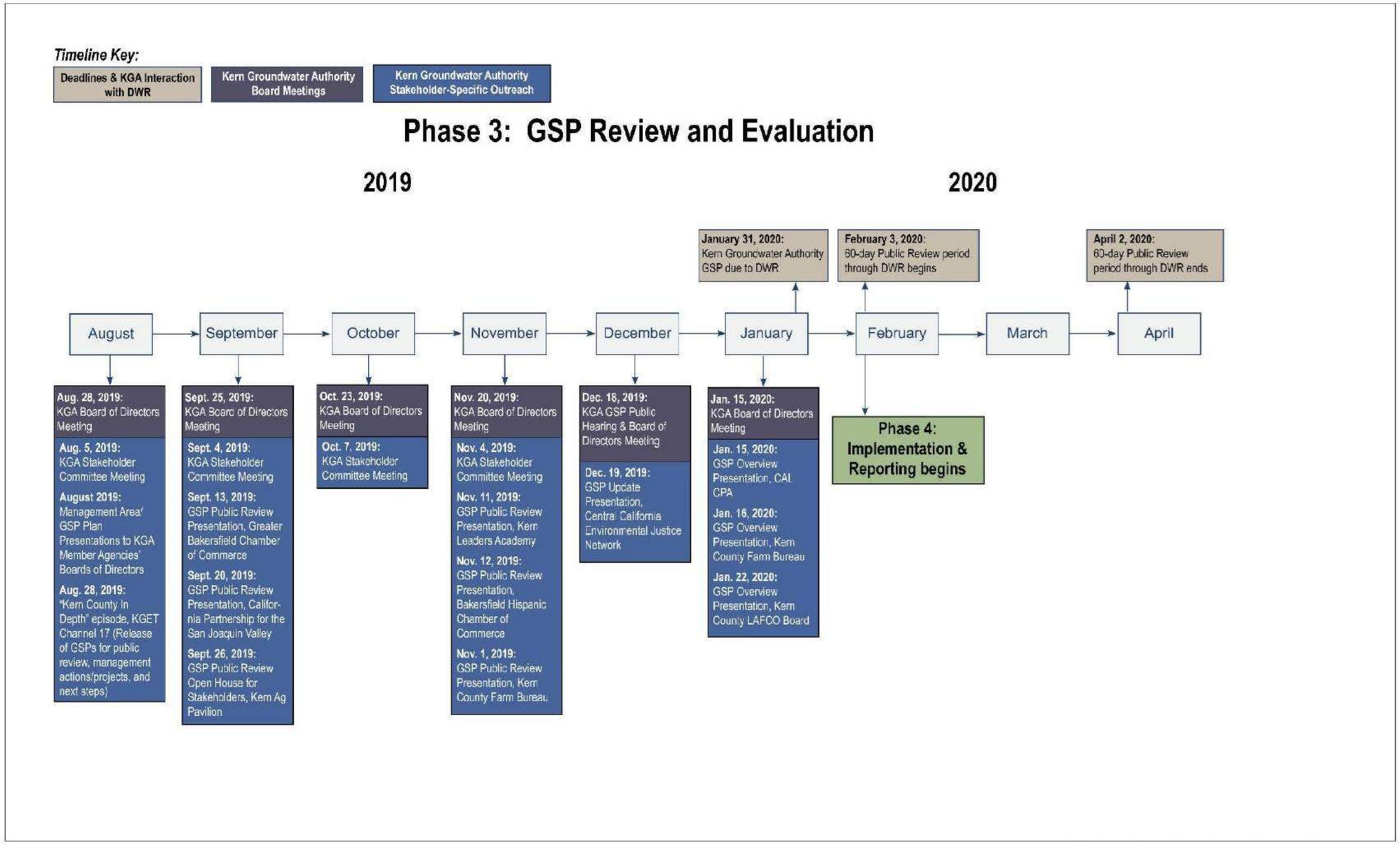

Figure 2-11. Kern Groundwater Authority's Communication & Engagement Timeline – Phase 3: GSP Review and Evaluation

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The JPA is written to provide open and transparent communication to all beneficial users; thus, the KGA's decision-making process consists of several public meeting opportunities:

- The KGA Board of Directors public meetings are on the fourth Wednesday of every month and include presentations regarding the development of the GSP as well as decisions on coordinated SGMA requirements with the other GSAs in the Subbasin. Public meetings also include administrative and financial decisions. Meeting notification includes public posting of the board agenda and background materials on the KGA website and an email notification to the interested parties list a week prior to the meeting, which also includes all relevant meeting materials.
- As the Subbasin GSPs were developed, KGA and the other GSAs established coordination meetings. These meetings began in July 2018 to coordinate each of the five GSPs scheduled to be developed and submitted to DWR. These meetings are held every Friday morning and are attended by all KGA member agency managers and the other four GSA managers. These meetings included discussions to obtain an understanding and consensus on the data and methodologies used in the five GSPs. Once an understanding and consensus was reached, the data and methodology were then discussed at the Kern GSA Coordination Committee meeting, where each of the five GSAs are represented by a policy or board member and a staff manager, as well as at stakeholder public meetings.
- Stakeholder public meetings were held on the first Monday of every month where presentations were made concerning the development of this GSP as well as items that need to be coordinated under SGMA with the other GSAs. These meetings began under the name of the Coordination Committee and then changed to Stakeholder meetings in 2018. Typically, meetings were open discussions with occasional presentations for specific GSP elements. If there were no new developments on the GSP, meetings were cancelled to take into consideration beneficial users' time. All meeting dates and presentation materials are located on the KGA website with email notifications sent out to the interested parties list prior to meetings, which included all relevant meeting materials.
- Kern GSA Coordination Committee meetings were established to coordinate the data and methodologies at a policy-level. These meetings were held on the third Wednesday of every month and were attended by one policy decision-maker from each of the GSAs and staff members to assist in the discussion. These meetings were established to maintain the coordination as well as the requirement of utilizing the same data and methodologies throughout the development of the five GSPs.

2.1.5.2.2 Public Engagement Opportunities

As previously stated, each KGA member implemented its own outreach programs to provide opportunities for beneficial users to participate in the development of individual management area plans. The details of these outreach programs can be found in the management area plans. However, the KGA held several public workshops, stakeholder meetings (mentioned above),

Farm Bureau meetings discussions, and media outreach. These meetings are listed in the C&E Plan and are also indicated in the list below.

2.1.5.3 Informing the Public about GSP Development Progress

2.1.5.3.1 KGA Website

The website was established immediately upon approval as an exclusive GSA and is updated monthly with materials from all the meetings including presentation materials and board packages. There is also a Resource & Outreach tab that provides the technical reports and workshop materials.

2.1.5.3.2 Interested Parties List

An email distribution list of stakeholders and beneficial users was developed and is constantly updated for outreach and notices throughout the GSP planning process. The list is maintained and updated by the KGA and is included in the C&E Plan.

2.1.5.3.3 Media

The KGA has participated in several media segments televised by Kern Golden Empire Television (KGET) Channel 17 – Kern County in Depth segment. There have been three tapings since the establishment of SGMA, one for the formation of the GSAs, the withdrawal of Kern County impacts to SGMA and the beginning process of the GSP, and the release of the GSP and the process moving forward. These are televised for a month and are also located on KGET Channel 17 website.

2.1.5.4 Public Comments

Public comments were collected throughout GSP development process and incorporated into the development of KGA Umbrella GSP and the management area plans of the KGA members, as described above. Additionally, the KGA prepared a Public Draft Kern Groundwater Authority Groundwater Sustainability Plan in August 2019. The draft KGA GSP was made available during a noticed public comment period from August 30, 2019 to November 28, 2019. Comments received were considered and responded to either in this final version of the KGA GSP or were forwarded to the appropriate KGA member agency for their consideration. All comments received and responded to those comments are included in Attachment D.

2.2 Basin Setting

This basin setting focuses on the area encompassed within the jurisdiction of the KGA, its participating members agencies, and collaborators. Figure 2-1R presents the current extent of the KGA jurisdictional area and member agencies. Due to the proximity of adjacent GSAs, details and data from adjacent GSAs are included herein. This basin setting is intended to represent an overview of the entire Subbasin. Additional details are included in the basin setting description of other GSPs prepared in the Subbasin and in the management area plans prepared by KGA member agencies.

2.2.1 Hydrogeologic Conceptual Model

Numerous descriptions and reports of local hydrogeologic conditions are available for the Subbasin. Details from previous investigations relating to the regional geologic and structural setting of the Subbasin; geologic features affecting groundwater flow; vertical and lateral boundaries; primary aquifers and aquitards; groundwater elevations and flow direction over time; and water quality are described below. This information is the foundation for the hydrogeologic conceptual model (HCM).

This HCM has been prepared under the supervision of Matthew Mayry, Certified Hydrogeologist.

2.2.1.1 Kern County and Lateral Boundaries

The Kern County Subbasin (5-022.14) (Figure 2-12), is within the southernmost portion of the Tulare Lake Hydrologic Region of the San Joaquin River Basin (5-022). The Subbasin encompasses a surface area of 1,792,000 acres (2,800 square miles) and contains approximately 32,000 feet (6 miles) of marine and continental sediments (DWR, 2006; Page, 1986). The Subbasin has approximately 40,000,000 acre-feet (AF) of groundwater storage with another 10,000,000 AF of storage capacity, including areas where water levels have declined (DWR, 2006). A recent U.S. Geological Survey (USGS) estimate of sediment thickness is 3 miles for the San Joaquin Valley (Faunt et al., 2009). Continental sediments comprise up to approximately 3,400 feet of the material along the Kern River near the town of Tupman (western side of the valley), and the base of the fill is over 18,000 feet deep (Davis et al., 1959).

The lateral boundaries of the Subbasin, are defined by various jurisdictional and geomorphic segments, as presented by DWR (2016b). The Subbasin is bounded by the Sierra Nevada on the east; by the Tehachapi mountains, San Emigdio mountains, and White Wolf Subbasin (5-022.18) on the south; and the Coast Range (Temblor Range) on the west. To the north of Subbasin are the following Subbasins: Kettleman Plain (5-022.17), Tulare Lake (5-022.12), and Tule (5-022.13).

2.2.1.2 Regional Geologic and Structural Setting

A brief description of the evolution of valley sediments and fill is included below, as it relates to the regional aquifer system of the Tulare Lake Region of the San Joaquin Valley Basin.

During pre-Tertiary time granitic rocks were deposited in the present-day area of the Sierra Nevada and Tehachapi Mountains (eastern and southeastern flanks of the Subbasin). Plutonic and tectonic activity also formed metamorphics that occur along the margins of the Subbasin. As tectonic activity uplifted these granitic and metamorphic deposits, erosion with subsequent transport of sediment into the basin occurred. These rocks form an almost impermeable boundary for the groundwater basin, but fractures and joints permit small yields of water to wells (Page, 1986).



Figure 2-12. Kern County Subbasin and Vicinity

Near the end of the Late Cretaceous, tectonic movements elevated the Coast Ranges to the west of the Central Valley which created a marine embayment in the present-day Southern San Joaquin region. During the Tertiary, seas advanced and retreated within this southern embayment, resulting in deposits comprised of both continental and marine sediments. The most recent of which are the Pyramid Hills, Vedder Sand, Olcese Sand, Santa Margarita Formation, and San Joaquin and Etchegoin Formations.

During the late Tertiary, uplift of basement occurred near present-day Bakersfield forming what researchers have termed the Bakersfield Arch. The Arch effectively resulted in depocenters for thick sequences of sediment to accumulate to the north and south of the Kern River (Bartow, 1991; Vasconcellos, 2016; Figure 2-13) during later Tertiary and Quaternary time. Tertiary crustal uplift and shifting caused the formation of the Sierra Nevada, Temblor, and Coast Ranges (Bartow, 1991). Crustal deformation along the proto-San Andreas and present-day San Andreas led to the formation of the structural traps for oil and gas accumulation throughout the west-side.

The Quaternary Period (Pleistocene and Holocene), marked a time when the seas retreated, and continental deposits from alluvial and fluvial systems formed (Tulare and Kern River Formations (Page, 1986). Marine rocks and deposits are, in part, the source rocks for the Tulare Formation on the west and the granitic from the Sierra Nevada on the east are the source rocks for the Kern River Formation. Some of the marine deposits on the west, contain saline water, that could have migrated into adjacent and overlying continental deposits (Page, 1986). Overall, the continental rocks make up most of the regional aquifer system in the central and eastern sides of the Subbasin while brackish to freshwater deposits and eroded marine deposits of the Coast Range make up a very small portion of the water-bearing units on the western side of the Subbasin.

The Pleistocene Epoch was dominated by brackish and freshwater lakes within the Subbasin, resulting in thick deposits of clay, as found throughout the upper Tulare Formation. In particular, the Corcoran Clay has been mapped over much of the San Joaquin Valley (including Tulare Lake Region), and its equivalents have been correlated to clays beneath the Kern and Buena Vista dry lake beds in the southern part of the Subbasin, as well as the Tulare Lake sediments on the northern boundary of Kern County (Croft 1972; Page, 1986) (Figure 2-14). This clay makes up a considerable impermeable to semipermeable zone that divides shallower poor-quality water from higher quality water of the regional aquifer system.

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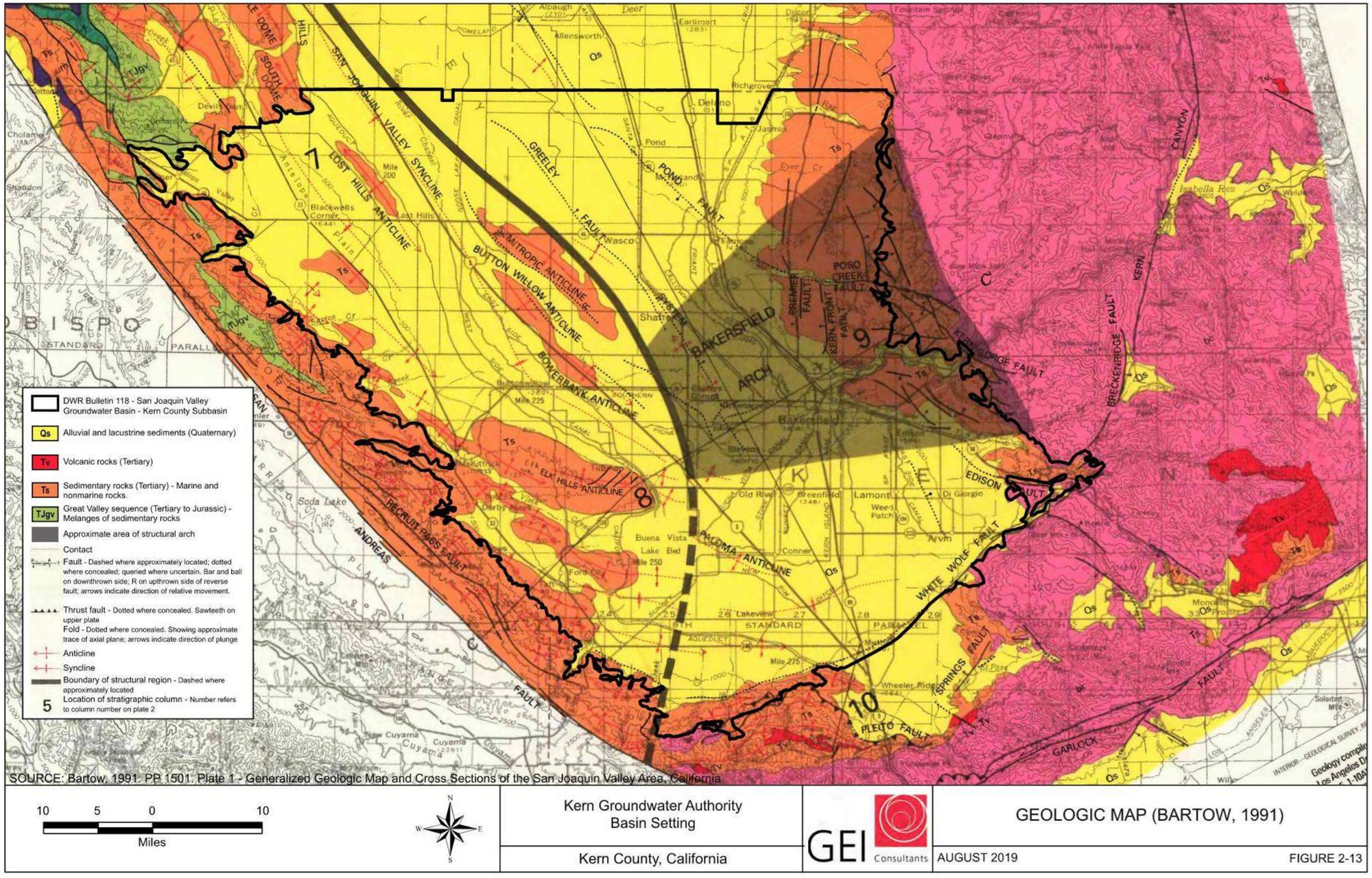

Figure 2-13. Geologic Map (Bartow, 1991)

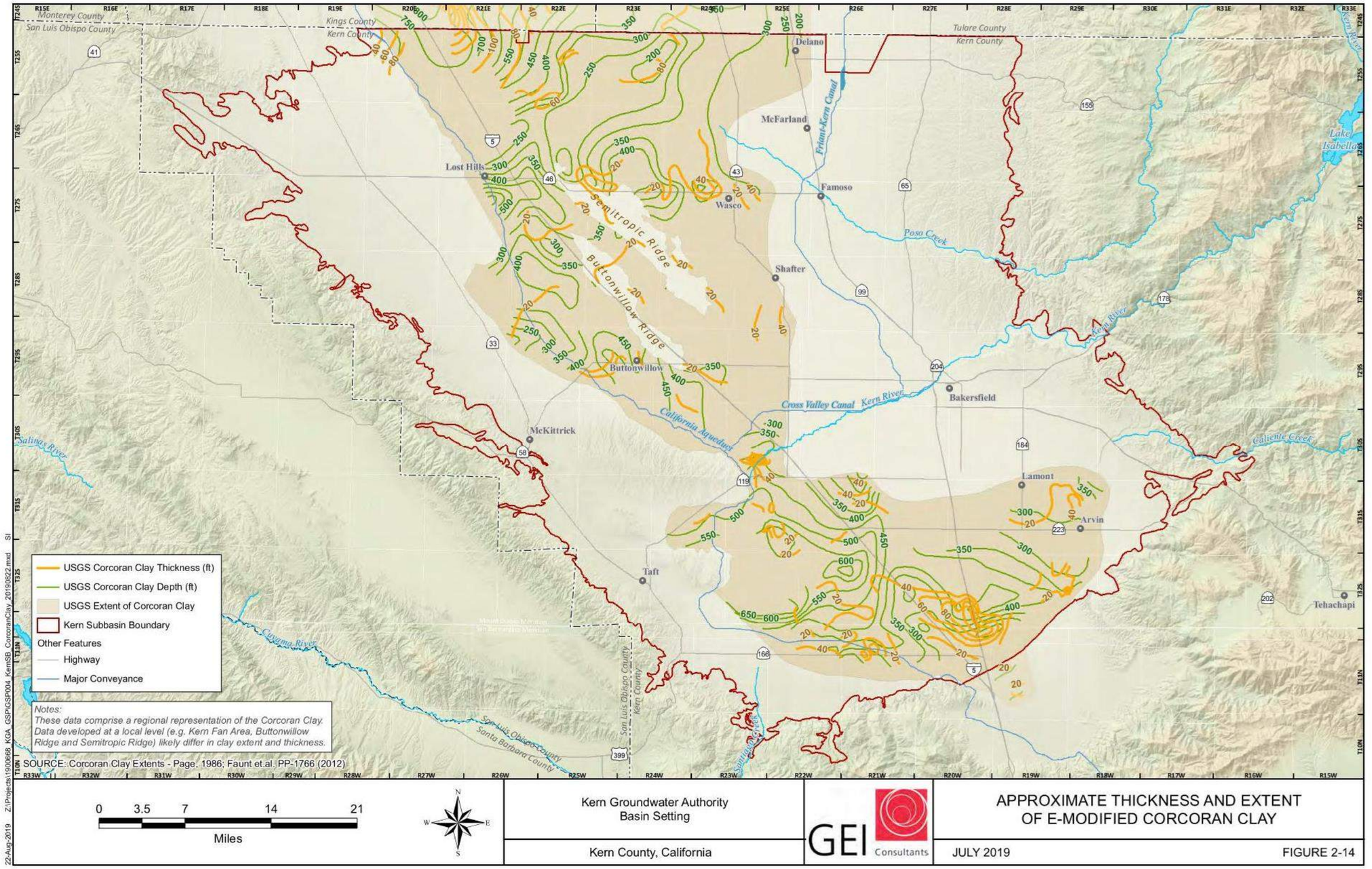

Figure 2-14. Approximate Thickness and Extent of E-Modified Corcoran Clay

Since the Pleistocene Epoch, stream channels, lakes, and rivers have deposited alluvium throughout the Subbasin. Alluvial fans have formed on both sides of the valley, but most notably on the eastern side where the Sierra Nevada granitics are the main source of sediment (Poso Creek Fan, Kern River Fan, and Caliente Creek Fan). On the eastern side of the valley, these stream channels are large, laterally migrating distributary channels. Over time, shifting stream channels have created coalescing fans, forming broad sheets of inter-fingering, wedge-shaped lenses of gravel, sand, and finer detritus (Page, 1986), which make up the shallow continental water-bearing deposits of the regional aquifer system. Page (1986) identified various depositional environments for the continental sediments, including alluvial fan and deltaic conditions on the eastern side of the valley, and flood-plain, lake, and marsh conditions on the western side. Consequently, coarse-grained deposits are predominant on the eastern side while fine-grained deposits are predominant within the central and western areas of the Subbasin.

Figure 2-15 is a conceptual block diagram that generally illustrates the highlands surrounding the Subbasin with folded beds separating the west side from the east side. This diagram displays the succession of marine deposition to more recent continental deposition and alluvium with fresher water deposits.

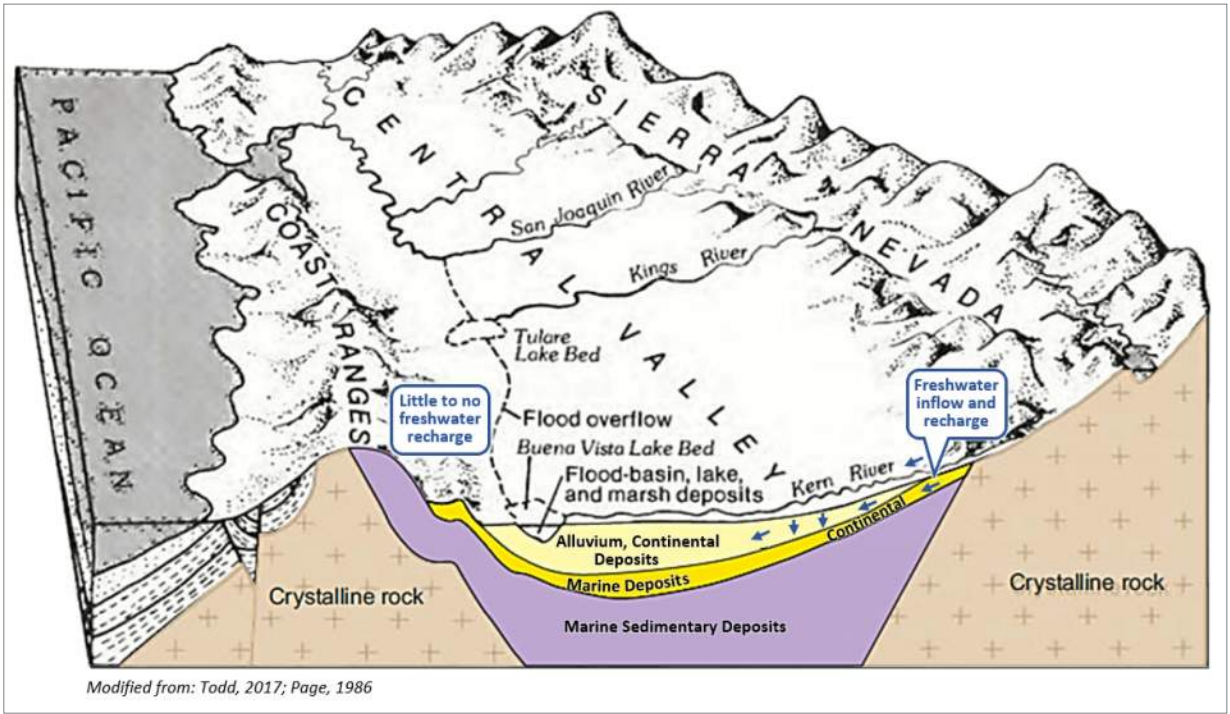

Figure 2-15. Conceptual Block Diagram Looking North from Kern River

The geologic history discussed above is related to the stratigraphy described below, and as summarized in Table 2-2. The description also includes a discussion of the portions of the formations that bear groundwater that have been utilized historically.

Table 2-2. Generalized Hydrostratigraphy of Kern County Subbasin

Age	Geologic Units of Interest	General Description		Deposition		AE	General Hydrogeologic Context
Recent	Alluvium	Discontinuous beds of sand, silt, clay and gravel, becoming finer grained toward the valley.		Continental / Alluvial	Alluvial Fans		Shallow unconfined aquifer in some areas of the subbasin.
Pleistocene	Older Alluvium						
	Tulare Formation	Interbedded gravel, sand, silt, and clay.			Marine, Debris Flows, Fluvial, Semi-arid to arid (West)/ Fluvial-Lacustrine (East)		Major freshwater aquifer of the subbasin.
	Corcoran Clay	Silt and clay. Lacustrine.					Confining/semi-confining aquitard in the west-central and central-southern subbasin.
	Tulare Formation	Kern River Formation Alluvial Fan Deposits. Interbedded gravel, sand, silt, and clay.	Interbedded gravel, sand, silt, and clay.			**AE**	Major fresh water aquifer of the subbasin.
Pliocene	San Joaquin Formation		Siltstone, clayey, diatomaceous with thin lenticular sand beds.	Transitional	Continental and brackish to restrictive marine		Fresh water production limited to deep wells.
Miocene	Etchegoin Formation **AE**	Fresh water production on east side of the valley.	Clay and silt to sand, gravel, and sandstone		Marine to partly continental	**AE**	Fresh water production limited to deep wells.
	Santa Margarita Sandstone **AE**	Chanac Formation Conglomerate with lenses of coarse sand and clays Non-Marine Clastic. Limited fresh water production on east side.	Fine to coarse white sand, gravel, and sandstone.		Shallow Marine Clastic	**AE**	Fresh water aquifer on east/northeast side of the valley
	Round Mountain Silt	Brown siltstone, diatomaceous		Marine	Marine		Aquitard on east side of the subbasin.
	Olcese Sand	Light gray sandstone with a few pebble and siltstone beds.			Marine/ nonmarine clastic wedge	**AE**	Fresh water aquifer on the east/northeast side of the subbasin.
	Freeman-Jewett Silt	Brown siltstone with interbedded ash.			Marine to shallow water	**AE**	Aquitard
Oligocene	Pyramid Hills and Vedder Sands	Interbedded sandstone and siltstone			Marine to shallow water	**AE**	Possible fresh water aquifer on the east/northeast side of the subbasin.

Data sources from: Page, 1986; Bartow, 1983 and 1991; Provost and Pritchard, 2003; Todd Engineers et al, 2007; Scheirer et al, 2007; SWSD, 2012; Tor Nilsen, 1996; and KTWD, 2016.

Aquifer Exemptions present (AE) - California Department of Conservation, https://www.conservation.ca.gov/dog/Pages/Aquifer-Exemptions-Status.aspx.

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2.2.1.2.1 Stratigraphy

The Oligocene Pyramid Hills and Vedder Sands are interbedded sandstone and siltstone deposited in a shallow to deep marine environment and in a limited non-marine environment. They may produce fresh groundwater on the east and southeast sides of the Subbasin (Page, 1986).

The Miocene Olcese Sand and Santa Margarita Sandstone are current sources of drinking water in the northeastern portion of the Subbasin where they occur as confined aquifers (KTWD, 2016). The origin of the Miocene Olcese Sand and Santa Margarita Sandstone varies from continental to marine going from east to west across the Subbasin (Scheirer, et al, 2007a). The Miocene Olcese Sand ranges up to 600 feet in thickness and consists of unconsolidated medium- to coarse-grained sand containing a few pebble and siltstone beds. The formation is exposed in the Poso Creek area (Page, 1986) and is utilized by the Olcese Water District in the Kern River Canyon. The Santa Margarita Sandstone ranges in thickness from 200 to 600 feet and consists of coarse-grained sand (DWR 2006), and includes an upper bed of fine, silty, well sorted gray sand, and a lower bed of brownish-gray and brown fossiliferous micaceous sandy siltstone. According to Page (1986), the sandstone is a major aquifer that reportedly yields as much as 1,950 gallons per minute (gpm) to wells. Croft (1972) reported that the formation also yields water to wells in the foothills southeast of Bakersfield. The Round Mountain Silt is an aquitard that separates the Miocene Olcese Sand from the Santa Margarita Sandstone and acts as a confining unit for the Miocene Olcese Sand (KTWD, 2016). This silt unit consists mostly of a gray and brown siltstone that contains beds of diatomite and silty sand (Page, 1986), and ranges in thickness from 0 to about 200 feet.

The Mio-Pliocene Etchegoin Formation varies considerably, ranging from clay and silt to sand, gravel, and sandstone. It ranges in thickness from a few tens of feet to more than 2,000 feet. Several wells near the foothills and a few deep wells in the valley derive fresh water from the Etchegoin; however, its depth is more than 3,000 feet beneath most of the valley and is limited to deep well production (Page, 1986).

Overlying the Etchegoin Formation is the Pliocene San Joaquin Formation of marine deposition. It contains silt and silty sandstone, with a conglomerate at the base of the formation. In the deep subsurface northeast of the Kettleman Hills, the formation is considered a shoreline deposit because the material is coarser and more permeable than in the Kettleman Hills area and yields fresh water to many wells. The San Joaquin Formation is the youngest marine deposit in the Central Valley (Page, 1986), representing the end of marine deposition in this area. Overlying sediments were deposited by alluvial, fluvial, and lacustrine processes.

The Tulare Formation is Plio-Pleistocene in age, and in conjunction with the Kern River Formation (Mio-Pliocene to possibly early Pleistocene), represents west-east facies change across the Subbasin. The Tulare and Kern River formations are moderately to highly permeable and are major freshwater sources within the Subbasin (Page, 1986; SWSD, 2012).

The Tulare Formation (western-central Subbasin) contains up to 2,200 feet of interbedded, oxidized to reduced sands, gypsiferous clays, and gravels derived primarily from Coast Range

sources. The permeable deposits of the Tulare Formation are divided into upper and lower units, separated by the E-modified Corcoran Clay member (Corcoran Clay) of the formation. Groundwater beneath the Corcoran Clay is typically confined to semiconfined (Page, 1986; SWSD, 2012). In addition to its confining properties, laboratory tests indicate that the clay is highly susceptible to compaction (Faunt, et al., 2009). On the west side of the Subbasin, the Tulare Formation is also divided by upper and lower units by potential equivalents to the Corcoran Clay that are reported locally (Rector, 1983; Geomega, 2001). While the central part of the basin was deposited in a fluvial-lacustrine environment, the west side has lacustrine claystones, fan-delta deposits, debris-flow dominated alluvial-fan deposits, but also paleosols representing an arid to semiarid setting (Nilsen and Campbell, 1996). The difference in Tulare deposition illustrates fundamental differences between the west side and east side aquifer system.

The Corcoran Clay occurs laterally in the north Subbasin (~34 miles wide in extent) from Delano to Lost Hills (Figure 2-14) and narrows to the south where it is not a confining bed in the Kern Fan Area. Although the USGS data present a clay in the western part of the Kern Fan area, local data do not support the presence of an extensive confining clay in the Kern Fan area. A clay in the south part of the Subbasin has been correlated as the Corcoran Clay by many investigators including Croft (1972) and Page (1986). It extends from Buena Vista Lake Beds to just east of Arvin and DiGiorgio (~31 miles wide in extent). In the south Subbasin, the Corcoran Clay is present at depths between 250 and 650 feet (DWR, 1981). Within the central area of the Subbasin between the Kern River and Highway 46, the depth to the Corcoran Clay varies from 300 to 450 feet. Further north to the county line, the depth varies from 200 to 750 feet. The Corcoran Clay, most notably the modified E-clay (Page, 1986) is generally very fine grained; however, isolated, coarser zones are possible, particularly where the clay is less than 20 feet thick. The thickness of the clay is as much as 100 feet in a small area of the southern Subbasin but typically varies between 20 and 40 feet. In the northern Subbasin, the clay might be as thick as 60 to 80 feet in isolated areas, but the thickness typically varies between 10 and 30 feet. The Corcoran Clay does not exist under the Kern Alluvial Fan (Kern Fan), where the shallow unconfined layers are separated from deeper layers by an intermediate zone of interbedded sands and silts which retard vertical groundwater flow and create an increase in semi-confinement with depth. The Corcoran Clay is also not present in the eastern/northeastern part of the Subbasin from the cities of McFarland and Bakersfield, to Edison (Faunt et al., 2009).

The Kern River Formation includes from 500 to 2,000 feet of poorly sorted, lenticular deposits of clay, silt, sand, and gravel derived from the Sierra Nevada. The Kern River Formation crops out in the east Subbasin and reaches its maximum thickness of 2,600 feet in the subsurface west of mapped outcrops (Bartow and Pittman, 1983). The formation consists mostly of poorly sorted fluvial sandstone and conglomerate with interbeds of siltstone or mudstone that becomes finer grained northward and westward. Some of the thicker siltstone or mudstone interbeds may represent deposits of small ephemeral lakes or ponds (Bartow and Pittman, 1983). The Kern River Formation is coarsest in its easternmost exposures, generally the area south of the Kern River, where the composition includes a cobble conglomerate with boulders near the base and pebbly sandstone. (Bartow and Pittman, 1983). Two oil-producing zones occur in the lower part

of the formation where it is believed to have migrated to the Kern River Formation from older marine sediments (Bartow and Pittman, 1983).

The Kern River Formation unconformably overlies the Chanac Formation and may be contemporaneous with the Etchegoin, San Joaquin, and the Tulare formations (Bartow and Pittman, 1983 and Bartow, 1991); however, Graham and others (1988) concluded that the Kern River Formation predates the Corcoran Clay, which has a basal age of about 725,000 years. Radiometric dating of a volcanic ash layer near the top of the Kern River Formation at the Kern River oilfield may agree with the aforementioned basal age; however, others dated this ash bed at 6 million years which would place the Kern River Formation solely in the Miocene (Scheirer et al., 2007a). Nevertheless, the gradational relationship between the Kern River Formation and seemingly younger units such as the Etchegoin, San Joaquin, and Tulare formations would have to be reexamined.

Older alluvium and terrace deposits overly the Tulare and Kern River formations. These deposits also make up a portion of the regional aquifer system. They are composed of up to 250 feet of Pleistocene-age lenticular deposits of clay, silt, sand, and gravel that are loosely consolidated to cemented. These deposits are moderately to highly permeable and yield sufficient water to wells. They are often indistinguishable from the underlying Tulare and Kern River formations (DWR, 2006).

The Holocene-age younger alluvium and flood basin deposits vary in character and thickness in the Subbasin. Along the eastern and southern Subbasin margins, these younger deposits consist of up to 150 feet of interstratified and discontinuous beds of clay, silt, sand, and gravel. In the southwestern portion of the Subbasin, the deposits are finer-grained and less permeable as they grade into fine-grained flood basin deposits underlying the historic lakebeds of Buena Vista and Kern lakes in the southern portion of the Subbasin. The flood basin deposits consist of silt, silty clay, sandy clay, and clay interbedded with poorly permeable sand layers. These flood basin deposits are difficult to distinguish from underlying fine-grained older alluvium (Page, 1986; DWR, 2006).

As described above for the deposition of the Tulare and Kern River formations and Quaternary facies differ from west to east across the basin. The below diagram (Figure 2-16) illustrates the general distribution of facies fluvial-deltaic deposition dominating the east-side; alluvial, lacustrine, and marsh deposition dominating the central portions of the basin, and alluvial and debris flow deposition dominating the western side of the Subbasin during the Quaternary.

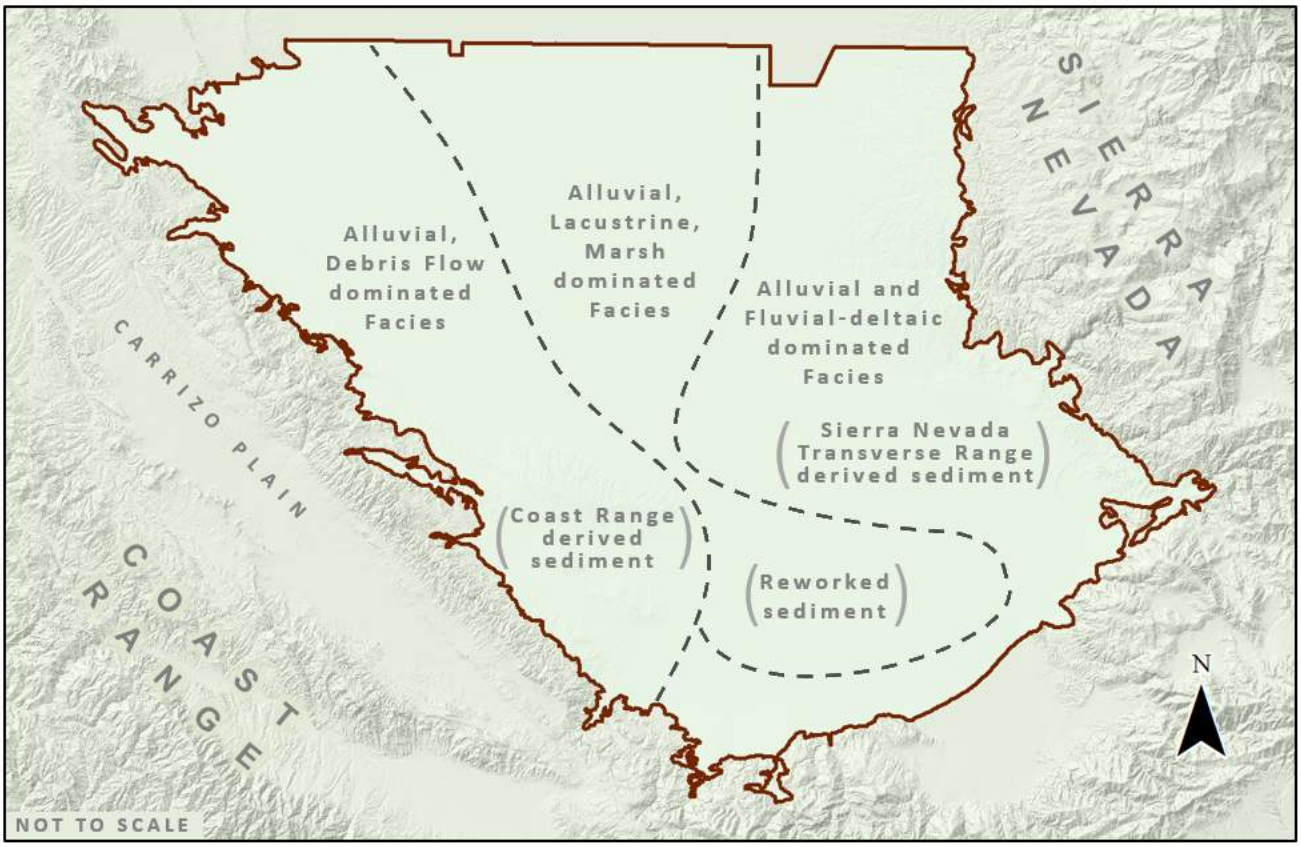

Figure 2-16: Generalized Quaternary Depositional Facies

2.2.1.3 Geologic Features that Significantly Affect Groundwater Flow

The primary structure in the Subbasin that affects groundwater flow is the large asymmetric structural trough (San Joaquin Valley Syncline) that has been the depocenter of thousands of feet of sediments since late Mesozoic time (Bartow, 1991). Groundwater naturally flows northwest along the trend of the syncline. Likewise, the Bakersfield Arch is a broad southwest-plunging arch of basement rock that separates the small Maricopa-Tejon sedimentary basin at the south end with the remainder of the sedimentary basin to the north and west (Figure 2-13, from Bartow, 1991). Groundwater recharging from the Kern River will flow north and south along the flanks of the arch away from the center of the Subbasin.

Numerous faults and folds are located in the Subbasin, as shown in local geologic maps (Figures 2-13, 2-17, and 2-18). Bartow (1991) identified portions of three types of structural regions in Subbasin, excluding the Bakersfield Arch. The northeastern third of the Subbasin, including the north half of the Arch, is located on the minimally-deformed eastern limb of the valley syncline. Normal faulting is associated with the Bakersfield Arch, occurring mostly in the older sediments (QPc; Ts) but extending into and concealed by the younger sediments (Qoa, Q; Qs), notably the Pond-Poso Creek Fault. Fault orientations vary from northwest to northeast due to alternating compressional and extensional forces.

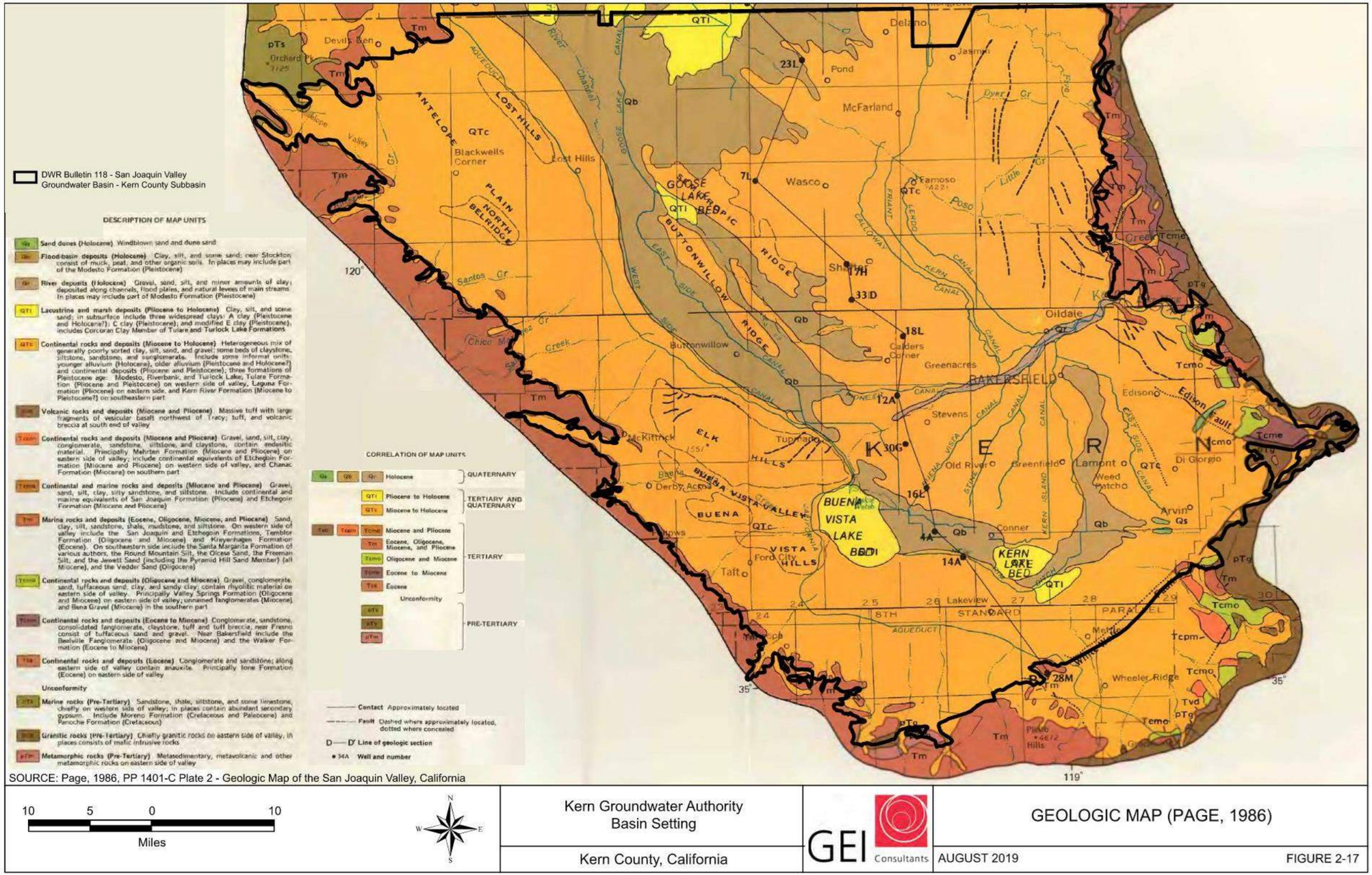

Figure 2-17. Geologic Map (Page, 1986)

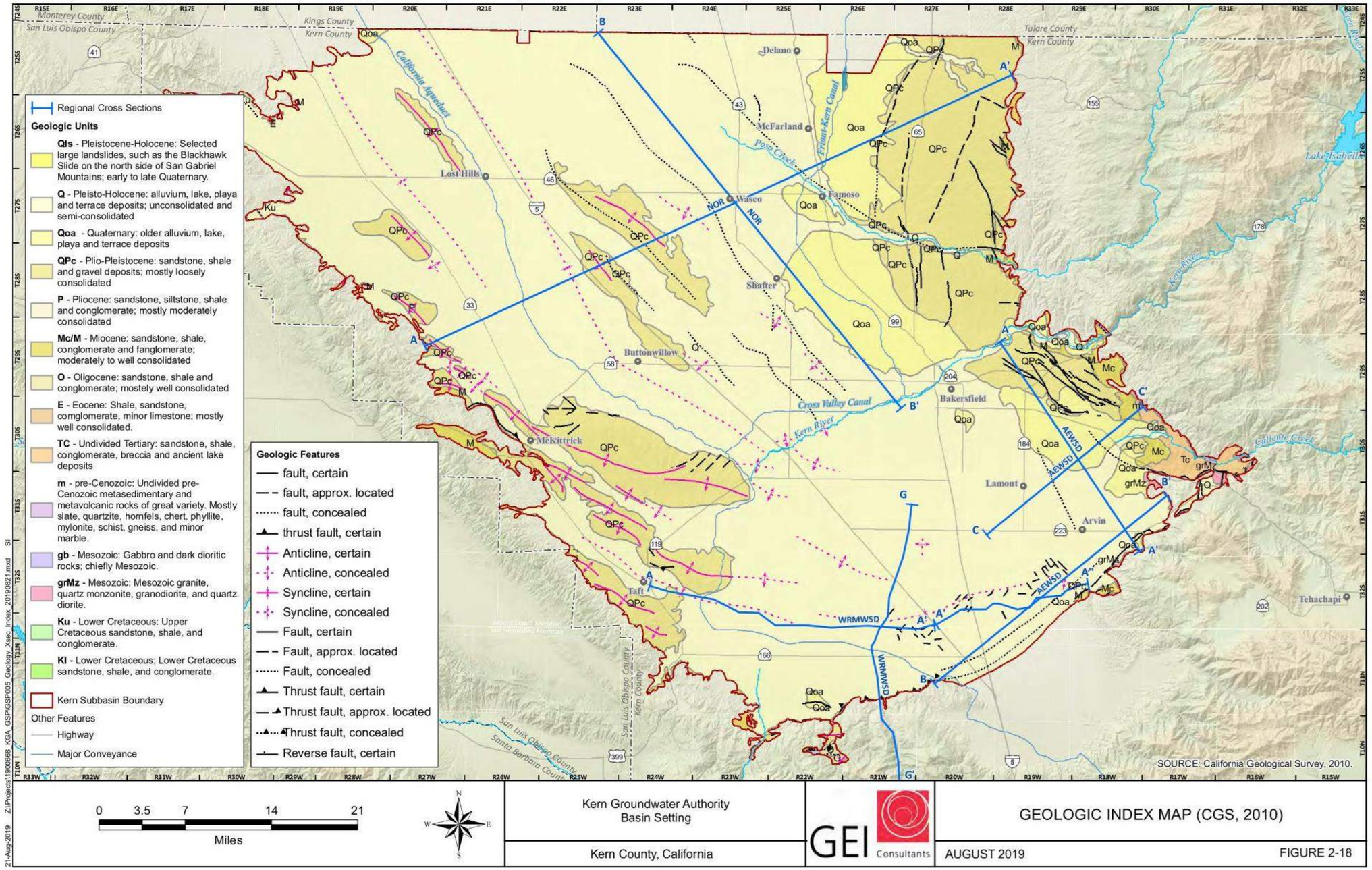

Figure 2-18. Geologic Map Index (CGS, 2010)

2.2.1.3.1 Faults

Several faults have historical displacement or have been identified as features that affect groundwater flow. The following are: Pond-Poso Fault, Edison Fault, White Wolf Fault, Kern Front Fault, Premier Fault, New Hope Fault, and small portions of the Pond Fault (California Geological Survey, 2010a). The Edison Fault and White Wolf Faults also affect the flow groundwater (DWR, 2006).

The southeastern quarter of the Subbasin, including the south half of the Bakersfield Arch, is considered to be "highly deformed" and the "most complex tectonic history" (Bartow, 1991) due to the alternating north-south compressional and extensional forces since the Cretaceous Period. The southern boundary of the Subbasin is delineated by the northeast-trending White Wolf Fault, a reverse fault with active displacement (DMG, 1955), that may have originally been a normal fault (Bartow, 1991). The White Wolf Fault separates the Subbasin from the new White Wolf Subbasin to the south. Two northeast-trending thrust faults are located at the southwestern corner of the Subbasin, including the Wheeler Ridge and Pleito Faults. During the 1952 Bakersfield earthquake, a group of small ground fractures developed in an alignment just north and subparallel to White Wolf Fault. Numerous normal faults are located along the eastern margin of the southern Subbasin, including the Edison Fault and many unnamed fault segments that were active during the 1952 earthquake. More detailed descriptions of local faults and folds of interest are described in the chapters herein.

2.2.1.3.2 Folds

Several concealed folds have been delineated in the central Subbasin, the Paloma anticline, Buttonwillow and Semitropic anticlines, San Joaquin Valley syncline, and other unnamed anticlines and synclines in the Subbasin.

2.2.1.3.3 West-Side Fold Belt and Groundwater Flow

The west-side fold belt includes anticlines: Kettleman Hills, Lost Hills, Elk Hills, and at the east boundary of the fold-belt, Buttonwillow and Semitropic anticlines (Bartow, 1991) (Figure 2-17; Page, 1986). These structures are oriented toward the northwest, subparallel to the Coast Range and the San Andreas Fault. Page (1986) and DWR (2006), identified the anticlinal folds of the highlands, specifically Lost Hills, as restrictions to groundwater flow within the lowlands, and this condition likely applies to other anticlines in the Subbasin.

Structurally, and to a large degree, lithological, the western side differs from the central and eastern portions of the Subbasin. Western Plio-Pleistocene deposits are derived from weathering and erosion of the Coastal Range made up of marine deposits yielding clays and silts and some sands. On the other hand, the east side is made up of quartzose and feldspathic coarser sized sediments from the Sierra Nevada.

In addition to structure, the thickness of fresh water bearing deposits and the sources of groundwater recharge differ between the west side and the central and east side of the Subbasin. In general, the differences result in more restrictive localized groundwater system with poorer quality water on the west side of the Subbasin.

2.2.1.4 Kern County Subbasin Boundaries

As described above, the lateral boundaries are defined by jurisdictional and structural boundaries (DWR, 2003, 2016a, 2016b). Within the jurisdictional boundaries of the Subbasin, are effective lateral boundaries of usable groundwater or effective extents of the principal aquifers.

These boundaries will be discussed in the remainder of this section, and include the presence or absence of: a sufficient quantity of groundwater for beneficial use; water quality changes rendering groundwater unusable; and aquifer exemptions of portions of the Subbasin that either contain commercially producible hydrocarbons or minerals, are high in total dissolved solids, and/or are otherwise isolated from the rest of the Subbasin by geologic boundaries. The characteristics of the effective groundwater Subbasin, as described above, also apply to the bottom of the groundwater basin and are discussed in Section 2.2.1.5.

2.2.1.4.1 Criteria for the Extent of Groundwater with Beneficial Use in the Subbasin

An aquifer may not be suitable for beneficial use if:

- It is not currently serving as a source of drinking water,
- It has commercially producible minerals or hydrocarbons, or
- It is not expected to supply a public water system, and
- It is either economically or technologically infeasible for treatment or recovery now or in the future for domestic, agricultural, or industrial use.

The purpose of this GSP is not to exempt aquifers, nor is it to define the maximum depth or water quality concentration at which groundwater is economically recoverable or treatable now or in the future. However, by applying the criteria of 40 CFR §144.3 and 40 CFR §146.4, active oil and gas aquifers and exempted aquifers are not a part of the groundwater basin for beneficial use.

The groundwater Subbasin's extent, where no exemptions or commercially producible hydrocarbons exist, likely ranges between 3,000 milligrams per liter (mg/l) and 10,000 mg/l total dissolved solids (TDS) depending on the feasibility of treatment and recovery of the groundwater for beneficial use. The estimated lateral extents of the Subbasin are further presented with the bottom of the Subbasin and cross sections of this plan.

2.2.1.5 Bottom of Subbasin

As described above, the following whichever is shallowest, are the lateral and vertical boundaries of the groundwater Subbasin:

- depth to producible minerals or hydrocarbons,
- depth to and aerial extent of exempted aquifers,
- depth that makes recovery of water for domestic, commercial, or industrial purposes no longer economically or technologically feasible, or

- the depth at which groundwater cannot now or in the future serve as a source of drinking water.

For example, water bearing zones below the depth to producible hydrocarbons are not within the groundwater basin; likewise, water bearing zones below an exempted aquifer are not within the groundwater basin.

In some parts of the Subbasin the lateral and bottom boundaries of the groundwater are subject to depths to producible hydrocarbons and extent of depths to aquifer exemptions. As described above, any water bearing zone below these three criteria are outside of the groundwater Subbasin. The available depth to hydrocarbons and aquifer exemptions at the time of this GSP compilation, although possibly generalized, are incorporated into Figures 2-19 and 2-20 for comparison.

As discussed above, it is not the intent of this plan to evaluate at which depth the groundwater is economically recoverable or treatable in the future; but, for discussion purposes only, a TDS of 2,000 mg/l is presented in Figure 2-19, to consider the vertical and lateral distribution of a fresh groundwater dataset in the Subbasin. A TDS of 2,000 mg/l has been mapped throughout the region by Page (1973), historically, it was considered a limiting TDS concentration for the irrigation of most crops (Page, 1973); however, it does not define the bottom of the groundwater Subbasin (or the depth to water that is no longer economically or technologically feasible for groundwater beneficial use). Other local datasets for a TDS of 2,000 mg/l are included in management area plans.

By comparison the depth to TDS of 10,000 mg/l (Gillespie et. al. 2017) (one of the criteria for classification as an underground source of drinking water (USDW)) is presented on Figure 2-20. As discussed above, this depth may not represent the USDW if there are aquifer exemptions or producible hydrocarbons shallower in the subsurface.

In addition to the datasets mentioned above, the SWRCB Resolution Number 88-63 (SRWCB, 1988), has also listed criteria for the suitable sources of drinking water for municipal or domestic water supply. These sources are defined as waters that: have a TDS of less than 3,000 mg/l; are reasonably expected by Regional Boards to supply a public water system, including sufficient yield; are not contaminated or beyond reasonable treatment; and are not exempted by 40 CFR §146.4 (SRWCB, 1988). At this time, there is no dataset developed to present basin-wide correlations of the SRWCB 88-63 base of drinking water.

An additional informal description of the bottom of the Subbasin may be referred to by some researchers, at times, as the “current operational bottom of the Subbasin” which basically describes the depth of active groundwater well pumping; however, this description should not be used to satisfy SGMA requirements § 354.14(b)(3) of the California Code. The range of well depths and perforations generally deepen in the alluvial aquifer system from the margins of the basin toward well discharge points in the south-central and north-central Subbasin. The historical operational bottom of the depth and/or the current operational bottom of the basin are not mapped herein because the operational bottom of the Subbasin has increased with depth as groundwater elevations have decreased over the years. In general, groundwater wells extend to

depths of more than 1,000 feet (Page, 1986), and the maximum thickness of freshwater deposits is calculated at about 4,400 feet, occurring at the south end of the valley (Page, 1986). Cross sections included in this plan provide a representation of current well depths in the Subbasin.

2.2.1.5.1 Page (1973) Base of Freshwater

Although, not the bottom of the groundwater basin, the base of fresh groundwater (Figure 2-19) has historically been defined by Page (1973), as the depth at which specific conductance (SpC) is 3,000 micromhos per centimeter (µmhos/cm) or microsiemens per centimeter (µS/cm), and is considered to be generally equivalent to a TDS concentration of 2,000 mg/l. These values have been reported because they may be considered a limiting factor for irrigation. The conversion factor from SpC to TDS used for this determination was 0.67, which is midway between the typical range of 0.55 to 0.75 (Hem, 1985), and is dependent on the composition of groundwater.

The base of fresh groundwater is quite variable in the Subbasin ranging over 4,000 feet, as listed below:

Location			Elevation, feet msl	Depth, feet below ground
Southeast,	T31S/R28E-Section 32,	West of Arvin	> -4400	~ 4700
Northwest,	T26S/R20E-Section 34,	Lost Hills area	0	~ 400
Northeast,	T25S/R27E-Section 6,	South of Richgrove	-2800	~ 3300
East central,	T29S/R27E-Section 12,	Oildale	-2000	~ 2500
West central,	T29S/R24E-Section 16,	East of Buttonwillow	-800	~ 1100

On the east side of the Subbasin, the base of fresh groundwater trends parallel to nearby faulting. The 2,400-foot below mean sea level (bmsl) contour (and other deep contours) on Figure 2-19 represents a northwest-trending trough of fresh groundwater between Bakersfield and Wasco. This trough lies between the concealed Poso Creek fault to the northeast and the pre-Quaternary Greeley Fault on the southwest that extends from the Kern River to the Kern National Wildlife Refuge. This “graben” of deeper fresh groundwater appears to be trending with these faults.

A smaller, northwest-trending trough of fresh groundwater is located east of Delano and south of Richgrove on the west side of several northeasterly-trending faults. This trough of fresh groundwater may be more of an indicator of freshwater in the Santa Margarita and Olcese aquifers.

On the west side of the Subbasin, notably, west of Lost Hills, Buttonwillow, and Elk Hills, Page (1973), reported very little data for groundwater less than 3,000 µmhos/cm. The lack of data is a combination of evidence suggesting that there is very little fresh water (<3,000 µmhos/cm), on the west side as corroborated by other sources (Gillespie et. al., 2017; and Metzger and Landon, 2018), and a potential data gap where additional data may be useful.

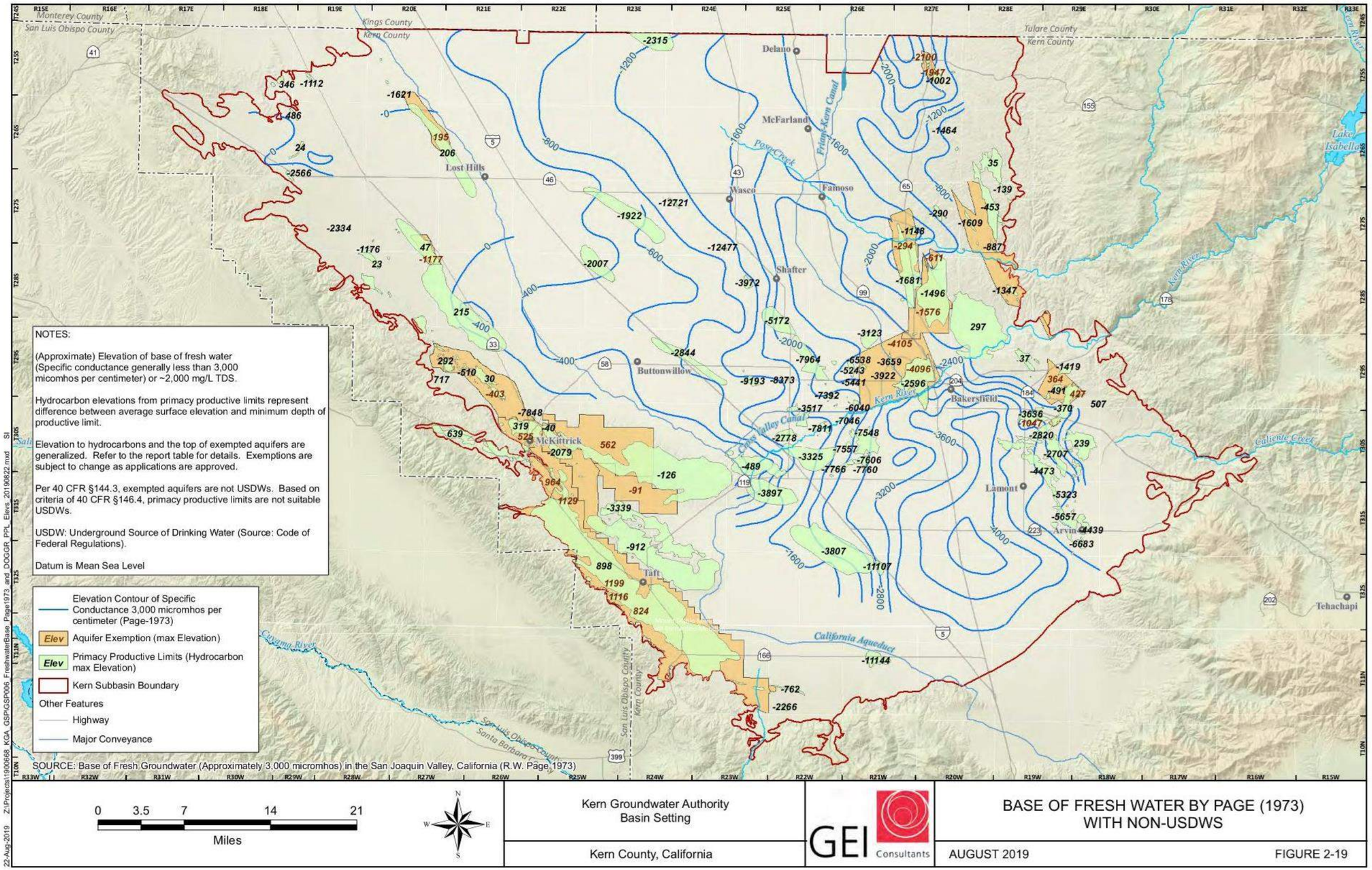

Figure 2-19. Base of Fresh Water by Page (1973) with Non-USDWs

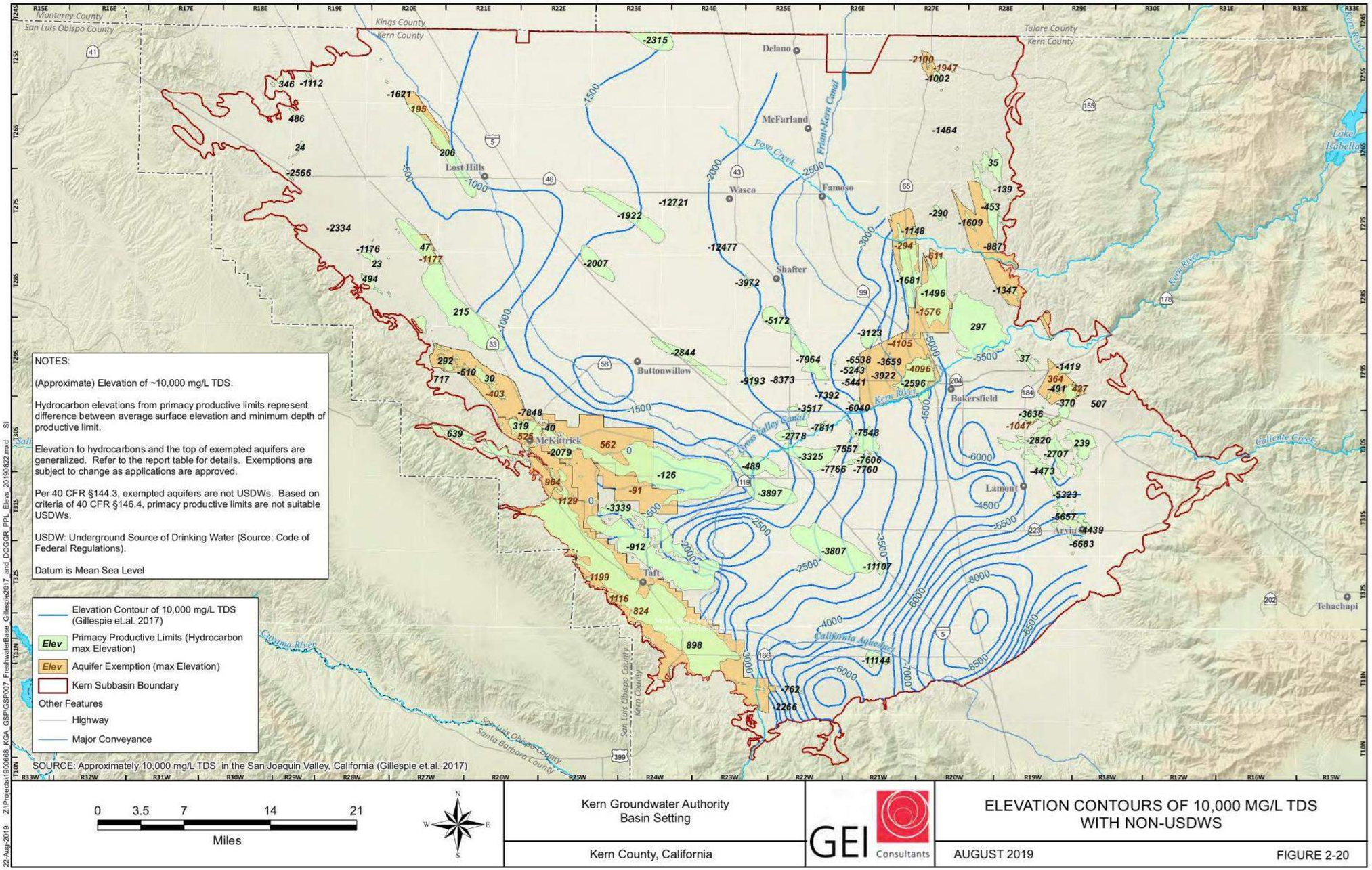

Figure 2-20. Elevation Contours of 10,000 MG/L TDS with Non-USDWs

2.2.1.5.2 Gillespie et. al. 10,000 mg/L TDS

The depth to groundwater with a TDS of 10,000 mg/l (Figure 2-20), is the deepest possible USDW. Gillespie et. al. (2017) and Kong (2016) developed these data based on geochemical analysis of water samples and geophysical log analysis. The depth to 10,000 mg/l TDS is generally consistent with regional trends within the Subbasin. Southeast of the City of Bakersfield, the 10,000 mg/l TDS is mapped to a depth of 6000 ft. This is consistent with the knowledge that this area of the Subbasin receives the greatest amount of fresh water recharge from the Sierras.

In the Maricopa depocenter in the south part of the Subbasin a couple miles north of Wheeler Ridge the 10,000 mg/l TDS contour may be as deep as 10,000 ft. No chemical analysis data were available to verify this geophysical log interpretation; however, the results from Page (1973), also mapped the depth to 2000 mg/l groundwater at 4600 ft (which was the deepest fresh water in the Subbasin) (Gillespie et. al., 2017). The Maricopa depocenter appears to have fresh water that extends deeper than anywhere else in the Subbasin.

Salinities in the west Subbasin are much higher, and depths to the base of USDW are more variable (Gillespie et. al., 2017). The structural complexity along the west side of the valley may be a contributing factor to the variable distribution of water salinity in this area. Gillespie et. al. (2017), cite that numerous wells contain waters between 3000 and 10,000 parts per million (ppm) in the nonmarine Tulare Formation and overlying alluvium in the western Subbasin.

Figure 2-21 below is a conceptual profile illustrating the general difference between the shallow and deep aquifer systems (fresh water continental deposits and alluvium, and saline water marine deposits), and the differences between the west and east side aquifer systems. In general, groundwater is more saline on the westside, while the freshwater column is thickened in the eastern-central part of the Subbasin.

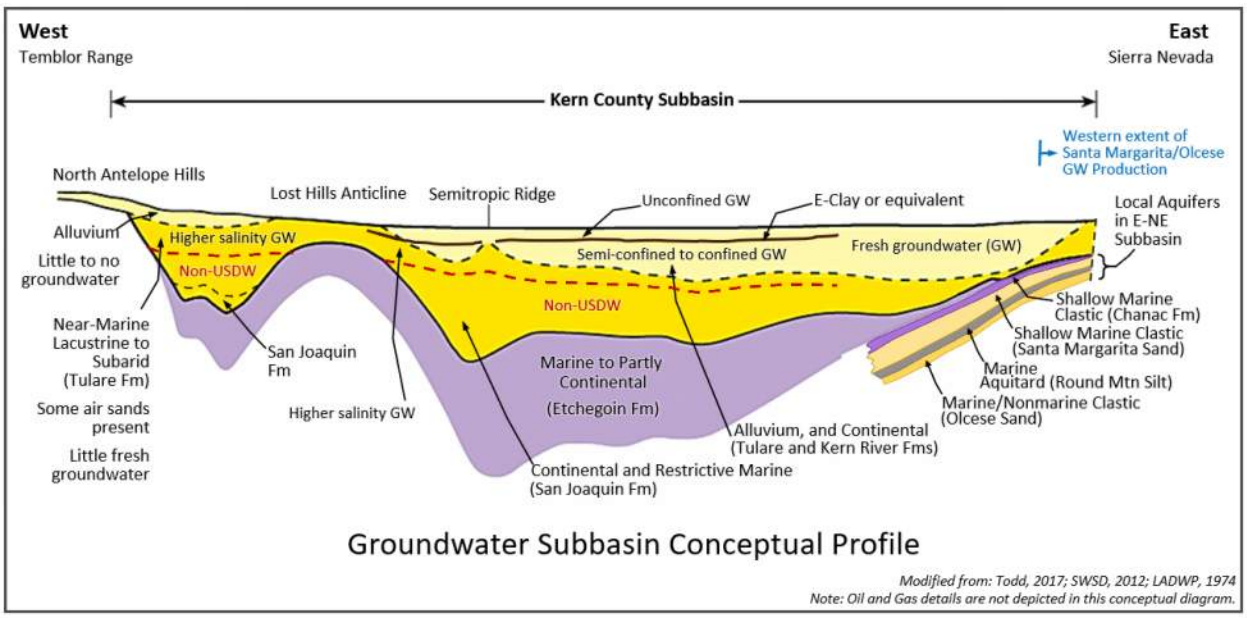

Figure 2-21. Groundwater Subbasin Conceptual Profile

2.2.1.6 Principal Aquifers and Aquitards

The groundwater aquifers of the Subbasin are geologically diverse with differing zones of confined, semiconfined, and unconfined groundwater conditions. As depicted in the below Figure 2-22, the primary aquifer system occurs in the central-northern, central, and central southern portions of the Subbasin. It consists of the Tulare formation, Kern River formation, and overlying alluvium. On the eastern side of the Subbasin are the confined Santa Margarita, Olcese, Pyramid Hills, and Vedder Sands. Groundwater wells extract water where these aquifers are not exempted and where they are feasible for groundwater supply use without hydrocarbons, On the western side of the Subbasin, very little usable groundwater occurs. In the northwest, groundwater supply production is likely limited and may occur in alluvium and/or the Tulare Formation.

In addition to the formations described above, groundwater may also be pumped from the San Joaquin and Etchegoin (Page, 1986; Bartow and Pittman, 1983) in the central portion of the Subbasin; however, little information is available to further document the groundwater characteristics or extraction within these zones.

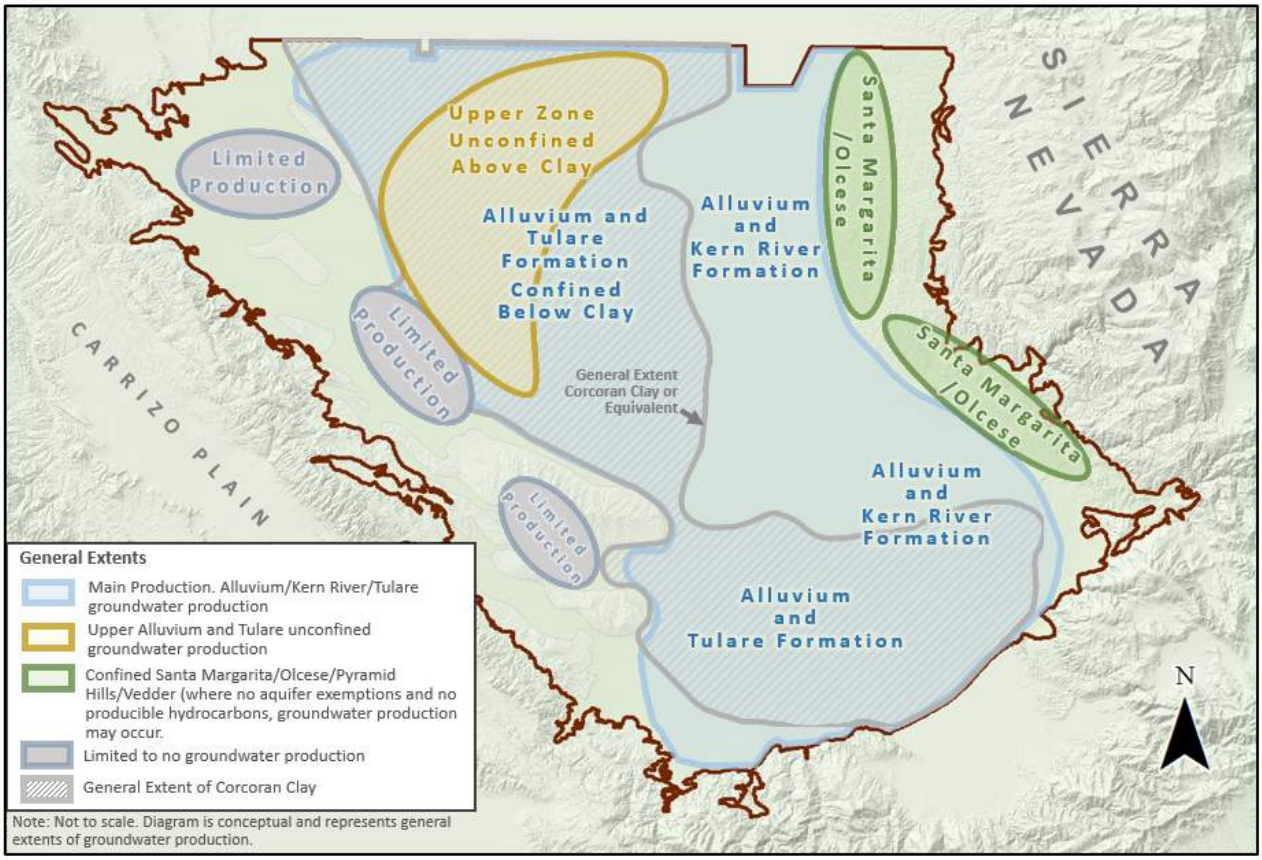

Figure 2-22. General Distribution of Groundwater Aquifer Supply Production in Kern County Subbasin

2.2.1.6.1 Formation Names

Table 2-2 presents the hydrostratigraphy and summary of the geologic units of interest with general details and a general summary of deposition and aquifer context.

The Subbasin groundwater system is dominated by alluvial/fluvial deposits on a basin-wide scale and produces an intricate, heterogenous grouping of aquifers. Although formations can be mapped across the Subbasin, much of the material is not distinctive in the subsurface and designation of a particular formation is difficult. Additionally, the E-modified layer of the Corcoran Clay member of the Tulare Formation is correlated across much of the Tulare Lake Hydrologic Region; however, there are still localized debates and questions on the extent and correlation of the E modified clay.

Refer to the discussion on stratigraphy in section 2.2.1.2. for a brief description of the formations and their general context in relation to the aquifer system.

2.2.1.6.2 Primary Aquifer System

The primary aquifer system of the Subbasin is within the Tulare and Kern River formations and overlying alluvium. It includes differing zones of confined, semiconfined, and unconfined groundwater conditions, due to the presence of clays that act as local aquitards. The Corcoran Clay and other equivalent clays occur within the Tulare Formation in the central and southern parts of the Subbasin (Page, 1983 and Page, 1986). Where extensive clays are present, some areas of the aquifer system may consist of a deeper confined zone and a shallower unconfined to semi-confined zone. Within the eastern portion of the Subbasin and in the vicinity of the Kern River Alluvial Fan, the aquifer system is made up of an unconfined to semi-confined zone. Shallow zones are also present locally in the northwestern and southern portions of the central Subbasin. The shallow zone is not a part of active groundwater extraction, but data are included in the groundwater conditions section of this report to evaluate changes over time.

Some researchers in the Subbasin define the primary aquifer system as one principal aquifer because the confining beds such as the E-modified Corcoran Clay or equivalent, are not laterally continuous across the Subbasin, or lithologically consistent allowing for continuous confinement. In addition, there are older wells in some parts of the Subbasin, that are screened across the Corcoran Clay which could allow interconnection of water between the upper and lower zones. However, for the past few decades, local county enforcement has worked to eliminate well construction practices with screens across encountered upper unconfined zones and lower confined zones.

In addition, to the aquifer zones described above, there is a shallow groundwater zone occurs above the A-Clay or other shallow clay; however, this zone has poor quality water and is not a part of the groundwater supply aquifer system.

Table 2-3 below is a summary of generalized aquifer characteristics of the primary aquifer system.

Table 2-3. Primary Aquifer System of Kern County Subbasin

Generalized Hydrostratigraphy	Relative Depth	Basin Extent	Water Quality	Corresponding Formations
Unconfined Zone	Middle to Deep	East side "main production zone"	Good	Eastside Alluvium and Kern River Formation
		Central, above the Corcoran Clay	Moderate	Central Subbasin, above the Corcoran Clay Member (E) of the Tulare Formation, or other equivalent fine-grained layers.
Confined, Semi-confined, or Lower Zone		Central "main production zone"	Good to Moderate	Confined to Semiconfined. Alluvium, Kern River Formation, and Tulare Formation

2.2.1.6.3 Eastern Confined Aquifers

Along the eastern margins of the Subbasin, other principal aquifers, where classified as USDWs and not exempted, include, semiconsolidated rock such as the Santa Margarita Sandstone, and Olcese Sands. These confined aquifers are hydraulically separated from the Kern River Formation aquifer system by Pliocene marine deposits. Other aquifers to the east, where classified as USDWs and not exempted, include the Pyramid Hills, Vedder Sand, and the Chanac Formation (Page, 1986; Bartow and Pittman, 1983). The extent of groundwater production in these aquifers is limited by the extent of producible hydrocarbons, aquifer exemptions, and increased salinity with depth.

2.2.1.6.4 West-side Aquifers

Alluvial aquifer zones on the west side of the Subbasin may contain groundwater that is higher in TDS. This groundwater occurs in the fold belt associated with folded and faulted strata. Where aquifers are classified as USDWs and not exempted per 40 CFR §144.3, groundwater may be pumped for beneficial use. The Tulare Formation makes up most of the aquifer system on the west side; however, the Tulare Formation differs in facies and origin than what is documented in the central portion of the Subbasin. West-side aquifers are described in more details in the management area plans.

2.2.1.6.5 Physical Properties of Each Aquifer and Aquitard

Aquifer parameters within the Subbasin are available from both well pumping tests and calibrated groundwater models. Data are summarized in Table 2-4 and Figure 2-23. Aquifer properties reported herein include hydraulic conductivity which is a volume of water that will move in a unit of time, under a unit hydraulic gradient through a unit area, and the specific yield

(unconfined systems) and storage coefficient (confined systems), which are functions of an aquifer's ability to store and release water from storage (storativity).

Table 2-4. Aquifer Parameters for Kern County Subbasin

Data Source	Calculated Horizontal Hydraulic Conductivity (feet/day)	Vertical Anisotropy Kh/Kz	Storage Coefficient	Specific Yield
Kern Pumping Tests Compilation (Todd, 2018)	7 to 250	--	0.0008 to 0.034	--
USGS - Kern Pumping Tests (Observation Wells)	20 to 1600	--	0.0004 to 0.002	--
USGS - Kern Recovery Tests	100 to 800	--	--	--
USGS - CVHM Range	0.24 to 3300	--	--	0.09 to 0.40
DWR - C2VSim Range				
Layer 1	15 to 78	275 to 500	--	0.12 to 0.40
Layer 2	< 1 to 100	20 to 4000	5.E-07 to 8.E-06	--
Layer 3	3.0 to 7.0	60 to 100	--	--
Todd Groundwater 2018 Model Range				
Layer 1	32 to 85	10 to 200	--	0.15 to 0.25
Layer 2			3.E-02	0.02 to 0.21
Layer 3	29 to 75	50 to 500	1.4E-07 to 9.4E-07	0.00004 to 0.00022
Layer 4	10 to 70	500		0.0011 to 0.0019
Todd Groundwater 2017 Model Average				
Layer 1	300 to 335	1150 to 1200	--	0.21
Layer 2	2	1050 to 1250	8.6E-06 1.4E-05	--
Layer 3	67 to 70	1000	0.00024	--
Layer 4	22 to 37	2200 to 3700	0.00058	--
USGS - Water Supply Paper 1618				
White-Poso Unit (upper 200 ft)	--	--	--	0.086 to 0.095
Kern River Unit (upper 200 ft)	--	--	--	0.125 to 0.132
Edison-Maricopa Unit (upper 200 ft)	--	--	--	0.12 to 0.14
USGS - Water Supply Paper 1618				
Clay and Fine Grained Units	--	--	--	0.03
Silt, Gravelly Clay, Sandy Clay Units	--	--	--	0.05
Fine, tight sand, tight gravel	--	--	--	0.10
Loose, well sorted sand, gravel	--	--	--	0.25

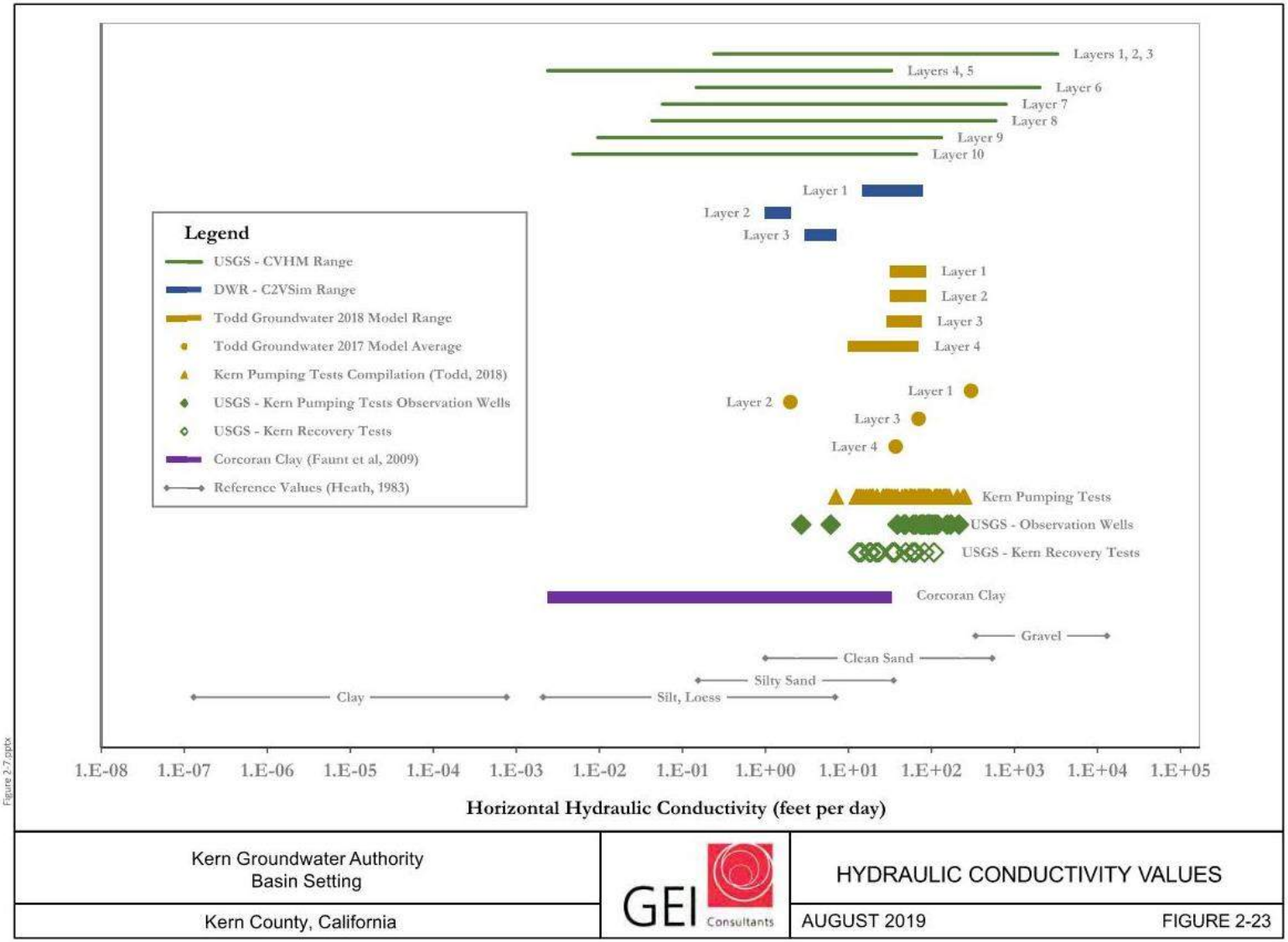

Figure 2-23. Hydraulic Conductivity Values

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2.2.1.6.6 Hydraulic Conductivity

Aquifer data derived from pumping tests were taken from two sources: 1) relatively short (1.5- to 5-hour) pumping tests by the USGS at irrigation wells during the late 1950s and 1960 (McClelland, 1962), and 2) from constant rate pumping tests from engineering consultants in the 2000's (Todd, 2018). The depth of these test wells varied from 98 to 1,500 feet below ground surface (bgs) (median: 650 ft bgs), and pumping rates varied from 44 to 4,480 gpm (median: 2,500 gpm). The analysis included the use of water level recovery data from pumping wells and water levels from observation wells. From these tests, the hydraulic conductivity was estimated and ranges from 3 to 250 feet per day (ft/d; median: 60 ft/d), which is consistent with published ranges for clean, medium- to coarse-grained sand (Heath, 1983), or for a fine sand to coarse gravel (Schwartz & Zhang, 2003). These values also fall within the range of the groundwater models that were partially calibrated with these data (C2VSim; CVHM; Todd, 2018; Todd, 2017) (Figure 2-23).

The Corcoran Clay of the Tulare Formation is most commonly known for its fine-grained beds; however, lithology does vary from fine (clay and silt) to coarse (sand) texture (Page, 1986; Faunt et al., 2009). These coarser-grained beds are isolated and principally occur where the Corcoran Clay is less than 20 feet thick. Faunt et al., (2009) compiled and estimated horizontal hydraulic conductivities within the range of 0.0024 to 33 ft/d, which is within the range of silt to fine/medium sand (Figure 2-23) (Heath, 1983). A range of vertical hydraulic conductivity was estimated from permeameters and field tests between 6.6×10^{-6} ft/d to 1.5×10^{-3} ft/d (Faunt et al., 2009), representing a potential vertical anisotropy range of 3.6×10^{2} to 2.2×10^{4}. As noted by Faunt et al., (2009) laboratory permeameter tests may have underestimated the hydraulic conductivity while field testing may have overestimated hydraulic conductivity due to potential for intra-borehole flow across the clay. Additionally, recent inelastic compaction of the Corcoran Clay in areas of subsidence may have further reduced vertical hydraulic conductivity (Faunt et al., 2009).

2.2.1.6.7 Specific Yield and Storage

Storage of an aquifer is primarily described and quantified by the storativity or the volume of water released from storage per unit surface area of the aquifer per unit decline in hydraulic head (Heath, 1983). It is important to note that while storativity applies to both confined and unconfined systems, it can be further simplified for these two systems. Storativity accounts for aquifer compression and water expansion (specific storage components), which are the primary factors for estimating storage in confined systems; thus, for confined systems, the specific storage or storage coefficient is most often reported. In contrast, for unconfined systems, the specific yield or effective porosity (gravity-driven dewatering of an aquifer) better represents storativity because aquifer compressibility and water expansion are somewhat negligible in unconfined systems. For unconfined systems, specific yield is most often reported, and is a function of porosity and specific retention.

For confined systems, the aquifer compressibility of the storage coefficient can be further defined as elastic and inelastic skeletal specific storage, where inelastic storage will be lost once compression and dewatering occur. It is estimated that in the Central Valley, the inelastic

specific storage typically is 30 to several hundred times larger than the elastic skeletal specific storage (Faunt et al., 2009; Ireland et al., 1984). Where fine-grained deposits with inelastic storage are thick in the aquifer system, water released could be a major source of water, but could also result in a permanent loss in storage capacity of fine-grained sediments.

Specific yield of unconfined zones and the storage coefficient of confined zones within the Subbasin have been estimated by laboratory testing of sample cores, calculation based on lithology type, and groundwater model calibration (Dale, 1966; Davis et al., 1959; Davis et al., 1964; Faunt et al., 2009; DWR, 2013; Todd, 2017 and 2018). A range is presented in Table 2-4 and is within the range of values published for similar grain sizes and lithology (Heath, 1983; Morris and Johnson, 1967) (generally 0.02-0.40).

2.2.1.6.8 General Water Quality of Principal Aquifers

As required in the regulations, this section is a general summary of water quality of the principal aquifers in the Subbasin. This section does not replace the discussion of water quality issues under Groundwater Quality Section 2.3.3.

This discussion provides a high-level description of water quality variation in the principal alluvial aquifer system of the Subbasin, both laterally (from west to east across the Subbasin) and vertically (shallow–deep within the Subbasin). For local details on water quality for specific areas of an aquifer, refer to the management area plans.

Total dissolved solids are discussed in this section only for the purpose of comparing and contrasting different portions of the aquifer system for Subbasin characterization. For details regarding water quality issues and current groundwater conditions, refer to Section 2.3.3 and individual management area plans. In general, water quality is higher in TDS in the western third of the Subbasin than in the rest of the Subbasin. Higher nitrate and other solutes concentrations are typically present in shallow perched zones and in the unconfined zone above the Corcoran Clay. Groundwater is progressively fresher and lower in TDS below the Corcoran Clay, toward the center of the basin, and in the eastern half of the Subbasin. In contrast, arsenic concentrations increase with depth and in close proximity near portions of the Corcoran Clay. Arsenic and salinity progressively increase with depth approaching the base of USDW.

Kern County Water Agency Water Supply Reports which end in 2011 presented groundwater quality maps using data pre-1997. These maps report that unconfined groundwater (typically above the E-modified Corcoran Clay) in the central portion of the Subbasin generally ranges from less than 500 to 1,500 ppm for TDS, while the west side unconfined groundwater ranges from 1,000 to 5,000 ppm for TDS. The confined aquifer zone (typically below the E-modified clay) in the central portion of the Subbasin generally ranges from less than 200 to 500 ppm for TDS, while west side confined water typically ranges from 1,000 to 4,000 ppm.

The high TDS groundwater in the west side with respect to the east side has recently been reported in a preliminary groundwater salinity mapping study conducted by the USGS (Metzger and Landon, 2018). Within the Subbasin, the study reported much higher TDS in west side water when compared with east side groundwater. Metzger and Landon suggest that higher TDS could

be related to a combination of natural conditions (west side sediments derived from marine deposits with some connate water) and anthropogenic factors such as infiltration from disposal ponds and/or agricultural drainage ponds. The researchers suggest that groundwater on the east side of the Subbasin have the lowest TDS and greatest depths to non-USDWs because they are adjacent to Sierra Nevada that is a source of low TDS (fresh water Ca-HCO_3 type) recharge, whereas, aquifer zones on the west side of the Subbasin have higher TDS values. The west side aquifer zones likely receive very little recharge from the Temblor Range which is made up of marine deposits, and west side aquifer zones such as the west side Tulare Formation likely contain connate water derived from marine deposits (Wood & Dale, 1964). This higher TDS water (Na/Ca-SO_4 type) in west side water is consistent with historical reports and is documented for more than 60 miles from north to south in the Subbasin (KCDEH, 1980; KCDEH and KCWA, 1982; Sierra Scientific Services, 2013). Additional sections of this GSP provided by west side entities, discuss further details on the west-side Subbasin aquifer system.

2.2.1.6.9 Primary Use of Each Principal Aquifer

The unconfined zone in the eastern portion of the Subbasin and in the Kern Fan, and the confined zone below the Corcoran Clay are the primary production zones of the Subbasin aquifer system. In addition, the upper unconfined zone is pumped for beneficial use in the north central and west central areas of the Subbasin. The primary uses of the Subbasin aquifer system include agricultural, municipal, domestic, and storage for the banking of surface water.

2.2.1.6.10 Summary of Beneficial Uses and Users of Groundwater

Land use in the Subbasin includes agriculture, urban/industrial/residential, and open space use. According to the 2014 SGMA legislation, beneficial users of groundwater and property interests potentially affected by the use of groundwater include:

- Agricultural Users
- Domestic Users
- Municipal Well Operators
- Public water systems
- Local Land Use Planning Agencies
- Environmental Users

According to DWR well completion reporting and the CASGEM program, groundwater wells are constructed for a variety of uses including:

- Domestic / Residential
- Irrigation
- Stock
- Municipal / Public
- Monitoring / Observation

- Industrial
- Cathodic Protection
- Other / Unknown

2.2.1.7 Data Gaps and Uncertainty

The primary data gaps in the hydrogeologic conceptual model include:

- Physical properties of the westside aquifers and eastside aquifers,
- Physical properties of the upper zone of the primary aquifer system,
- Groundwater characterization on the eastern and western flanks of the Subbasin and in the upper and shallow zones, and
- Groundwater quality of the primary aquifer zones and confined zones on the eastern and western flanks of the Subbasin, from wells screened solely in a single aquifer zone.

As improvements to monitoring networks are made, data can be used to fill data gaps in the Subbasin.

2.2.1.8 Cross Sections

A general summary of regional subsurface information is provided below in the context of cross sections developed for this plan. Where applicable, detailed discussions of the subsurface are included in some management area plans of the Subbasin.

Cross sections were developed to illustrate the subsurface conditions of the Subbasin. The locations of the cross sections discussed below are provided on Figure 2-18. Section A-A' north of the Kern River (Figure 2-24a) is northeast-trending and perpendicular to the numerous faults and folds within the valley. Section B-B' north of the Kern River (Figure 2-24b) is northwest-trending to be parallel to the axis of the valley. Geologic and hydrogeologic data were compiled from DWR well logs, DOGGR well logs, Page (1973), Gillespie et al (2017), *California Oil and Gas Fields* (DOGGR, 1998), and other regional investigations.

Cross sections spanning the southern and southeastern portions of the Subbasin were developed for management area plans and are included herein (Figures 2-24c to 2-24g). For a discussion of the subsurface across the White Wolf Fault, data including a cross section are presented in the *White Wolf Subbasin Technical Report* (EKI, 2016), that was a part of the 2016 Basin Boundary Modification Request.

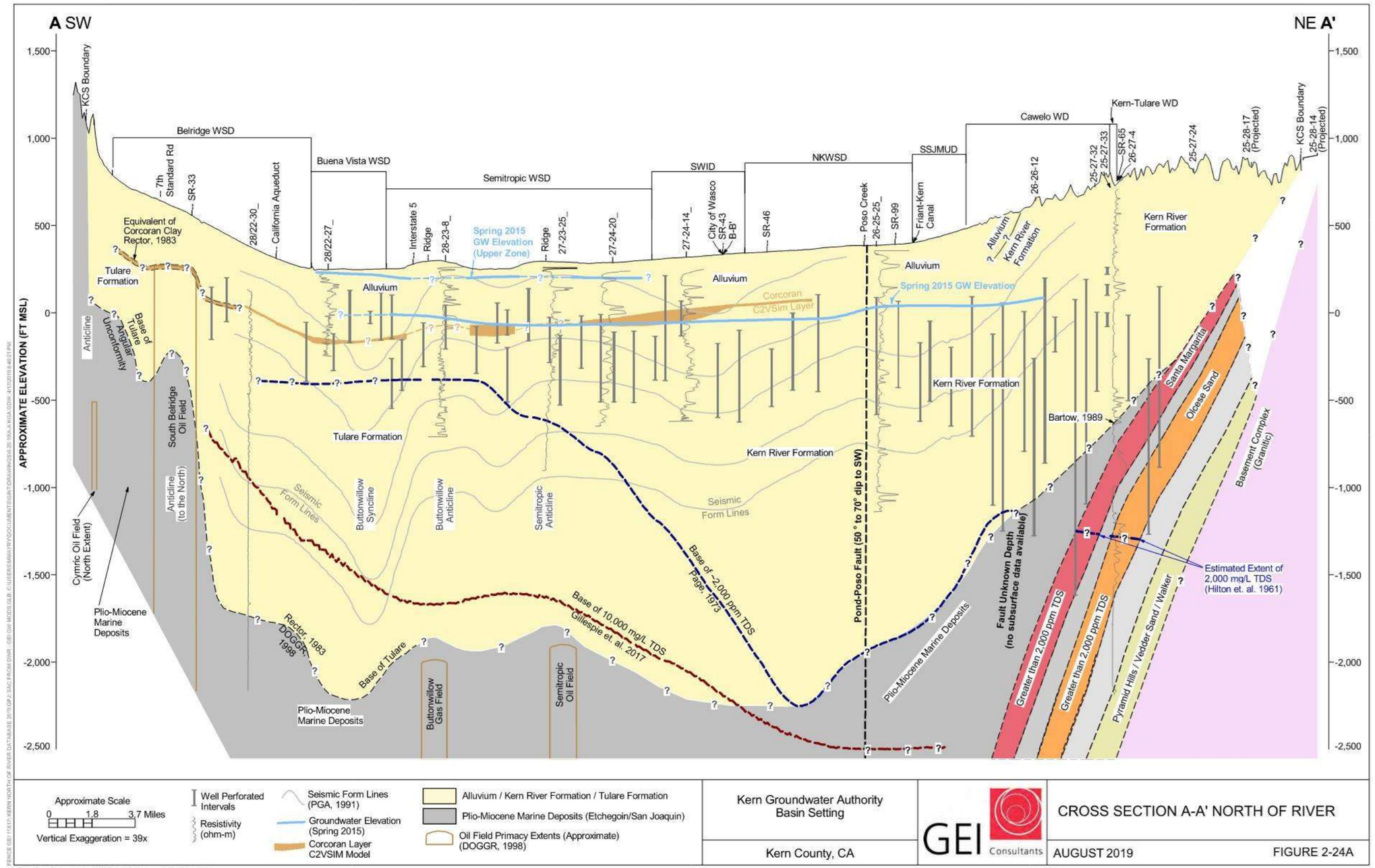
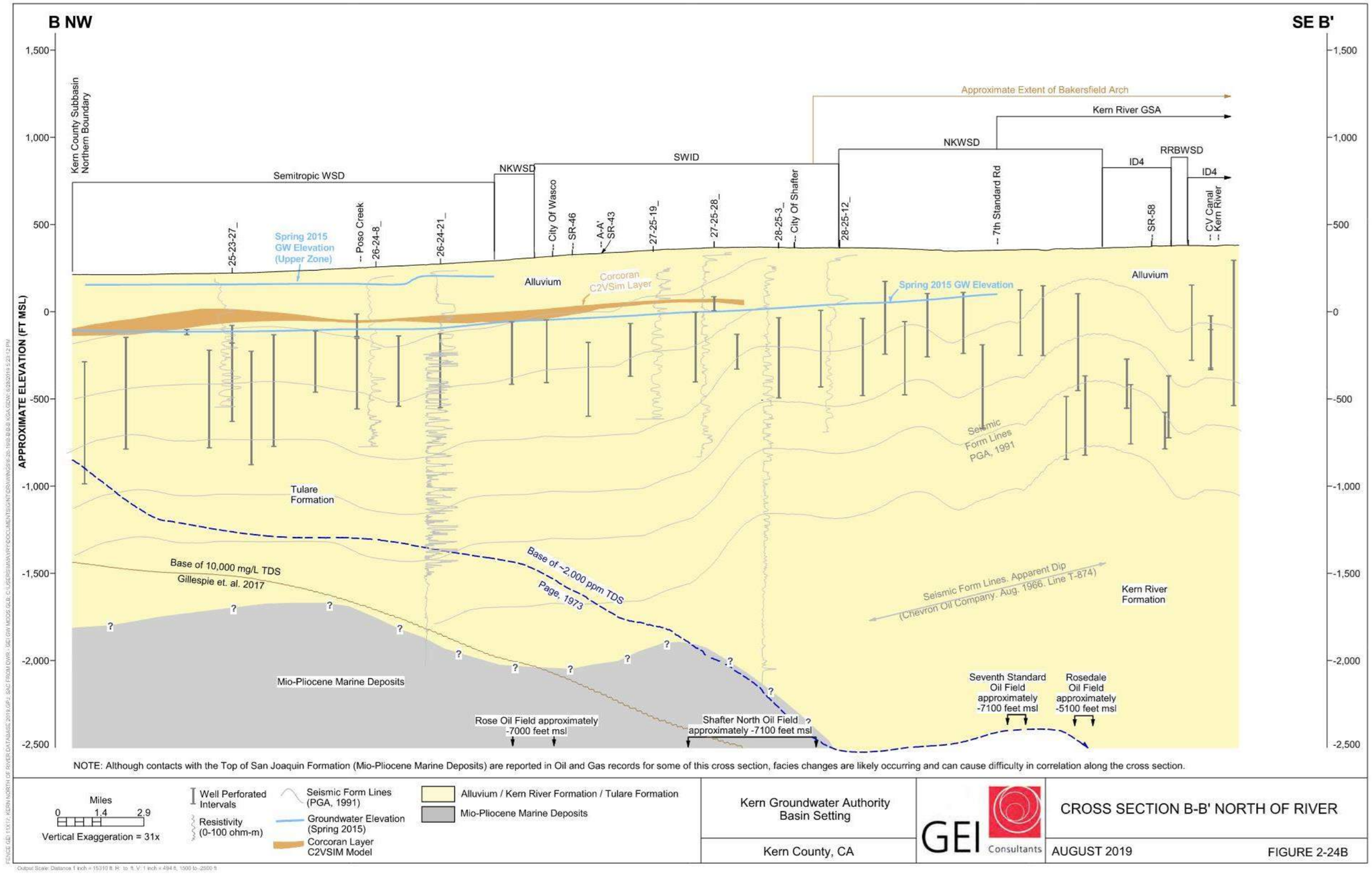
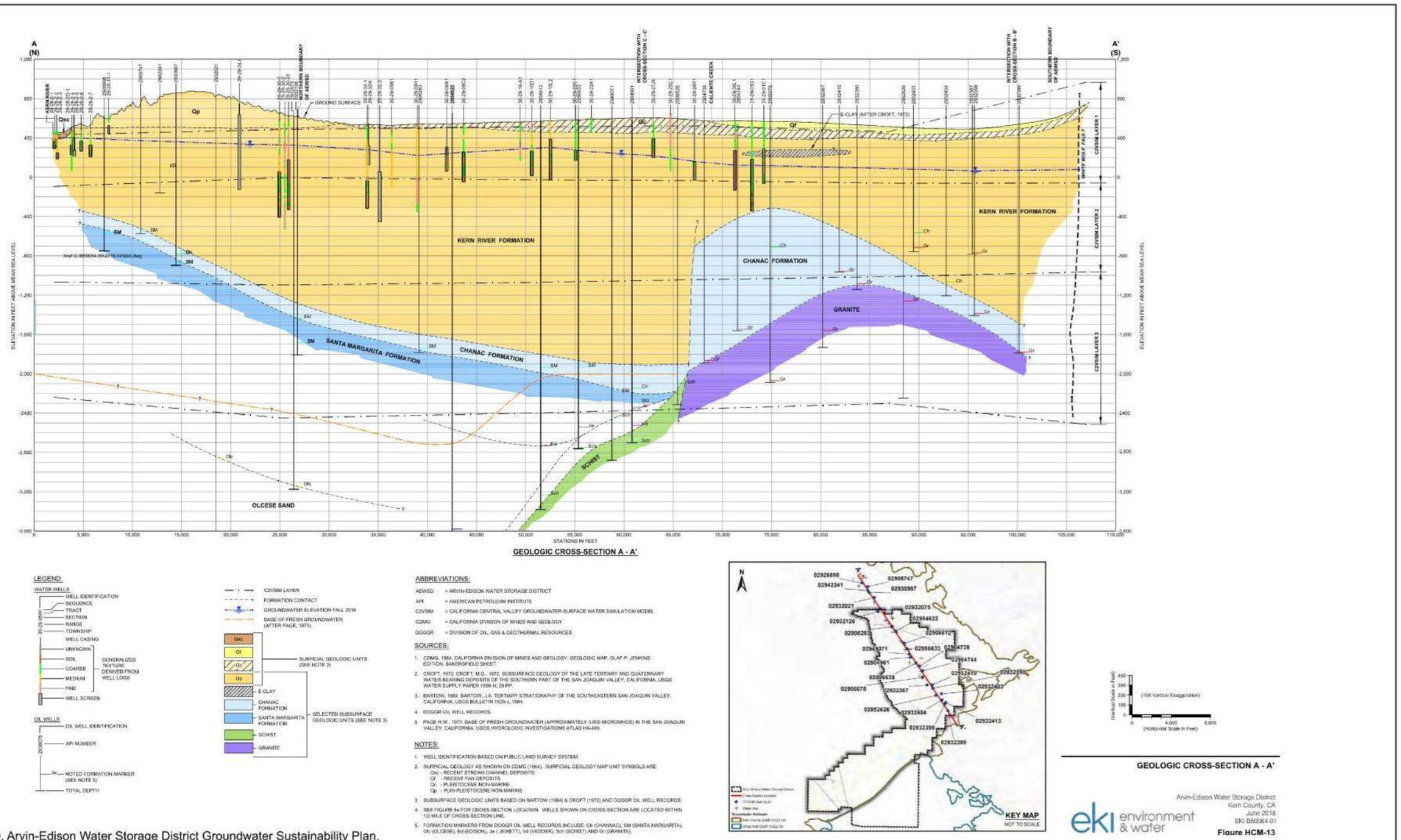


Figure 2-24a. Cross Section A-A’ North of River



NOTE: Although contacts with the Top of San Joaquin Formation (Mio-Pliocene Marine Deposits) are reported in Oil and Gas records for some of this cross section, facies changes are likely occurring and can cause difficulty in correlation along the cross section.

Figure 2-24b. Cross Section B-B' North of River



Source: EKI, 2019. Arvin-Edison Water Storage District Groundwater Sustainability Plan.

Kern Groundwater Authority Basin Setting	GEI Consultants	GEOLOGIC CROSS SECTIONS A-A' (AEWSD)
Kern County, California	NOVEMBER 2019	FIGURE 2-24C

Figure 2-24c. Geologic Cross-Section A-A', Arvin-Edison Water Storage District

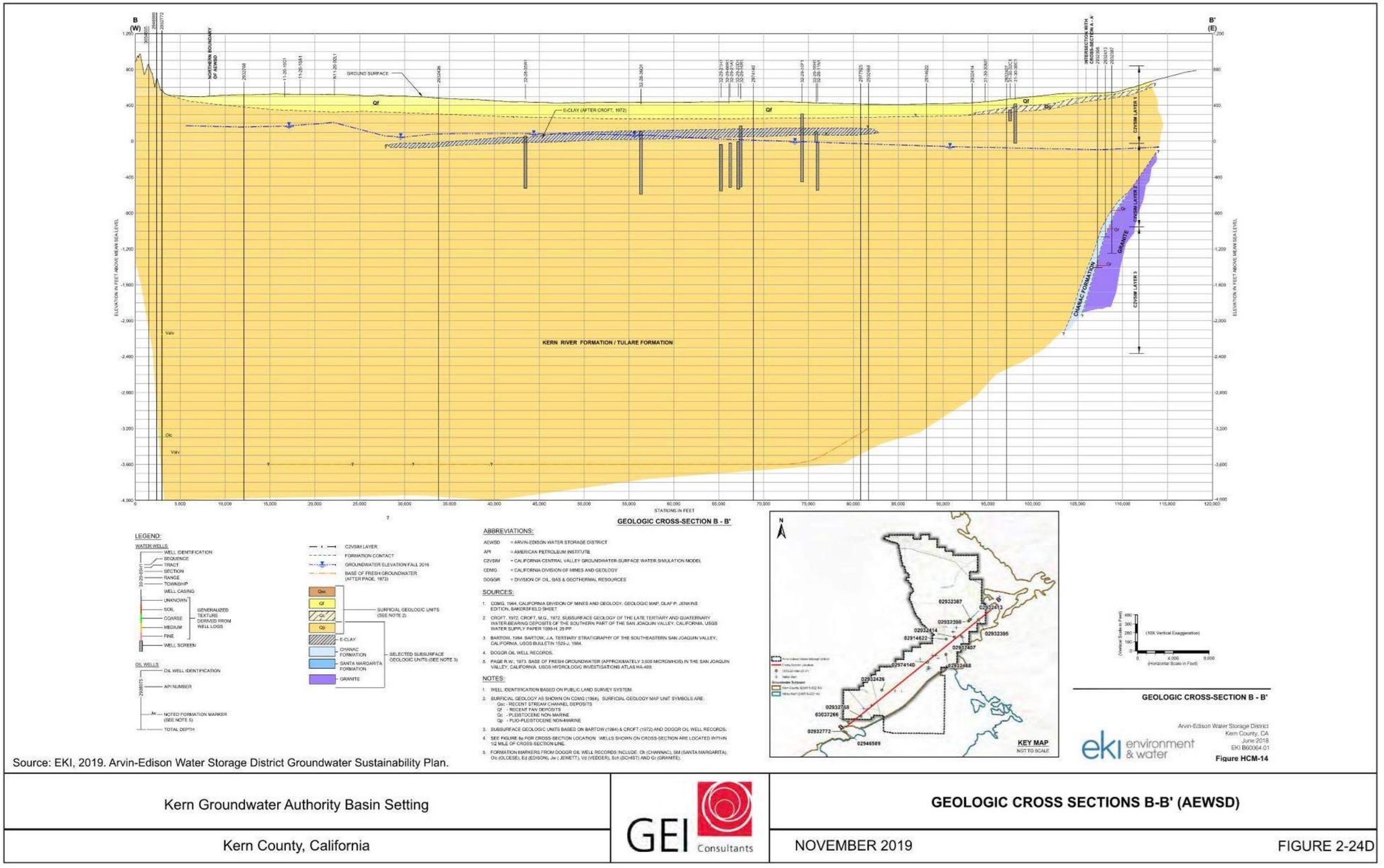
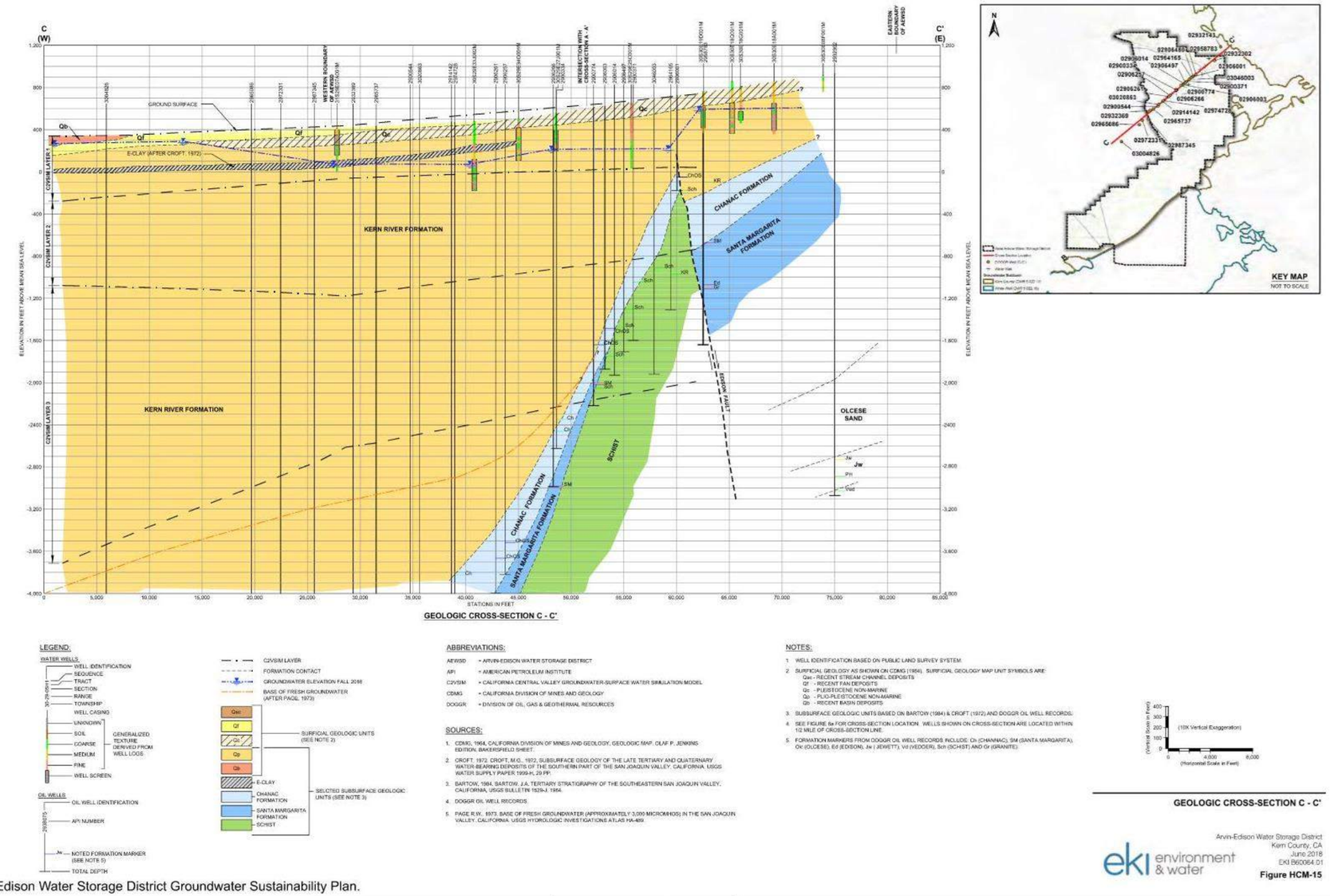


Figure 2-24d. Geologic Cross-Section B-B', Arvin-Edison Water Storage District



Source: EKI, 2019. Arvin-Edison Water Storage District Groundwater Sustainability Plan.

Kern Groundwater Authority Basin Setting	GEI Consultants	GEOLOGIC CROSS SECTIONS C-C' (AEWSD)
Kern County, California	NOVEMBER 2019	FIGURE 2-24E

Figure 2-24e. Geologic Cross-Section C-C', Arvin-Edison Water Storage District

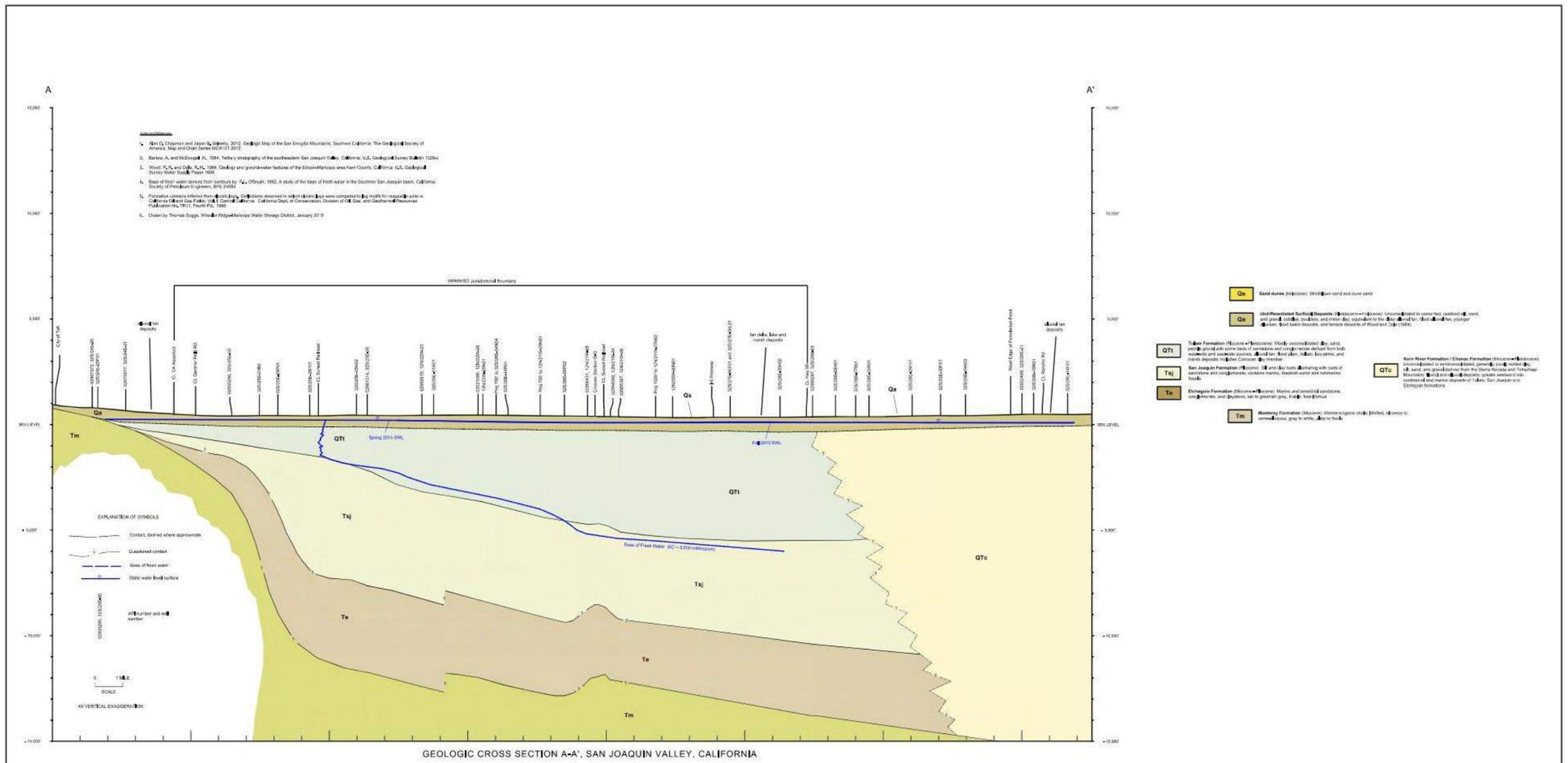
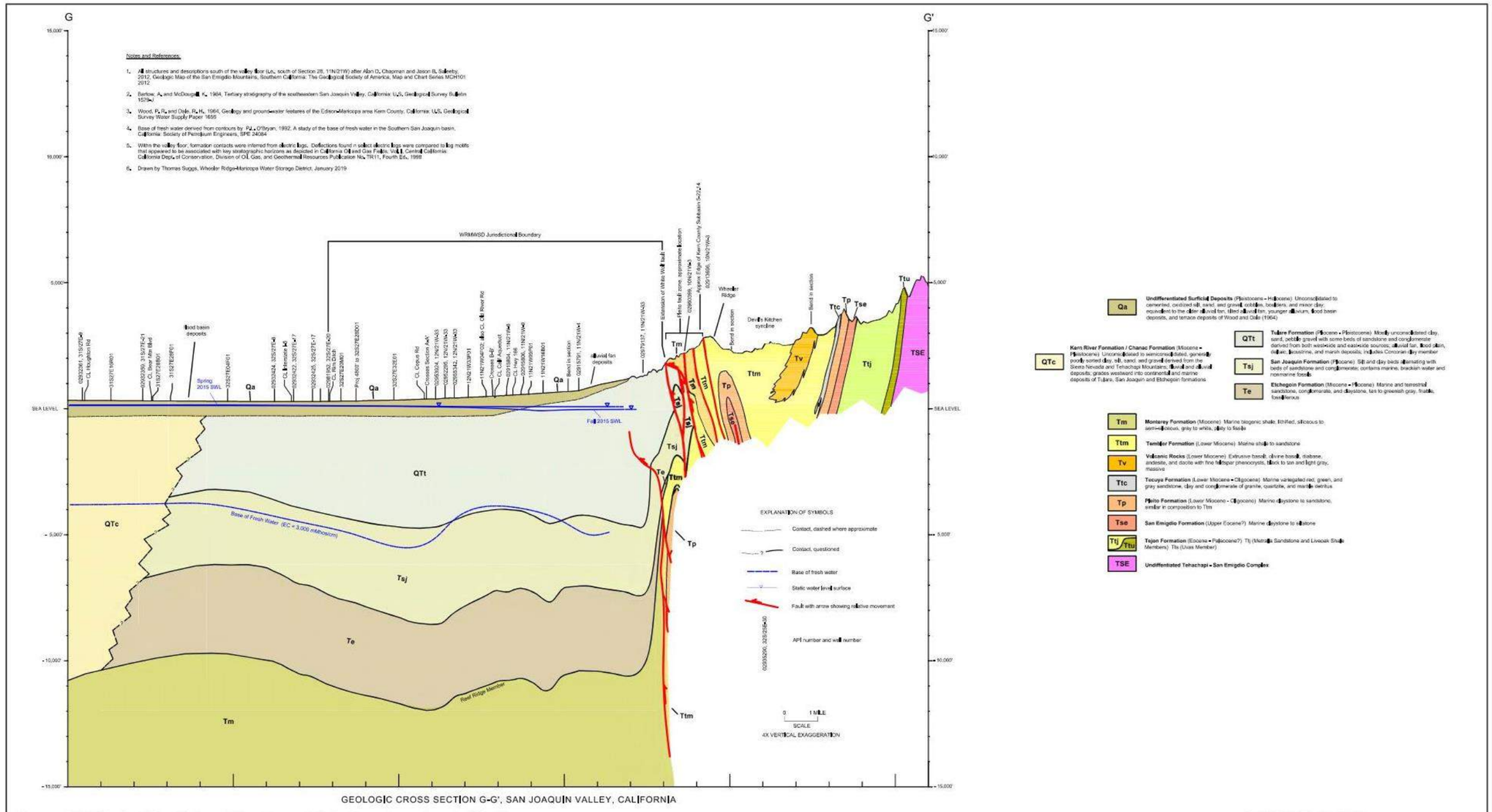


FIGURE 2-19F

Source: 2019 Wheeler Ridge Maricopa Water Storage District Groundwater Sustainability Plan.

Kern Groundwater Authority Basin Setting	GEI Consultants	**GEOLOGIC CROSS SECTIONS A-A' (WRMWSD)**
Kern County, California	NOVEMBER 2019	FIGURE 2-24F

Figure 2-24f. Geologic Cross-Section A-A', Wheeler Ridge-Maricopa Water Storage District



GEOLOGIC CROSS SECTION G-G', SAN JOAQUIN VALLEY, CALIFORNIA

Source: 2019 Wheeler Ridge Maricopa Water Storage District Groundwater Sustainability Plan.

FIGURE 2-19G

Kern Groundwater Authority Basin Setting	GEI Consultants	**GEOLOGIC CROSS SECTIONS G-G' (WRMWSD)**
Kern County, California	NOVEMBER 2019	FIGURE 2-24G

Figure 2-24g. Geologic Cross-Section G-G', Wheeler Ridge-Maricopa Water Storage District

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2.2.1.8.1 A-A' North of the River

A-A' north of the river illustrates the change in hydrogeology from west to east. The westside has a thin fresh water zone due to a shallow base of fresh water. The geology on the westside is dominated by marine deposits and the overlying Tulare formation consists of alluvial fan and debris flow facies primarily from sediments derived from the Coast Range marine deposits. To the east of the California Aqueduct, the Corcoran Clay of the Tulare includes diatomaceous clay and other fine-grained deposits associated with basin center facies. Section A-A' includes seismic form lines from the PGA (1991) investigation that show general structure of bedding that are consistent with mapped Buttonwillow and Semitropic folds and the structure of the base of the Tulare. In contrast, traditionally mapped Corcoran Clay layers which are available through the USGS and DWR (C2VSIM on Section A-A'), correlate clays that do now follow the general bedding forms observed in seismic lines. Future investigation may clarify the discrepancies between these interpretations.

The upper zone groundwater elevation is plotted on section A-A' which is generally considered to pertain to wells screened above the Corcoran Clay. Section A-A' displays wells screened in the upper zone above the Corcoran Clay which is the primary groundwater production zone to the west of Interstate 5 (I-5). Some groundwater production in the upper zone occurs east of I-5 with wells screened above the mapped Corcoran Clay and other wells screened across the Corcoran Clay. The upper zone likely extends further west and east; however, additional data were not available to continue the correlation.

The main regional groundwater surface is plotted across the basin. The groundwater is generally confined where wells are below the Corcoran Clay and semiconfined where wells are outside the extent of the Clay. As described in section 2.2.1.3, Pond-Poso Fault has been documented to affect groundwater flow. High resolution water level data across the fault, however, were not available for this cross section.

The central portion of the Subbasin (just west of the Pond-Poso Fault), has a much thicker aquifer zone with a deeper base of freshwater and thicker deposits of continental sediments (Kern River formation) derived from the Sierra Nevada where freshwater recharge into the Subbasin predominates.

Further to the east, wells have been drilled deeper (greater than 2000 feet) in order to extract fresh groundwater from the Santa Margarita formation and Olcese Sand. Although these aquifers are separate from the main alluvial aquifer system of the valley by Plio-Miocene Marine Deposits, some wells are screened across the continental deposits (Kern River formation), extending through marine and into the Santa Margarita formation and Olcese Sand.

2.2.1.8.2 B-B' North of the River

Section B-B' from northwest to southeast trends through a portion of the Subbasin with a deep base of freshwater. Seismic form lines confirm bedding gradually rise to the south onto the Bakersfield Arch beginning from just north of the City of Shafter southward toward the City of Bakersfield and the Kern River. The alluvium and Kern River formation become thicker toward the south where the Kern River has been a major source of the sediment input into the Subbasin.

2.2.1.8.3 South of the River Cross Sections

Cross sections developed for management area plans in the southern portion of the Subbasin are included herein (Figures 2-24c to 2-24g). These sections present the base of fresh water where it is deepest in the central southern area of the Subbasin southwest of the City of Arvin. They also present the White Wolf Fault and Edison Fault which alter groundwater flow. In general, water wells are screened in the upper 1000 feet of the subsurface across the southern portions of the Subbasin, in the Kern River Formation and Tulare Formation. In the southeastern portion of the Subbasin, faulting and folding has created a thinner column of Kern River Formation deposits to the east of Lamont. The top of the Chanac Formation may be as shallow as 900 feet below ground surface in T31S-R29E. Consequently, data on the base of fresh water were not readily available for plotting in the southeastern portion of the Subbasin.

Cross sections across the White Wolf Fault are provided in the *White Wolf Subbasin Technical Report* (EKI, 2016). Historical sections document change in groundwater elevations (generally a 50 feet decline) across the fault from south to north. Displacement of beds across the fault increases with depth. In general, groundwater aquifer thickness is not significantly affected by displacement across the fault. Additional information is available at the Basin Boundary Modification website: https://sgma.water.ca.gov/basinmod/basinrequest/preview/34.

2.2.1.9 Mapped Physical Characteristics

2.2.1.9.1 Topographic Information

Figure 2-25 presents a basin-wide topographic map of the Subbasin. The rim elevation of the Subbasin varies from approximately 600 feet msl along the White Wolf Fault on the south to over 2,000 feet in the foothills of the adjacent San Emigdio Mountains. On the east and west sides, the rim elevations vary between 1,000 and 2,000 feet msl. As such, the topography of the Subbasin slopes toward the center of the valley on three sides, and the 400-foot contour line generally defines a long and narrow valley floor, which slopes to the northwest. The lowest land surface elevations are approximately 210 feet msl and are located along the County line between Highway 43 and Interstate 5 (18 of 24 miles). Within the Subbasin, prominent topographic features include the Elk Hills, and the Buttonwillow and Semitropic ridges.

2.2.1.9.2 Surficial Geology (Including Location of Geologic Sections)

The surficial geology of the Subbasin has been documented in a variety of previous investigations and is presented on Figures 2-13, 2-17, and 2-18 (Bartow, 1991; Page, 1986; and CGS, 2010b) According to the California Geological Survey (2010b), the center of the basin consists mainly of Pleistocene to recent unconsolidated and semi-consolidated alluvial (Q of Figure 2-17), lake, playa, and terrace deposits. Older Pleistocene alluvium (Qao) is present in the eastern portion of the basin on top of Pliocene-Pleistocene deposits (QPc) of sandstone, shale and gravel deposits, including the Kern River Formation. The QPc unit includes the Tulare Formation and occurs as islands, surrounded by recent alluvium, within the center of the northern Subbasin along the western side and within the alluvium. Small remnants of older continental sediments are included along the southeastern flank of the Subbasin, including undivided

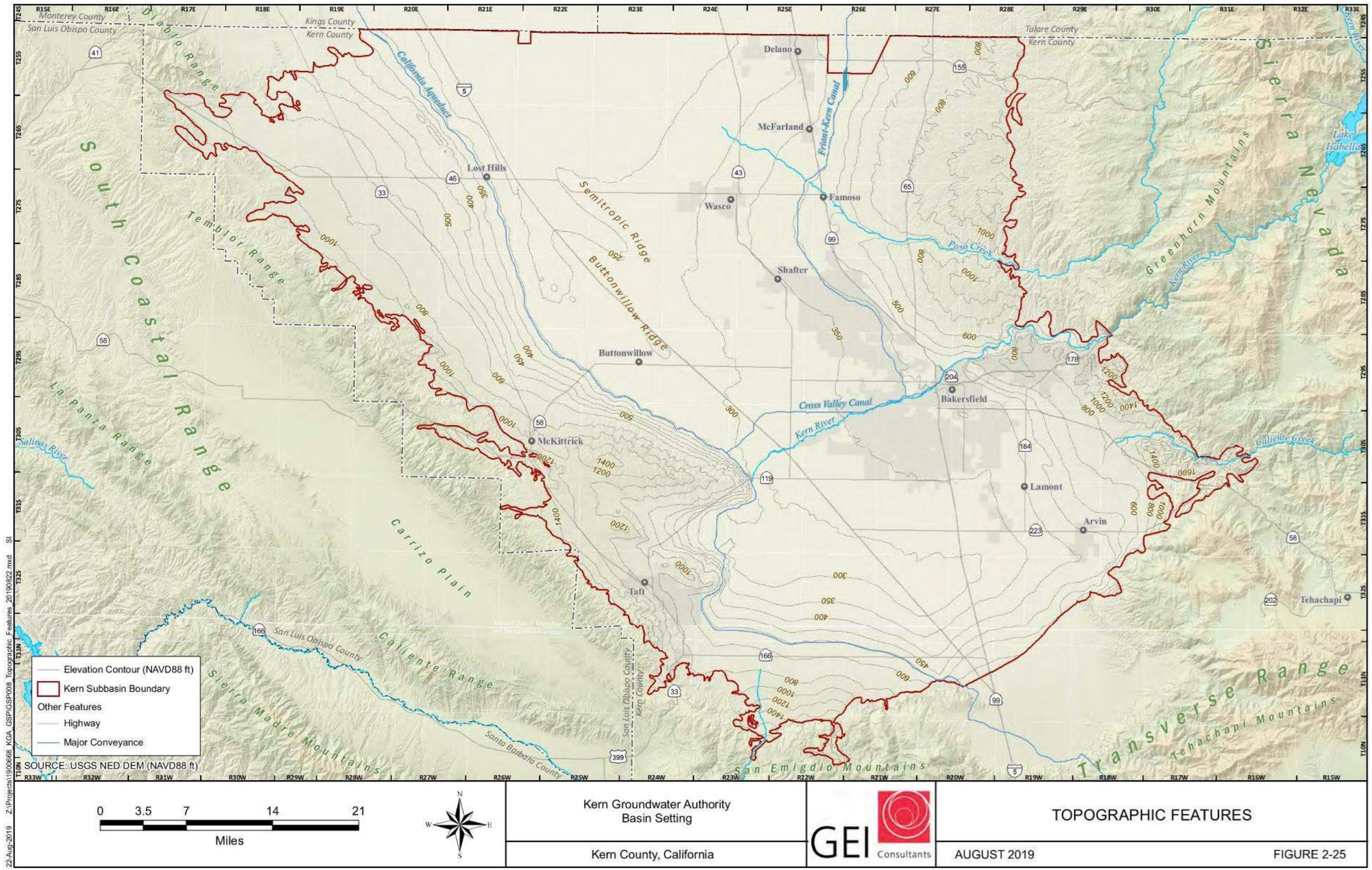

Figure 2-25. Topographic Features

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Tertiary-age sandstone, shale, conglomerate, breccia, and lake deposits (Tc) and Miocene-age sandstone, shale, conglomerate, and fanglomerate (Mc) plus smaller remnants of older marine sediments: Miocene-age sandstone, siltstone, shale, conglomerate, breccia (M). These remnant units would include the Santa Margarita Formation, Round Mountain Silt, and Olcese Sand.

Bartow (1991) provides a similar map (Figure 2-13) as the California Geological Survey map but refers to Quaternary alluvial and lacustrine sediments (Qs) on the valley floor and Tertiary sedimentary rocks (TS) along the flanks and for the islands of older rocks in the valley center. As discussed further below, the map shows the location of the Bakersfield Arch as well as three structural regions within the Subbasin.

Page's (1986) presentation of the surficial geology, as shown by Figure 2-17 better display the lakebed deposits. Recent river deposits (Qr) associated with the present-day Kern River, are shown as a long, narrow strip from the mouth of the Kern Canyon, and are comprised of gravel, sand, silt, and minor amounts of clay. The center of the valley floor is underlain by Recent flood basin (Qb) – clay, silt, and some sand; and by Pliocene to Recent lacustrine and marsh deposits (QTl) – clay, silt, and some sand with extensive subsurface clay layers (A, C, E/Corcoran). The former unit is associated with the original Kern River drainage and flood basin while the latter unit is associated with the historical Kern Lake Bed, Buena Vista Lake Bed, Goose Lake Beds, and the southern edge of the Tulare Lake Bed. The remainder of the valley is underlain by Miocene to recent continental deposits (QTc) – a heterogenous mixture of gravel, sand, silt, and clay with some layers of conglomerate, sandstone, siltstone, and claystone. Like the other maps, remnants of older continental deposits are shown along the rim of the Subbasin, primarily the southeastern side, including Oligocene to Miocene deposits (Tcmo) of gravel, conglomerate, sand, and clay; and Eocene to Miocene deposits (Tcme) of conglomerate, sandstone, fanglomerate, claystone, and breccia plus limited occurrences of undifferentiated marine deposits (Tm) of sand, clay, silt, sandstone, shale, mudstone, and siltstone of Eocene to Pliocene ages.

2.2.1.9.3 Soil Characteristics

Soils within the Subbasin have two general origins that are approximately delineated by the trough of the valley, which also mirror depositional patterns as mapped in surficial geology. The eastern alluvial fans were deposited primarily by runoff from the Sierra Nevada, Tehachapi, and Transverse mountain ranges. These soils are of igneous and metamorphic origin; are typically well drained, very low in salinity, and ideal quality for agriculture. The northwestern alluvial fans originated from Coast Range sedimentary rock formed on the sea bottom. This northwest region tends to have more areas with poorly drained soils of relatively marginal quality (Provost & Pritchard, et al., 2015). The Groundwater Quality Assessment Report (Provost & Pritchard, et al., 2015) describes five areas of different soil texture in the Subbasin: the clay rim area of fine grained texture near the historical lake beds, the foothills of medium texture, the Kern Fan region derive from river deposition, northern areas with some alluvium and other sources, and Wheeler Ridge/Arvin Edison with coarse soil. These five areas contain the different soil types described below.

Soils in the center of the Subbasin are generally categorized into three types according to texture. Fine-grained soils are found in the southwest, the historical lake beds, and northwest corners of

Subbasin. Coarse grained soils within the Poso Creek fan, Kern River fan, and Caliente creek fan. And the moderate infiltration of soils along the distal edges of the fans. The lake bed areas are composed of fine-grained soils of the historical Buena Vista and Kern lakebeds, and swamp and overflow lands, which continue north along the historical drainage paralleling the Goose Slough, Goose Lake, and southern edge of the Tulare Lake depositional environment. Medium to coarse grained soils are distributed in the Poso Creek and Kern River drainage beds as well as the proximal and medial portions of the Kern Fan, and the south boundary of the Subbasin.

Figure 2-26 and 2-27 present the soil distribution within the Subbasin as defined by U.S. Dept. of Agriculture (USDA), National Resources Conservation Service, Soil Survey Geographical Database (SSURGO) as obtained from the DWR SGMA Data Viewer website (2018). Figure 2-26 shows that six soil orders are present in the Subbasin, including Aridisols and Entisols throughout most of the Subbasin, with Inceptisols along the eastern highland, and much lesser amounts of Alfisoils, Mollisols, and Vertisols. According to the online Encyclopedia Britannica (EB, 2018), Ardisols are dry soils characterized by a low humus, light-colored surface horizon with a subsurface accumulation of soluble salts, silicate clays, and possibly a cemented layer of calcium carbonate, calcium sulfate (gypsum) or silica. Entisols are characterized by the absence of soil horizons due to recent deposition or active erosion under extreme wet or dry conditions (EB, 2018). Inceptisols exhibit a weak appearance of soil horizons overlying a weathering-resistant parent material. Alfisols are characterized by well-developed soil horizons enriched with aluminum- and iron-bearing (Al/Fe-) minerals but depleted of calcium carbonate (EB, 2018). Translocated clays typically form a layer with relatively high amounts of mineral nutrients (calcium, magnesium, sodium, and potassium). Mollisols are characterized by a thick, dark surface horizon of humus, which typically originates from native grass vegetation, and mineral nutrients are present in most horizons (EB, 2018). Humus and Al/Fe-bearing minerals do not migrate to subsurface layers. Vertisols are clay-rich soils (>30 percent) with significant cracking during the dry season due to the shrink-swell response of the clay minerals during the dry and wet seasons (EB, 2018). The shrink-swell action produces significant vertical mixing of the soil.

Figure 2-27 shows the distribution of hydrogeologic soil groups, which is based largely on four categories of infiltration rates: high, moderate, slow, and very slow. Group A soils have a high infiltration rate due to well drained sands or gravelly sands. Group B soils are moderately well drained due to moderately fine to coarse textures. These soils are present on the east, west, and south sides of the valley floor. Group C soils have a low infiltration rate due to their fine texture or because of a layer that impedes downward movement of water. These soils are present along the valley floor, along the eastern highlands, and at various locations along the northwestern side of the Subbasin. Group D soils have a very slow infiltration rate due to the presence of clay and are located primarily along the northern Subbasin boundary within the valley floor. More detailed soil survey data can be found in four USDA reports on various portions of the Subbasin: *Soil Survey of Kern County, California* (USDA, 1981, 1988, 2007, and 2009), including recent online updates.

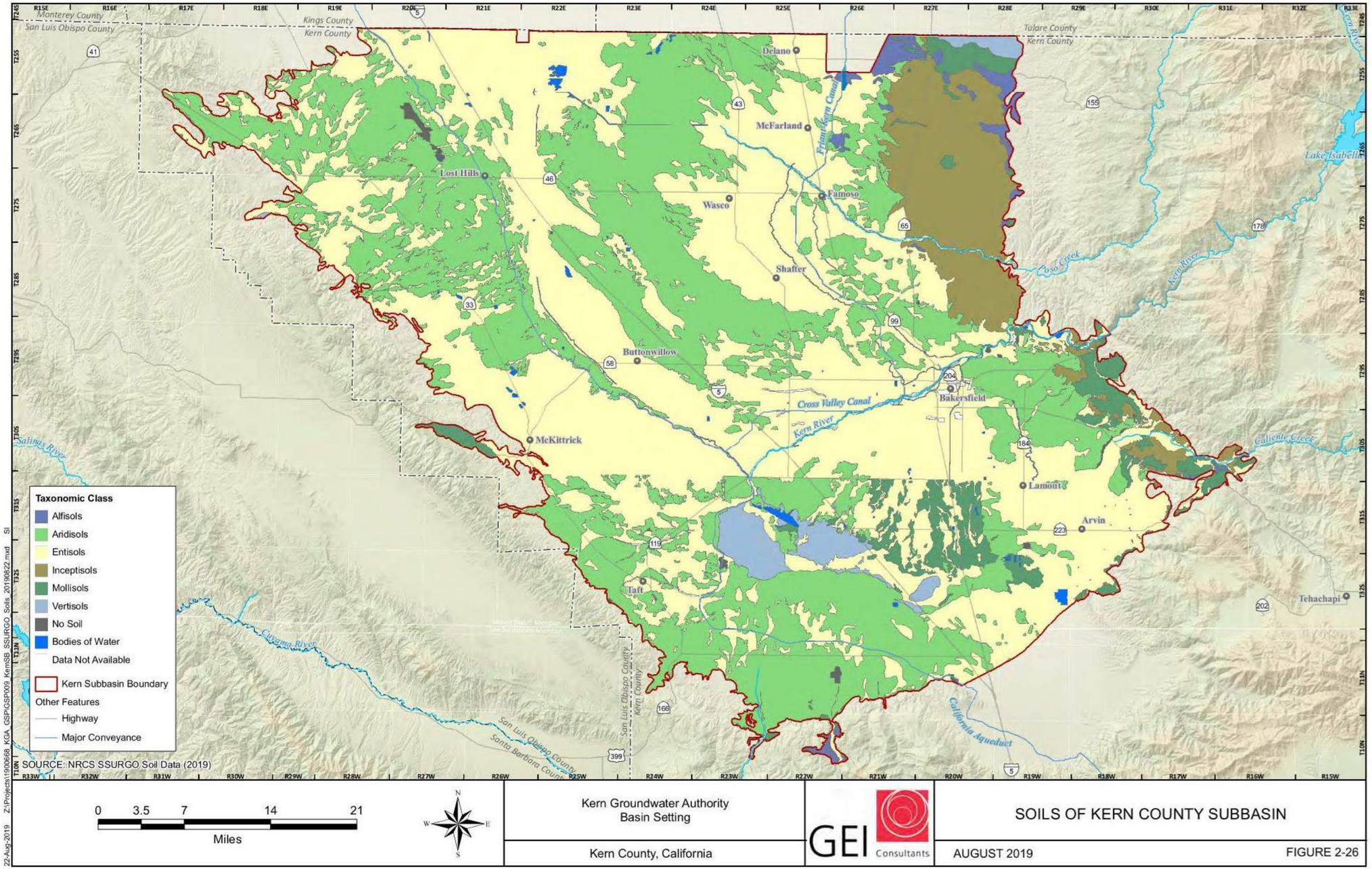

Figure 2-26. Soils of Kern County Subbasin

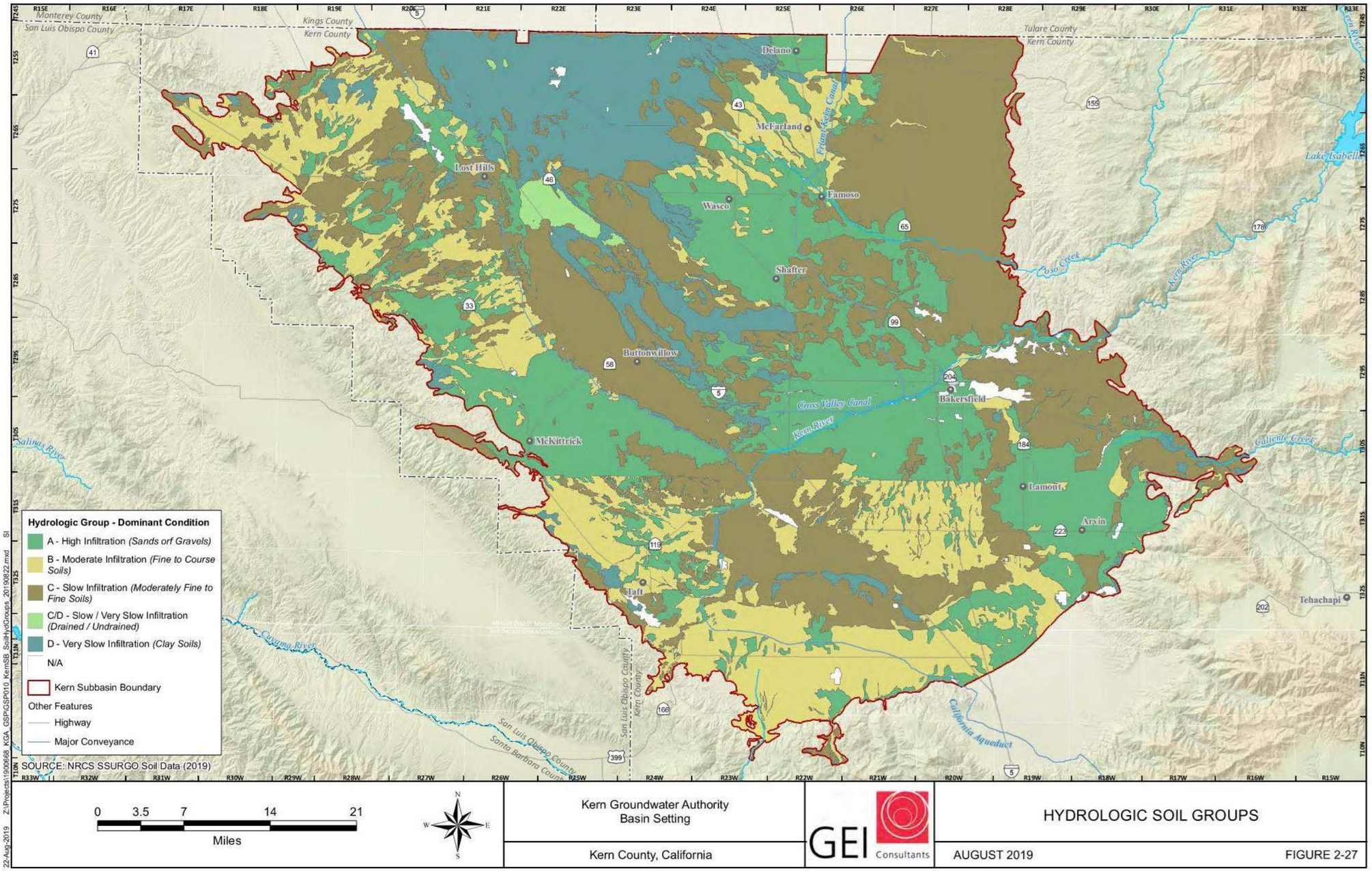

Figure 2-27. Hydrologic Soil Groups

2.2.1.9.4 Natural Recharge, Direct Recharge Areas, and Potential Recharge Areas

Direct recharge and potential recharge areas are differentiated in this section from natural recharge. Natural recharge occurs by groundwater underflow from adjacent sources, precipitation outgaining evapotranspiration in a Subbasin, or from natural surface waters flowing into the Subbasin. On the other hand, direct recharge is either planned or unplanned application of surface water by unlined conveyance, field application, managed recharge, and spreading operations. This section focuses mainly on direct recharge and potential recharge to the Subbasin, but briefly discusses natural recharge to the Subbasin. In-lieu recharge is not discussed in this section because it does not provide an actual input to the groundwater system for budgeting purposes, but only curtails or reduces the amount of groundwater that would have been pumped. In-lieu recharge is discussed in other sections of this GSP. This section may not include all localized recharge activities and facilities, but these local activities and facilities are further described within the individual management area plans.

Natural recharge to the Subbasin occurs mainly by underflow or surface recharge from the eastern and southern highlands (Sierra Nevada and Tehachapi Mountains). The surface water bodies as a source of recharge are discussed in the next section. In general, natural in-situ recharge by precipitation is absent in Subbasin, and may only occur in extreme wet years, because typically evapotranspiration outgains the amount of natural precipitation to the Subbasin (Provost and Pritchard et. al., 2015). The absence of natural recharge by in-situ precipitation in the Subbasin further illustrates the lack of recharge to the west side of the Subbasin where it is likely that very little if any freshwater underflow recharges the west side. In contrast, the east side is dominated by recharge from the Kern River and the Sierra Nevada.

Significant direct recharge to groundwater in the Subbasin occurs through managed recharge and water banking (storage) projects; as well as unmanaged recharge through natural waterways, unlined spill basins and regulating (balancing) reservoirs, percolation of applied water to crops that descend below the root zone, and unlined canals. Numerous sources of water are recharged by various projects, including local surface water (Kern River, Poso Creek, and other drainages) and imported water (State Water Project [SWP] and Central Valley Project [CVP]).

The major areas of direct recharge (facilities and drainages) are presented in Figure 2-28. Additional areas of unmanaged or managed recharge may include agricultural land where excess irrigation water percolates below the root zone, wastewater treatment spreading areas, and urban drainage spreading areas. Additional locations of natural recharge from surface water features may include springs, seeps, ephemeral/intermittent streams flowing into the Subbasin (Figure 2-29). The surface water features are described in more detail in the following section.

Since the late 1980s, large-scale groundwater recharge/banking operations have been constructed along the Kern River. Given the permeable nature of sediments within the Kern River Fan, most of the enhanced recharge projects involve surface spreading through ponds, low-lying fields, or basins. Some projects are dedicated to the replenishment of the groundwater basin, while other projects store surplus SWP and CVP water for subsequent extraction; and some banking projects do both. (Todd, 2017).

The Soil Agricultural Groundwater Banking Index (SAGBI), can further estimate groundwater recharge suitability to quantify recharge of deep percolated applied irrigation water and potential recharge from future managed recharge within the Subbasin. The California Soil Resource Lab at University of California Davis has developed an online application (https://casoilresource.lawr.ucdavis.edu/sagbi/) to present the SAGBI, which estimates groundwater recharge suitability based on five major factors: deep percolation, root zone residence time, topography, chemical limitations, and soil surface condition. The application includes mapping coverage of the SAGBI and indicates a moderately good to excellent rating for the Poso Creek alluvial fan in the north central Subbasin, the Kern River alluvial fan in the central area, and in much of the southeastern to southwestern corners of the Subbasin. SAGBI ratings are moderately poor to very poor along the eastern margin, central western margin, as well as the center of the valley from the former Kern and Buena Vista lake beds, north along the Goose Neck Slough to the Tulare Lake Bed. While moderately good to good SAGBI is shown for much of the western margin, this area is underlain by marine sediments and is not likely to be a useful area for recharge. The SAGBI ratings generally agree with mapped soil data where higher rated SAGBI soil corresponds with moderate to high infiltration soils. Note that an abrupt east-west alignment of good versus poor SAGBI occurs in the southern central Subbasin and is likely due to the methods and results of historical soil surveys.

Groundwater discharge areas in the Subbasin are limited due to the depth of usable groundwater, typically greater than 100 feet throughout the Subbasin. Shallow, poor-quality groundwater (above the A-clay) does occur in the west central and southern areas. These shallow groundwater areas may support salt-tolerant vegetation. Effects of a shallow water table and evapotranspiration may discharge poor quality shallow groundwater from these areas to the surface. Historically, flowing wells were present throughout much of the valley floor (Mendenhall, 1916), including the Buena Vista and Kern lakes and the area to the north (>180 square mi), and from Buttonwillow north beyond the county line (>400 square mi). Over 100 flowing wells were identified in 1905 and reductions in flow were recognized in the following years. According to the USGS groundwater model (Faunt, 2009), the Kern River is a groundwater discharge area along a nominal 7-mile reach within Bakersfield, east of Highway 99; however, the City of Bakersfield measures flow at six weirs along the river across the valley and shows an overall loss of flow (seepage) from the Kern River.

2.2.1.9.5 Surface Water Bodies

Figure 2-29 presents the location of surface water bodies in the Subbasin according to the National Hydrography Dataset. These water bodies include the California Aqueduct (SWP) and federal Friant-Kern Canal, and other local canals that help convey Kern River water and imported surface water to beneficial users in the Subbasin. This dataset also includes the Kern River, Poso Creek, Caliente Creek, and other significant ephemeral streams, spring, and seeps, that are sources of recharge from the mountains on the east, southeast, and south sides of the Subbasin. The National Hydrography Dataset also includes wetlands delineations around the Kern Wildlife Refuge. The refuge is now sustained by imported surface water typically wheeled from the California Aqueduct and conveyed by the Goose Lake Canal to the refuge (USFS, 2005).

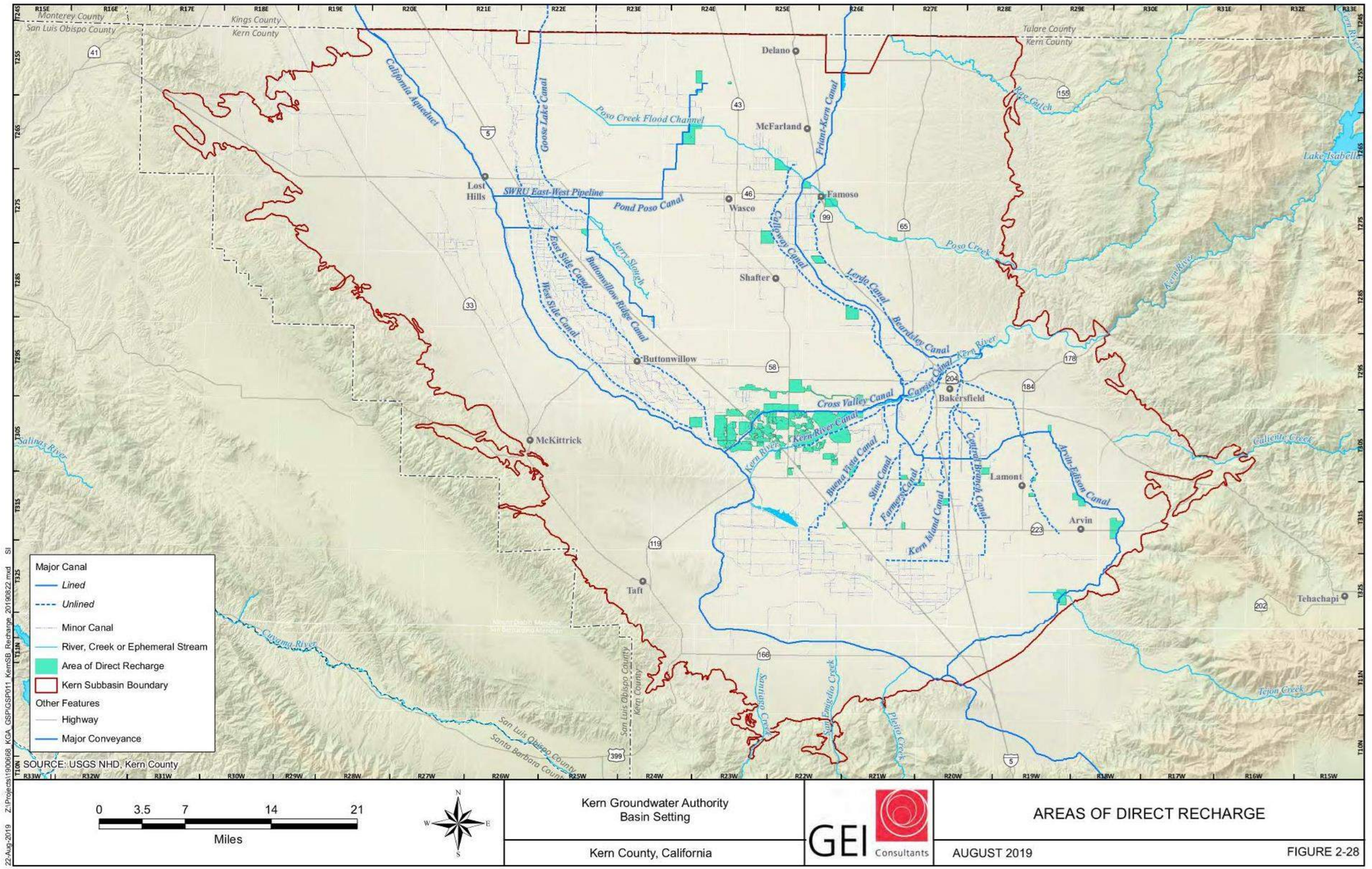

Figure 2-28. Areas of Direct Recharge

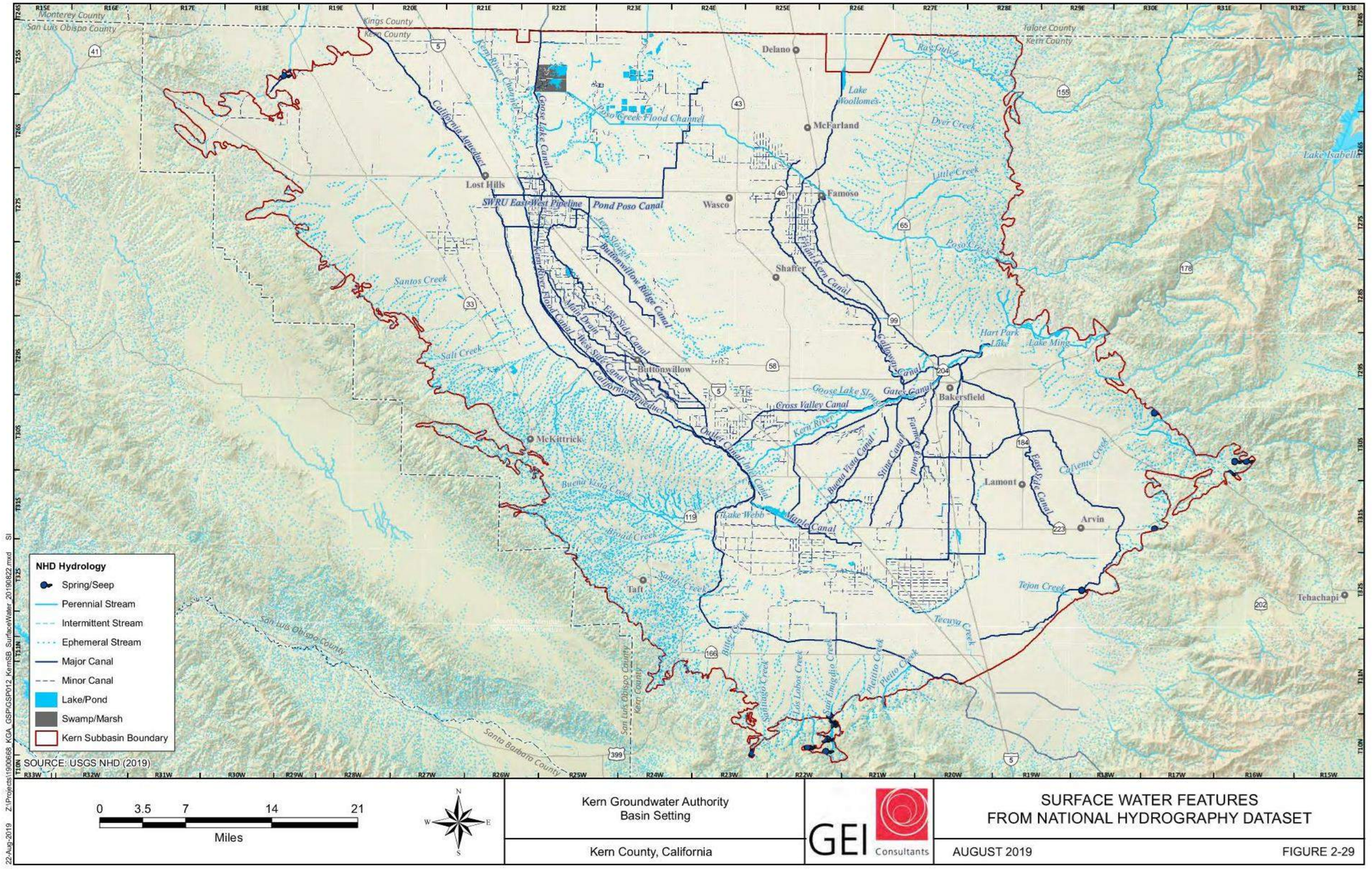

Figure 2-29. Surface Water Features from National Hydrography Dataset

The most important source of naturally occurring surface water for the Subbasin is the Kern River, which has been regulated by the Isabella Dam and Reservoir since 1954. The dam and reservoir are operated by the U.S. Army Corps of Engineers and the distribution of water is administered by the Kern River Watermaster. The Kern River is approximately 164 miles long and is fed by rain and snowmelt from the Southern Sierra Nevada, including Mount Whitney. The last 35 to 40 miles of river crosses the Subbasin.

Local streams, many of which are ephemeral, provide additional local surface water during the wet season and during above normal and wet water years. A very small percentage of minor stream runoff is collected and used for irrigation; the majority of these irregularly occurring flows likely serve to recharge local groundwater basins (Kennedy and Jenks, 2011).

2.2.1.9.6 Source and Point of Delivery for Imported Water Supplies

Imported water is supplied by the Central Valley Project's (CVP) Friant-Kern Canal and California Department of Water Resources through the SWP. CVP water from the Friant Division is conveyed to users in the Subbasin through the Friant-Kern Canal, and SWP water is conveyed through the California Aqueduct together with CVP water from the Delta Division. Treated produced water is also used as an imported source of water to the groundwater Subbasin for beneficial use.

Central Valley Project – Friant Division

The CVP Friant-Kern Canal diverts water from Millerton Reservoir, created by Friant Dam on the San Joaquin River, and extends southward a distance of 152 miles through Fresno, Tulare and Kern counties to its terminus at the Kern River in Bakersfield. The capacity of Millerton Reservoir is about 520,000 AF, but 130,000 AF of this storage lies below the intake for the Friant-Kern Canal.

Water districts along the east side of the San Joaquin Valley entered into long-term water supply contracts with Reclamation, which provide for the delivery of three types of water; Class 1, Class 2, and Section 215.

Class 1 Water is the supply of water stored in or flowing through Millerton Lake which, subject to the contingencies described in the Contracts, will be available for delivery from Millerton Lake and the Friant-Kern and Madera Canals as a dependable water supply during each Contract Year.

Class 2 Water is the supply of water which can be made available subject to the contingencies described in the Contracts for delivery from Millerton Lake and the Friant-Kern and Madera Canals in addition to the supply of Class 1 Water. Because of its uncertainty as to availability and time of occurrence, such water will be undependable in character and will be furnished only if, as, and when it can be made available as determined by the Contracting Officer.

Section 215 Water is a temporary supply of water, other than Class 1 Water or Class 2 Water, made available to the Contractors in addition to water provided pursuant to water service contracts, including water made available that is not subject to acreage limitation pursuant to

Section 215 of the Reclamation Reform Act of October 12, 1982 (96 Stat. 1263), as amended. The historical allocation priorities for Section 215 Water are as follows:

- Long-term contractors
- Cross Valley contractors
- Other parties within the Friant Division service area with direct delivery capabilities
- CVP contractors outside of the Friant Division service area
- Other parties

Central Valley Project – Delta Division

In 1973, DWR completed the initial facilities of the SWP, including the main line of the California Aqueduct. Portions of the SWP were constructed for use in conjunction with the facilities of the CVP. As the state and federal projects developed, a group of water users planned the Cross-Valley Canal as a means of taking delivery of CVP water conveyed through the California Aqueduct. The Cross-Valley Canal was completed in 1975 and, in 1976, the water users entered into three-party contracts with DWR and Reclamation. Under these contracts, CVP water available to Reclamation in the Delta can be pumped by the SWP's Harvey O. Banks Pumping Plant into the California Aqueduct for delivery to the Tupman turnout where this water is diverted into the Cross-Valley Canal. This federal water, conveyance of which is subordinate to conveyance of SWP water, can then be delivered to water users in the Subbasin.

State Water Project

The Kern County Water Agency was formed in the 1960s to contract with the DWR for the importation of SWP water to Kern County. The California Aqueduct, the SWP's principal conveyance feature, transports water from the Delta along the west side of the San Joaquin Valley to the Subbasin. Individual water districts holding contracts with Kern County Water Agency have turnouts directly from the aqueduct into their service areas or receive water via the Cross-Valley Canal.

Two types of water are available from the SWP, including relatively firm Table A Water and surplus Article 21 Water. Table A Water takes its name from an exhibit to the contract between the DWR and the SWP contracting agencies that serves as the basis for allocating water among the agencies.

While the reliability of SWP water is less than was anticipated when the contracts were executed, a contract amendment, introduced in the Monterey Agreement of 1994, put agricultural and urban contractors on equal footing respecting the allocation of water supply during shortages. Prior to the amendment, agricultural contractors were burdened with a larger share of any shortages.

Article 21 Water, unlike Table A water, cannot be scheduled; rather, it must be taken at the time it is declared to be available and is analogous to Section 215 Water for the CVP-Friant contractors. The following conditions govern the availability of Article 21 Water:

- Available only when deliveries do not interfere with Table A allocations and SWP operations
- Available only when excess water is available in the Delta
- Available only when conveyance capacity is not being used for SWP purposes or scheduled SWP deliveries
- Cannot be stored within the SWP system. In other words, the contractors must be able to use the Article 21 water directly or store it in their own system

Due to these conditions, Article 21 Water is only available during the wet months of the year, typically December through March.

Produced Water

Water brought to the surface when oil is extracted is often referred to as "produced water." Produced water is groundwater that is commingled with hydrocarbons and located within the hydrocarbon bearing reservoir. Produced water is generated as oil is extracted for use. Often, produced water is returned to the original geological formation for enhanced oil recovery or disposal. Some produced water is suitable for beneficial use with treatment, though most is higher in salinity and must undergo extensive treatment and be blended with other water before use. New technology and the need to find new sources of water are driving the ability to process and treat produced water for beneficial use.

2.3 Groundwater Conditions

Annual groundwater elevation contour maps covering much of the Subbasin have historically been prepared by Kern County Water Agency in Water Supply Reports since before the 1990s until 2012. These maps provide seasonal high groundwater level conditions from spring water level data, and generally depict groundwater flow conditions over time consistent with flow directions observed in 2015. Groundwater conditions are also monitored through a number of local and joint district activities, as well as state mandated programs, such as CASGEM.

2.3.1 Groundwater Trends

Based on historical groundwater trends from USGS and the Kern County Water Agency (Page, 1986; and KCWA), groundwater flows into the Subbasin mostly from the uplands along the south and east margins of the Subbasin. Below is a generalized diagram depicting groundwater flow into the Subbasin (Figure 2-30). In the absence of pumping or significant barriers, groundwater naturally flows from high elevation points of recharge to lower elevation points with less recharge. In general, groundwater flow diverges to the north and south away from natural and managed recharge points along the Kern River. The river flows into Subbasin roughly along the axis of the Bakersfield Arch, which has a broad topographical rise that gradually dips to the north and south; thus, the rough alignment of the river effectively splits the Subbasin into northern and southern groundwater flow regimes. Groundwater to the south of the river flows toward discharge points at pumping wells within the south-central areas of the Subbasin, and groundwater to the north of the river migrates toward the northwest discharge points at pumping wells and continues north until it leaves the Subbasin as subsurface underflow.

Figure 2-30 presents the approximate location of the San Joaquin Valley (Buttonwillow) Syncline which likely affects the flow of westside groundwater from significantly impacting the main production zone of the Subbasin. In general, groundwater elevation trends near the river may be highly variable due to high volumes of managed groundwater recharge and extractions associated with groundwater banking projects. Groundwater elevation patterns further away from banking operations show more seasonal responses from pumping and recharge, and, an overall, long-term decline in groundwater level in the majority of the Subbasin.

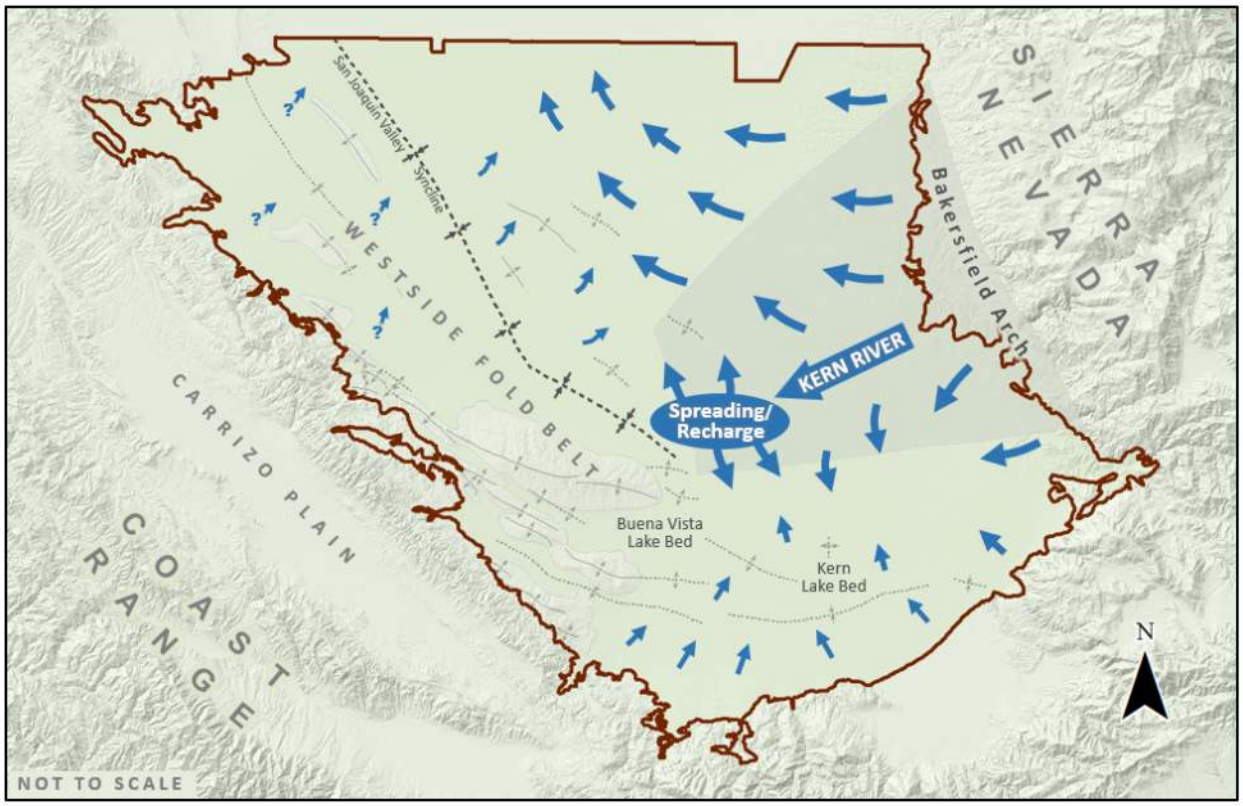

Figure 2-30. Generalized Diagram of Groundwater Flow in Kern County Subbasin

2.3.1.1 Elevation and Flow Directions

Groundwater elevation contour maps were prepared for Spring 2015 to provide relatively current groundwater flow trends across the Subbasin since the inception of SGMA. Contours were prepared for Spring 2015 (seasonal high) in the primary aquifer zone or "main production zone" which is generally confined below the E-clay or Corcoran and unconfined to semiconfined outside the extent of the E-clay (Figure 2-31). Contours for the "Upper Zone" by Schmidt and Associates (2018) are presented on Figure 2-32 for Spring 2015 data. They represent the upper unconfined to semiconfined zone (above the E-clay or equivalent) underlying the northwest-central part of the Subbasin. A Fall 2015 contour map was also developed to represent seasonal low groundwater conditions in the primary aquifer zone (Figure 2-33). At this time, there is insufficient data to contour a fall 2015 upper zone map. In addition, to production zones, depth contours developed by the Kern County Water Agency (2012) for the shallow unconfined zone (above the A-clay or equivalent) are presented on Figure 2-34.

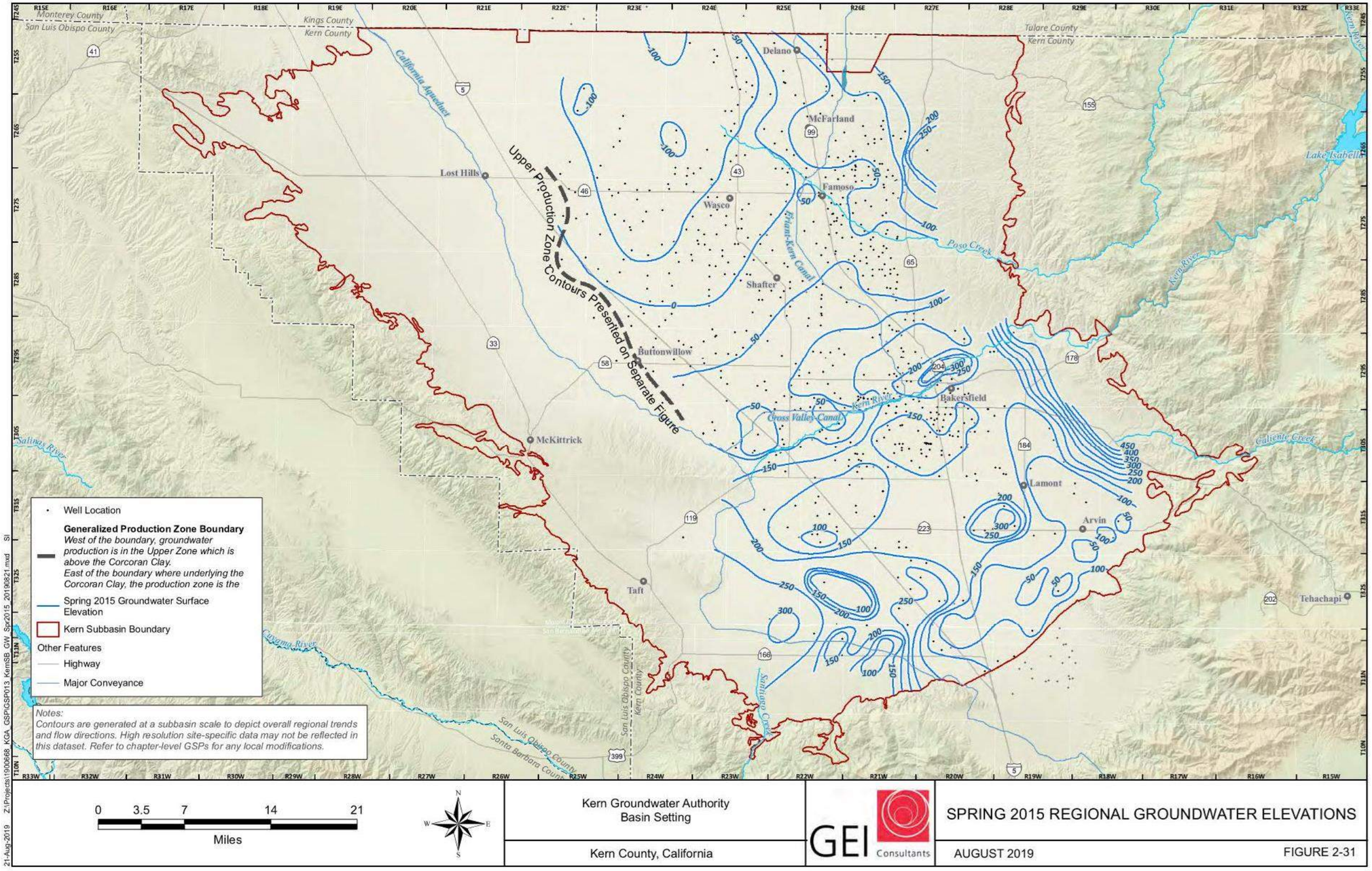

Figure 2-31. Spring 2015 Regional Groundwater Elevations

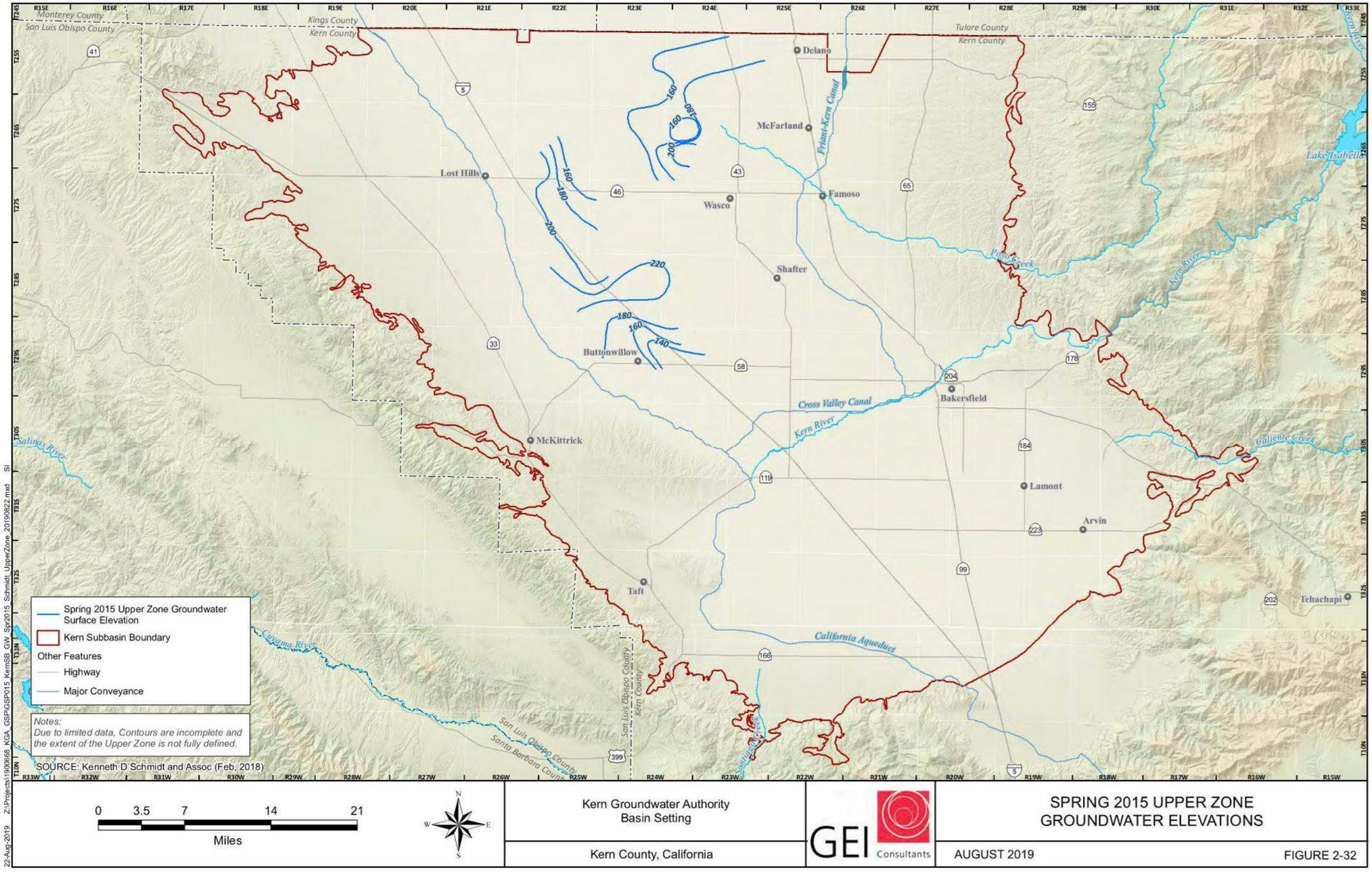

Figure 2-32. Spring 2015 Upper Zone Groundwater Elevations

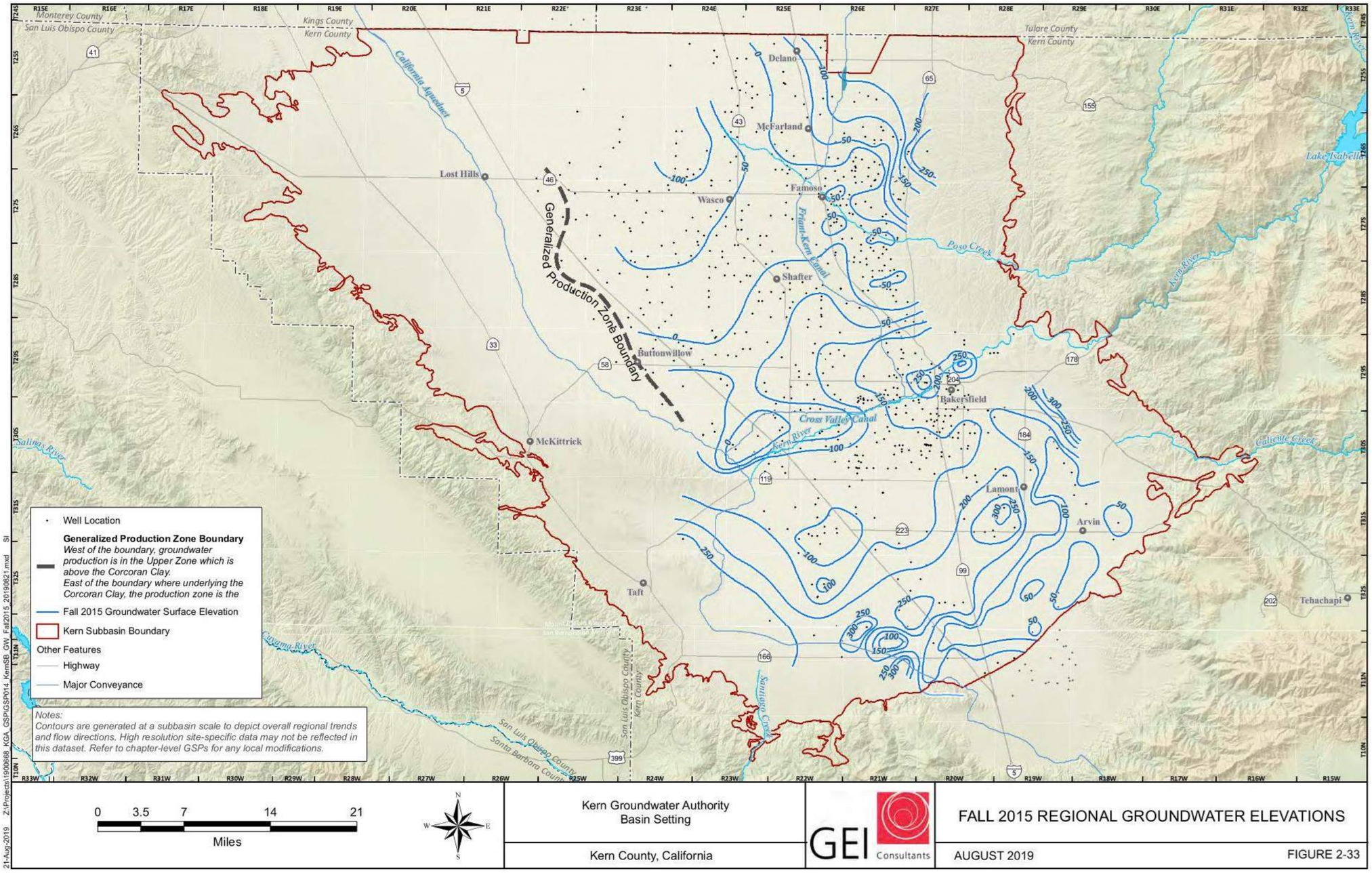

Figure 2-33. Fall 2015 Regional Groundwater Elevations

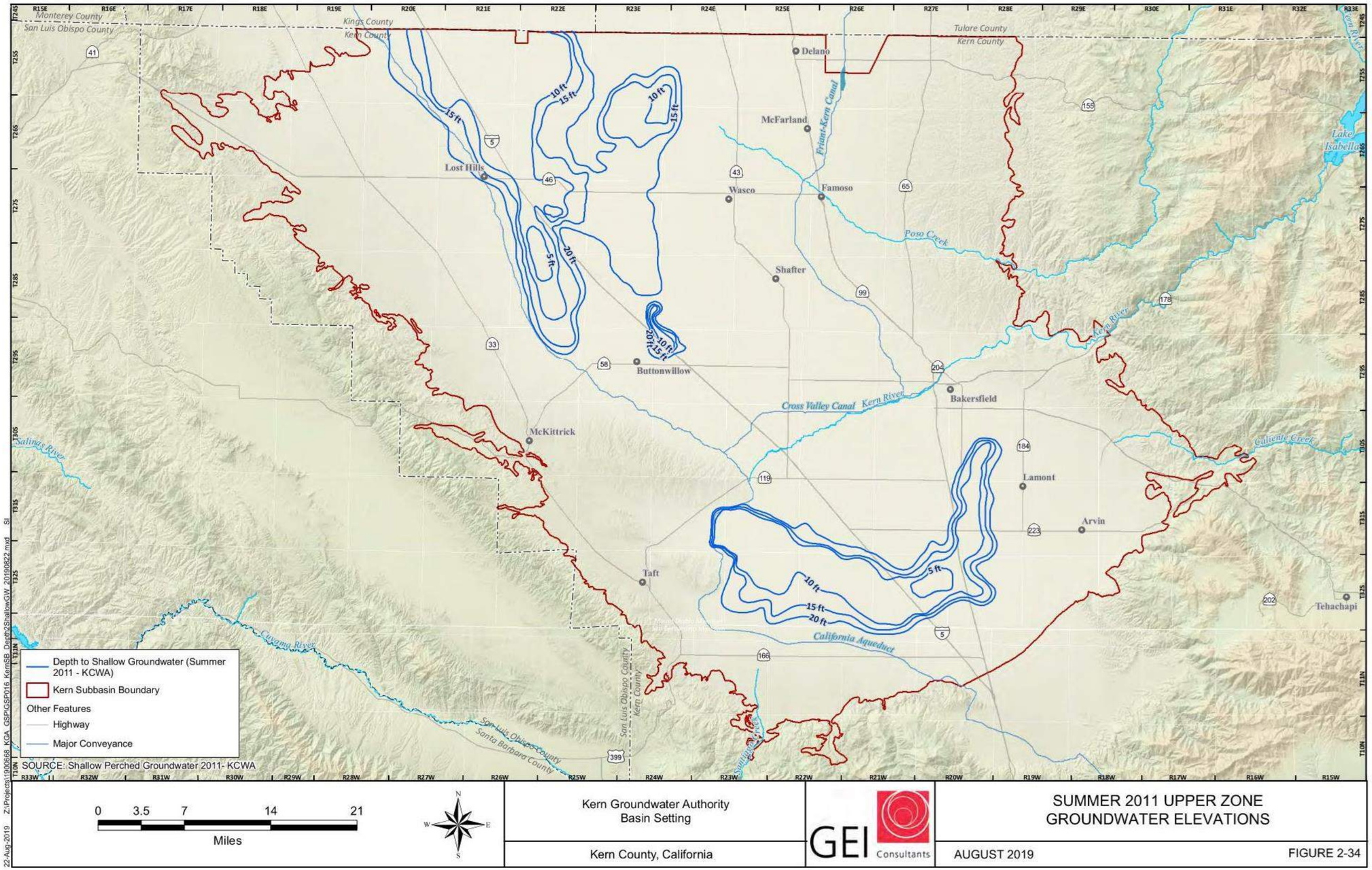

Figure 2-34. Summer 2011 Upper Zone Groundwater Elevations

These contours were developed from Summer 2011 and are generally representative of 2015 conditions. In general, shallow elevations are fairly constant over time.

2.3.1.1.1 Regional Contours

In general, groundwater flow directions reported are consistent with historical trends, with groundwater flowing from the uplands on the south, east, and west of the Subbasin toward the center of the Subbasin. Groundwater tends to diverge at the Kern River with flow to the south of the river toward pumping well discharge points, and flow to the northwest of the river toward pumping wells, and further north until it leaves the Subbasin. Based on 2015 groundwater elevations, the divergence to the North and to the South along the river is less notable due to the drought conditions which resulted in greater groundwater use with very little recharge during 2013 to 2015. Depressions in the groundwater potentiometric do occur south of the river; however, a general trend of flow toward the north and center "trough" of the Subbasin is apparent.

Groundwater elevations during Spring 2015 in the main production zone of the aquifer system ranged from less than minus 100 ft msl in the north-central part of the Subbasin to greater than 300 ft msl in the eastern and southeastern part of the Subbasin.

Groundwater elevation data for the Fall 2015 were limited in availability due to the high demand for pumping; therefore, the data range is incomplete, it may be affected by pumping, and it represents only a partial dataset; however, general groundwater flow trends are consistent with historical trends. Groundwater elevation data for the Fall 2015 in the main production zone of the aquifer system ranged from less than minus 150 ft msl (north-central Subbasin) to greater than 250 ft msl (south-southeast Subbasin). Contours in the upper unconfined zone of north-central Subbasin and shallow zone of Subbasin were not prepared for Fall 2015 due to a lack of sufficient data.

2.3.1.1.2 Upper Zone Contours

Groundwater elevations during Spring 2015 in the upper zone of the north central part of the Subbasin ranged from 220 ft msl to 160 ft msl. Within Townships 27S and the northern half of 28S, groundwater in the Upper Zone flows northeasterly. Within the southern half of Township 28S and 29S, groundwater flows southeasterly. Some of this flow may be affected by the Buttonwillow Syncline and Buttonwillow Ridge (anticline). As observed in Cross Section A-A' of North of the River (Figure 2-24a), beds from this groundwater aquifer system are deformed (folded).

2.3.1.1.3 Shallow Depth Contours

Groundwater depths in the shallow zone historically range from approximately 20 to 25 ft bgs to less than 5 ft bgs (ranging from 200 ft msl to 245 ft msl). Representative contour maps were chosen from the Kern County Water Agency's 2011 Water Supply Report (KCWA, 2012) (Figure 2-34), because more recent data from 2011 to 2015 are limited in extent; nonetheless, the recent data agree with DWR published maps of shallow perched groundwater in the San Joaquin Valley (DWR, 2009), and with the Kern County Water Agency's historical water supply reports.

Shallow groundwater is not significantly impacted by groundwater pumping in the production zone, as observed by the relatively consistent shallow groundwater depths and extents in historical water supply reports from the Kern County Water Agency and DWR across multiple water year types. The source of shallow groundwater as mapped by the Kern County Water Agency, is derived from the percolation of applied irrigation water, as well as historical natural percolation during large storm events. The extent of shallow groundwater, which is typically perched on shallow fine-grained sedimentary units and likely disconnected from the productive aquifer system, is relatively consistent with Page's (1986) extent of mapped surficial fine-grained flood deposits (Figure 2-17 and shallow clay units related to the "A" Clay of the Corcoran Clay (KCWA, 1976). During the mid to late 1980's, sufficient data were collected for the Kern County Water Agency's water supply report to show that, at times, the perched shallow groundwater units to the north of the river and to the south of the river have been joined at the northwest of the Kern River Fan, generally following the extent of flood plain deposits as mapped by Page (1986).

While shallow groundwater data is collected in certain regions of the Subbasin, the current data collection effort does not provide sufficient data to understand the interconnection between the lower production aquifer and the shallow purged groundwater system that existing in portions of the basin. This data gap will be addressed in projects and management actions identified in individual management area plans.

2.3.1.1.4 Horizontal Gradients

The following is a summary of general regional groundwater flow direction and general regional horizontal gradients based on the contour maps presented herein. For more detailed trends, refer to management area plans.

Groundwater in Spring 2015 for the main production zone (confined below the E-clay and semi-confined outside of the clay) in the east-northeast flows southwesterly at a gradient of 0.011 ft/ft. In the north-central area, groundwater flows northwesterly at a gradient of 0.002 ft/ft. In the central area of the Subbasin near the Kern River and banking activities, groundwater flows north to northwesterly at a gradient of 0.002 to 0.004 ft/ft. In the southeast, groundwater flows southwesterly at a gradient of 0.025 ft/ft. In the south, groundwater flows northwesterly to southeasterly at gradients of 0.004-0.012 ft/ft and 0.004 ft/ft respectively. In the southwest, groundwater flows northeasterly at a gradient of 0.001 ft/ft. Groundwater in the Bakersfield area flows away from the river from 0.005 to 0.011 ft/ft in a southeasterly to northwesterly gradient.

Groundwater in Fall 2015 for the main production zone (confined below the E-clay and semi-confined outside of the clay) in the east-northeast flows west to southwesterly at a gradient of 0.015 ft/ft. In the north-central area, groundwater flows northwesterly at a gradient of 0.002 ft/ft. In the central area of the Subbasin near the Kern River groundwater flows toward the banking activities northeasterly and southwesterly at gradients of 0.006 ft/ft and 0.003 ft/ft respectively. In the southeast, groundwater flows southwesterly at a gradient of 0.016 ft/ft. In the south, groundwater flows northwesterly to southeasterly at gradients of 0.007 ft/ft and 0.008 ft/ft respectively. In the southwest, groundwater flows northwesterly at a gradient of 0.005 ft/ft.

Groundwater in Spring 2015 for the upper unconfined zone (unconfined above the E-clay) in the north half of Township 28S and 27S flows northeasterly at a gradient of 0.002 ft/ft. In the south half of T28S and T29S, groundwater flows southeasterly at a gradient of 0.003 ft/ft. In the far north mapped area of the upper unconfined zone, groundwater flows at a gradient of 0.001 ft/ft northwesterly and 0.004 ft/ft westerly.

2.3.1.2 Hydrographs and Vertical Gradients

Hydrographs presenting change in groundwater elevation over time and vertical groundwater gradients for specific areas of the Subbasin are provided in the chapters herein for local management areas. In general, hydrographs presented in the management area plans indicate that groundwater elevations decline during below normal water years (as defined by the water year index), and groundwater elevations begin recovering during above normal water years. Additional information can be found Section 2.4, Water Budget Information.

2.3.2 Seawater Intrusion

The Subbasin is located in the Central Valley, more than 40 miles from the Pacific Ocean. Seawater intrusion will not affect the Subbasin.

2.3.3 Groundwater Quality

To characterize groundwater quality in the Subbasin, a literature review was conducted using USGS studies and other technical reports, as well as data extracted from GeoTracker and EnviroStor to identify contaminant plumes. The SWRCB's Human Right to Water portal was used to identify contaminants that are commonly violating drinking water standards and an evaluation of the groundwater water quality was conducted using data from local Water Districts and the State Drinking Water Information System (SDWIS), which collects sample results from all State regulated public water systems. This section of the report provides a brief introduction to the contaminants most commonly found in the Subbasin. A more focused evaluation of the groundwater is provided in the management area plans for each member agency that comprises the KGA.

Characterization of groundwater quality was conducted to comply with (California Code of Regulations – Title 23 – Waters; Subarticle 2 §354.16(d) – Groundwater Conditions: groundwater quality issues that may affect the supply and beneficial uses of groundwater, including a description and map of the location of known groundwater contamination sites and plumes. Constituents evaluated and the methodology used were consistent with guidance provided in:

- Assembly Bill 1249 (AB 1249) which states that "if the IRWM region has areas of nitrate, arsenic, perchlorate, or hexavalent chromium contamination, the (IRWM) Plan must include a description of location, extent, and impacts of the contamination; actions undertaken to address the contamination, and a description of any additional actions needed to address the contamination" (Water Code §10541.(e)(14)).

- Division of Drinking Water's (DDW) Human Right to Water (HR2W) portal, which identifies the contaminants that public water systems have received maximum contaminant level (MCL) violations. Commonly found contaminants were trended and occurrence data was evaluated.
- Water Quality Control Plan for Tulare Lake Basin (Basin Plan), dated May 2018, which is the State Board's implementation plan for Water Code §106.3. The amended Basin Plan requires permittees to "address the immediate needs of those drinking groundwater that exceeds the drinking water standard for nitrate."

Incorporating guidance from these sources was intended to incorporate the major constituents of concern and characterize groundwater in a manner that is consistent with current water quality focused programs. Of the regulated drinking water constituents considered, the most common water quality issues within the Subbasin are: nitrate, arsenic, boron, hexavalent chromium, dibromochloropropane (DBCP), 1,2,3-trichloropropane (TCP), total dissolved solids (TDS), sodium, and chloride. This water quality discussion is divided by constituent to explain the drinking water and agricultural standards and how these constituents' impact beneficial uses in the different regions of the Subbasin. Since the predominant land use in the Subbasin is for agricultural purposes, agricultural Water Quality Goals (as established by Ayers and Westcott) are referenced for evaluation of groundwater salinity (SWRCB, 2016a). The most applicable standard, Drinking Water Standard or agricultural goals will be used as a reference point when discussing each constituent.

Maps created to show constituent prevalence were developed using data extracted from the Groundwater Ambient Monitoring and Assessment (GAMA) Groundwater Information System. Only wells from the Public Water System dataset were used because they provide more consistent results since compliance monitoring frequency is regulated by DDW. To depict the highest contaminant values, the maximum concentrations were plotted, rather than average concentrations, from each public water system spanning a 10-year timeframe (2009-2019). These maps are intended to provide a general overview of constituent prevalence and concentrations. They should not be interpreted as indicating contamination throughout the region because constituent concentrations typically vary depending on well construction and local hydrogeologic conditions. More detailed analysis of water quality trends is discussed in the individual management area plans.

2.3.3.1 Arsenic

Arsenic has a primary drinking water MCL of 10 parts per billion (ppb) and an agricultural goal of 100 ppb. Reports published by the Department of Pesticide Regulation and USGS studies and the hydrogeology of the Subbasin indicate that the major source of arsenic in this Subbasin is naturally occurring from erosion of natural deposits. Throughout the southern San Joaquin Valley, arsenic-rich minerals such as arsenopyrite, a common constituent of shales and apatite, and phosphorites are the most common sources of arsenic leaching materials in the aquifer (Burton et al, 2012). In the Subbasin, these minerals are mostly found in lake bed deposits or the

Corcoran Clay. USGS reports that most of the highest arsenic detections are near the City of Delano and at the southwest extents of the Kern Fan, near the City of Bakersfield.

Since arsenic is mostly derived from natural geochemical processes, elevated concentrations are localized and appear to be associated with lake bed areas where there are thick clay deposits: Tulare Lake, Kern Lake, and Buena Vista Lake (Bulletin 118, DWR). In the Subbasin, consistently high concentrations generally concentrate in the center of the valley along the north margin of Buena Vista lake bed. Data trending indicates that its predominately found in wells constructed deeper than 1,000 feet below ground surface (bgs). Trending of the public water system wells in the Kern Fan indicates elevated arsenic is consistently found in wells constructed deeper than 650 feet bgs, and when groundwater elevations decline. A study conducted by USGS reports that arsenic is the trace element most frequently present at high concentrations in the Subbasin. Concentrations found in nearly 1,400 samples ranged from 10 to 30 ppb (Burton et al, 2012).

Severe drought conditions from 2012 through 2016 resulted in groundwater levels significantly declining throughout Kern County; subsequently, wells located in the Kern Fan are showing higher concentrations of arsenic from the deeper aquifers into the pumping zone due to the proportion of water from the deeper screened intervals increasing. Consequently, higher concentrations of arsenic have been observed in municipal wells. As groundwater levels temporarily recovered in 2017, there was a noticeable correlation to lower arsenic concentrations.

Findings from a study conducted by Negrini et. al (2008) explain that the thickest part of the coarsening-upward unit in the Kern Fan is in the same region as the wells with elevated arsenic concentrations. The study identified a large-scale sedimentary sequence (a specific geologic sequence) that was primarily prevalent in most of the wells in this study area. This sequence unit consists mostly of uniformly fine-grained silts and clays and the unit abruptly thickens basin-wide. The thickest part of this unit was found to have groundwater arsenic concentrations above 50 ppb. Depth interval containing sediments from this unit generally coincide with intervals having elevated arsenic concentrations. It was also found that at the same depth interval, arsenic is in an easily exchangeable state in the bulk sediment where oxidizing geochemical conditions dissolve the pyrite and release arsenic into the groundwater.

In addition to the lake bed areas, there is common arsenic detections associated with the Corcoran Clay. Mineral deposits transported by rivers into the San Joaquin Valley, from the Sierra Nevada and the coastal mountain ranges, became enriched with arsenic mineral deposits then adsorbed on the clay surfaces that were buried over time. When the oxygen deprived mineral deposits come into contact with oxygenated water, the result is dissolution of arsenic within the clay pore and into the groundwater. These deposits typically begin at depths greater than 180 feet bgs. Occurrence of arsenic in groundwater and any associations to the Corcoran Clay are addressed at the management area plans water quality sections.

2.3.3.2 Nitrate

Nitrate as nitrogen has an acute drinking water MCL of 10 parts per million (ppm); there is no agricultural goal. Sources of nitrate contamination in groundwater are runoff and leaching from fertilizer use; leaching from septic systems and sewage; confined animal facilities; and very small concentrations from erosion of natural deposits. Typically wells in the San Joaquin Valley have higher nitrate concentrations in the shallower zones. However, higher nitrate concentrations can also occur in deep wells, depending on source concentrations, lithology, and well construction. Dubrovsky et al (2010) considers background nitrate concentrations above 1 ppm to indicate human activity.

Although the agricultural industry is believed to be a primary contributor to nitrate contamination of the groundwater basins in the Central Valley, based on mass loading calculations, irrigation practices in this Subbasin have been improved to reduce nitrate leaching into groundwater. In a study conducted for the Kern River Watershed Coalition Authority (KRWCA, 2013), it is acknowledged that nitrate leaching from agricultural irrigation is not like other basins to the north because irrigation practices are more efficient here, which reduced nitrate leaching into the groundwater. This assessment is supported by a comparison of the Nitrate Hazard Index results from 1990 and 2012, which shows a significant reduction in nitrate risk to groundwater.

KRWCA is leading the Irrigated Lands Regulatory Program (ILRP) for the Subbasin and have provided results from the initial groundwater sampling that took place in fall of 2018 (KRWCA, 2019). Their groundwater trend monitoring program requires nitrate sampling of first encounter groundwater during spring and fall each year. Trends are not ascertained yet since fall of 2018 was the first year of monitoring and these are the only results that are publicly available. Of the 26 representative wells sampled (14 domestic and 12 irrigation), nitrate results ranged from 1.1 to 21 parts per million (ppm) with a median value of 9.9 ppm. Nine of the wells sampled exceed 10 ppm: of these, seven wells are domestic and two are used for irrigation. Nitrate concentrations of these wells is included in Figure 2-35, although they are not specifically labeled as first encounter groundwater wells.

In addition to studies evaluating agricultural impacts of nitrate contamination, studies investigating the correlation of other potential nitrate sources were also reviewed. Dubrovsky et al (2010) finds that domestic wells located in agricultural areas are not only influenced by irrigation practices and/or livestock as a potential nitrate source, but also from septic systems. A USGS study (Burton et al, 2012) was conducted in the Southeast San Joaquin Valley and the Kern County Subbasin. This study used statistical analysis of land uses, well construction data, water quality parameters and number of septic systems around each study well to determine that land uses fairly represent nitrate sources impacting the well. Some of the data obtained for the Burton et. al, (2012) study were from the State Water Board's GAMA Domestic Well Project, where wells were sampled in 2006 (Shelton, 2006). The Project analyzed 29 of the 181 domestic study wells in the Kaweah Subbasin study area, for stable isotopes of nitrogen and oxygen. Wells with higher nitrate concentrations (median of 5 ppm and mean of 11 ppm) were targeted for this study. Testing showed that 28 of the 29 impacted wells have nitrate characteristics consistent

with a dairy manure or septic system source. Septic systems elevate groundwater nitrate concentrations since they only remove half of the nitrogen in the wastewater, leaving the remaining half to percolate to groundwater (McCalasand, 2019). One of the 29 wells showed an isotopic composition indicative of a synthetic fertilizer. While the isotopic composition of nitrate varies with land use, it is consistent between nitrate source (soil, fertilizer, manure, septic or community wastewater). Private well sampling for stable isotopes of nitrate was not conducted in the Kern County Subbasin.

Kern County Environmental Health Department (EHD) updated their program and ordinance with the development of the County's Local Agency Management Program (LAMP) to comply with the State Water Board's policy on septic systems (SWRCB, 2012). This was adopted to allow local agencies to continue use of septic systems, while protecting water quality and public health. An analysis was conducted to estimate baseline septic systems in Kern County. Four basic elements used in their analysis were parcel development status; general soil/septic systems suitability mapping; hydrologic areas; and groundwater basins. Since it was assumed that incorporated areas have municipal sewer systems that either serve or are available to these parcels, only non-sewerage unincorporated areas of the County were included in the analysis. This study revealed that approximately 30 percent of developed parcels within the Subbasin rely on septic systems. KGA is working with Kern County to document the location of these septic systems. A partial list of system recently inspected was provided and is shown in Figure 2-35.

Prior to the State's policy, EHD has been collecting water quality data on newly drilled wells to gain an understanding of groundwater quality. Initial assessment showed about eight percent of the wells tested are above the nitrate MCL; data from 1998 through 2019 are included in Figure 2-35. While there is currently a data gap, it is anticipated that continued work with Kern County and through the implementation of their LAMP that the domestic well water quality data and location of septic systems will be available to KGA. Although not all septic system location data is available at the time of this evaluation, it is noted areas with septic systems and domestic wells, generally show elevated nitrate concentrations.

Studies conducted by UC Davis, Center for Watershed Sciences have evaluated nitrate sources in the Tulare Lake Basin and documented that on a regional scale, groundwater nitrogen loading from sewer collection system leaks and septic systems is negligible compared to fertilizers. However, when looking at a local level, septic systems can be a significant source of nitrate contamination to domestic wells in peri-urban areas surrounding cities, or in areas of relatively high rural household density (Viers et. al, 2012). Findings also indicate that disadvantaged communities with water quality issues are in these same areas. Septic systems are considered low-hanging fruit (Dzurella et al, 2012), but is an important issue to address due to its impact to localized drinking water sources.

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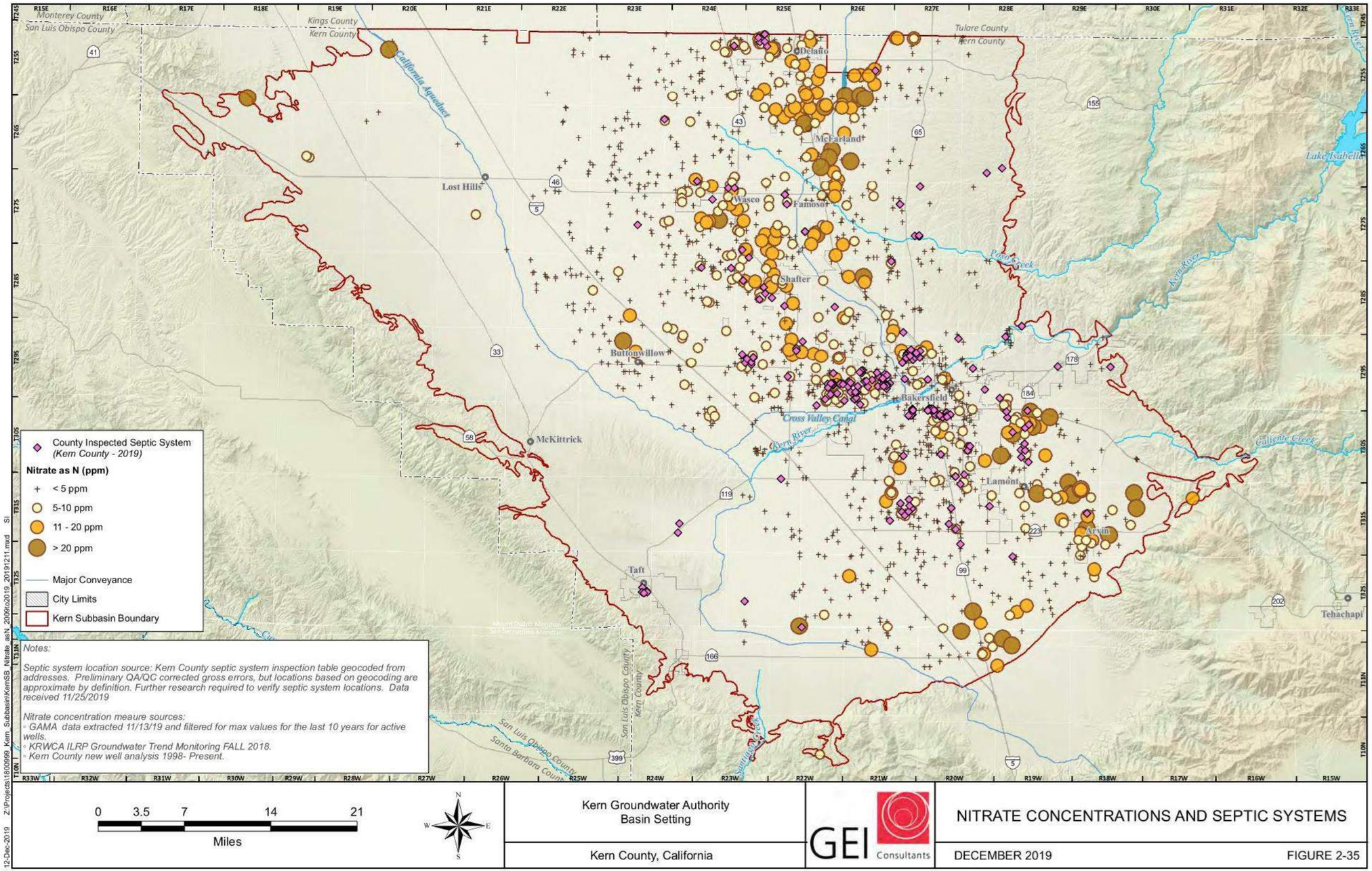

Figure 2-35. Nitrate Concentrations and Septic Systems

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Data gaps often identified in these studies include lack of localized data such as location of septic systems, proximity of domestic wells to septic systems, and water quality of unregulated domestic wells. Reports such as Viers et al, (2012) and the initial assessment for the LAMP report have acknowledged these data gaps. To better assess nitrate sources, future monitoring programs should be geared towards better data collection methods to conduct a more comprehensive evaluation on septic system impacts to groundwater. Additionally, nitrate issues need to be evaluated on a local level rather than regional approach, especially when looking at the impacts to human health and consumption of water from unregulated domestic wells.

2.3.3.3 Boron

There is no federal or state MCL for boron. However, California does have a Notification Level of 1,000 ppb, and there is an agricultural goal of 700 ppb. The agricultural goal is set to protect various agricultural uses of water, including irrigation of various types of crops and stock watering. These levels are used as a baseline to compare against and are not intended to represent an acceptable maximum value for the Subbasin. Since most of the land use in the Subbasin is irrigated lands, the agricultural goal for boron is used as a reference point, rather than the drinking water Notification Level. The most prevalent sources of boron in drinking water are from leaching of rocks and soils, wastewater, and fertilizer/pesticides applications.

According to the USGS Scientific Investigations Report 2011-5218 (Burton et al, 2012) boron is most commonly found in the southern part of the Subbasin near the Tehachapi Mountains. Even though the USGS study for boron was limited to the southern part of the Subbasin, it was concluded that elevated concentrations of boron may be naturally occurring. Boron is potentially associated with sediments in the aquifer derived from marine deposits that are naturally high in boron from the Coast Ranges and San Emigdio Mountains. Saline waters have also been found to contain relatively high concentrations of boron, groundwater that underlies the freshwater aquifer could contribute high boron concentrations in deep wells.

2.3.3.4 Hexavalent Chromium

There is no federal MCL for hexavalent chromium. In July 2014, California adopted a primary MCL of 10 ppb, which was invalidated as of September 2017. While DDW is repeating the regulatory process for adopting a new MCL, the federal MCL of 50 ppb for total chromium applies. There is no agricultural goal for hexavalent chromium.

Hexavalent chromium can come from anthropogenic and natural sources. Anthropogenic sources include discharges of dye and paint pigments, wood preservatives, chrome-plating liquid wastes, and leaching from hazardous waste sites into the environment. Naturally occurring chromium is a metal found in ore deposits containing other elements, mostly as chrome-iron ore. Chromium is also prevalent in soil and plants: the phenomenon of releasing chromium into groundwater is believed to be similar geochemical processes to arsenic. Generally, natural chromium in the environment occurs as trivalent chromium (Cr3) then is oxidized to a hexavalent state (Cr6+). This typically occurs in oxidizing conditions such as alkaline pH range (between 8 and 14 units)

or in the presence of manganese dioxide; in these conditions, naturally occurring hexavalent chromium is likely to exist.

The presence of manganese oxide minerals within ultramafic and serpentinite derived soils and/or sediments can trigger the oxidation of chromium, leading to the presence of naturally occurring hexavalent chromium in the aquifers (SWRCB, 2017; Groundwater Information Sheet 2017). While studies have not been conducted on the types of soils and sediments in the Subbasin where hexavalent chromium is present, the relatively low concentrations (typically in the range of 5 – 13 ppb) indicate the source is naturally occurring (GAMA). Additionally, GeoTracker and EnviroStor databases were searched for open contamination cleanup sites and do not identify any point source contamination in the Subbasin.

2.3.3.5 Synthetic Organic Chemicals

Synthetic organic chemicals predominately found in the Subbasin are dibromo-3-chloropropane (DBCP) and 1,2,3-trichloropropane (TCP). Both chemicals have very low drinking water MCLs. There are no agricultural goals. DBCP has a primary MCL of 0.2 ppb; sources of contamination are a banned nematicide that is still present in soils and groundwater due to runoff or leaching from former use on soybeans, cotton, vineyards, tomatoes, and tree fruit. Since its use was banned in 1977, groundwater contaminant concentrations in municipal wells have shown either steady or decreasing trends. In 2008 the Department of Public Health (transferred to State Water Board as DDW in July 2014) estimated the median half-life of DBCP in the Central Valley is 20 years. This is consistent with the public well data that has been evaluated for this Subbasin.

TCP has a primary MCL of 5 parts per trillion (ppt), which became effective in January 2018 and requires all active drinking water sources are tested at least quarterly during 2018. Since the MCL is set at the detection limit, any well with a detection is identified as exceeding the standard. According to the Water Boards Q1 Report, there is a clear correlation between the location of the of drinking water sources contaminated with TCP and agricultural activities (State Water Resources Control Board, TCP Sampling in Q1 2018).

In the past, TCP was present as an impurity in certain soil fumigants (1,3-D soil fumigants) used to kill nematodes. TCP also has some limited industrial uses. Throughout the Central Valley, most of the TCP found in groundwater was introduced through agricultural application of soil fumigants sold under the trade names of D-D and Telone. In the mid-1970s, Telone was reformulated and the name changed to Telone II. D-D was discontinued in 1984. Telone II remains on the market today but no longer contains TCP. Because TCP was an impurity in these soil fumigants, the potential groundwater contamination was not disclosed to distributors or users, by the product manufacturers. Application rates were not tracked, making it difficult to determine where groundwater contamination is likely to occur. TCP is a highly stable compound, meaning that it is resistant to degradation and has a half-life of hundreds of years (Samin et. al. 2012).

Many large public water systems (serving more than 10,000 population) began sampling their wells for TCP using a low-level analytical method around 2003, as a requirement of the Unregulated Chemical Monitoring Rule. From this data, DDW determined that the most

impacted counties are Kern, Fresno, Tulare, Merced, and Los Angeles. Since a primary MCL was adopted, all water systems were required to test their wells quarterly beginning January 2018. Occurrence data from the State Water Board's DDW shows 94 of California's public water systems have 562 TCP impacted wells (DDW, June 2016). In Kern County, 18 water systems have 124 impacted wells, or approximately 52 percent of their total wells (State Water Board, June 2016).

Figure 2-36 provides a graphical representation of TCP concentrations for the public water system wells within the Subbasin (data extracted on April 29, 2019). To simplify the figure, only the maximum concentrations from January 2018 to April 2019 are shown. Results from the initial compliance monitoring indicates that increased testing requirements directly increased the prevalence of TCP impacted wells in the Subbasin.

the maximum concentrations from January 2018 to April 2019 are shown. Results from the initial compliance monitoring indicates that increased testing requirements directly increased the prevalence of TCP impacted wells in the Subbasin.

2.3.3.6 Total Dissolved Solids (TDS), Sodium and Chloride

Based on drinking water standards, the recommended secondary maximum contaminant level (SMCL) of total dissolved solids is 500 parts per million with an upper limit of 1,000 ppm and chloride is 250 ppm with an upper limit of 500 ppm. There is no drinking water standard for sodium; however, Water Quality Goals for Agriculture, published by the Food and Agriculture Organization of the United Nations in 1985, has set agricultural goals for TDS, sodium, and chloride at 450 ppm, 69 ppm, and 106 ppm, respectively. The criteria identified are protective of various agricultural uses of water, including irrigation of various types of crops and stock watering. These levels are used as a baseline to compare against and are not intended to represent an acceptable maximum value for the Subbasin. Since a majority of the land use in the Subbasin is irrigated lands, the agricultural goals for TDS, sodium, and chloride are used for this portion of the water quality evaluation.

The Burton et. al (2012) report states that in general the higher concentrations of TDS may be affected by sediments from the Tehachapi and San Emigdio Mountains and the Coast Ranges which contain marine deposits. Report findings showed positive correlations between agricultural land use and TDS levels but concluded that higher concentrations of TDS in the Subbasin may primarily be from natural sources as well as human activities. The same findings were true for chloride concentrations.

In a preliminary groundwater salinity mapping study conducted by USGS Scientific Investigations (Report 2018-5082, Metzger and Landon, 2018), groundwater salinity related to the distribution of 31 oil fields and adjacent aquifers was mapped across major oil-producing areas of central and southern California. The objective of this mapping study was to define groundwater with TDS concentrations less than 10,000 ppm using data from petroleum and groundwater wells, and to document data gaps. The study concluded that there is no hydrogeological connection between oil wells and water wells in the mapped regions. This conclusion is based on salinity mapping and well construction: the top perforation of the oil

wells is deeper than the bottom perforation of water wells, except for oil fields in the north eastern part of Kern County. Well perforations in the north eastern part showed little to no vertical separation. Additionally, the study found that the west side of the San Joaquin Valley (in in Kern County) generally has the highest TDS levels at the shallowest depths.

Salinity defined in the chapters of this report are sometimes general, referring to TDS levels, or may be more specific to address the ions of concern based on predominant land uses. TDS is comprised of several dissolved minerals (calcium, phosphates, nitrates, sodium, potassium, and chloride), most of which have minimal impact on beneficial uses of the groundwater. Throughout the Subbasin, sources of salinity identified include a combination of naturally occurring marine deposits; infiltration from produced water disposal ponds; perched water subject to evaporative pumping; or agricultural drainage ponds.

Sodium and chloride ions contribute to TDS and in this region are more important to evaluate due to its impact to the agricultural industry. Both sodium and chloride show similar trends in the wells evaluated; therefore, some sections of the water quality evaluation collectively refer to these ions as salinity. There is slightly more focus on sodium since it is an important measurement to crop yield.

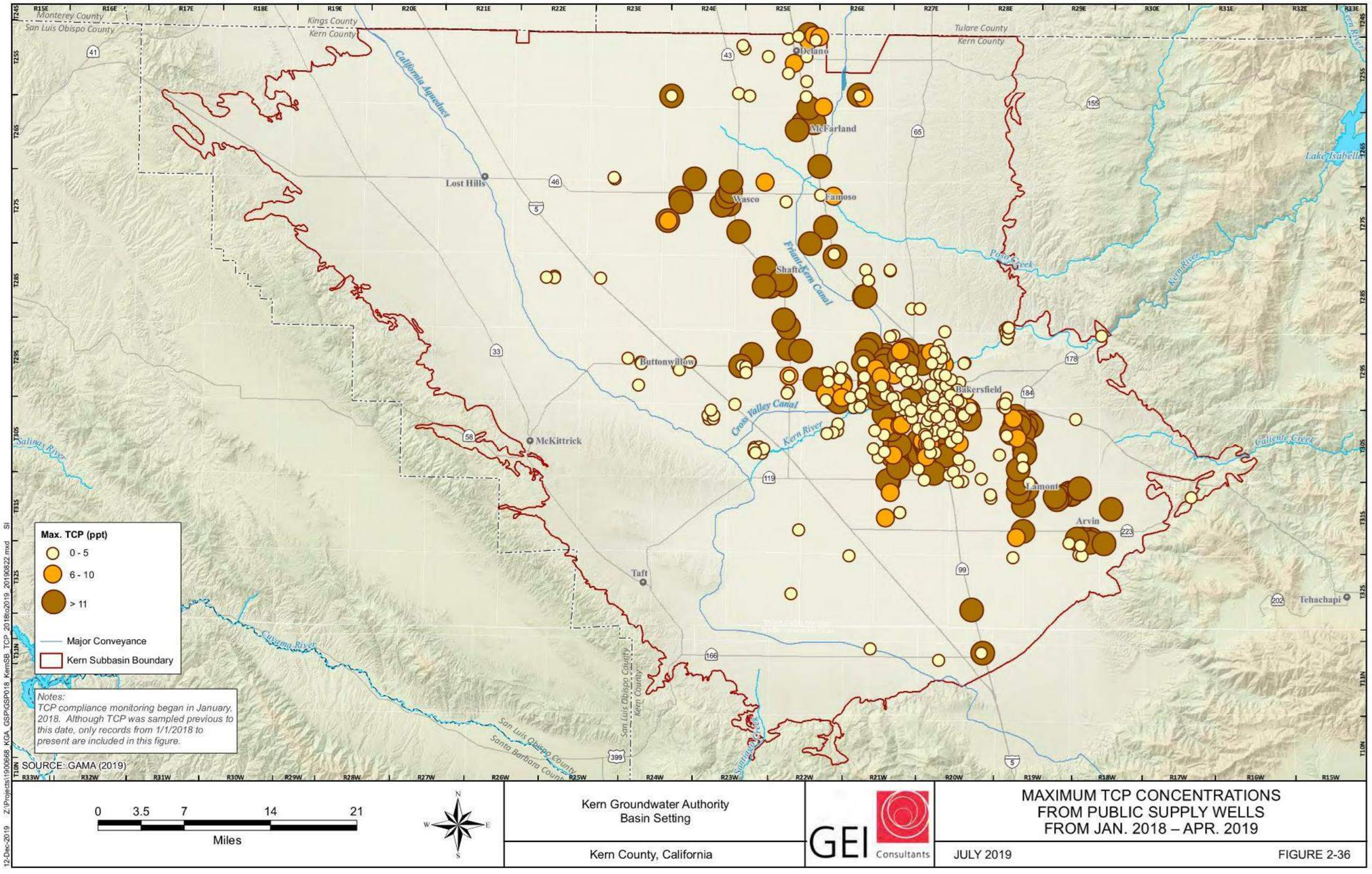

Figure 2-36. Maximum TCP Concentrations from Public Supply Wells from Jan. 2018- Apr. 2019

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2.3.3.7 Groundwater Contaminant Sites

An evaluation of documented groundwater contaminant sites in the Subbasin were identified through the GAMA Groundwater Information System. GAMA contains information from other programs and databases, such as SWRCB – GeoTracker and Department of Toxic Substances (DTSC) – EnviroStor databases. The data included in this basin setting is in response to the emergency regulations § 354.16(d), that requests within the GSP, "a description and map of the location of known groundwater contamination sites and plumes." However, it is not the intent of this section to evaluate or confirm whether any of these sites as listed by regulatory agencies are impacting groundwater with beneficial use. Furthermore, this GSP cannot guarantee the accuracy of the data acquired from these regulatory sources. This section presents cases as were listed from the regulatory databases that may document potentially impacted groundwater sites. Programs listed below were reviewed from GAMA. There are two figures to graphically represent the distribution of sites; Figure 2-37 shows permitted facilities and Figure 2-38 shows clean-up sites.

- Waste Discharge Requirements (WDR)
- Underground Storage Tank (UST)
- Leaking Underground Storage Tank (LUST)
- Cleanup Program Sites
- DTSC Hazardous Waste Sites
- Department of Pesticide Regulation
- Underground Injection Control (UIC) Wells
- Oil and Gas Sites
- Irrigated Lands Regulatory Program Sites
- Confined Animal Site

2.3.3.7.1 Permitted Facilities with Waste Discharge Requirements Orders

While GeoTracker does not include water quality data for WDRs a list of sites and their general location is accessible through the State Board's California Integrated Water Quality System (CIWQS). The general location of Confined Animal Facilities is also available through this database. Figure 2-37 is a graphical representation of the known WDRs and Confined Animal Sites in the Subbasin. A total of 264 sites were identified; however, 43 sites are not included in this figure because latitude/longitude coordinates were not available to confirm that the site are within the Subbasin. The intent of mapping the location of the sites is to provide an idea of where the WDRs and Confined Animal Sites are located throughout the Subbasin.

Irrigated Lands Regulatory Program (ILRP) is permitted as a third-party WDR, like the WDR permit for Confined Animal Sites. However, site specific information is not publicly available because there are too many enrolled parcels under the Order. The Kern River Watershed

Coalition Authority reports on the program. Relevant reports were reviewed and incorporated into the water quality discussion.

2.3.3.7.2 Underground Injection Control Permitted Wells

UIC permitted wells are not included in the list of groundwater contaminant sites because the UIC program's objective is to confine injected fluid to the approved injection zone so that injected fluid does not migrate to a zone where it could degrade valuable groundwater or hydrocarbon resources. Wells permitted under the State's Class II UIC program are presented on Figure 2-39. The UIC program's objective is to confine injected fluid to the approved injection zone so that injected fluid does not migrate to a zone where it could degrade valuable groundwater or hydrocarbon resources (DOGGR, April 2019). This program requires that any injection well have at least two cemented strings of casing across any underground source of drinking water located above a proposed injection zone, an annual Mechanical Integrity Test (MIT) and an annual step-rate test to ensure that groundwater is protected.

Data acquired from the regulatory sources listed above are included in Table 2-5 (Envirostor and Geotracker Databases) only if they applied to the following criteria in the order listed below:

1. potential media of concern defined as "groundwater," "other groundwater," or "drinking groundwater,"
2. potential contaminant of concern defined, or "unknown,"
3. the site/case reported as "not closed", and had one of the following statuses:
    - active cleanup
    - active land use restrictions
    - open remediation
    - open site assessment
    - open – eligible for closure
    - inactive-action required
    - other evaluation
    - under review
    - open-inactive
    - inactive-permitted
    - inactive-unpermitted

There is a total of 77 sites identified within the Subbasin. Figure 2-38 and Table 2-5, with cross referenced Map IDs, present the locations and details of known impacted groundwater or potentially impacted groundwater within the Subbasin. Table 2-5 provides the Site/Facility Name, Site Regulatory Identification and Status, associated site address and latitude/longitude, CalEnviroScreen Score (if applicable), as well as any identified constituents of concern impacting the groundwater at these sites.

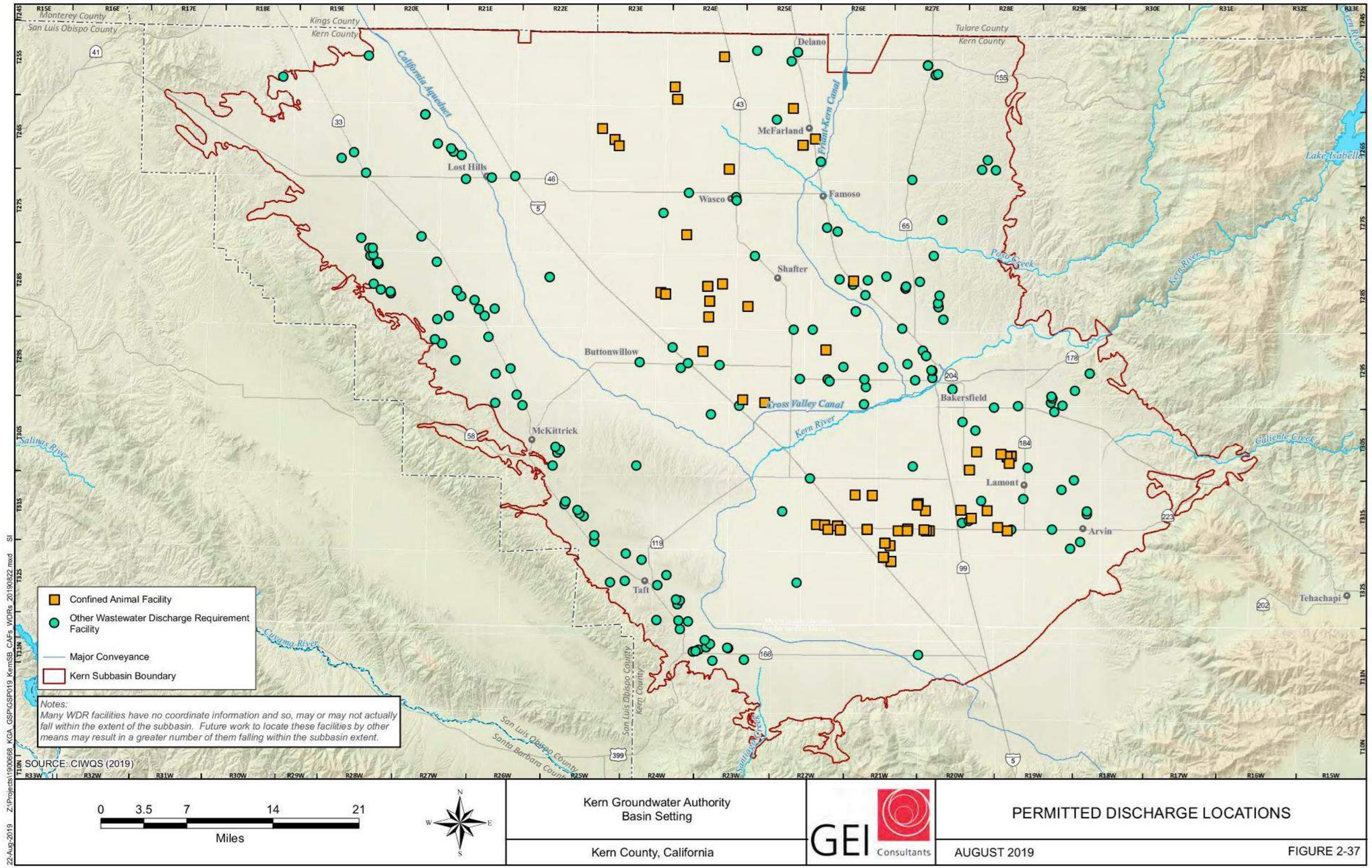

Figure 2-37. Permitted Discharge Locations

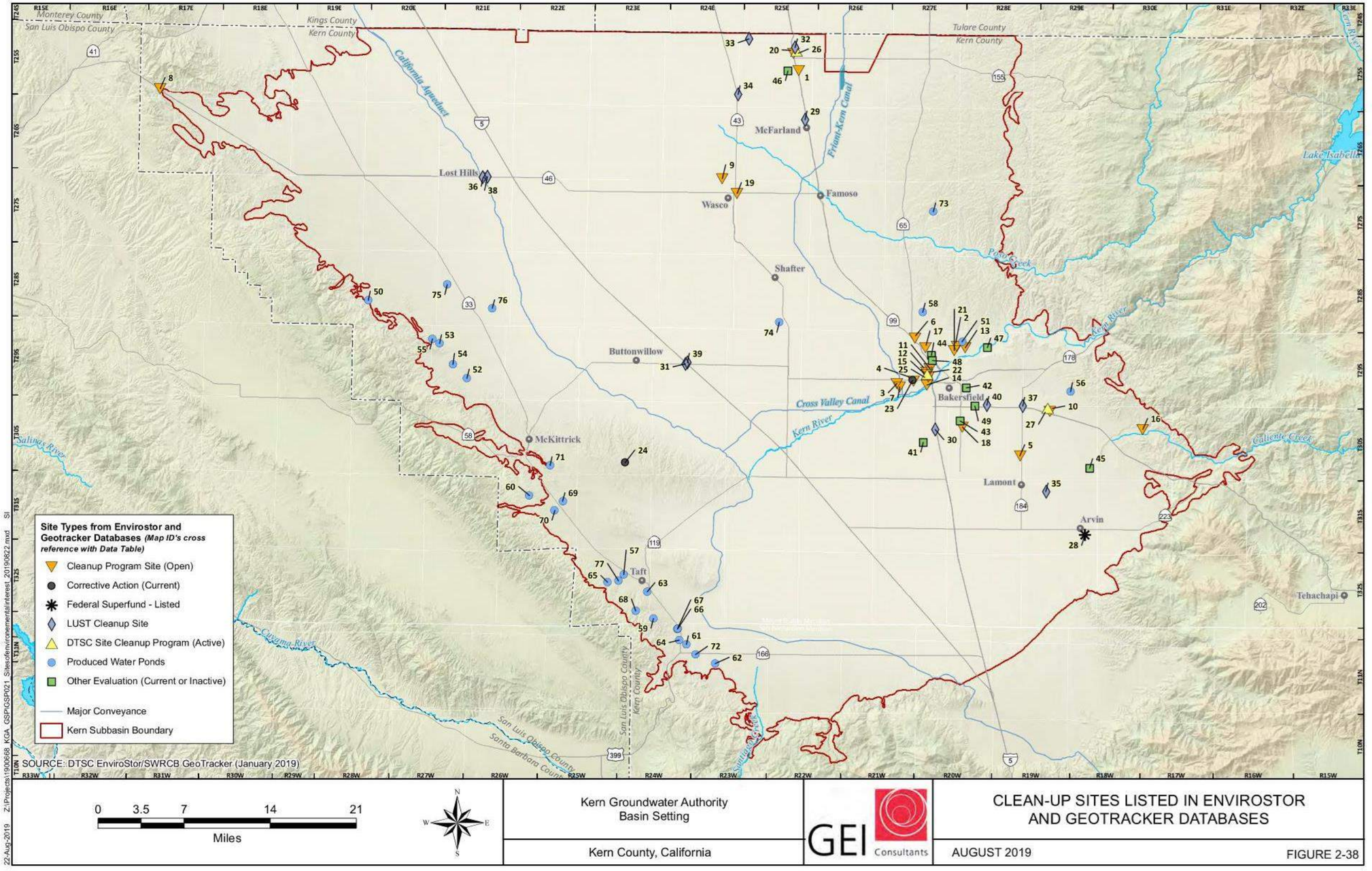

Figure 2-38. Clean-up Sites Listed in Envirostor and GeoTracker Databases

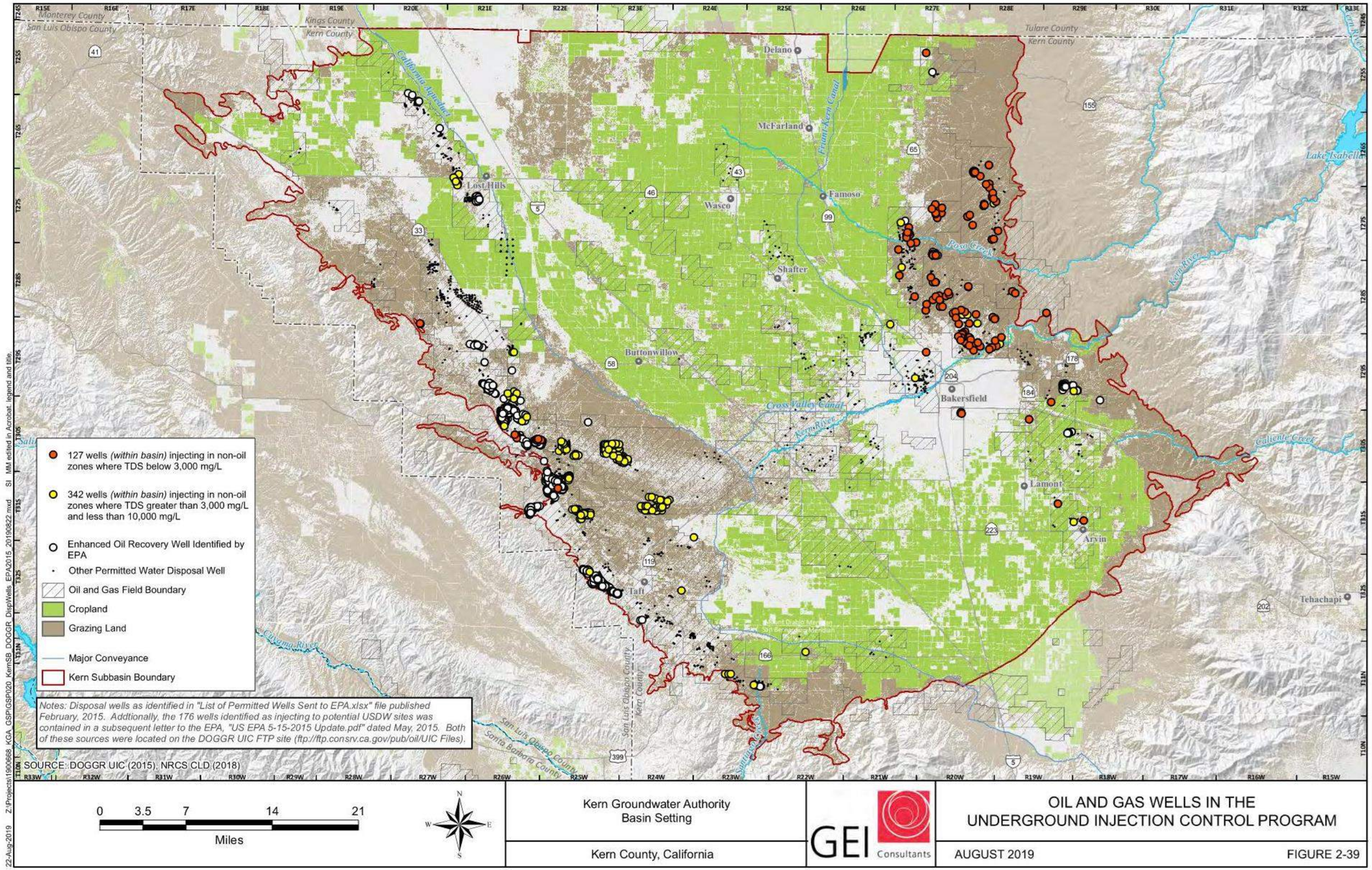

Figure 2-39. Oil and Gas Wells in the Underground Injection Control Program

Table 2-5. GeoTracker EnviroStor Sites with Potential Groundwater Media

Table 2-5
GeoTracker and EnviroStor Sites with Potential Groundwater Media
Kern Groundwater Authority
Kern County, California
(Updated January 2019)

New Map ID	Site / Facility Name	ENVIROSTOR/ Geotracker ID	Source	Program Type	Status	Address	City	Zip	CALEnviroscreen Score	X Coord	Y Coord	Constituents of Concern
1	CROP PRODUCTION SERVICES (CPS) DELANO	SL185724257	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	930 WOOLOMES AVE	DELANO	93215-9553	---	-119.2422	35.7466	VOCs and Pesticides, NITRATE, OTHER CHLORINATED HYDROCARBONS, OTHER SOLVENT OR NON-PETROLEUM HYDROCARBON
2	CHEVRON USA (AKA: CHEVRON REFINERY & WAIT TANK YD)	SL205064267	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	2525 NORTH MANOR STREET	BAKERSFIELD	93308	---	-119.0087	35.4238	BENZENE, CRUDE OIL, LEAD, OTHER PETROLEUM
3	PG&E KERN POWER PLANT (FORMER:COFFEE RD. OVERPASS)	SLT5FP024290	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	2401 COFFEE ROAD	BAKERSFIELD	93308-5748	---	-119.094919	35.37920074	BENZENE, CRUDE OIL, OTHER PETROLEUM
4	BAKERSFIELD REFINERY	SL205314279	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	6451 ROSEDALE HIGHWAY	BAKERSFIELD	93308	---	-119.071219	35.38198244	BTEX, TPH, MTBE / TBA / OTHER FUEL OXYGENATES, OTHER SOLVENT OR NON-PETROLEUM HYDROCARBON
5	KERN OIL & REFINING	SL372524510	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	7724 E PANAMA LANE	BAKERSFIELD	93307-9210	---	-118.9169	35.2954	BTEX, TPH, MTBE / TBA / OTHER FUEL OXYGENATES, PAHs
6	BAKERSFIELD AIRPORT BUSINESS PARK (CHEVRON LAND/D)	SL0602981532	Geotracker	CLEANUP PROGRAM SITE	OPEN - VERIFICATION MONITORING	UNICORN RD. AT HWY 99/65	BAKERSFIELD	93308	---	-119.0698	35.4328	CRUDE OIL
7	SUNLAND REFINING CORPORATION	SL205224272	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	2152 COFFEE ROAD	BAKERSFIELD	93308-5746	---	-119.0911102	35.37550916	CRUDE OIL, GASOLINE, MTBE / TBA / OTHER FUEL OXYGENATES
8	CHEVRON - ANTELOPE PUMP STATION	SL0602985189	Geotracker	CLEANUP PROGRAM SITE	OPEN - ASSESSMENT & INTERIM REMEDIAL ACTION	STATE ROUTE 46	LOST HILLS	93249	---	-120.164723	35.71251	CRUDE OIL, WASTE OIL / MOTOR / HYDRAULIC / LUBRICATING
9	WASCO AIRPORT	SLT5FQ444336	Geotracker	CLEANUP PROGRAM SITE	OPEN - VERIFICATION MONITORING	PALM AVE & MCCOMBS	WASCO	93280	---	-119.3505	35.6184	DDD / DDE / DDT, OTHER INSECTICIDES / PESTICIDE / FUMIGANTS / HERBICIDES
10	J. R. SIMPLOT - EDISON	SLT5FS324450	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	430 PEPPER DR.	EDISON	93220	---	-118.8745	35.3485	DIBROMOCHLOROPROPANE (DBCP), FERTILIZER, PESTICIDES/HERBICIDES
11	SAN JOAQUIN REFINING CO - FRUITVALE REFINERY	SL205714283	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	STANDARD STREET	BAKERSFIELD	93308	---	-119.048	35.3972	DIESEL
12	BAKERSFIELD REFINERY - AREA 3	T10000001848	Geotracker	CLEANUP PROGRAM SITE	OPEN - VERIFICATION MONITORING	3663 GIBSON STREET	BAKERSFIELD	93308	---	-119.0527654	35.39330068	DIESEL, GASOLINE
13	WEST COAST OIL REFINERY, BAKERSFIELD	SL0602978387	Geotracker	CLEANUP PROGRAM SITE	OPEN - INACTIVE	1157 CHINA GRADE LOOP	BAKERSFIELD	93308	---	-118.9975	35.4225	DIESEL, GASOLINE, LEAD
14	APEX BULK COMMODITIES	T10000011271	Geotracker	CLEANUP PROGRAM SITE	OPEN - ASSESSMENT & INTERIM REMEDIAL ACTION	2111 BRICYN LANE	BAKERSFIELD	93308	---	-119.05178	35.37789	DIESEL, OTHER PETROLEUM
15	SAN JOAQUIN DRUM	SLT5FR634417	Geotracker	CLEANUP PROGRAM SITE	OPEN - SITE ASSESSMENT	3930 GILMORE AVE	BAKERSFIELD	93308-6214	---	-119.05165	35.39017952	METALS/HEAVY METALS, PESTICIDES/HERBICIDES, VOLATILE ORGANIC COMPOUNDS
16	J. R. SIMPLOT - BENA (AKA: BENA FERTILIZER)	SLT5FS304448	Geotracker	CLEANUP PROGRAM SITE	OPEN - SITE ASSESSMENT	NONE	EDISON	93220	---	-118.7406	35.3276	NITRATE, OTHER INSECTICIDES / PESTICIDE / FUMIGANTS / HERBICIDES
17	WESTERN FARM SERVICE INC-1610 NORRIS ROAD BAKERSFIELD	SL186364605	Geotracker	CLEANUP PROGRAM SITE	OPEN - SITE ASSESSMENT	1610 NORRIS RD	BAKERSFIELD	93308-2234	---	-119.0541923	35.42200027	OTHER CHLORINATED HYDROCARBONS
18	GARRIOTT CROPDUSTERS	SLT5FQ134306	Geotracker	CLEANUP PROGRAM SITE	OPEN - SITE ASSESSMENT	2010 S UNION AVE	BAKERSFIELD	93307-4154	---	-119.0003209	35.32892143	OTHER INSECTICIDES / PESTICIDE / FUMIGANTS / HERBICIDES
19	SIMPLOT WASCO	SLT5FS184436	Geotracker	CLEANUP PROGRAM SITE	OPEN - REMEDIATION	541 HWY 46	WASCO	93280-1433	---	-119.3289256	35.60078769	OTHER INSECTICIDES / PESTICIDE / FUMIGANTS / HERBICIDES
20	WIP - DELANO, PCE	SL0602943992	Geotracker	CLEANUP PROGRAM SITE	OPEN - INACTIVE		DELANO	93215	---	-119.2496	35.7672	PCE
21	WITCO REFINERY (OILDALE)	SLT5FQ474339	Geotracker	CLEANUP PROGRAM SITE	OPEN - SITE ASSESSMENT	1134 MANOR STREET	BAKERSFIELD	93308-3553	---	-119.0129	35.419	PETROLEUM/FUELS/OILS
22	SABRE REFINERY	SLT5FQ334326	Geotracker	CLEANUP PROGRAM SITE	OPEN - INACTIVE	W. BAKERSFIELD-ROSEDALE AREA	BAKERSFIELD	93308	---	-119.05	35.3876	TOTAL PETROLEUM HYDROCARBONS (TPH)
23	BIG WEST OF CALIFORNIA LLC	80001738	EnviroStor	CORRECTIVE ACTION (CURRENT)	REFER: RWQCB	6451 ROSEDALE HWY	BAKERSFIELD	93308	81-85%	-119.072547	35.383247	BTEX, MTBE
24	OCCIDENTAL OF ELK HILLS INC	80001254	EnviroStor	CORRECTIVE ACTION (CURRENT)	ACTIVE - LAND USE RESTRICTIONS, POST CLOSURE RCRA PERMIT	28590 HIGHWAY 119	TUPMAN	93276	76-80%	-119.484792	35.281959	Metals, Petroleum, PCBS, Radioactive isotopes, Volatile Organics
25	ASSURED TRANSPORTATION SITE	15420001	EnviroStor	DTSC SITE CLEANUP PROGRAM (ACTIVE)	ACTIVE	3228 GIBSON ST	BAKERSFIELD	93308	81-85%	-119.051671	35.3904494	Halogenated Organic Compounds, Tetrachloroethylene (PCE)
26	DELANO PCE PLUME	60001327	EnviroStor	DTSC SITE CLEANUP PROGRAM (ACTIVE)	ACTIVE	MAIN STREET AND 10TH AVENUE	DELANO	93215	66-70%	-119.2456698	35.76910534	Tetrachloroethylene (PCE)
27	J R SIMPLOT, EDISON	15070030	EnviroStor	DTSC SITE CLEANUP PROGRAM (ACTIVE)	ACTIVE - LAND USE RESTRICTIONS	430 PEPPER DRIVE	EDISON	93220	81-85%	-118.8778	35.35147831	Organochlorine pesticides (8081 OCPS), Volatile Organics (8260B VOCS)
28	BROWN AND BRYANT, INC., ARVIN FACILITY	15280011	EnviroStor	FEDERAL SUPERFUND - LISTED	ACTIVE	600 S DERBY ST	ARVIN	93203	81-85%	-118.8231039	35.20314691	DINOSEB and Volatile Organics (8260B VOCS)

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Kern County, California
(Updated January 2019)

New Map ID	Site / Facility Name	ENVIROSTOR/ Geotracker ID	Source	Program Type	Status	Address	City	Zip	CALEnviroscreen Score	X Coord	Y Coord	Constituents of Concern
29	FASTLANE MINI MART	T0602912732	Geotracker	LUST CLEANUP SITE	OPEN - ELIGIBLE FOR CLOSURE	201 ELMO HWY	MCFARLAND	93250	---	-119.2322588	35.68861163	Gasoline
30	HOWARDS MINI MARKET	T10000000635	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	3300 PLANZ ROAD	BAKERSFIELD	93309	---	-119.0392612	35.325438	Diesel, Gasoline
31	JEFFRIES BROS, OASIS	T10000007369	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	35750 HWY 58	BUTTONWILLOW	93206	---	-119.39992	35.39946	Benzene, Diesel, Ethylbenzene, Gasoline, MTBE / TBA / Other Fuel Oxygenates, Naphthalene, Toluene, Xylene
32	LOGRECCO PROPERTY	T0602925877	Geotracker	LUST CLEANUP SITE	OPEN - SITE ASSESSMENT	1330 HIGH STREET	DELANO	93215	---	-119.247728	35.773859	Gasoline
33	NORTH KERN STATE PRISON	T0602900672	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	2737 CECIL AVE W	DELANO	93216	---	-119.3145731	35.7831358	Gasoline
34	POND MERCANTILE	T0602900113	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	29310 POND RD.	POND	93280	---	-119.3292703	35.71777716	Gasoline
35	RIBIER MARKET	T0602900267	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	11228 EDISON RD $ 21124 HWY	LAMONT	93241	---	-118.8792731	35.25343586	gasoline
36	ROBERTSONS MARKET	T0602902377	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	46(FORMERLY 62160 HWY 46)	LOST HILLS	93249	---	-119.6964148	35.6153236	Diesel, Gasoline
37	SAMCO FOOD STORE NO. 3	T10000009045	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	8101 EAST BRUNDAGE LANE	BAKERSFIELD		---	-118.91375	35.35406	Diesel, Gasoline
38	TAYLOR AUTOMATED FUELS	T0602900529	Geotracker	LUST CLEANUP SITE	OPEN - SITE ASSESSMENT	61700 HWY 46, (NW CORNER OF HWY 46 AND LOST HILLS RD)	LOST HILLS	93249	---	-119.6900572	35.61639925	Gasoline
39	TRAVEL CENTERS OF AMERICA	T10000010004	Geotracker	LUST CLEANUP SITE	OPEN - SITE ASSESSMENT	27769 LAGOON DRIVE	BUTTONWILLOW	93206	---	-119.39723	35.40124	Benzene, Diesel, Gasoline, MTBE / TBA / Other Fuel Oxygenates, Naphthalene, Toluene, Xylene
40	WHOLESALE FUELS, INC.	T10000007773	Geotracker	LUST CLEANUP SITE	OPEN - REMEDIATION	2200 EAST BRUNDAGE LANE	BAKERSFIELD	93307	---	-118.96564	35.35471	Benzene, Ethylbenzene, Gasoline, MTBE / TBA / Other Fuel Oxygenates, Naphthalene, Toluene, Xylene
41	BAKERSFIELD DISCOVERY PROJECT	60001630	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	INACTIVE - ACTION REQUIRED	PACHECO ROAD AND STINE ROAD	BAKERSFIELD	93318	66-70%	-119.056751	35.310412	Tetrachloroethylene (PCE), Trichloroethylene (TCE)
42	BAKERSFIELD PLATING WORKS	15340012	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	REFER: OTHER AGENCY	527 EAST 19TH	BAKERSFIELD	93305	81-85%	-118.9954948	35.37490554	Metals (cadmium, chromium III/VI. Copper. Lead, Nickel)
43	BC CHEMICALS	15280041	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	REFER: RWQCB	1511 SOUTH UNION AVENUE	BAKERSFIELD	93307	91-95%	-119.0036166	35.33598464	Arsenic
44	CALTRANS SERVICE YARD	60001605	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	INACTIVE - NEEDS OTHER EVALUATION (CURRENT OR INACTIVE)	1200 OLIVE DRIVE	OILDALE	93308	86-90%	-119.046228	35.413042	PCE, TCE
45	EASTLAND FLYING SERVICE	15070006	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	INACTIVE - NEEDS OTHER EVALUATION (CURRENT OR INACTIVE)	16849 MT. VIEW ROAD	LAMONT	93241	76-80%	-118.816845	35.28164	Carbaryl, 8141A OPPS, Toxaphene
46	KERN COUNTY DUMP	15490017	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	REFER: RWQCB	SE OF XING OF STRADLEY & WOOLOMES AVES	DELANO	93215	96-100%	-119.25779	35.74616	Tetrachloroethylene, trichloroethylene, Dichlorodifluoromethane, 1,1 Dichloroethane
47	KERN COUNTY GUN CLUB	15860001	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	REFER: OTHER AGENCY	2818 CHINA GRADE LOOP	BAKERSFIELD	93308	76-80%	-118.965412	35.422405	Lead, Other Organic Solids, Polynuclear aromatic hydrocarbons
48	RAIN FOR RENT	60001771	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	INACTIVE - NEEDS OTHER EVALUATION (CURRENT OR INACTIVE)	3404 STATE STREET	OILDALE	93308	96-100%	-119.044861	35.406524	Unknown
49	SPARKLE/BRUNDAGE CLEANERS	60002071	EnviroStor	OTHER EVALUATION (CURRENT OR INACTIVE)	BACKLOG	1517 W. BRUNDAGE ROAD	BAKERSFIELD	93304	96-100%	-118.9824817	35.3539159	Tetrachloroethylene, trichloroethylene
50	CARNEROS CREEK, THETA	L10009422184	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	CARNEROS CREEK OIL FIELD	LOST HILLS		---	-119.85852	35.46844	Crude Oil
51	CHEVRON USA INC-KERN RIVER-SAN JOAQUIN	T10000007105	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	KERN RIVER OIL FIELD	MALTHA		---	-119.001769	35.428919	Crude Oil
52	CYMRIC OIL FIELD, BOWLES LEASE	T10000006948	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	SW OF LOKEN RD / LOST HILLS RD	MCKITTRICK	93251	---	-119.71424	35.37855	Crude Oil
53	CYMRIC OIL FIELD, LEHI-RICHARDSON LEASE	T10000007036	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	CYMRIC OIL FIELD	MCKITTRICK		---	-119.754775	35.418844	Crude Oil
54	CYMRIC OIL FIELD, OVERLAND ANDERSON LEASE	T10000007035	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	NE TAFT (S20, T29S, R21E, MDB&M)	MCKITTRICK	93251	---	-119.73454	35.3944	Crude Oil
55	CYMRIC OIL FIELD, USL LEASE	T10000007037	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	CYMRIC OIL FIELD	MCKITTRICK		---	-119.765	35.42378	Crude Oil
56	EDISON OIL FIELD, RACETRACK LEASE	T10000007136	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	EDISON OIL FIELD	EDISON		---	-118.84515	35.37177	Other inorganic / salt, TDS, Crude Oil
57	J&K, MIDWAY-SUNSET OIL FIELD, JADE KERN PROJECT LEASE	T10000006764	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	KRISTIN STREET NE 1/4, SEC 15 T32S R23E MDB&M	TAFT	93268	---	-119.48427	35.14988	Crude Oil
58	KERN FRONT NO. 2	T10000007097	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	KERN FRONT OIL FIELD	SACO		---	-119.05882	35.46374	Crude Oil

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59	MIDWAY-SUNSET OIL FIELD, BERRY & EWING LEASE	T10000007297	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	MIDWAY-SUNSET OIL FIELD	MARICOPA		---	-119.44121	35.09873	Crude Oil
60	MIDWAY-SUNSET OIL FIELD, C. E. HOUCHIN ET AL LEASE	T10000006771	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	SEC 9, T31S, R22E, MDB&M	FELLOWS	93224	---	-119.62194	35.24141	Crude Oil
61	MIDWAY-SUNSET OIL FIELD, FULTON LEASE	T10000007030	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	NORTHEAST OF MARICOPA (S1, T11N, R24W, SBB&M)	MARIPOSA	93252	---	-119.39335	35.06877	Crude Oil
62	MIDWAY-SUNSET OIL FIELD, HAVENSTRITE LEASE	T10000006789	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	MIDWAY-SUNSET OIL FIELD	MARICOPA		---	-119.35188	35.0463	Crude Oil
63	MIDWAY-SUNSET OIL FIELD, JAMESON TRUST LEASE	T10000006947	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	7026 DARNOCH WAY	WEST HILLS	91307	---	-119.45068	35.13032	Crude Oil
64	MIDWAY-SUNSET OIL FIELD, JAMESON TRUST LEASE	L10002548641	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	MIDWAY-SUNSET OIL FIELD	MARICOPA		---	-119.40374	35.0736	Crude Oil
65	MIDWAY-SUNSET OIL FIELD, LOCKWOOD LEASE	T10000007029	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	WEST OF TAFT	TAFT	93628	---	-119.5077454	35.14047576	Crude Oil
66	MIDWAY-SUNSET OIL FIELD, MOCO 35 LEASE (PLASTIC-LINED POND 3)	T10000007039	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	NORTH OF MARICOPA (S35, T12N, R24W, MDB&M)	MARICOPA	93252	---	-119.4057919	35.08717628	Crude Oil
67	MIDWAY-SUNSET OIL FIELD, MOCO 35 LEASE (PONDS 1&2, SAND PITS)	T10000007031	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	NORTH OF MARICOPA (S35, T12N, R24W, MDB&M)	MARIPOSA	93252	---	-119.4065	35.08679	Crude Oil
68	MIDWAY-SUNSET OIL FIELD, NATIONAL USL LEASE	T10000007032	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	TWO MILES SOUTHWEST OF TAFT (S35, T32S, R23E, MDB&M)	TAFT	93268	---	-119.46687	35.10715	Crude Oil
69	MIDWAY-SUNSET OIL FIELD, SHALE 14 LEASE	T10000007033	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	1.5 MILES SOUTHEAST OF DERBY ACRES (S14, T31S, R22E)	DERBY ACRES	93224	---	-119.57365	35.23502	Crude Oil
70	MIDWAY-SUNSET OIL FIELD, W & S LEASE	T10000007034	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	2 MILES SOUTHEAST OF DERBY ACRES (S14, T31S, R22E)	DERBY ACRES	93224	---	-119.5852	35.22457	Crude Oil
71	MIDWAY-SUNSET OIL FIELD, WEBBER LEASE	T10000006776	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	LDD ENERGY - NE ¼ SECTION 34, T30S, R22E, MDB&M	FELLOWS	93224	---	-119.59296	35.27708	Crude Oil
72	MIDWAY-SUNSET, HOYT LEASE	T10000006779	Geotracker	PRODUCED WATER PONDS	UNDER REVIEW	MIDWAY-SUNSET OIL FIELD	MARICOPA		---	-119.37986	35.05688	Crude Oil
73	POSO CREEK, POSO	T10000007301	Geotracker	PRODUCED WATER PONDS	INACTIVE - UNPERMITTED	LINN OPERATING INC - NW OF BRONZE HILL RD. & WHITE CROWN DR.	MCFARLAND	93250	---	-119.0452	35.58195	Crude Oil
74	RIO BRAVO OIL FIELD, KERNCO LEASE	T10000006733	Geotracker	PRODUCED WATER PONDS	OPEN - INACTIVE	NW OF 7TH STANDARD RD / TRANSPORT LN S1/2 OF THE NE1/4 OF SECTION 34, T28S, R25E, MDB&M	SHAFTER	93263	---	-119.2656	35.44952	Crude Oil
75	S. BELRIDGE OIL FIELD, HILL LEASE	SL0602935481	Geotracker	PRODUCED WATER PONDS	INACTIVE - PERMITTED	SEC 19, T28S, R21E, MDB&M	SOUTH BELRIDGE OIL FIELD		---	-119.7453854	35.4882413	Other inorganic, Salt
76	SOUTH BELRIDGE OIL FIELD, SOUTH WASTEWATER DISPOSAL FACILITY	SL0602990565	Geotracker	PRODUCED WATER PONDS	INACTIVE - PERMITTED	SOUTH BELRIDGE OIL FIELD	SPICER CITY		---	-119.6796305	35.46115366	Other inorganic / salt
77	VAUGHN-MIDWAY-SUNSET OIL FIELD, USL 15	T10000006813	Geotracker	PRODUCED WATER PONDS	OPEN - SITE ASSESSMENT	NORTHWEST IF MIDOIL RD / THOMAS ST	TAFT	93268	---	-119.49199	35.14231	Crude Oil

Source: DTSC Envirostor: https://www.envirostor.dtsc.ca.gov/public/ and SWRCB Geotracker: http://geotracker.waterboards.ca.gov/

2.3.4 Land Subsidence

Prior to COVID, the Kern Subbasin had been meeting with the DWR-California Aqueduct Subsidence Project (CASP) team to share KGA findings related to non-SGMA related sources of subsidence (e.g., oil field, geotechnical etc.) on the Aqueduct. These studies had been shared with the DWR SGMA Team on a separate occasion. Knowing that DWR SGMA Team and DWR CASP do not directly communicate on a staff level, the Subbasin recently held two additional meetings (July 8th and June 3rd) to bring new DWR CASP staff up to speed on the findings of KGA subsidence work conducted between 2020 and 2022. At the July 8th meeting, the CASP team expressed that they are still analyzing data for their 2022 Precise Survey Report on the California Aqueduct and as such, they were unable to provide any concrete findings or direction on potential subsidence rates for comparison to the KGA studies.

The Kern Subbasin presented an Aqueduct "white paper" (Attachment G3) to the CASP that details the proposed methodology for evaluating future subsidence rates, and the need to set interim (i.e., through 2025) MO/MTs per the direction of DWR SGMA Team. The Subbasin and DWR CASP also explored mutually beneficial studies that could be implemented between 2022 and 2025 that would address identified data gaps for both the Subbasin and DWR CASP. The CASP team indicated that they understood the white paper approach and were also evaluating non-SGMA related sources of subsidence. As an initial step, DWR CASP had held a meeting with California Department of Conservation Geologic Energy Management Division (CalGEM) to discuss how to account for those activities in their evaluations. The CASP team stated that they believe themselves to be similar to the GSAs as an infrastructure owner, and thus a participant of SGMA not a regulator.

As the Kern Subbasin moves forward, we believe significant data gaps pertaining to the various causes and rates of subsidence in the Subbasin still exist and, that if addressed, will lead to better defined management objectives for the Aqueduct and other critical infrastructure and help focus planned and future monitoring resources where they will be most effective. We also believe that working jointly and in close consultation with the CASP team would multiply the respective expertise and resources of both parties to the benefit of all those dependent on the Aqueduct.

Inelastic (irrecoverable) land subsidence (subsidence) is an undesirable result and the DWR of the Subbasin Groundwater Sustainability Plans (GSP) placed subsidence as one of the deficiencies to be further described and addressed. In response, the Subbasin has developed coordinated definitions for Subsidence Undesirable Results and Critical Infrastructure as follows:

Undesirable Results – Land Subsidence:

An undesirable result for land subsidence is defined as the point at which the amount of inelastic subsidence, if caused by Subbasin groundwater extractions, creates a significant and unreasonable impact to surface land uses or Subbasin critical infrastructure.

Critical Infrastructure – Land Subsidence:

The KCS has adopted two classifications for critical infrastructure: Regional Critical Infrastructure and Management Area Critical Infrastructure.

Regional Critical Infrastructure is defined as infrastructure located within the Subbasin that serves multiple areas of the Subbasin and whose loss of significant functionality due to inelastic subsidence, if caused by Subbasin groundwater extractions, would have significant impacts to beneficial users. The Subbasin has collectively determined that the only infrastructure that meets the definition for Regional Critical Infrastructure are the California Aqueduct and the Friant-Kern Canal.

Management Area Critical Infrastructure is defined as infrastructure located within a particular Subbasin Management Area whose loss of significant functionality due to inelastic subsidence if caused by Subbasin groundwater extractions would have significant impacts to beneficial users within that Subbasin Management Area. Each Subbasin Management Area has identified their respective Management Area Critical Infrastructure in their Management Area Plan or individual GSP.

Inelastic land subsidence has the potential to alter the land surface in ways that could increase flood risk in low lying areas; and damage well casing, canals, and other linear infrastructure. This section summarizes land subsidence data collected within the Subbasin and discusses documented impacts and potential impacts of land subsidence in or near the Subbasin.

Historically, it was commonly believed that the principal cause of subsidence in the Subbasin was groundwater extraction for agriculture and municipal use. However, recent separate subsidence studies conducted by the Westside District Water Authority (WDWA) and the KCS have found that the underlying causes of subsidence in the Subbasin are more complex and likely include several interrelated contributing factors. Chief among these are groundwater extraction for beneficial use, oilfield activities, geotechnical conditions related to the disparate types of soil native to the Subbasin, and natural settlement of critical infrastructure. None of the subsidence modes besides groundwater extraction for agricultural and other Management Area uses are within the control of Subbasin GSAs.

2.3.4.1 Processes Leading to Land Subsidence

Inelastic compaction or land subsidence occurs in the fine-grained beds of the aquifer system. Clays and silts, although not very permeable, are typically highly porous. In many of these fine-grained layers, pore spaces are supported by water at the time of deposition. This water is essentially groundwater storage to the Subbasin, although the majority of it is a component of inelastic storage, and therefore, it is not reusable. During over-pumping conditions, groundwater is pumped from pore spaces between grains of sand and gravel. Once the aquifer system is pumped beyond the sustainable yield, the lowered water pressure in the sand and gravel causes slow drainage of water from the clay and silt beds. The subsequent release of water and water pressure from the clay and silt beds result in compaction (the beds become thinner) as clay particles supported by water in pore spaces rearrange and collapse. Groundwater cannot re-enter the clay structure after the collapse. This condition represents a permanent loss of the water storage volume in the clay layers. The effects of compaction are also seen as a lowering of the land surface, otherwise known as land subsidence

The WDWA recently completed the WDWA Subsidence Review (2020) and found that oilfield activities have also contributed to subsidence. Oilfields on the west side of the Subbasin extract oil and produced water from some of the same aquifers used for beneficial use elsewhere in the Subbasin. The WDWA determined that oilfield pumping has resulted in impacts to regional critical infrastructure such as the California Aqueduct between Mileposts 195 to approximately Milepost 215. The Subbasin has identified other areas that are likely experiencing oilfield-induced subsidence. These areas will be the subject of future studies.

2.3.4.2 Lawrence Berkeley National Laboratory Subsidence Study

The Lawrence Berkeley National Laboratory (LBL) Subsidence Study was undertaken in order to determine the baseline rate of subsidence in the Kern County Subbasin for the study period (2015-2021). Study data was also compared to the March 2021 Differential Interferometric Synthetic Aperture Radar (DInSAR) Study conducted by Earth Consultants International (ECI) on behalf of the KGA and other GSAs in the Kern Subbasin. This study determined that the data from the ECI study was in reasonable scientific agreement with the LBL Data.

For comparison, and to understand yearly variations, the cumulative line-of-sight displacement and the yearly displacement rates were determined for a roughly seven-year interval extending from early 2015 until late 2021. These values will be used in a follow-on study to better assess the vulnerability of critical infrastructure within the subbasin. These include, but are not limited to, gravity-driven surface water delivery systems, of which the primary regional conveyance structures are the California Aqueduct (Aqueduct) and the Friant-Kernel Canal (FKC). Due to varying processes within the sub-basin, which include groundwater pumping for agricultural, industrial, and oil and gas extraction, the basin will be further sub-divided into eastern, western, southern, and central regions as shown in Figure 2-40 and the maximum, minimum, and mean subsidence will be computed for each area.

The west region of the Subbasin is distinguished by extensive areas of open range land and oil field operations interspersed with cultivated lands. Much of the Westside has no significant current or planned groundwater use because of naturally poor water quality due to the presence of marine sediments and saline connate water. As such, surface water deliveries from the State Water Project via the Aqueduct are a primary source of water for agriculture. Significant volumes of oil field produced water are generated in the west region. Produced water is a by-product of oil production common to almost all oil fields in the KCS. Produced water is exempt from SGMA, and therefore outside of the control of the KGA or other GSAs in the Subbasin.

The southern region is characterized by a mixture of land uses including agriculture, urban development and oil field operations. SGMA related groundwater extractions include industrial, municipal and agriculture. The southern region also receives surface water delivered by the Aqueduct. The eastern region is bounded by the FKC on the west and the foothills of the Sierra-Nevada Range on the east. It encompasses both agriculture use and oil field activities. Groundwater quality is generally good in this area and is utilized for various SGMA related purposes (e.g., municipal, agriculture, industry). Deliveries of surface water via the FKC is a primary source of water for agriculture, although not all growers have access to FKC water.

The central region of the Subbasin is characterized by widespread agricultural activity, interspersed with municipal and industrial uses. Scattered oilfield operations are also present. The central region is particularly susceptible to land subsidence caused by groundwater extraction. This is due to the presence of extensive and layers of clay (e.g. Corcoran Clay) and other fine grained sediments in the subsurface. The sources of water include groundwater, and surface water deliveries from the Aqueduct and FKC.

The summarized results of the LBL study for the period 2015 to 2021 are provided in the Table 2-6.

Table 2-6. Summary of Results of the LBL Study for the Period 2015 to 2021

Region	Description	Subsidence Rate (inches/year)
Entire Region	Mean yearly rate	-0.440
	Minimum yearly rate	+0.046
	Maximum yearly rate	-1.111
Central Region	Mean yearly rate	-0.654
	Minimum yearly rate	+0.064
	Maximum yearly rate	-1.791
Southern Region	Mean yearly rate	-0.361
	Minimum yearly rate	+0.265
	Maximum yearly rate	-0.838
Eastern Region	Mean yearly rate	-0.356
	Minimum yearly rate	+0.281
	Maximum yearly rate	-0.811
Western Region	Mean yearly rate	-0.365
	Minimum yearly	+0.265
	Maximum yearly rate	-0.984

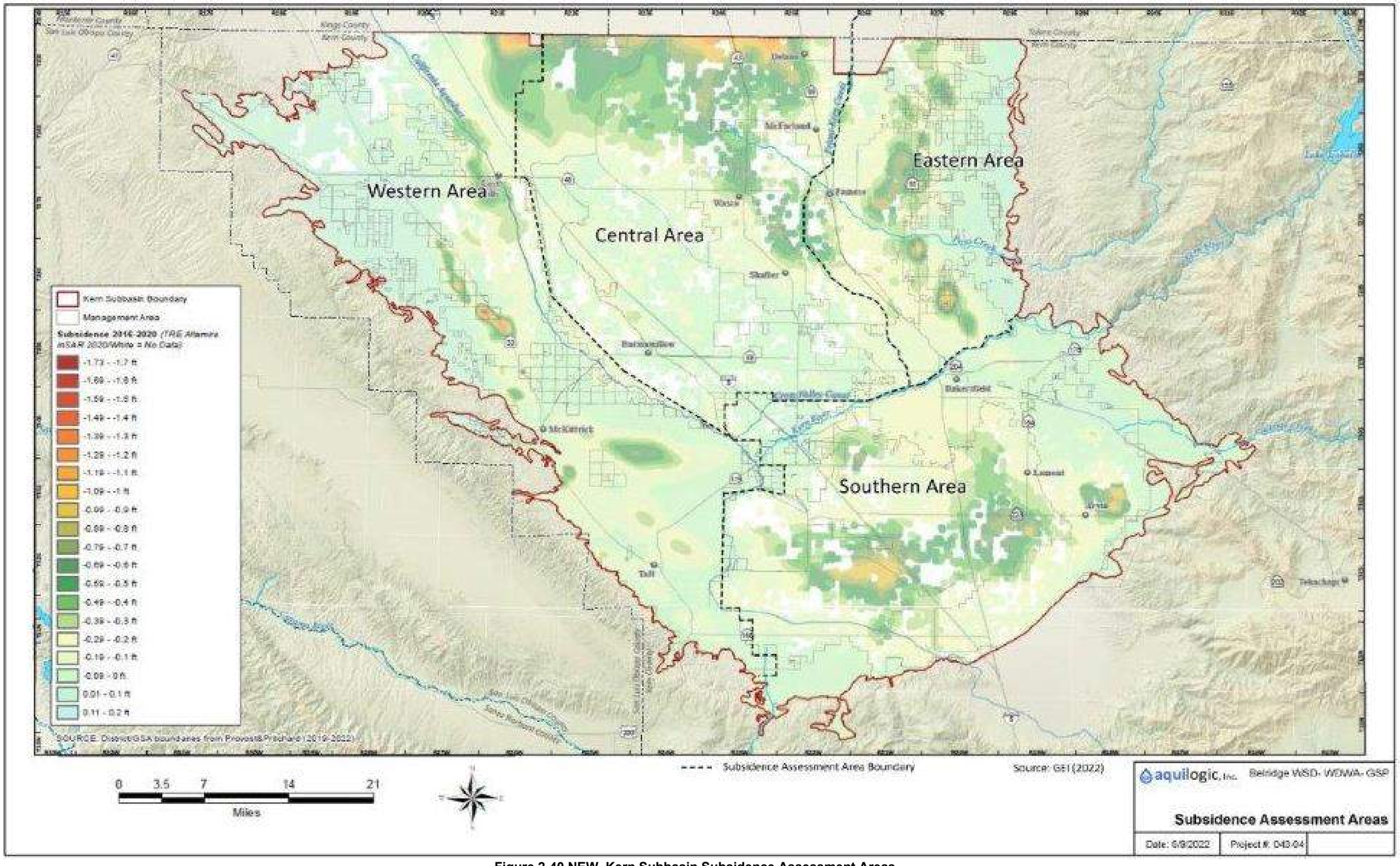

Figure 2-40 NEW. Kern Subbasin Subsidence Assessment Areas

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2.3.4.3 Regional Critical Infrastructure

Some types of large-scale linear infrastructure such as concrete-lined canals, can be susceptible to the regional subsidence caused by groundwater withdrawal. When subsidence rates are not equal across a region, differential compaction can occur. This differential compaction or subsidence may result in the formation of new low-lying areas for which canal designs have not taken into account. Newly formed low-lying areas are what impact large-scale linear infrastructure such as canals; often reducing freeboard and capacity. Examples of infrastructure that have been impacted by subsidence in the Southern San Joaquin Valley include the Friant-Kern Canal and California Aqueduct. The LBL study concluded that given the current rates of subsidence on buried infrastructure, like pipelines, would not experience significant adverse effects provided "hinge line" factors (i.e., stream crossings, faults, and changes in elevation etc.) were minimal. Figures 2-41 and 2-42 show Subbasin infrastructure and recent JPL InSAR data for October 2020 through 2021. Figure 2-43 shows the Identified Regional Critical Infrastructure within the Kern Subasin.

Friant-Kern Canal Subsidence impacts have been well documented to the north of the Subbasin in an approximate 18 mile stretch from Milepost 102.7 through 121.5, centered around Deer Creek (FWA, 2019). Subsidence was roughly 12 feet of the original design elevation, including 3 feet of subsidence from 2016 to 2019. Due to land subsidence the canal's water delivery capability has been reduced by nearly 40 percent of its original capacity, Class 2 contractors have suffered nearly 60 percent reduced capacity (FWA, 2019). Within the Subbasin, the FKC has experienced a few inches of subsidence near Poso Creek (Mileposts 127 to 137).

A recent InSAR study conducted by the Subbasin determined that subsidence was historically overestimated by previous JPL InSAR studies in the Subbasin. The exact cause of subsidence near the Friant-Kern Canal in the Subbasin is therefore the subject of ongoing study. As a first step, recently acquired grant funding will be utilized to install new extensometers to improve the quality and quantity of data necessary to establish future sustainable management criteria in close consultation with the DWR, Friant Water Authority, and other key stakeholders.

California Aqueduct

The March 2019, *California Aqueduct Subsidence Study: Supplemental Report* prepared by the Department of Water Resources California Aqueduct Subsidence Project (DWR-CASP) provided much substantive data on the Aqueduct that will be useful for ongoing and future planning by the various GSAs) within the Subbasin. The report also identified several Aqueduct pools within the Subbasin as areas of concern because of diminished operational capacity due to subsidence. Perhaps the most prominent of these areas are located between Aqueduct milepost (MP) 195 and 215, and MP 267 and 271. Historically, it was commonly believed that the principal cause of subsidence in the Subbasin and Central Valley at large was groundwater extraction for agriculture and municipal use. However, recent separate subsidence studies conducted by the Westside Districts Water Authority (WDWA) and the KCS have found that the underlying causes of subsidence in the KCS are more complex and likely include several interrelated factors. Chief among these are groundwater extraction for beneficial use, oilfield

activities and geotechnical conditions related to the disparate types of soil native to the KCS, and natural settlement of the 60 year old Aqueduct.

Two segments of the Aqueduct were raised in 1989 and 1996 in Kern County. The first between MP 194.94 and 197.05 (T25S-R20E) in 1989, and the second between MP 206.10 and 207.94 (T27S-R21E). In general, this northwest portion of the basin is far from the main groundwater production in the central part of the Subbasin. A recent study conducted by the WDWA determined that subsidence between Mileposts 195 and Milepost 215 is attributed to oilfield extraction activities and not agricultural pumping. A separate Subbasin-wide InSAR study determined that previous JPL InSAR studies likely overestimated the rate of subsidence in the Subbasin. These data were shared with DWR and DWR-CASP. Future studies by the Subbasin along the Aqueduct are planned.

At the time of the submittals on January 31, 2020, the Subbasin GSPs expressed that significant data gaps existed with regard to the differing causes of subsidence that may be unique to each of the five subsidence areas of interest identified in the Subbasin. This lack of representative data precluded setting meaningful data-based sustainable management requirements until additional data was obtained. In the intervening 18 months since submittal of the Subbasin GSPs in 2020, the Subbasin has made progress in acquiring the data necessary to set sustainable management criteria. This work includes (some completed and other ongoing) the two aforementioned WDWA and Subbasin studies, retaining the Lawrence Berkeley National Laboratory (LBNL) to perform a baseline subsidence and infrastructure status assessment of the Aqueduct and other critical infrastructure in the Subbasin, preparing a revised basin study and the planned installation of additional subsidence monitoring sites in consultation with the DWR-CASP and the Friant Water Authority (FWA).

Based on the data from the WDWA and Subbasin investigations, it is apparent that key data gaps pertaining to the various causes and rates of subsidence in the Subbasin still remain and that further study is needed to better define realistic management objectives for the Subbasin. To this end, in addition to the LBNL study, the KCS will install extensometers, near the Friant-Kern Canal, and work in close consultation with DWR-CASP and Friant Water Authority to update and interpret new InSAR and oilfield data. In addition, the Subbasin is in the process of preparing an updated basin study. The Subbasin has also committed to working cooperatively with the DWR- CASP and the FWA in the planning and installation of other geodetic-based monitoring technology in the Subbasin. The goal of the ongoing studies is to: 1.) more fully quantify the individual causes of subsidence, and 2.) establish data-based subsidence MOs/MTs for Subbasin critical infrastructure and individual management area critical infrastructure as appropriate.

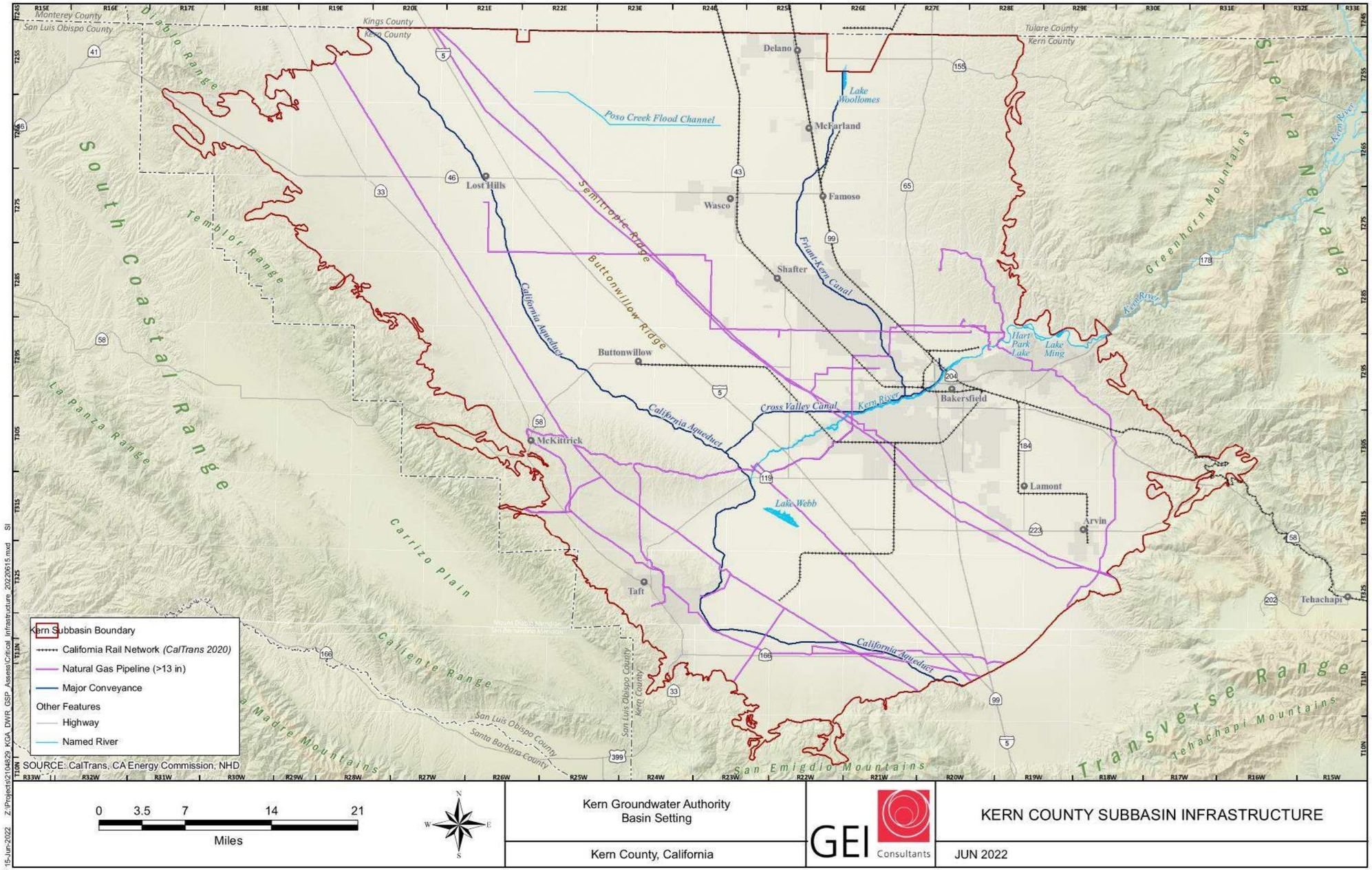

Figure 2-42 NEW. Potentially Impacted Regional Critical Infrastructure.

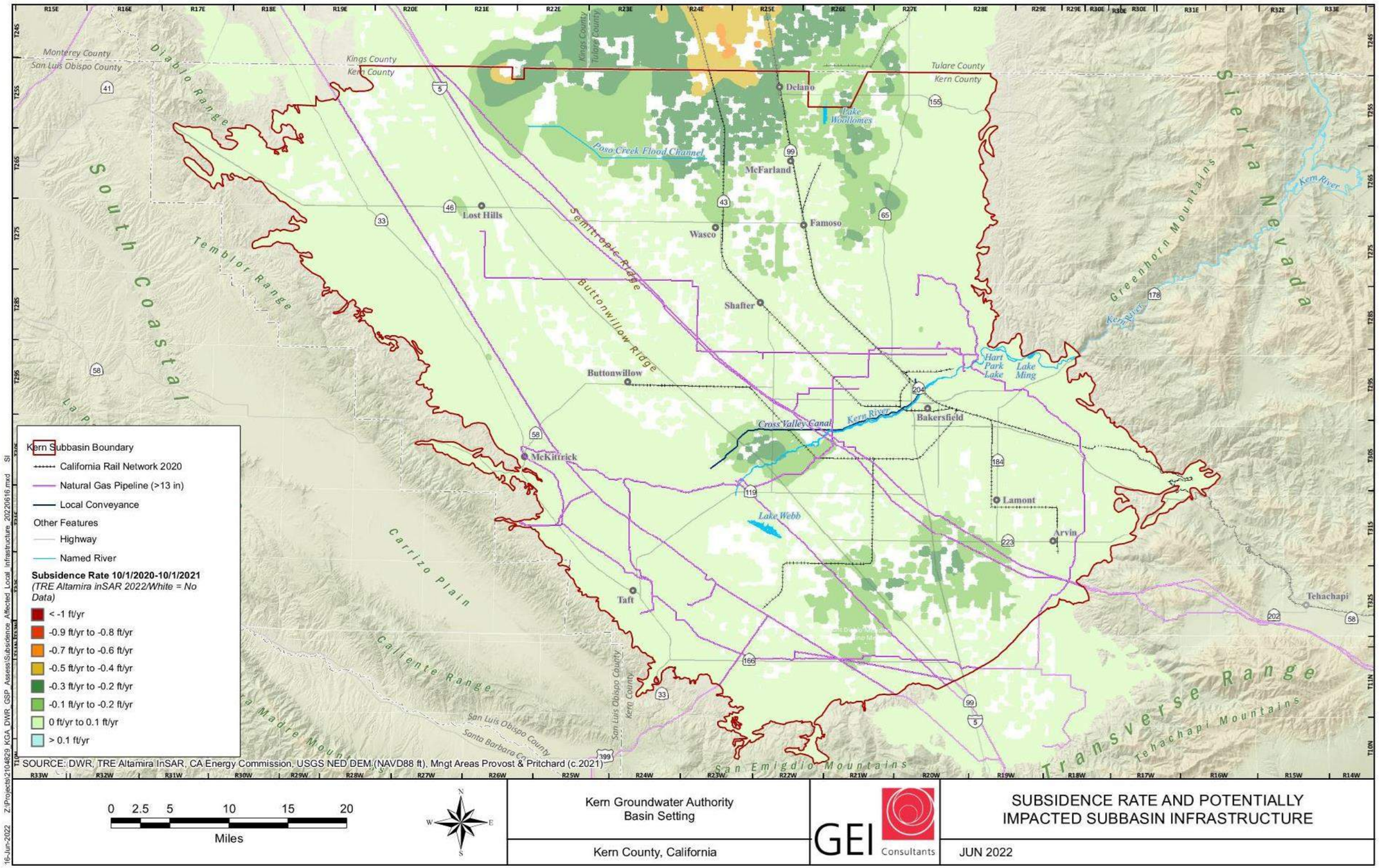

Figure 2-43 NEW. Potentially Impacted Regional Critical Infrastructure with Subsidence Rate.

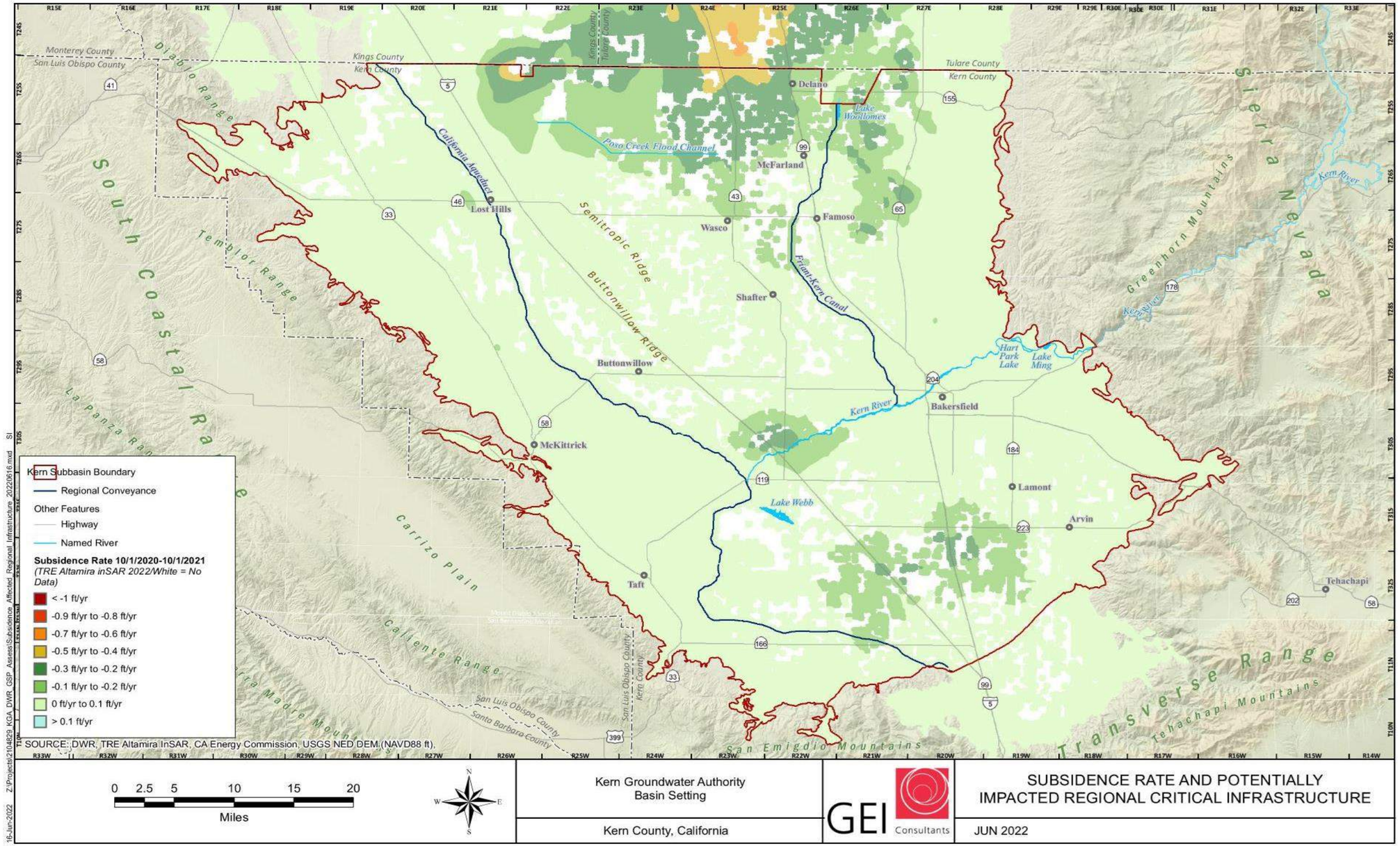

Figure 2-44 NEW. Identified Regional Critical Infrastructure with Subsidence Rate.

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Recognizing the wide variability in geologic, geotechnical and extraction activities present in the Subbasin, the Subbasin has developed two separate but coordinated methodologies for determining MOs and MTs for Aqueduct and the Friant-Kern Canal. The metric common to each of the methodologies is the amount of concrete liner freeboard in an area of interest and its relationship to operational capacity of the infrastructure. These methodologies, along with the aforementioned ongoing studies, will serve as the foundation for the development of future MOs and MTs in consultation with the DWR-CASP and the FWA.

2.3.4.4 Fault Movement

Within the Subbasin, Pond-Poso Fault movement has been detected during dry years. Although the impact to infrastructure is unknown, Holzer (1980) observed fault movement along the Pond-Poso Fault from February 1977 to March 1979. This fault movement was observed during seasons of water level decline, and Holzer concluded that 9 inches of offset had occurred along the Pond-Poso Fault System since the 1950's. In addition, Holzer (1980) observed that fault offset of groundwater levels was greater during dry years when the lowest seasonal water level low occurred.

2.3.4.5 Impacts to Well Casing

Just north of Subbasin, near Los Banos-Kettleman City, Wilson (1968) documented well casing failures attributed to land subsidence. Wilson reported that during 1950-1961 wells that were screened primarily below the Corcoran Clay experienced screen failures associated with compaction or land subsidence.

2.3.4.6 Degraded Water Quality

Degradation of water quality due to land subsidence has been studied in the San Joaquin Basin to the north of the Subbasin. Smith et. al. (2018), hypothesizes that poor water quality in clays may be released to the aquifer system during over pumping and compaction of clays. Specifically, data north of the Subbasin in the San Joaquin Valley may indicate that areas with a thicker Corcoran Clay extent have seen an increase in arsenic concentrations as subsidence rates have increased due to over pumping (Smith et. al., 2018).

2.3.4.7 Land Subsidence Monitoring

Historical documentation of subsidence has relied on various types of data, including ground surveys, declining groundwater levels, and borehole extensometers. Recent subsidence studies have relied on ground surveys, borehole extensometers, continuous GPS stations, and remote sensing (InSAR) to collect data.

Each method has advantages and drawbacks. An extensometer measures a discrete subsurface interval, or typically the interval of the ground surface to the total depth of the extensometer. On the other hand, CGPS and InSAR monitor overall change in ground surface relative to a datum such as sea level, regardless of the depth interval. Moreover, InSAR provides information over a

wide area, and when processed carefully, is extremely accurate, especially when coordinated with land-based CGPS.

2.3.4.8 Remote Sensing

Within the Central Valley, and in particular the Subbasin, researchers have utilized remote sensing techniques such as satellite-based Interferometric Synthetic Aperture Radar (InSAR) and aircraft-based L-band SAR or Unmanned Aerial Vehicle Synthetic Aperture Radar (UAVSAR). These surveys have been led by the National Aeronautics and Space Administration (NASA) and Jet Propulsion Laboratory (JPL), as well as other international researchers. The benefit of remote sensing is that large areas of land can be surveyed with no invasive actions or land surface access complications. DWR has commissioned studies (TRE Altamira, 2019) to evaluate the accuracy of remote sensing and identify additional processing and calibration methods for accuracy.

The following is a summary of recent remote sensing findings with respect to the TRE Altamira report:

- InSAR data with nearby UNAVCO CGPS have been processed and calibrated for northern Kern County Subbasin to the north of Visalia using the TRE Altamira-patented method SqueeSAR.
- InSAR calibration by TRE Altamira reports accuracy to 20 mm (0.07 feet) at 95% confidence interval.
- The calibration points include UNAVCO CGPS points (subsidence results as great as 8 inches over the time period of 2015 to 2018).
- Other points in the SOPAC network including Corcoran and Lemoore stations were not included in calibration; however, Ojha et al (2019) demonstrated that LEMA Lemoore and CRCN Corcoran (high subsidence areas) (at least 50 inches of subsidence between 2015 to 2018) may correlate well with InSAR.

Filling data gaps in the San Joaquin Valley with high subsidence areas lacking calibration monitoring points such as CGPS may be beneficial for future remote sensing work and calibration.

2.3.4.9 Historical Subsidence Results

Within the Subbasin, subsidence has been documented from leveling by the National Geodetic Survey at up to 12 feet from 1926 to 1970 (Ireland et al., 1984). USGS estimates that about 75 percent of the subsidence occurred in the 1950s and 1960s, corresponding to extensive groundwater development (Galloway, et al., 1999). Water levels during this period were continuing to fall to historic lows each year, for the first time, which were associated with larger amounts of subsidence (Todd, 2017).

Subsidence was also measured by USGS borehole extensometers in the west Subbasin from 1978 to 1983 (26S/23E-16H2 and 16H3) and to the south of Bakersfield from 1963 to 1978 in

Extensometer 32S-28E-20Q1). These two extensometers have since been abandoned; however, a couple new extensometers have been installed in the Subbasin.

2.3.4.10 Recent Subsidence Results

A comprehensive Differential InSAR study conducted by Earth Consultants International (ECI) (2021) (Attachment E1) on behalf of the Subbasin determined that previous InSAR studies by others may be overestimating subsidence rates by a significant factor (45 to 50 percent) within the Subbasin. It is believed that this discrepancy is the result of the short time intervals related to the acquisition of available InSAR data in the previous studies. To mitigate this condition ECI recommended that future Subbasin InSAR studies include a minimum time interval of five years' worth of InSAR data to enhance data resolution and accuracy. The vertical resolution of the Subbasin study was approximately 2.4 millimeters per year (mm/yr) and was ground-truthed with land-based GPS data. Examples of data from the ECI study versus previous studies is provided here.

- Friant-Kern Cana Mileposts 120-130 (AOI-1). Previous InSAR monitoring had detected up to five inches per year of subsidence in areas surrounding this segment of the Friant-Kern Canal. The ECI study found the rate of annual subsidence to average between two and three inches.
- Aqueduct Mileposts 196 to 215 (AOI-2). A separate study by the WDWA in 2019 and early 2020 identified Lost Hills Oilfield activities as the contributing cause of identified subsidence. The ECI study found that subsidence along this segment displays the characteristics of oil field activities, and that the area is isolated by areas of generally lower subsidence, suggesting that agricultural groundwater extraction is minimal in this area.
- Friant-Kern Canal Mileposts 130 to 137 (AOI-3). The ECI study estimated annual subsidence rates at around two to three inches. This rate is similar to that for AOI 1.
- Aqueduct Mileposts 267 to 271 (AOI-4). The ECI study estimated annual subsidence in this area to be approximately one to two inches. Previous studies reported subsidence as being between two and four inches.
- North Boundary of Subbasin (AOI-5). A review of the subsidence rate for 2015-2016 presented in the JPL/NASA data indicates this area experienced between five and eight inches of subsidence. Data from the ECI study found the average rate of subsidence for the period between April 2015 and September 2020 was much lower at approximately two to four inches.

More recent DWR data now seems to correlate with the ECI data, and LBL InSAR data was concluded to be in reasonable agreement with the ECI data. The KGA and its members recognize InSAR is a valuable tool, in conjunction with ground-based geodetic technology, for assessing subsidence in relation to Subbasin identified critical infrastructure. To ensure the best suite of technologies and methodology are brought to bear on subsidence affecting Subbasin critical

infrastructure, the Subbasin will reassess both the methodology for determining the current interim MOs/MTs and the infrastructure specific MO/MT levels in 2025.

2.3.4.11 Annual Rate of Subsidence

The following tabulated summary data includes cumulative inches of subsidence within Subbasin, and a calculated approximate annual rate for the time period for the data collection period. As discussed above the InSAR data in this Table 2-7 may be overestimating subsidence by a significant factor (approximately 45% to 50% over estimation).

Table 2-7 Land Subsidence Data

Subbasin Area	Date Range	Cumulative Subsidence (inches)	Calculated Annual Rate of Subsidence (inches/year)	Source
Historical Range in the Subbasin	1926 - 1970	12 - 96	~ 0.3 - 2.2	Ireland, 1984. Topographic Maps and Leveling Data.
North Central Subbasin	1978 - 1983	-0.04 – 1.5	-0.001 – 0.03	Extensometer 26S/23E-16H2 and -H3, USGS
South of Bakersfield	1963 – 1977	23.3	~0.14	Extensometer 32S-28E-20Q1, USGS
North and West Subbasin	2005 - 2017	0.1 – 11.7 0.2	~0 – 1.3	CGPS PBO. (BVPP, P544, P545, P563, P564, P565).
South Central Subbasin	2006-2016	9.8 - 11.5	~1.1	CGPS (BKR1/BKR2, ARM1)
West Subbasin and South of Bakersfield	Jan. 2007 – Mar. 2011	6.0	~1.4	LSCE, 2014. Compiled from InSAR.
North Central Subbasin	Dec. 2013 – Mar. 2018	3.2	~0.8	SWSD Extensometer 25S22E35B001M
Central Subbasin	July 1994 - June 2018	-3 (negative value indicates uplift)	Not Presented Here.	Kern Fan Extensometer 30S/25E-16L According to AECOM (2016), data from extensometer show “little response to changes in water level changes during recharge or recovery operations.”
Southwest Subbasin along California Aqueduct	Apr. 2014 – Jan. 2015	0.5 - 5	~0.7 – 6.7	UAVSAR. InSAR Canadian Radarsat-2 (Farr et al., 2015)
North Central Subbasin	May 2015 – Sep. 2016	~1 - 12	~1.3 – 9.2	InSAR ESA Sentinel-1A (Farr et al., 2016)
Southwest Subbasin along California Aqueduct	Apr. 2014 – Jun. 2016	0 - 16	~0 – 7.4	UAVSAR (Farr et al., 2016)

2.3.4.12 Map of Subsidence Locations

Historic JPL InSAR data (Figures 2-44 to 2-48) is provided for context and comparison to Figures 2-49 and 2-50 which shows the recent subsidence rate in the Kern Subbasin from

California Groundwater Live website. Analysis of historic JPL InSAR data by ECI as part of their 2021 InSAR Study concluded that the JPL data may be over estimating subsidence rates by 40 to 50% in areas with seasonal groundwater withdrawals. A subsequent study conducted by the Lawrence Berkeley Laboratory (LBL) concluded that their subsidence rate for various ports of the Kern Subbasin were in reasonable agreement with the ECI data. The data in Figure 2-49 and 2-50 provides more current InSAR data reported by DWR on the California Groundwater Live website which appears to comport with ECI and LBL findings.

2.3.4.13 Data Gaps in Subsidence Understanding

Based on the data gathered through recent investigations, it is apparent that key data gaps pertaining to the various causes and rates of subsidence in the Subbasin still remain and that further study is needed to better define realistic management objectives for the Subbasin. To this end, in addition to the LBNL study, the Subbasin will install extensometers, near the FKC, and work in close consultation with DWR-CASP and Friant Water Authority to update and interpret new InSAR data. In addition, the Subbasin is in the process of preparing an updated basin study. The Subbasin has also committed to working cooperatively with the DWR- CASP and the FWA in the planning and installation of other geodetic-based monitoring technology in the Subbasin. The goal of the ongoing studies is to: 1.) more fully quantify the individual causes of subsidence, and 2.) establish data-based subsidence MOs/MTs for Subbasin critical infrastructure and individual management area critical infrastructure as appropriate.

There are data gaps in land subsidence that will be considered for future data collection. These data gaps include subsidence monitoring along points of critical infrastructure such as the Friant Kern Canal and California Aqueduct.

As described herein, there are a valuable dataset of CGPS monitoring points with which to pair water level monitoring data; however, InSAR data show that many of the CGPS points are not in zones of high subsidence, nor adjacent to critical infrastructure. Therefore, CGPS points alone are useful as quality control points, but they are likely not situated in areas of high subsidence or near critical infrastructure to facilitate decision making on sustainable management criteria.

InSAR is a dataset that may be able to fill the gaps between CGPS points. Continued InSAR data collection over appropriate time intervals as recommended by ECI and LBL can fill the temporal data gap in the record. Correlations between CGPS and InSAR could confirm InSAR results in high subsidence areas near Subbasin, as they have been demonstrated in low subsidence and other areas (Tre Altamira, 2019; and Ojha et al, 2019, ECI 2021).

As the water level monitoring network is established in the Subbasin, collocated temporal water level data with CGPS data can be collected to evaluate the relationship between active subsidence and residual subsidence with respect to water level change over time. The understanding of residual subsidence will better inform sustainable management criteria for setting thresholds.

2.3.4.13.1 Work in Progress

At the June 17, 2022, meeting with DWR, the Kern Subbasin presented the findings of two important subsidence studies conducted subsequent to the January 2020 submission of the Subbasin groundwater sustainability plans (GSP). Both subsidence studies indicate that groundwater extractions under the purview of SGMA are not the sole cause of historical subsidence. The studies also identified that significant additional data is required to fully understand the dynamics of subsidence, its impacts on critical infrastructure including the California Aqueduct and the Friant-Kern Canal, and whether such impacts can be influenced by groundwater management as altered by future projects and management actions.

Based on the presentation of data, the Kern Subbasin Groundwater Sustainability Agencies (GSAs) expressed concern with setting SMCs where significant data gaps exist. The Kern Subbasin GSAs understand that DWR has addressed the issue of data gaps in the Monitoring Networks and Identification of Data Gaps Best Management Practice warning that "Data must be of sufficient quality to enable scientifically defensible decision." (Monitoring Networks and Identification of Data Gaps Best Management Practice, page 27.)

DWR SGMA staff understood the data provided by the Kern subbasin and appreciated the challenge of setting sustainable management criteria in the face of data gaps. However, DWR stated substantial compliance with the requirements of the Sustainable Groundwater Management Act (SGMA) requires the development of interim SMCs for subsidence and DWR SGMA staff stated that the setting of the SMC can include caveats. Therefore, the Kern subbasin will proceed with the development of interim sustainable management criteria for subsidence with the following caveats which may not be inclusive.

- The sustainable management criteria can be interim, and will be updated in the 2025 GSP update;
- Due to the complexity of the Kern Subbasin, setting of an interim SMC for subsidence, does not require GSAs take responsibility, manage, regulate or otherwise be liable for impacts resulting from actions outside the authority of the GSA or outside the GSA's ability to manage sustainability under SGMA; and
- That the Kern Subbasin GSAs are not responsible for addressing subsidence caused by activities outside of the jurisdiction of SGMA i.e., extractions from exempt aquifers, or caused by activities other than extraction of water on behalf of the beneficial users under the purview of SGMA.

The SMCs for subsidence described in the remainder of this white paper were developed with consideration of these caveats.

2.3.4.13.2 CA Aqueduct

As the Kern subbasin moves forward, we believe significant data gaps pertaining to the various causes and rates of subsidence in the KCS still exist and, that if addressed, will lead to better defined management objectives for the Aqueduct and help focus planned and future monitoring

resources where they will be most effective. We also believe that working jointly and in close consultation with the DWR-CASP team would multiply the respective expertise and resources of both parties to the benefit of all those dependent on the Aqueduct. The Kern subbasin has been meeting with the CASP team since 2019 to move forward this concept of joint cooperation to develop data-based management objectives and future sustainable management criteria. As such, the Kern Subbasin and DWR CASP have agreed, as proponents for the sustainable management of the Aqueduct, to continue to work collaboratively to assess the causes and potential solutions to subsidence on the Aqueduct.

2.3.4.13.3 Friant-Kern Canal

Kern Subbasin is in contact with the FWA and will continue to work with FWA on filling data gaps as well as coordinate on a monitoring network. The FWA (in conjunction with the Bureau of Reclamation) is developing a proposed a system-wide Friant-Kern Canal Capacity Correction Program (Program). Both entities have already begun the correction phase of the Middle Reach, which experienced significant capacity loss (over 60%) as a result of regional subsidence. The proposed Program includes identifying impacts to water supplies from the loss of flow capacity in the Lower Reach. Several Kern Subbasin representatives are involved in the Program and will continue to monitor the Program with respect to SGMA compliance and implementation.

2.3.5 Interconnected Surface Water Systems

Interconnected surface water systems are surface waters that are hydraulically connected by a continuous saturated zone to an underlying aquifer 23-CCR § 351(o). Within the Subbasin, there are no interconnected natural surface water systems in monitored areas associated with the pumping zone of the regional aquifer system.

The following are naturally occurring surface water bodies within the Subbasin:

- Kern River: Flows within the Subbasin (located within the Olcese and Kern River GSAs) are a function of hydrologic conditions in the Kern River watershed and regulation by Isabella Dam and Reservoir; and
- Poso Creek and other minor streams: Streamflow is unregulated and is ephemeral within the Subbasin, principally occurring during “wet” months of “wet” years.

Other surface water bodies, such as the Buena Vista Aquatic Recreation Area lakes, are situated in former basins of natural surface water bodies but are now dependent on managed water deliveries.

Since the advent of groundwater pumping in the Subbasin and subsequent impoundment and regulation of flow of the Kern River, groundwater levels near the river are no longer connected with the riverbed by a continuous saturated zone. Water quality data suggest that some portion of the recharge to the principal water-bearing aquifer underlying the far eastern portion of the Subbasin (the Olcese Sand Aquifer) may come from percolation of Kern River surface water via seepage through the Kern Gorge Fault and/or through the overlying shallow alluvium. However, such recharge occurs independent of groundwater production in the principal aquifer, and there is

no known pumping from the shallow alluvium zone itself. Thus, there is no interconnected surface water under the influence of groundwater pumping in the principal aquifer in this area and no impacts to interconnected surface water have been observed.

The observation that there are now no interconnected surface water systems in the Subbasin is reflected in the aquifer characterization found in locally developed groundwater models. For example, groundwater levels in the Kern Delta Water District Superposition Model are indicated to be disconnected from the Kern River and other simulated streams (Todd, 2017). See the Kern River GSA GSP, which addresses in more detail the lack of interconnected surface water around the Kern River bed, as the area in around the Kern River bed is located within the jurisdiction of the Kern River GSA. The information below, as required by GSP regulations, is provided for completeness of the KGA GSP basin setting, however, for a more detailed discussion of interconnected surface water systems related to the Kern River, see the Olcese and Kern River GSAs GSPs, as the Kern River is outside of the jurisdictional area of the KGA.

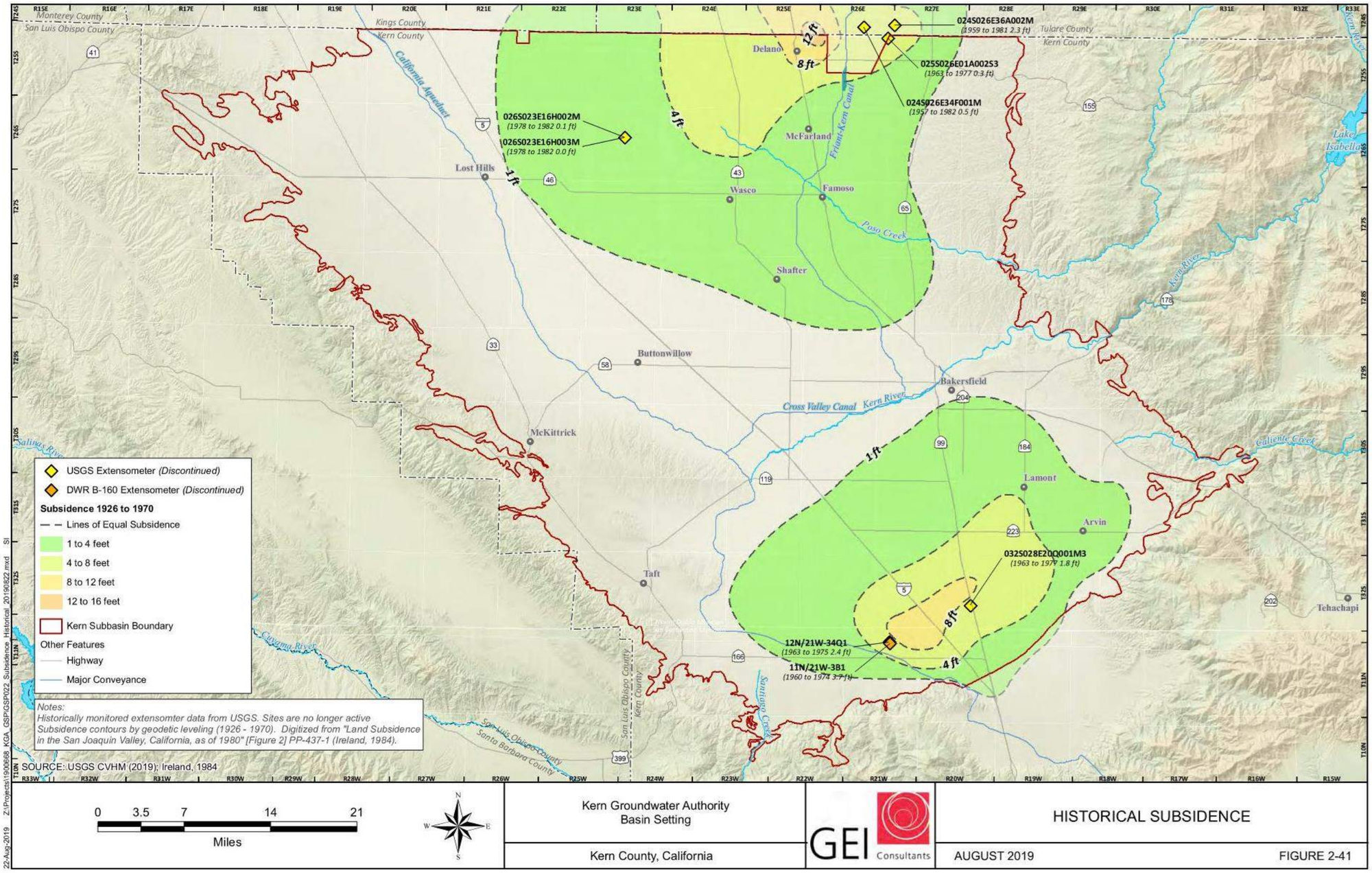

Figure 2-44. Historical Subsidence

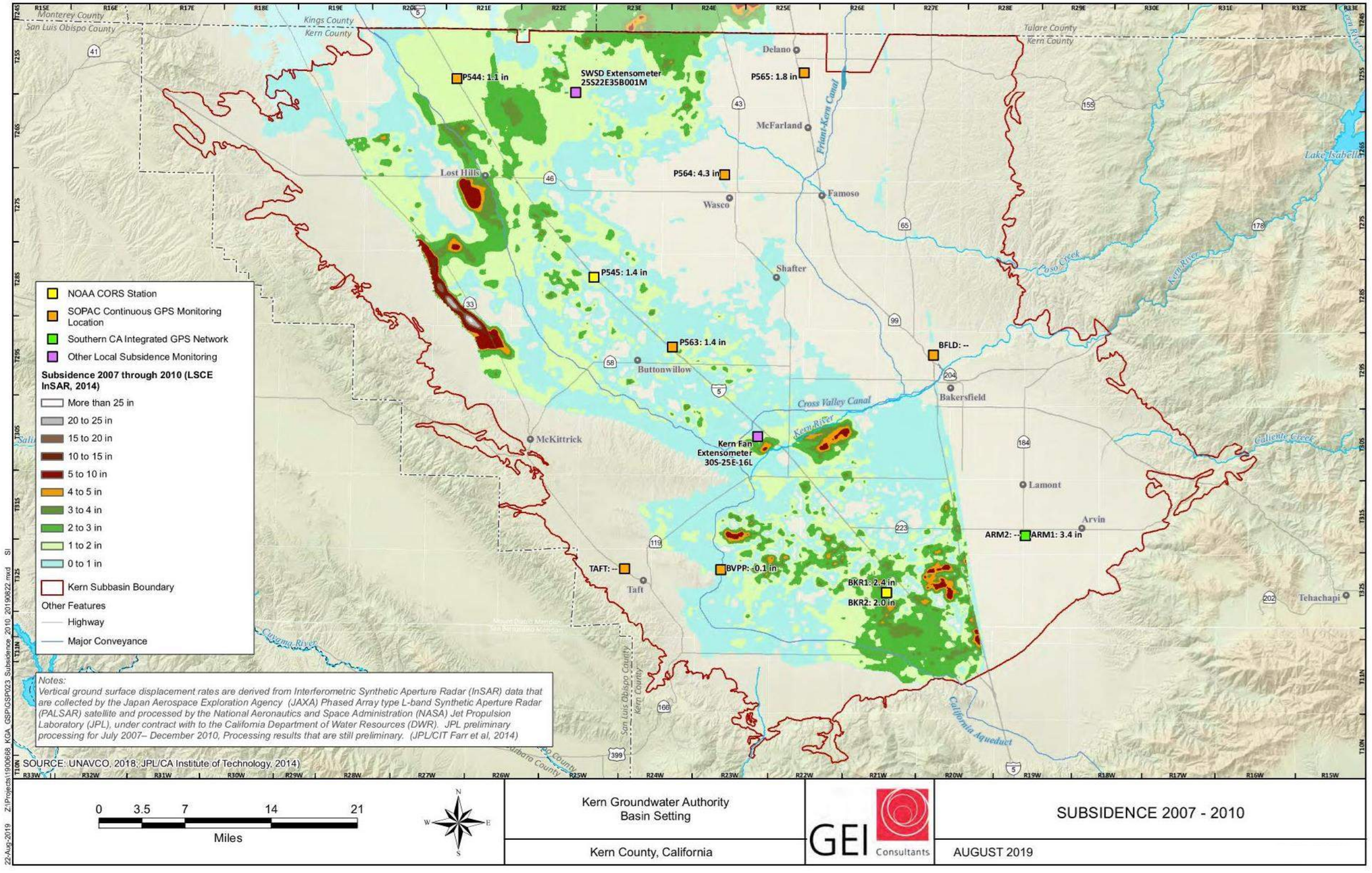

Figure 2-45. Subsidence 2007-2010

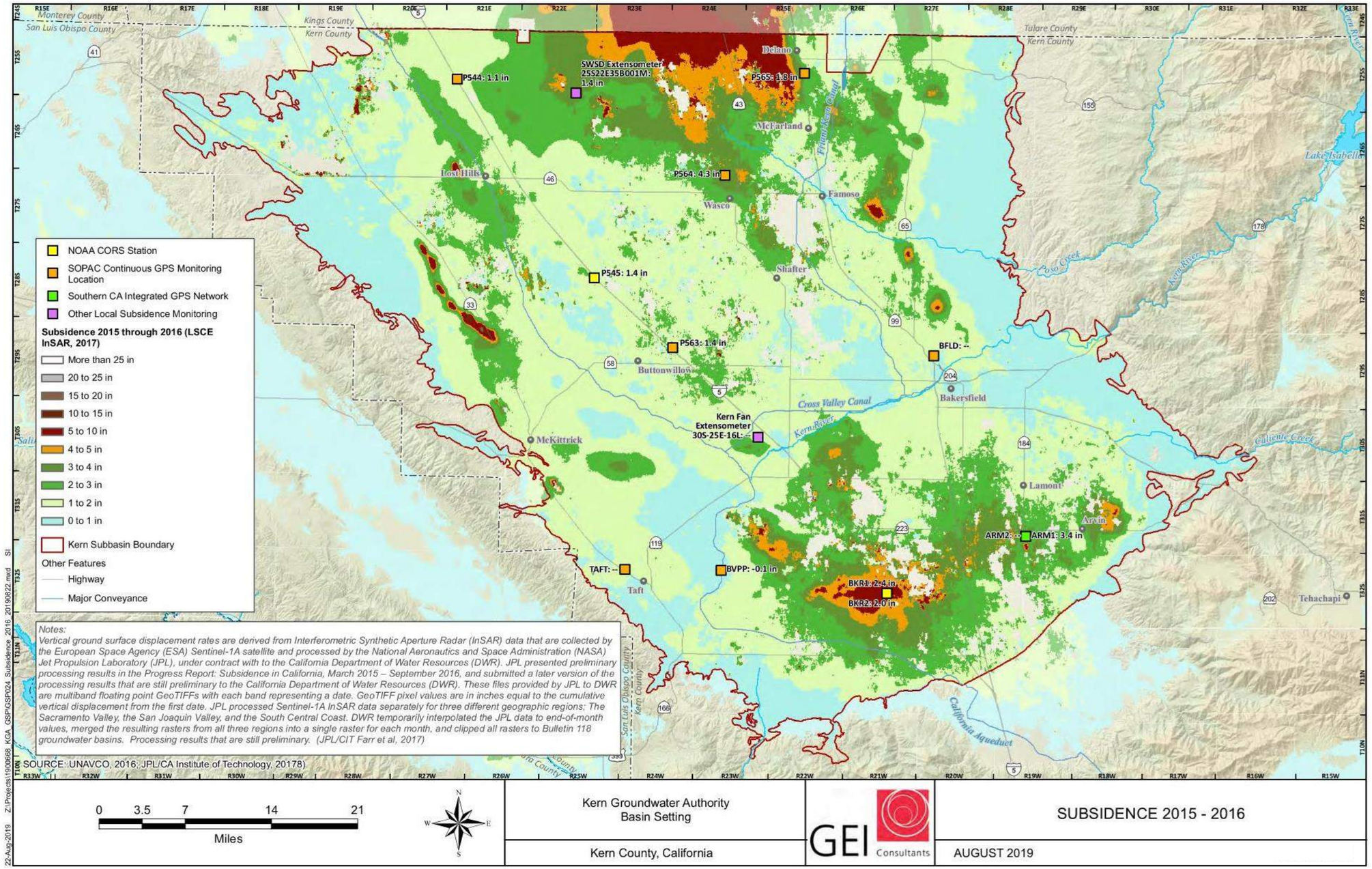

Figure 2-46. Subsidence 2015-2016

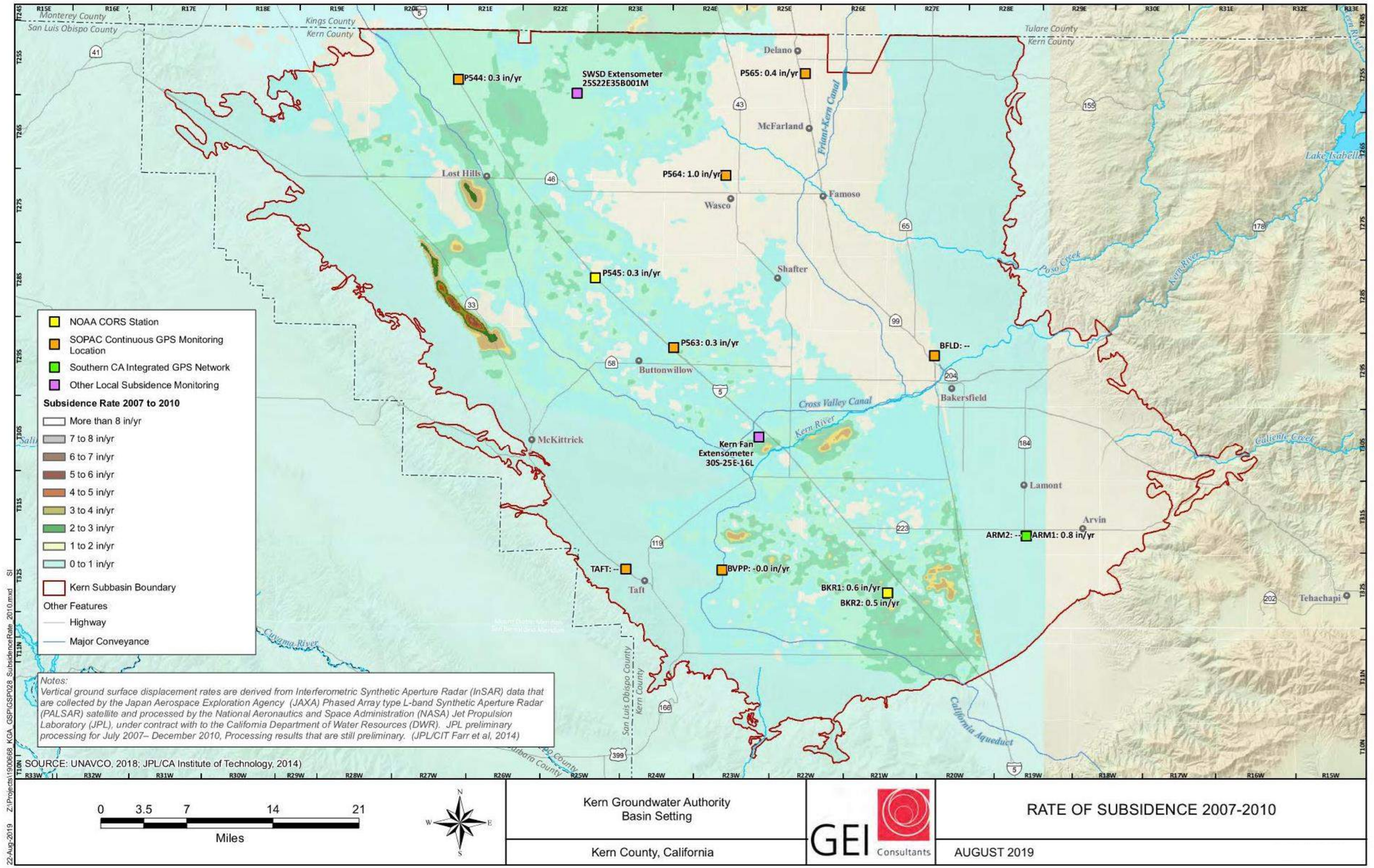

Figure 2-47. Rate of Subsidence 2007-2010

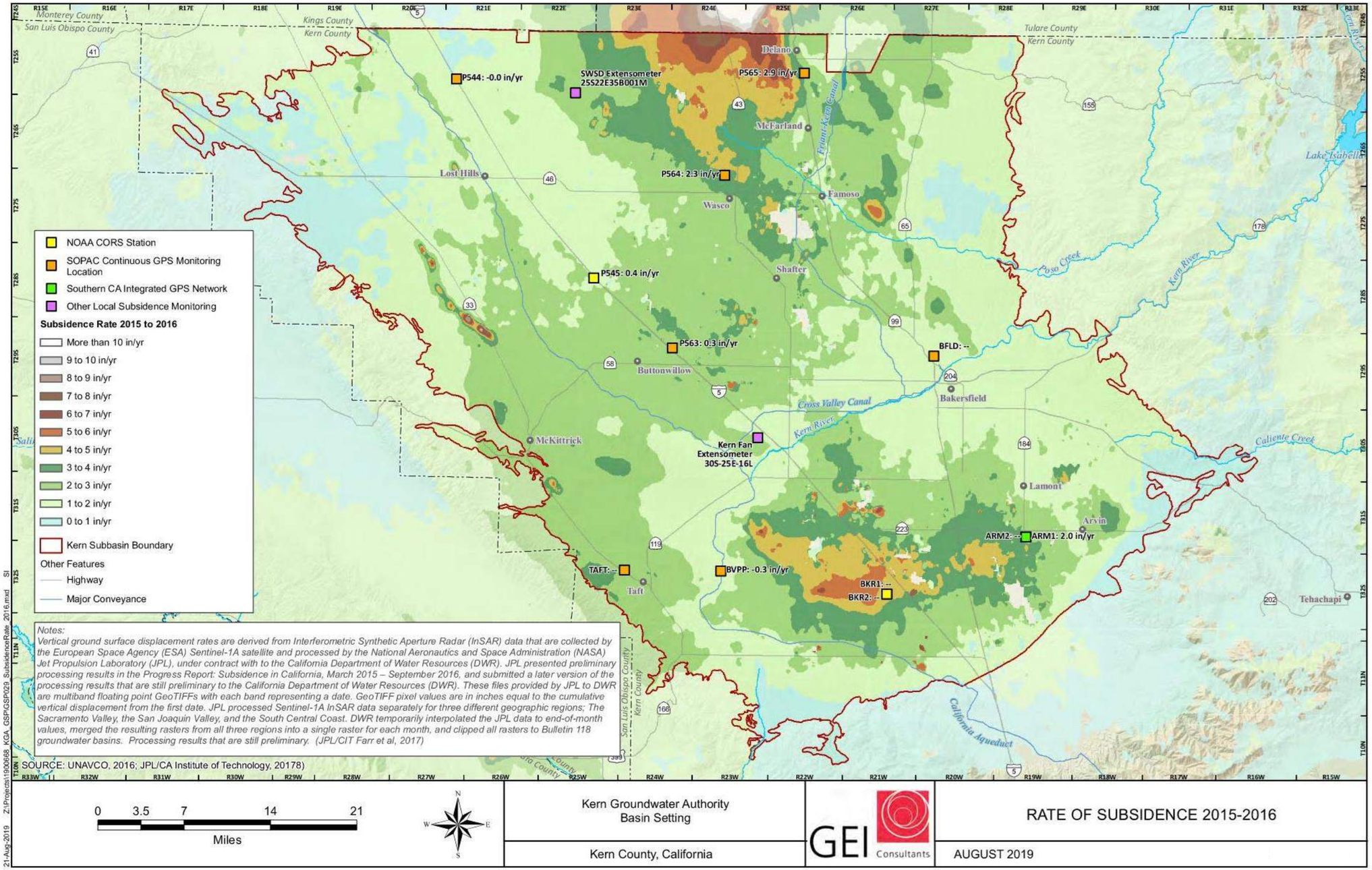

Figure 2-48. Rate of Subsidence 2015-2016

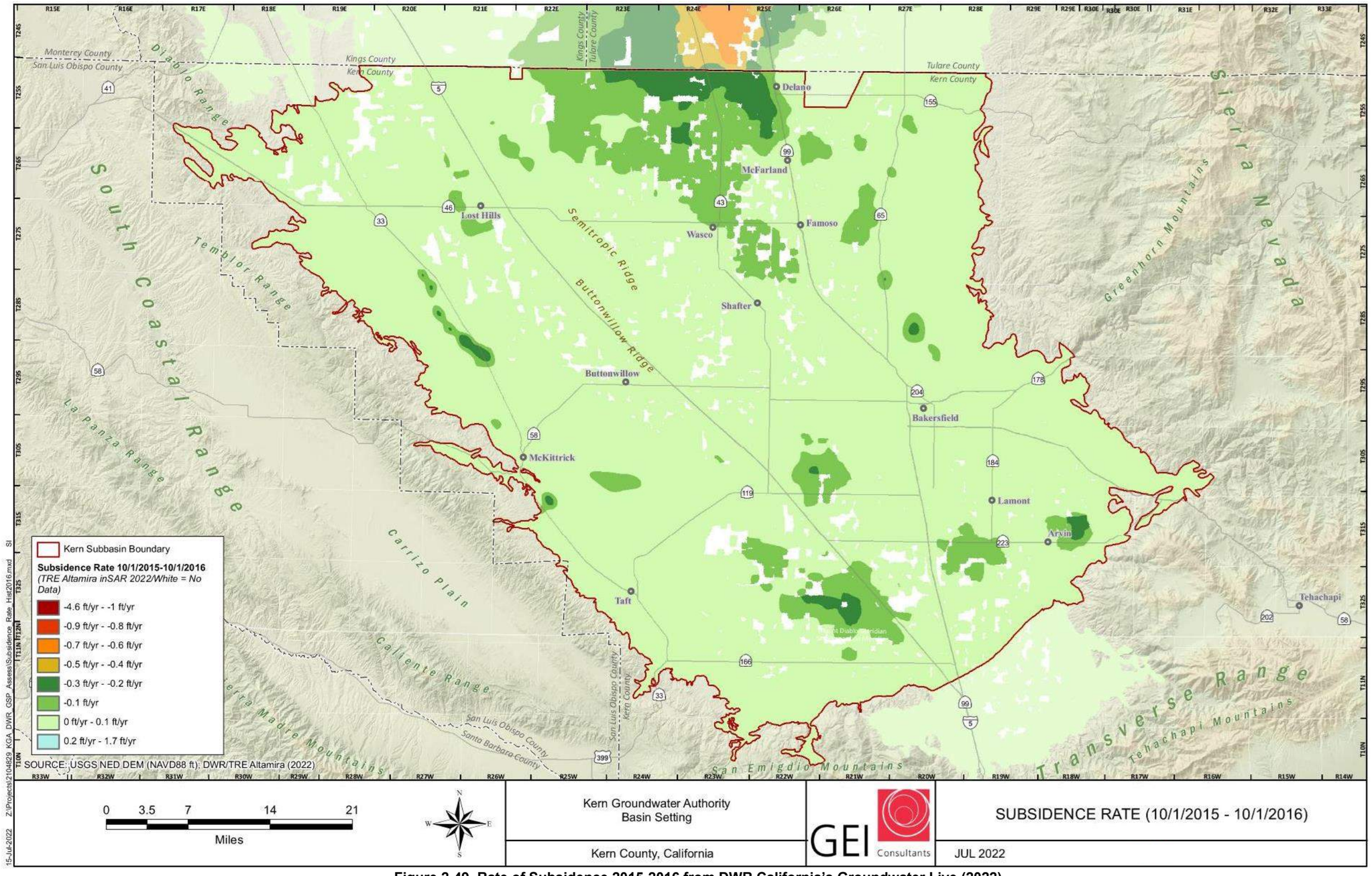

Figure 2-49. Rate of Subsidence 2015-2016 from DWR California's Groundwater Live (2022)

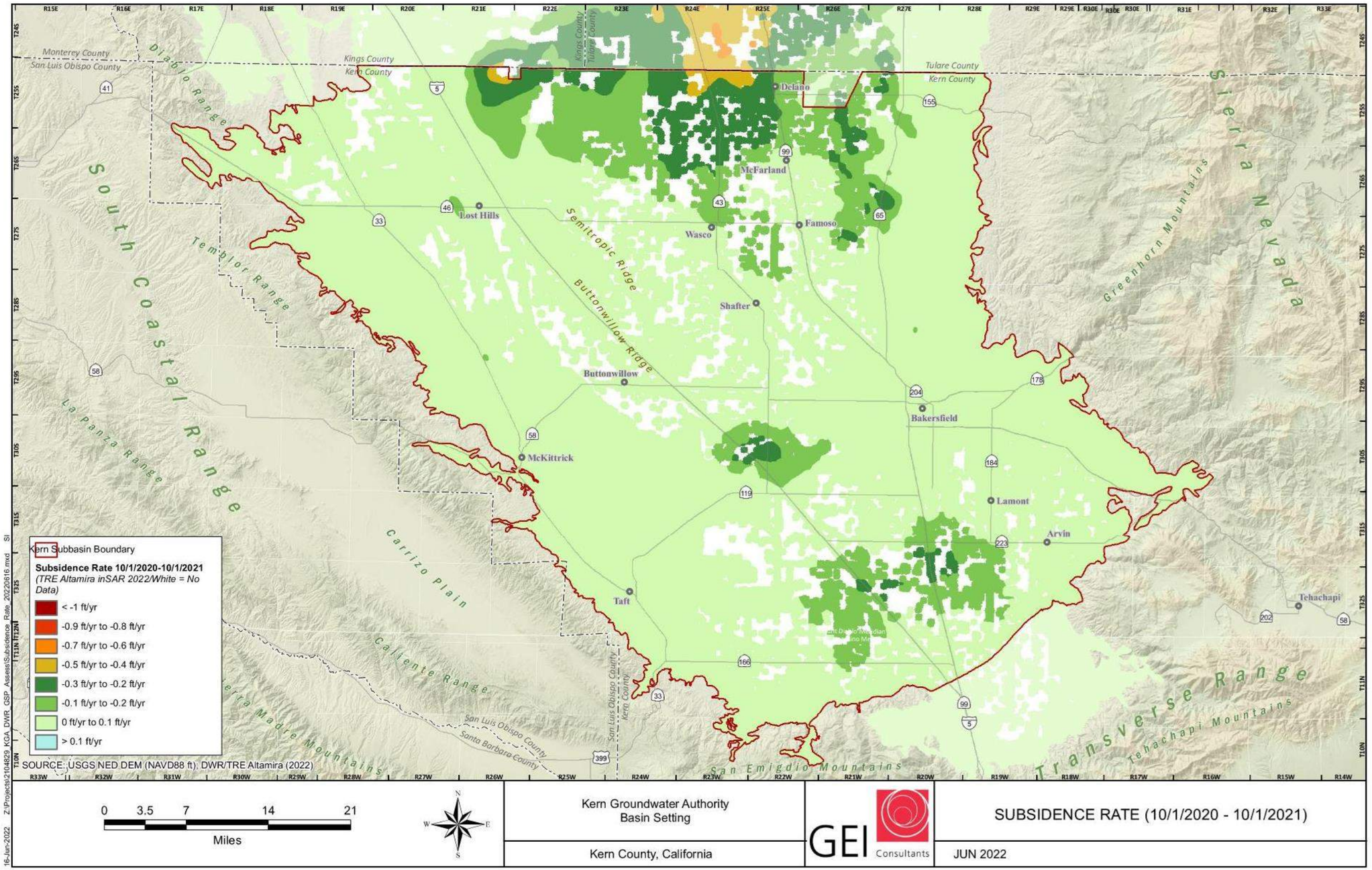

Figure 2-50. Rate of Subsidence 2020-2021 from DWR California's Groundwater Live (2022)

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2.3.5.1 Groundwater Elevation and the Kern River

Recent maps of groundwater contours developed by the Kern County Water Agency Improvement District 4 indicate there is a significant separation between the potentiometric surface near the river channel and the elevation of the river bed in areas where groundwater elevations have been mapped near the Kern River. The Hydrologic Profile from the most recent *Kern Fan Operations Report* (KCWA, 2018), illustrates prevailing groundwater conditions both spatially and temporally near the Kern River. This profile, which is transverse to the axis of the Kern River, indicates that during "wet" years, such as 1998 and 2006, groundwater elevations are highest directly below the Kern River bed while, during "dry" years, groundwater levels have declined to depths greater than 200 feet below the river bed. This prevailing pattern suggests that, during wet years, recharge to groundwater from the Kern River channel and nearby water banking operations forms a groundwater mound that gradually flows away from the river to the north and the south. Conversely, in dry years, there is an overall decrease in groundwater levels due to the lack of recharge from the Kern River and nearby water banking operations.

2.3.5.2 Hydrographs

Upstream of the Improvement District 4 monitoring coverage is a segment of the river, near Hart Park and the First Point of Measurement within Subbasin, that has available groundwater elevation data from the Kern County Water Agency for supply wells 29S/28E-02A01 and 29S/28E-10K01. These wells are located upgradient of Rocky Point Weir, and groundwater elevation data are plotted against the elevation of the adjacent river bed. In general, water levels in the wells consistently ranged from approximately 27 to 49 feet lower than the river bed between 1995 to 2016 (Figure 2-51). The Kern River is outside of the KGA jurisdictional area. For more information see the Olcese and Kern River GSA GSPs.

2.3.5.3 Stream Gaging

Stream gaging data for the Kern River are available for stations upstream of the Subbasin at Democrat Springs (USGS 11192500 and USGS 11192000), as well as at the First Point of Measurement upstream of Beardsley River Weir and Rocky Point Weir. Differences in annual flow volumes were calculated between Democrat Springs and the First Point of Measurement (factoring in diversions between these points) for water years 1990 through 2016. In general, streamflow tends to increase between Democrat Springs and the First Point of Measurement during wet years (i.e. 1993, 1998, 2005, and 2011), which in part reflects surface water inflow from tributaries along this segment of the River. In contrast, Kern River flows decrease during some dry years such as 2001, 2008, 2009, and 2013, but also exhibit gains during the periods from 2001 to 2002 and from 2013 to 2014.

The Kern River is outside of the KGA jurisdictional area. For more information see the Olcese and Kern River GSA GSPs.

2.3.5.4 Data Gaps

Although available data confirm that the Kern River is not interconnected with the underlying groundwater downstream of the First Point of Measurement, it appears that the Kern River from Democrat Springs to the First Point of Measurement may be gaining flow, with accretion from groundwater being one of the sources contributing to these gains. However, available data between these two locations (approximate 22 1/2-mile reach) are not adequate to refine the assessment of gaining and losing segments from the east boundary of the Subbasin to the First Point of Measurement (approximate 10-mile reach). In this regard, there are several mapped springs throughout the Kern River Canyon, with an absence of any mapped springs below the mouth of the canyon within the Subbasin, indicating that the majority of gains are likely within the canyon. For additional information see the Olcese and Kern River GSA GSP.

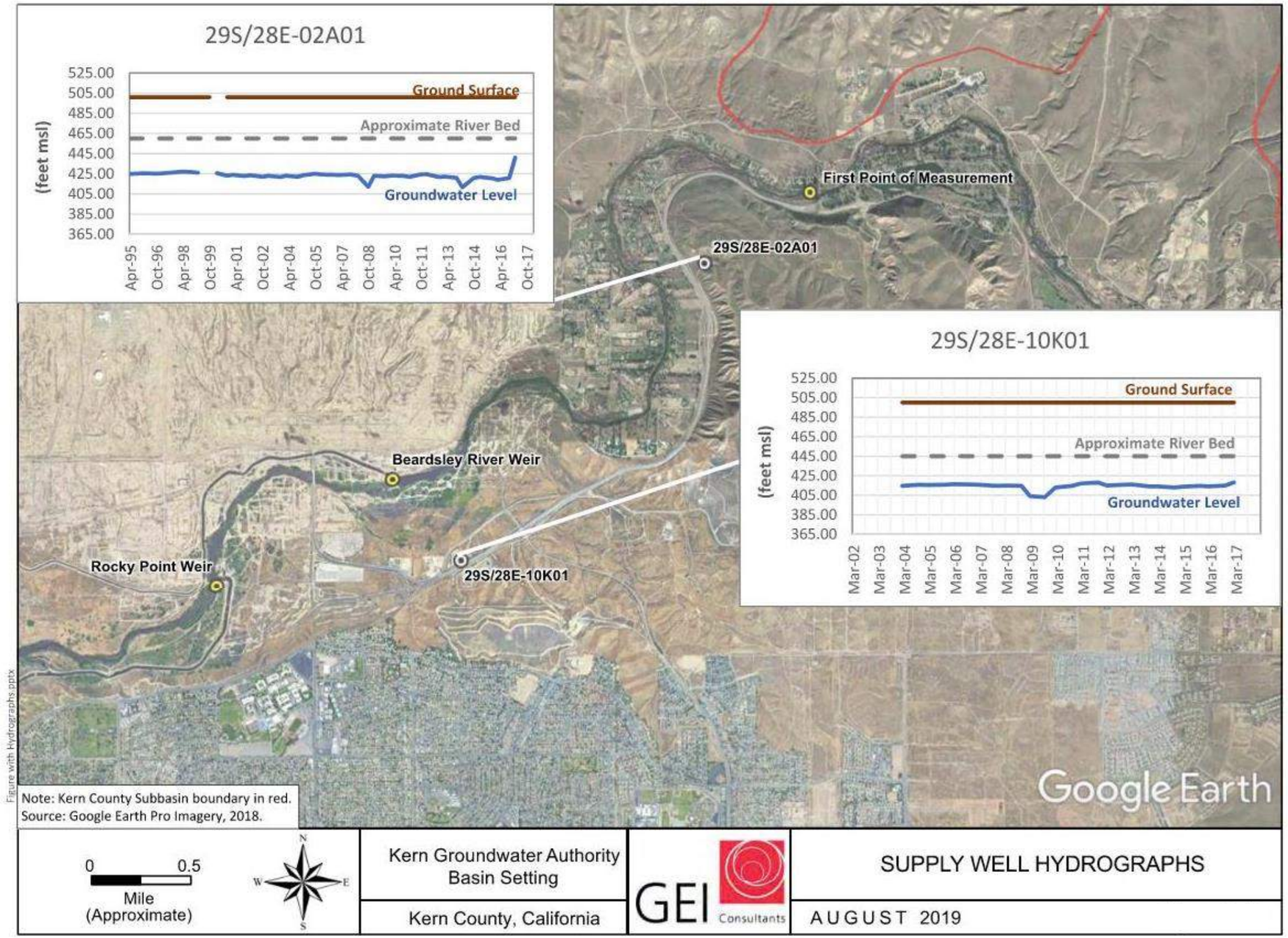

Figure 2-51. Supply Well Hydrographs

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2.3.6 Groundwater Dependent Ecosystems

Groundwater Dependent Ecosystems (GDEs) are ecological communities that depend on groundwater emerging from aquifers or groundwater occurring near the ground surface (shallow water table). In the Kern Subbasin, potential GDEs are likely to be associated with wetlands and riparian areas that are supported either by shallow groundwater or by a combination of shallow groundwater and surface water. As discussed previously, shallow groundwater is present in west-central and southern portions of the Subbasin. Ephemeral wetlands covered by water seasonally are likely to be supported by irrigation deliveries and precipitation and are unlikely to be surface expressions of groundwater. For example, the Kern National Wildlife Refuge, is now sustained by imported surface water (USFS, 2005). Other features having the potential to provide habitat, such as groundwater recharge basins that are artificially flooded with surface water, also depend on diversion of surface water rather than a shallow groundwater table. The distribution of potential GDEs in the Kern Subbasin was assessed based on DWR's Natural Communities Commonly Associated with Groundwater (NCCAG) data.

The following is taken from the DWR Natural Communities dataset website for NCCAG (DWR, 2019):

> *"*The Natural Communities dataset is a compilation of 48 publicly available State and Federal agency datasets that map vegetation, wetlands, springs, and seeps in California. A working group comprised of DWR, the California Department of Fish and Wildlife (CDFW), and The Nature Conservancy (TNC) reviewed the compiled dataset and conducted a screening process to exclude vegetation and wetland types less likely to be associated with groundwater and retain types commonly associated with groundwater, based on criteria described in Klausmeyer et al., 2018. Two habitat classes are included in the Natural Communities dataset: (1) wetland features commonly associated with the surface expression of groundwater under natural, unmodified conditions; and (2) vegetation types commonly associated with the sub-surface presence of groundwater (phreatophytes)."

The data included in the Natural Communities dataset do not represent DWRs determination of a GDE. However, the Natural Communities dataset can be used by GSAs as a starting point when approaching the task of identifying GDEs within a groundwater basin."

Figure 2-52 shows CDFW lands in the Central Region. Similarly, Figure 2-53a and 2-53b shows potential location of wetlands and GDEs in the Subbasin, respectively, as identified in the National Hydrography Dataset. In addition, the surface water bodies from the National Hydrography Dataset are also discussed in relation to potential GDEs.

The below discussion presents NCCAG dataset of the Subbasin. Any further details regarding these mapped datasets are provided in the management area plans. Where data gaps exist, future monitoring and GSP updates will seek to fill these gaps, as described in the management area plans of the individual KGA members.

2.3.6.1 NCCAG Mapped Data

Figure 2-29 displays the locations of seeps and springs based on data extracted from the National Hydrography Dataset at the base of the mountains and foothills in the southeast, southwest, and northwest edges of the Subbasin.

Figure 2-53a and 2-53b displays NCCAG data in the Subbasin. NCCAG features are mapped along spring-fed streams in the southwest along the perimeter of the Subbasin: Santiago Creek to San Emigdio Creek situated in the Wind Wolves Preserve. Toward the east, Pleitito and Pleito Creeks have mapped NCCAG datasets. Potential spring-fed streams to the southeast of Sycamore Canyon Golf Course may have associated NCCAG mapped data. In the southeast corner of the Subbasin, in the highlands along the Caliente Creek drainage are mapped NCCAG features. On the eastern side of the Subbasin, NCCAG wetlands and vegetation are mapped along the Kern River and Poso Creek. On the northern boundary of the Subbasin, NCCAG wetlands and vegetation are mapped in the Kern River channel to the southwest of Kern Wildlife Refuge. Along the western edges of the Subbasin, there are mapped NCCAG features.

Groundwater potentiometric surfaces from Kern Fan Monitoring Reports (KCWA, 2016) indicate that underlying aquifers are not connected with stream channels. Some flow in the Kern River, as well as in Poso Creek and other mountain-front creeks, is likely to be sustained periodically by release of bank storage (surface water stored in stream banks), but the underlying groundwater is too deep to sustain flow in the valley floor.

2.3.6.2 Evaluation of NCCAG Results

The conditions in the center of the Subbasin suggest that the groundwater production aquifer does not reach the shallow subsurface. The production aquifer lies at depths that prevent surface water expressions or accessibility for vegetation. The respective chapters within this GSP may present additional data regarding NCCAG mapped dataset.

Based on the NCCAG dataset along the margins of the Subbasin where spring-fed streams exist, further confirmation is needed to evaluate the presence of GDEs. Chapter-level GSPs, where necessary, provide local details regarding the current understanding of potential GDEs in the respective area.

In the west-central and southern-central Subbasin, shallow groundwater levels are present. These clays have historically been a concern regarding encroachment of poor-quality perched groundwater into crop root zones. The shallow groundwater in the west-central and southern-central Subbasin is not well suited for agricultural or domestic water supply; therefore, existing water management practices and practices that may be introduced through the implementation of SGMA are unlikely to draw on the shallow groundwater that may support potential GDEs.

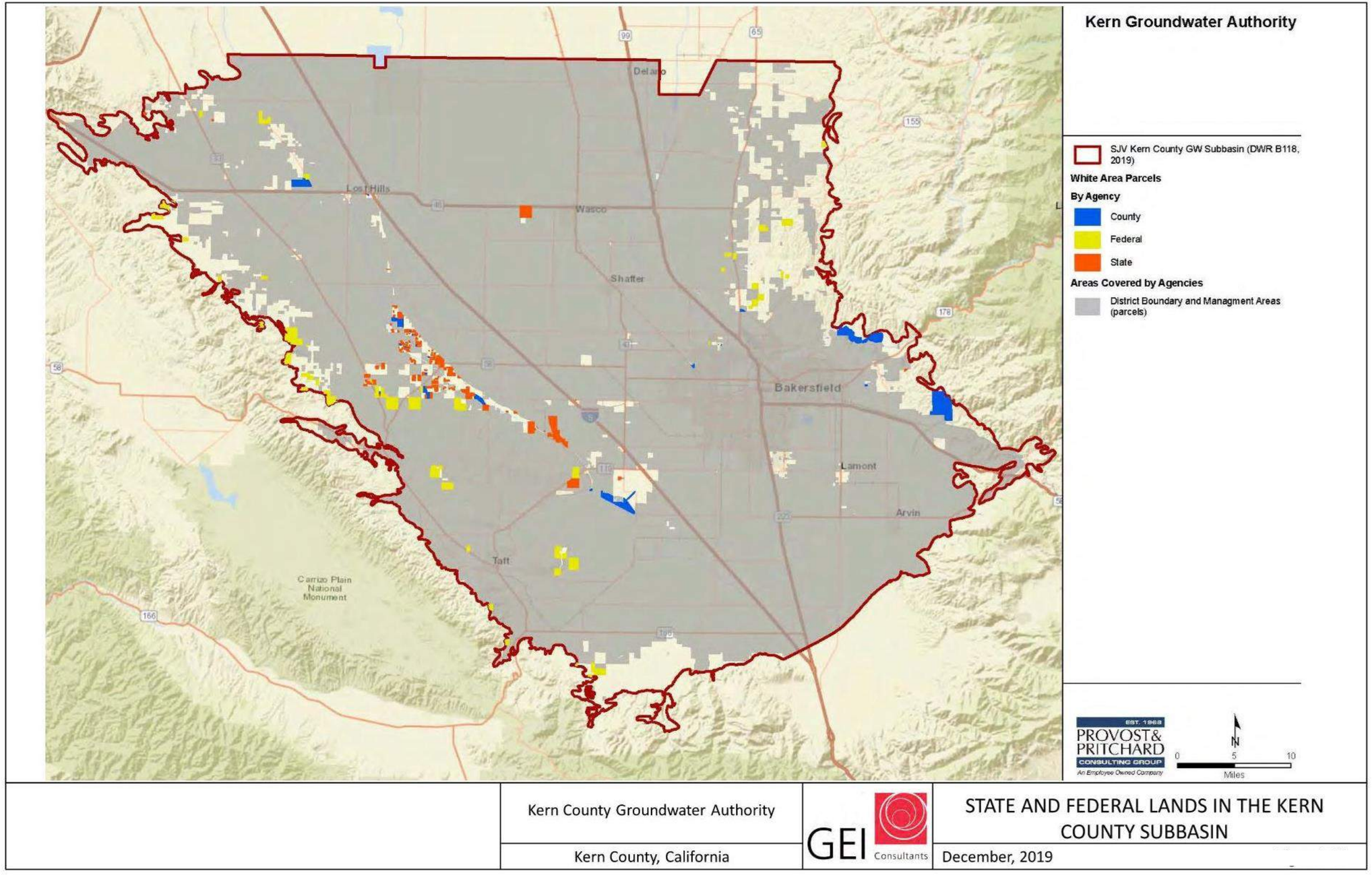

Figure 2-52. State and Federal Lands in the Kern County Subbasin

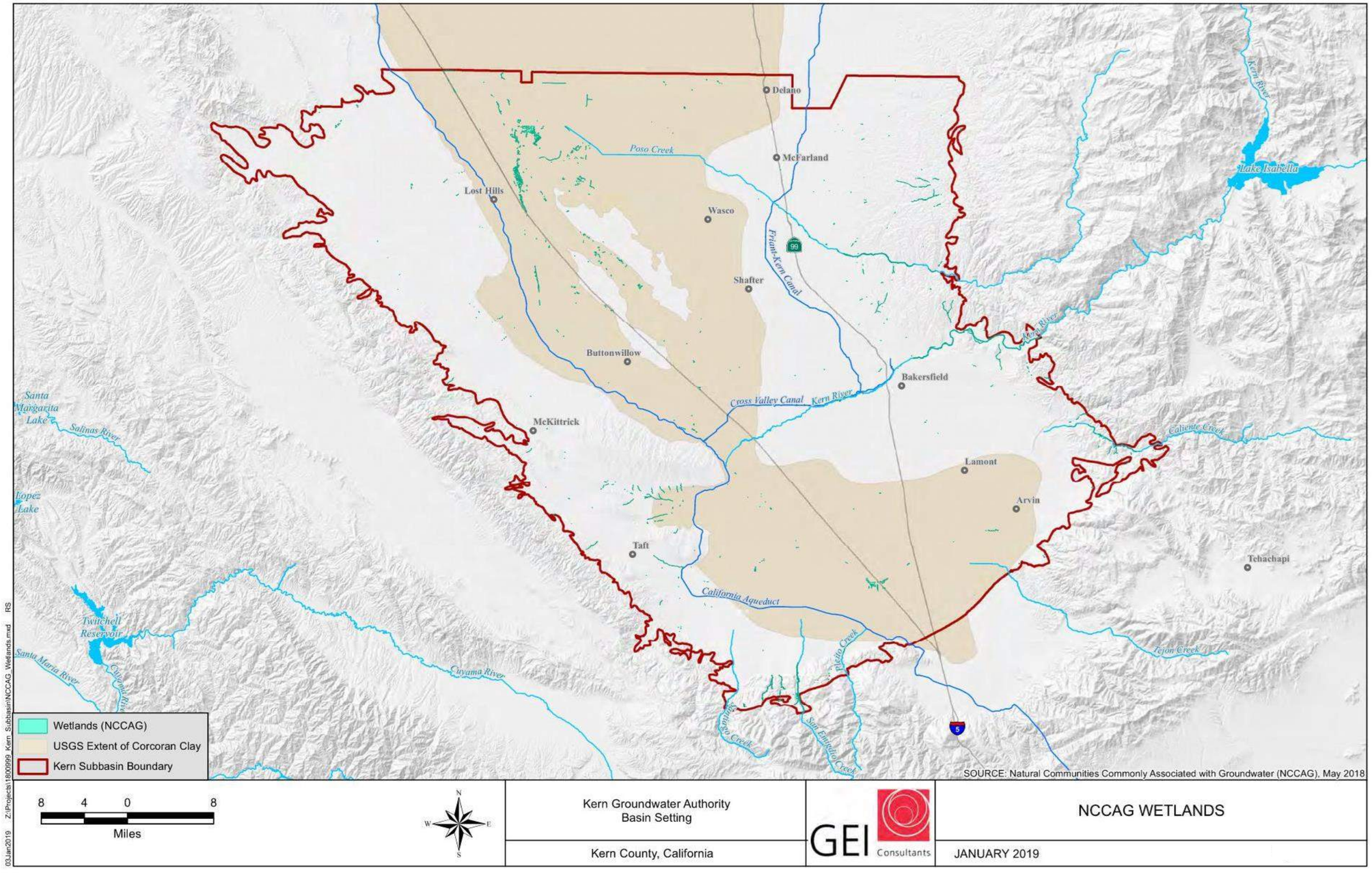

Figure 2-53a. NCCAG Wetlands

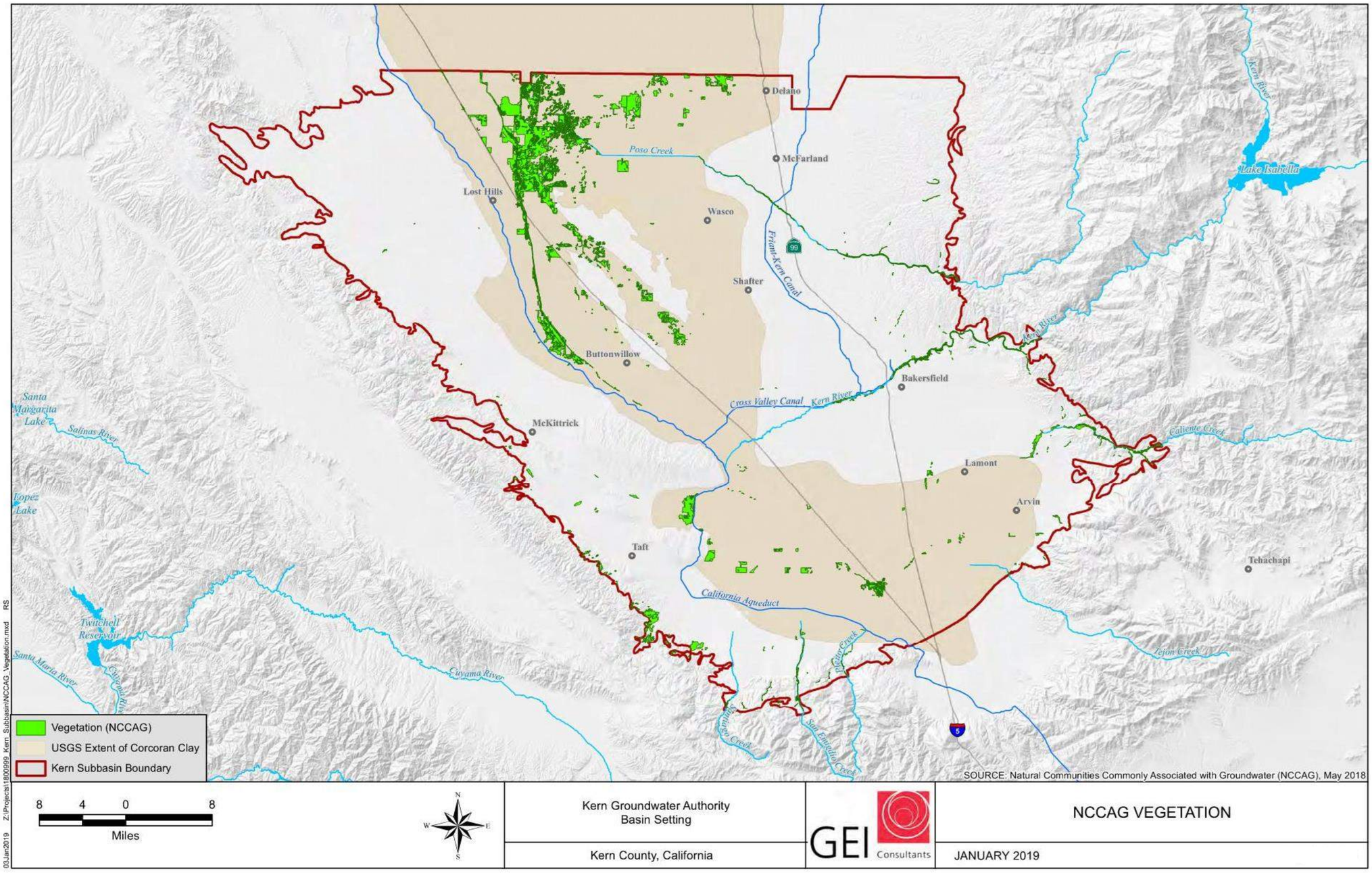

Figure 2-53b. NCCAG Vegetation

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2.4 Water Budget Information

All GSAs in the Subbasin coordinated and collaborated on the development of water modeling budgets (historical, baseline and projected). The GSAs entered into a Cost Share Agreement with the Kern River GSA who took the lead and contracted with Todd Groundwater to develop a groundwater model on behalf of the Subbasin. The contract required that Todd Groundwater use the California Central Valley Groundwater-Surface Water Simulation Model (C2VSim) provided by DWR. Considerable effort and resources were expended to update the C2VSim model with local data to better represent Subbasin conditions, as described below. The process Todd Groundwater used to update C2VSim is more fully described in the Historical and Projected Future Water Budget Development (Attachment H). Subbasin -wide water budget results from the numerical model-based water budget are provided in Attachment H and show the Subbasin, as a whole, has a total storage deficit of 324,326 acre-feet per year (AFY) over the baseline period.

The Subbasin's dynamic conjunctive use programs, water banking operations, and water transfers/exchanges made it necessary to coordinate a separate water accounting system using Subbasin specific values for supply, demand and net results. The C2VSim model results reflect Subbasin-wide conditions and does not allocate water shortages/surpluses, nor do the results allocate the "ownership" of water. As a result, the GSAs, through a coordinated effort, developed water budgets that estimate current conditions for each GSA that are generally consistent with the C2VSim model results under baseline condition. These GSA-level budgets are based upon best available information, recognizing however, each estimate includes data gaps and has varying degrees of accuracy and/or reliability. Table 2-8 reflects the coordinated development the GSA-level water budgets for the Kern Subbasin and is also included in the Coordination Agreement for the Kern Subbasin.

Table 2-8. (REVISED) Kern Subbasin GSA Level Water Budgets

Entity	Total Water Demand (acre-feet)	Total Water Supply (acre-feet)	Net Water Budget (acre-feet)
Kern Groundwater Authority	1,489,171	1,249,825	-239,346
Kern Groundwater Authority - Non-Districted	4,200		-4,200
Henry Miller GSA	40,884	35,791	-5,093
Olcese Water District GSA	2,650	3,202	552
Kern River GSA	305,310	276,157	-29,153
Kern River GSA – App. K Properties	1,308		-1,308
Buena Vista GSA	103,950	126,936	22,986
South of Kern GSA	464,051	433,303	-30,748
TOTALS:	**2,411,524**	**2,125,214**	**-286,310**
Todd Groundwater Model Results for Baseline Condition:			**-324,326**
Todd Groundwater Model Results for Historical Change in Groundwater Storage:			**-277,114**

*Most of the irrigated non-districted lands are now managed /covered under SGMA by GSAs.

To ensure the KGA individual water budgets reflected actual conditions, the KGA members developed a coordinated water accounting methodology. The result of that effort indicates a current baseline shortage/deficit for KGA members of -239,346AFY[1]. This reflects the difference between a total demand for KGA members of 1,489,171 AFY, and a total supply of 1,249,825 AFY. Each KGA member agency management area plan reflects their consistent management area water budget in their individual water budget sections.

2.4.1 Model Development

SGMA regulations require that water budget analyses for GSPs be conducted on a basin-wide basis. DWR developed C2VSim to simulate water demands and supplies in the Central Valley. The C2VSim Fine Grid Beta Model (C2VSimFG-Beta) is derived from a series of Central Valley hydrologic models developed by DWR and other agencies beginning in the early 1990s. C2VSimFG Beta includes historical input data for WY1922-2015 in the Kern Subbasin. These data include monthly precipitation and annual land use for each model element and estimated monthly evapotranspiration for each modeled land use type and agricultural crop. Historical surface water data include monthly surface water inflow for each river entering the model boundary and monthly surface water diversions.

C2VSimFG Beta input files have been modified to incorporate locally-derived managed water supply and demand data to better represent the local water balance for the Subbasin. known as C2VSimFG-Kern model. This model includes revised data for the Kern County subbasins to better represent local water conditions. To comply with the SGMA water budget requirements (Section 354.18), the KGA and the other four GSAs in the Subbasin engaged in a basin-wide effort to develop a basin-wide groundwater model. The results of this effort are provided in Attachment H - TODD Groundwater C2VSimFG-Kern Report and Results, which is summarized below.

2.4.2 Data Compilation

Historical surface water diversions, water bank recharge and water bank withdrawal information were collected from Kern County water purveyors. Urban land use was restricted to developed areas, and urban populations and per-capita water demands were updated. Detailed description of data compilation methodology, assumptions and sources are provided in Attachment H: Historical and Projected Future Water Budget Development with C2VSimFG-Kern.

2.4.3 Historical and Current Water Budget

C2VSimFG-Kern was used to develop historical (WY1995 to WY2014) water budget for the Kern County Subbasin and is presented in Figure 2-54. The results are summarized as follows:

[1] The water supplies available to each KGA member from the Pioneer and Kern Water Bank banking programs are incorporated into the listed total available supplies. Note that both programs only store surface supplies, and do not have consumptive demands that contribute to the listed shortages. For more detail on the banking projects, please see the respective chapters.

- **Deep Percolation –** This is defined as precipitation and applied water that reaches the groundwater after simulated transport across the unsaturated zone. The simulated historical 20-year average resulted in a net inflow of 669,398 AFY.
- **Managed Recharge and Canal Seepage –** This is defined as combined groundwater recharge from managed aquifer recharge operations, groundwater banking, and seepage from canals and other conveyance. The simulated historical 20-year average resulted in a net inflow of 583,598 AFY.
- **Net Groundwater-Surface Water (GW/SW) Interactions –** This is defined as net volumetric exchange of surface water and groundwater between the aquifer and streams: Positive represents a net groundwater recharge, and negative represents a net groundwater discharge to the stream. The simulated historical 20-year average resulted in a net inflow of 98,606 AFY.
- **Groundwater (GW) Pumping –** This is defined as total groundwater pumping by wells. Groundwater banking recovery pumping is specified as fixed input values and agricultural and municipal pumping is calculated by C2VSimFG-Kern based on demand minus surface water diversions. The simulated historical 20-year average resulted in a net outflow of 1,590,373 AFY.
- **Small Watershed Inflow –** This is defined as runoff, small stream inflow and subsurface inflow from the small watersheds and areas surrounding the groundwater basin. The simulated historical 20-year average resulted in a net inflow of 48,760 AFY.
- **Subsurface Flow with Adjacent Groundwater (GW) Basins –** This is defined as net subsurface groundwater flow to and from the Subbasin with adjoining groundwater basins: negative is a net flow out of the Subbasin and positive is a net flow into the Subbasin. The simulated historical 20-year average resulted in a net outflow of 87,102 AFY.
- **Change in Groundwater Storage –** This is the sum of the inflow components (positive numbers) plus the outflow components (negative numbers): positive is an increase in storage typified by a rise in groundwater levels whereas a negative is a decrease in storage typified by a decline in groundwater levels. The simulated historical 20-year average resulted in a decline in groundwater storage of 277,114 AFY.

Figure 2-55 presents the average annual historical water budget for the Subbasin that includes the out-of-basin groundwater banking obligation of 85,965 AFY.

Figure 2-56 shows the simulated annual and cumulative change in groundwater storage over the 20-year historical period. It was observed that during the periods of WY1995 to WY2000, WY2005 to WY2006 and WY2010 and WY2011, the groundwater storage volume was stable to increasing and correlates to the above average rainfall and surface water availability during these times. Similarly, during the periods WY2001 to WY2004, WY2007 to WY2009 and WY2012 to WY2015, groundwater storage volume decreased, correlated to periods of drought and low surface water availability. Figure 2-57 shows the simulated historical groundwater recharge by

source that also reflects a climatic pattern with high deep percolation to groundwater and steep increases in managed aquifer recharge and canal seepage during the above average rainfall periods and lower groundwater recharge during the drought years.

As a result, groundwater pumping for agriculture shows a general increasing trend from WY1995 to WY2014; however, groundwater pumping is lower in above average rainfall years and higher during droughts as shown in Figure 2-58. This general increasing trend follows a comparable decreasing trend in surface water deliveries over the same period as shown in Figure 2-59.

2.4.3.1 Sustainable Yield

SGMA defines Sustainable Yield as "the maximum quantity of water, calculated over a base period representative of long-term conditions in the basin and including any temporary surplus, that can be withdrawn annually from a groundwater supply without causing an undesirable result". To determine the sustainable yield for the Kern Subbasin, the results of the C2VSimFG-Kern model were used with two methods to estimate the amount of groundwater pumping that would avoid the undesirable result of a reduction in groundwater storage over the historical base period 1995 to 2014.

- **Sustainable Yield from Groundwater Pumping** – The model results produced an average annual groundwater pumping in the Kern Subbasin of 1,590,373 AFY with a decline in groundwater storage of 277,114 AFY. Subtracting the groundwater storage decline from groundwater pumping produced a sustainable yield of approximately 1,313,000 AFY for the Kern Subbasin.
- **Sustainable Yield from Groundwater Recharge** – The model results produced an average annual groundwater recharge in the Kern Subbasin of 1,400,362 AFY. The subsurface outflow from the GSA totals 87,102 AFY. Subtracting these losses from the groundwater recharge produced a sustainable yield of approximately 1,331,000 AFY.

Using WY1995 to WY2015 as the base period, C2VSimFG-Kern results show declining groundwater levels and long-term reduction of groundwater storage. During this period, average annual inflow to the aquifer is 1,400,362 AFY, and outflow is 1,677,475 AFY. This yields an average annual deficit of 277,144 AFY. Based on these historical C2VSimFG-Kern results, the sustainable yield of the basin is approximately 1,313,000 AFY, plus or minus 10%.

2.4.3.2 Native Yield

SGMA does not require the native yield to be considered or addressed, however, in the process of working on the Sustainable Yield, water budget allocations, and the water modeling for the entire Kern Subbasin, the discussion of the native yield and how best to address it in the Kern Subbasin occurred. The C2VSimFG-Kern results does model the concept of native yield, however, as described in section 4.2.2 of Attachment H, the Native Yield at this time is based on available data. However, there exists in this area data gaps and as such, as those data gaps are eliminated and management actions are implemented, the estimate of native yield is likely to

change. With the current available data for input to the C2VSimFG-Kern, the model provides the following results:

- The volume of precipitation that recharges the groundwater in the irrigated agricultural areas is 77,780 AFY
- The volume of precipitation that recharges groundwater in the other areas is 132,981 AFY
- The volume of inflow from unallocated small watersheds that recharges the groundwater in the irrigated agricultural areas is 48,760 AFY
- The above inputs resulted in a native yield for the Kern Subbasin of 259,520 AFY which resulted in the native yield estimate of 0.144 acre-feet per acre for the total area of the Kern County Subbasin.

During the process of working through the water budget allocations for the entire Kern Subbasin with all GSAs, the native yield was one of the most critical supply source to be coordinate. Acknowledging the presence of data gaps and implementation of projects and management actions, the GSAs of the Kern Subbasin have agreed to the continued analysis and refinement of the native yield, from a technical and legal basis. This has been identified as a management action for the KGA, in coordination with all other Kern Subbasin GSAs, in 2020.

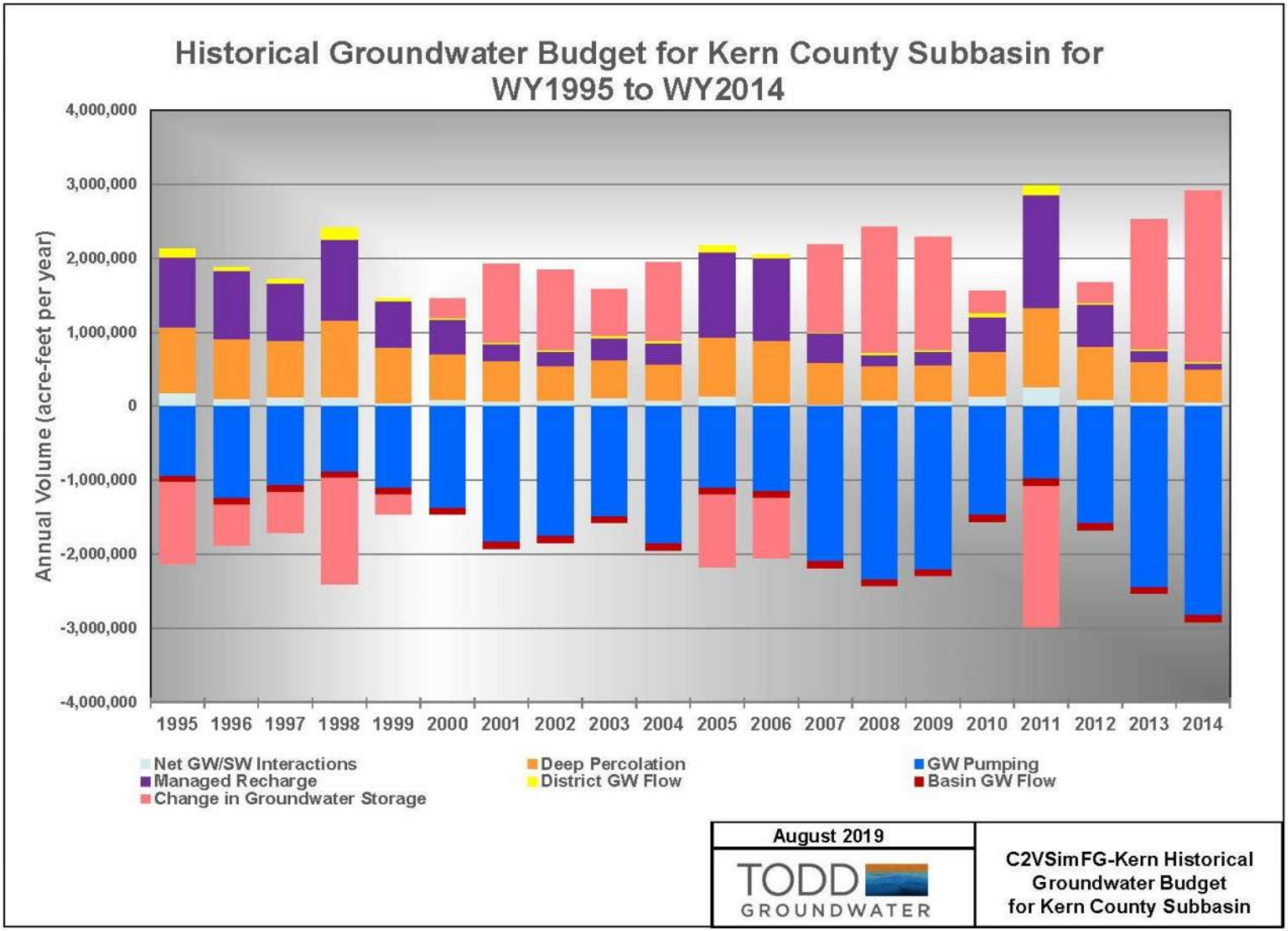

Figure 2-54. Historical Groundwater Budget for Kern County Subbasin for WY1995 to WY2014

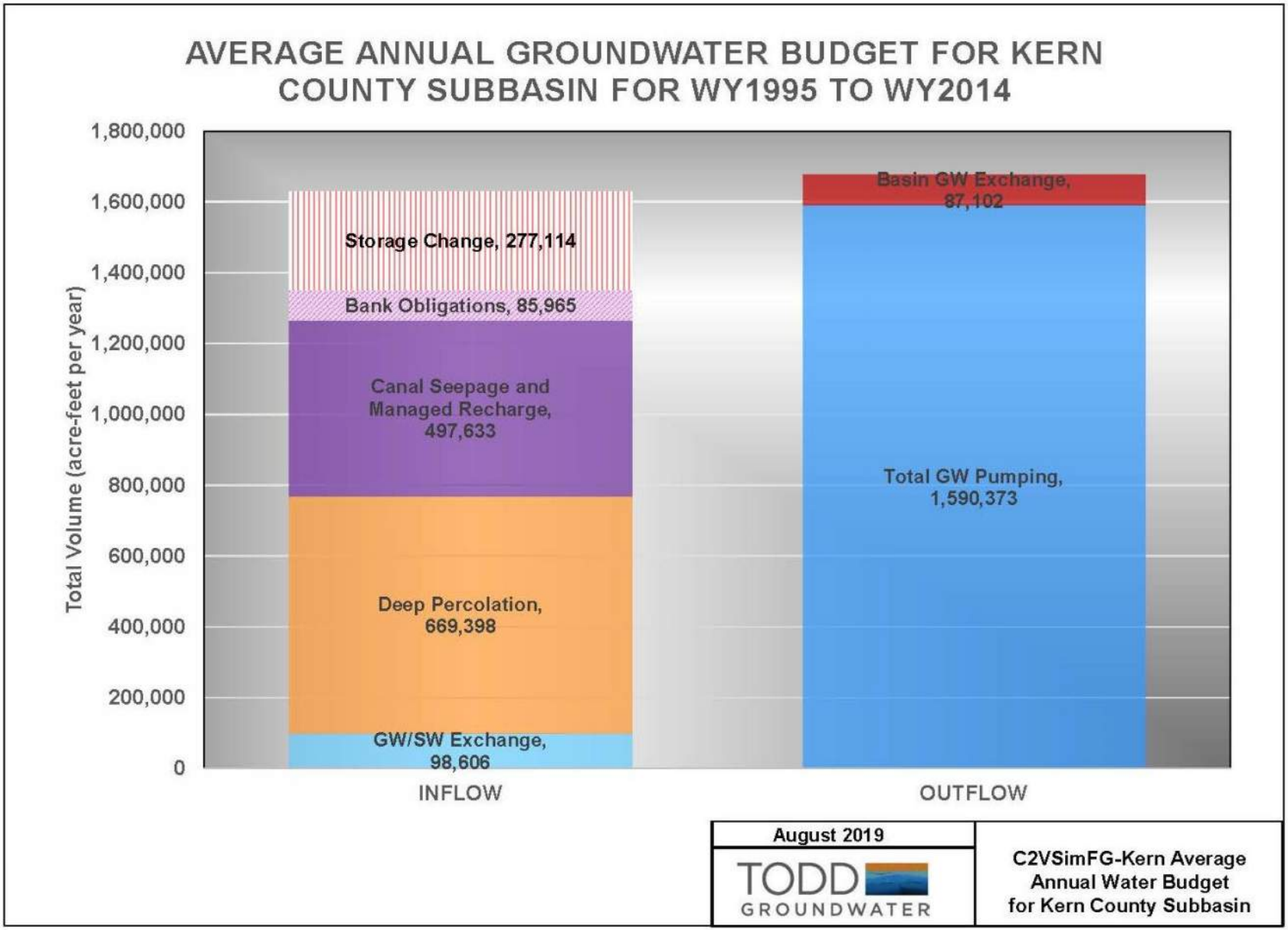

Figure 2-55. Average Annual Groundwater Budget for Kern County Subbasin for WY1995 to WY2014

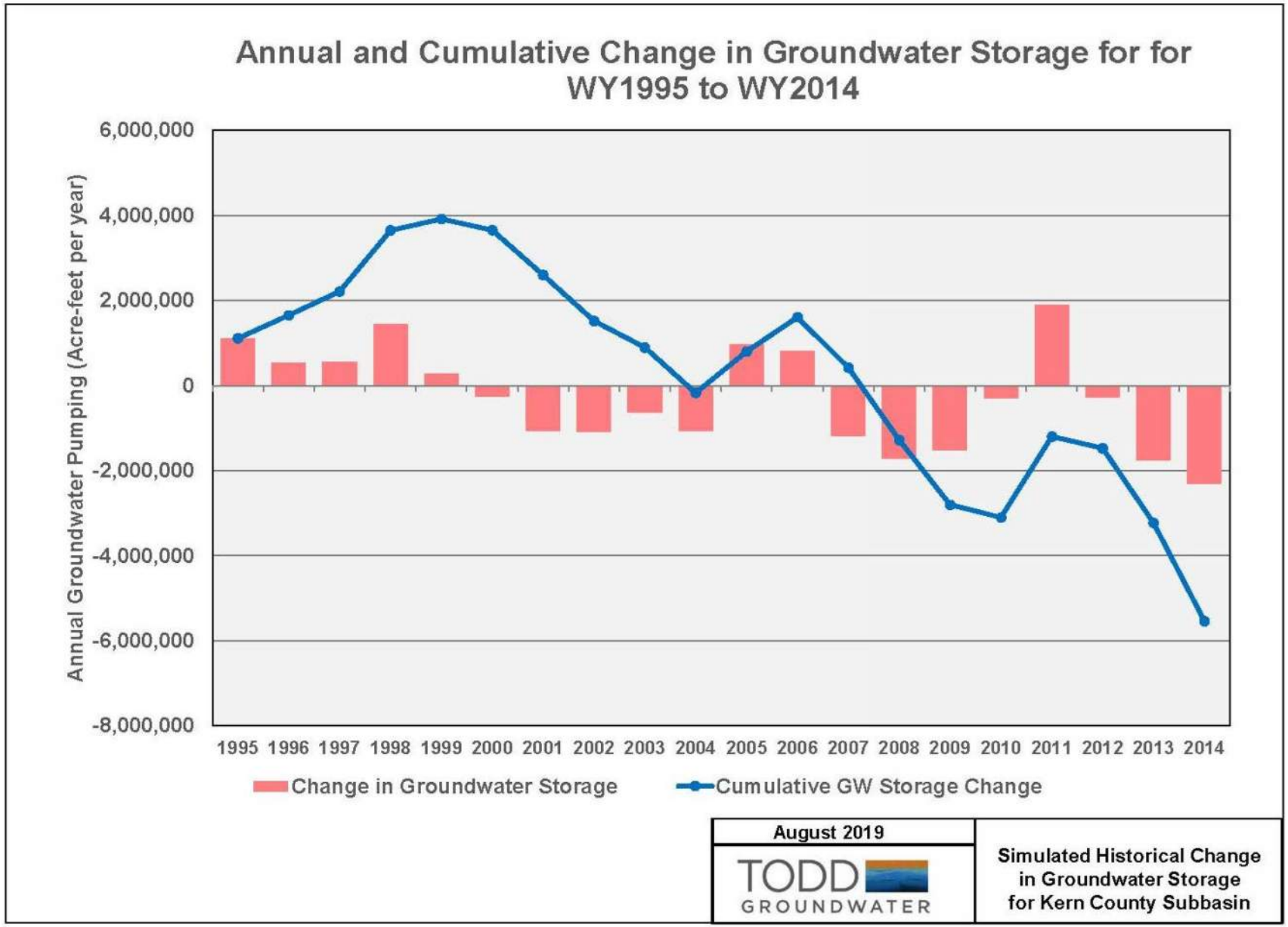

Figure 2-56. Annual and Cumulative Change in Groundwater Storage for WY1995 to WY2014

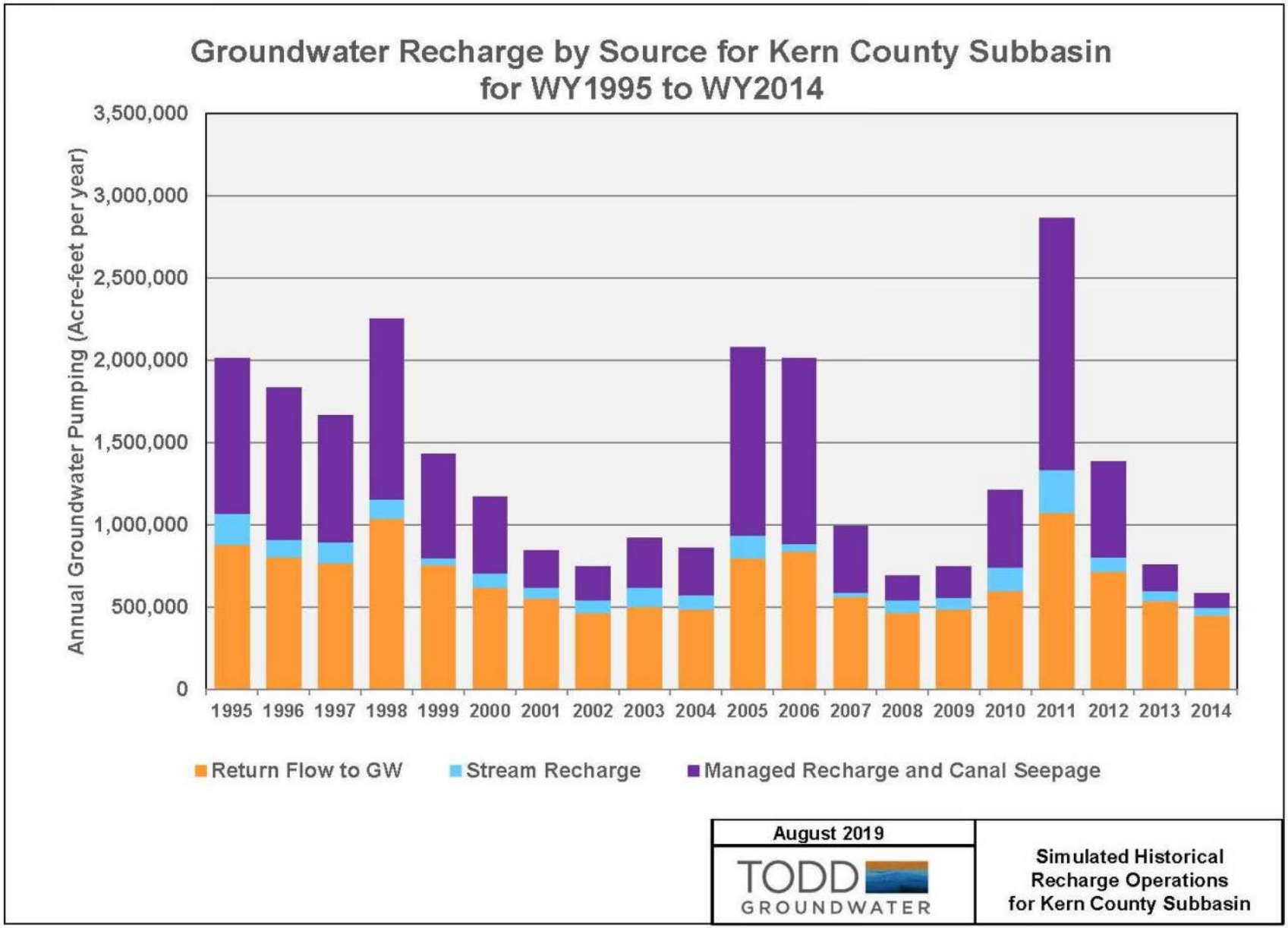

Figure 2-57. Groundwater Recharge by Source for Kern County Subbasin for WY1995 to WY2014

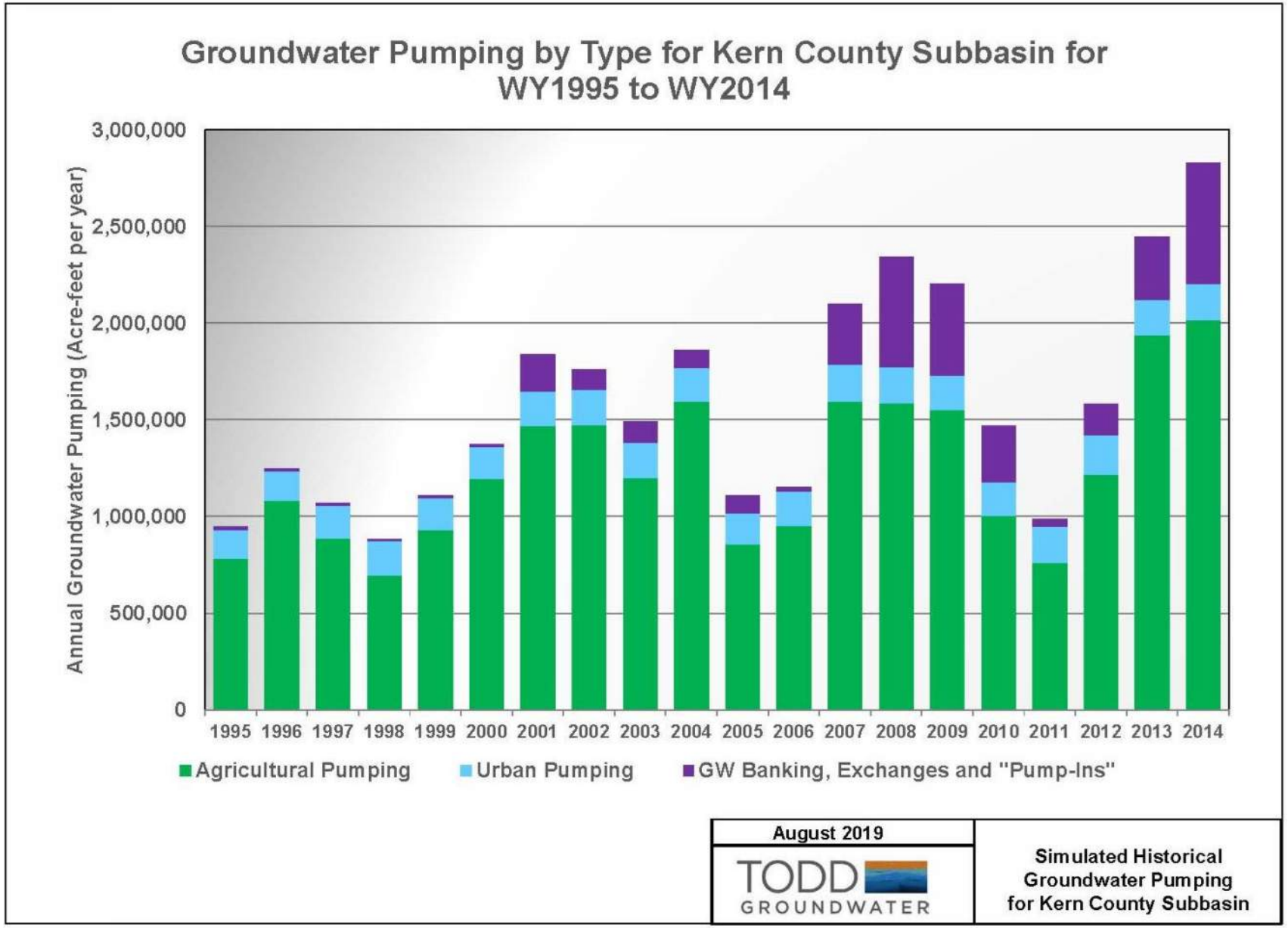

Figure 2-58. Groundwater Pumping by Type for Kern County Subbasin for WY1995 to WY2014

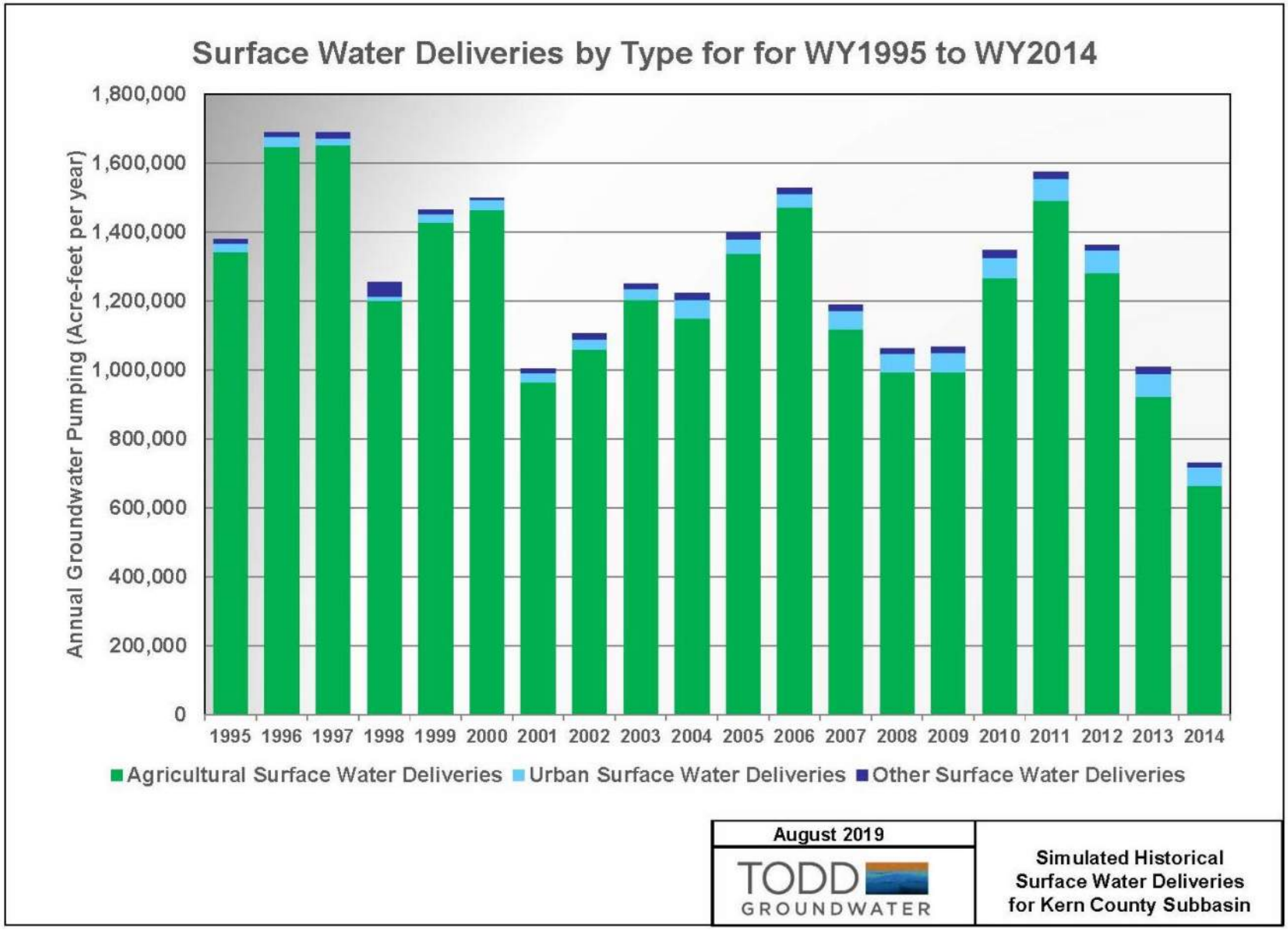

Figure 2-59. Surface Water Deliveries by Type for WY1995 to WY2014

2.4.4 Projected Future Water Budgets without SGMA Implementation

Projected future water budgets for the Subbasin were developed using the C2VSimFG-Kern for future baseline conditions and 2030 and 2070 Climate Conditions over a 50-year planning and implementation horizon. These scenario models provide a basis of comparison for evaluating proposed sustainability management actions and projects over the SGMA planning and implementation horizon.

- **Future Baseline Conditions:** Repeat historical hydrology with future water supply reliability provided by DWR.
- **2030 Climate Conditions:** Adjust historical hydrology for 2030 climatic conditions and water supply reliability provided by DWR.
- **2070 Climate Conditions:** Adjust historical hydrology for 2070 climatic conditions and water supply reliability provided by DWR.

Detailed description of assumptions, hydrology estimations, precipitation rates, surface water deliveries, sources of data and groundwater banking conditions are provided in Attachment H: Historical and Projected Future Water Budget Development with C2VSimFG-Kern.

2.4.4.1 Future Baseline Water Budget

The Baseline Scenario simulates how the Subbasin aquifer would respond if the recent hydrology were repeated with current expected surface water availability and current land use. The primary difference between historical conditions and the projected future baseline is a nearly 20% decrease in imported surface water deliveries primarily from the SWP due to the long-term Operational Criteria and Plan (OCAP) Biological Opinion and is replaced with additional groundwater pumping. As a result, total net aquifer outflows increase by about 35,600 AFY, total net aquifer inflows decrease by about 11,600 AFY with the average groundwater pumping of 1,625,000 AFY, which includes agricultural pumping, urban pumping and exported water. This results in an additional loss of groundwater storage of about 47,200 AFY over the 50-year projected future baseline. Baseline simulation results indicate that the Subbasin has an average annual overdraft of 324,326 AFY, however, with the implementation and completion of projects and management actions as stated in the individual management area plans and GSPs from the other GSAs in the Subbasin, the baseline simulation results show that the Subbasin has an average surplus of 85,578 AFY.

2.4.4.2 2030 Climate Change Water Budget

The 2030 Scenario simulates how the Subbasin aquifer would respond assuming hydrologic conditions representing a potentially drier climate (no or limited amount of snow pack) and are based on the DWR Climate Change Guidance (DWR 2018). The 2030 DWR climate change factors were applied to the Baseline Scenario Conditions. Additional adjustments were made to the imported surface water supplies from the SWP, CVP and Kern River, accounting for about an additional 2% decrease from the Baseline Conditions.

The results show a net increase in aquifer inflows of about 44,700 AFY along with an increase in aquifer net outflows of about 101,200 AFY. This is mostly attributed to the climate shift to earlier rainfall making more surface water available for managed aquifer recharge during the winter but less available for irrigation in the summer resulting in higher groundwater pumping. The net change in groundwater storage is an additional decline of about 56,600 AFY due to the climate change impacts. 2030 Climate Change simulation results indicate that the Subbasin has an average annual overdraft of 372,120 AFY with the net change in groundwater storage showing an additional decline of about 47,794 AFY, compared to the Baseline, due to the climate change impacts. However, with the implementation and completion of management actions/projects as stated in the individual management area plans and GSPs from the other GSAs in the Kern Subbasin, 2030 Climate Change simulation results indicate that the Subbasin has an average deficit of approximately 46,829 AFY.

2.4.4.3 2070 Climate Change Water Budget

The 2070 Scenario simulates how the Subbasin aquifer would respond assuming hydrologic conditions representing a potentially very dry climate and are based on the DWR Climate Change Guidance (DWR 2018). The 2070 DWR climate change factors were applied to the Baseline Scenario Conditions. Additional adjustments were made to the imported surface water supplies from the SWP, CVP and Kern River, but these accounted for an additional 6% decrease from the Baseline Conditions. The 2070 Climate Change Scenarios were run both with and without SGMA Projects.

The results show a net increase in aquifer inflows of about 66,100 AFY along with an increase in aquifer net outflows of about 231,600 AFY. This is mostly attributed to an even greater climate shift to earlier rainfall making more surface water available for managed aquifer recharge during the winter but less available for irrigation in the summer resulting in higher groundwater pumping. 2070 Climate Change simulation results indicate that the Kern County Subbasin has an average annual overdraft of 472,336 AFY with the net change in groundwater storage showing an additional decline of about 148,010 AFY due to the climate change assumptions. As indicated in the above model simulations, with the implementation and completion of management actions/projects as stated in the individual management area plans and GSPs from the other GSAs in the Kern Subbasin, the 2070 Climate Change model results unfortunately still indicate a average deficit of 45,969 AFY.

2.5 Management Areas

KGA members worked together to establish management areas and watch areas within the Subbasin to implement projects and management actions as well as better capture local groundwater conditions. To prevent undesirable results in adjacent management areas, members have established minimum thresholds consistent with each other. Definitions for management areas and watch areas are as follows:

- Management Area: Management areas are areas that will be considered against the determination of an undesirable result at the basin level.

- Watch Areas: Areas with no significant groundwater use and no planned groundwater use as documented in the management area plans. Watch areas will be monitored for land use changes and groundwater conditions that could change its designation to a "management area" with specified Sustainable Management Criteria.

The Subbasin consists of many entities with land use or water management authority. While a majority of these entities are members of the KGA who have water management authority as explained in Section 1.4, they retain their local responsibility for compliance with SGMA. The County of Kern and municipalities located within the management areas retain their land use jurisdiction. Ultimately the members of the KGA have the responsibility to implement projects and management actions, as described in Section 4 of this GSP and in the individual management area plans, to achieve sustainability within their management areas. The management areas within the KGA are summarized in Table 2-9. A detailed explanation of each management area under the KGA is provided in their respective management area plans. The following section provides a brief overview of how and why management areas were created as well as how each area will be managed.

Management areas were created by the districts/member agencies under the KGA to support groundwater sustainability in the Subbasin. While there is no one approach, majority of the management areas in the region maintain respective district boundaries. Districts and member agencies under the KGA already maintain/manage water rights, contracts, and governing agreements in their regions. By creating their own management areas, Districts/members can maintain/manage maximum flexibility and control over SGMA compliance within its service area, allowing them to implement projects and management actions applicable to their respective areas.

Management areas are designated within the Subbasin to leverage existing relationships with water users for local water accounting and management actions of imports; exports; water consumption and conservation; and groundwater pumping. While most were created from district boundaries, other management areas were developed based off groundwater and geological conditions in each respective service area, which is why some districts have multiple management areas as shown in Table 2-9. These management areas will preserve groundwater management practices and implement additional requirements set forth in this GSP. The JPA with KGA allows for each district or member agency to establish individual management areas and manage them to support the sustainability of the region.

Table 2-9. (REVISED) Management Areas Under the Kern Groundwater Authority

KGA Management Area	Acres in Management Area	Percentage of Subbasin
Cawelo GSA	62,616	3.5
Eastside Water Management Agency	38,222	2.1
Kern-Tulare Water District (in Kern)	11,219	0.6
North Kern WSD		
MA-1 (Old District)	61,741	3.4
MA-2 (RRID)	5,802	0.3
KCWA-Pioneer GSA	2,233	0.1
Kern Water Bank Authority	20,490	1.1
Rosedale-Rio Bravo WSD	48,610	2.7
Southern San Joaquin MUD	65,693	3.7
Shafter-Wasco Irrigation District	39,980	2.2
7th Standard Annex	10,045	0.6
Semitropic GSA		
MA-1 (Pond Poso)	82,638	4.6
MA-2 (Buttonwillow)	92,633	5.2
MA-3 (Undeveloped)	49,140	2.7
West Kern GSA		
North Project MA	521	0.0
South Project MA	889	0.0
Western Watch Area [1]	183,128	10.2
Lake Watch Area [1]	653	0.0
LSMV Watch Area [1]	1,947	0.1
Westside Districts Water Authority		
Westside District MA	195,263	10.9
Lost Hills Watch Area [1]	33,191	1.9
Southwest Watch Area [1]	48,739	2.7
Non-District White Lands Watch Areas [1]	210,034	11.7

1 - Watch Areas" are areas with no significant groundwater use and no planned groundwater use as documented by the management area member agency. Watch areas will be monitored for land use changes and groundwater conditions which could change its designation to a "management area" with specified SMCs.

3 Sustainable Management Criteria

The Sustainable Management Criteria requirements of a GSP are defined in Subarticle 3 of the GSP Regulations. The KGA has satisfied these requirements through the commitment of each of its Member Agencies to the following actions:

1. Manage their respective management areas at or above their measurable objectives,
2. Manage each management area to a water budget that will collectively eliminate the KGA Member Agencies deficit of 239,346 AFY by 2040 (see Section 2.4),
3. Implement projects and management actions identified in Section 4.0 and listed in Table 4.1.

The KGA has developed sustainable management criteria that meets the GSP Regulations and enhances the process by including additional steps to better manage political, operational and demographic conditions found across the Kern Subbasin. In establishing the criteria, the KGA and its members worked with adjacent GSAs and other members to achieve as much consistency as possible due to the different hydrogeological conditions and beneficial users. The KGA process is proactive in identifying and managing the occurrence of undesirable results to the beneficial users identified in each management area of the Subbasin as well as considering adjacent beneficial users. The complexity of the Kern Subbasin required the KGA and other Subbasin GSAs coordinate this process that recognizes the diversity found across the Subbasin. The core of this process is the identification of key beneficial users within each management area as well as adjacent beneficial users and conditions that create significant and unreasonable impacts to those beneficial users from groundwater operations in that management area. This enhanced process follows the following steps.

- Sustainability Goal (SGMA Requirement) – Developed as a Subbasin wide goal for achieving conditions of sustainability that recognizes the diversity of the hydrology and beneficial users in the Kern Subbasin. Due to this diversity each management area could elect to develop a supportive Sustainability Goal that specifies the objectives and desired conditions for sustainability within a management area and the protection of beneficial users and uses within that management area however with the consideration of adjacent beneficial users as well as the adjacent management area/GSA.
- Minimum Threshold Exceedances (KGA Enhancement) – Establishes a process for identifying and addressing a single minimum threshold exceedance to proactively manage potential degradation of groundwater conditions and impacts to beneficial users. This is facilitated through the KGA Exceedance Action Plan. The Exceedance Policy focuses on an area surrounding the exceedance to proactively identify and address the causes of the exceedance, thus attempting to limit to the potential of an entire management area exceedance (next step in the process). Even though this is a KGA policy, the KGA members will also work with other surrounding GSAs to explore the cause and to find solutions that limit further impacts to beneficial users and uses. In line with this, the Kern subbasin has agreed from the onset of submitting the annual report, to identify all minimum threshold exceedances and to address the management action to

correct. This is now being supported through the development of the Kern Subbasin data management system that enables managers to assess compliance within their respective management area(s) and throughout the Subbasin.

- Management Area Exceedance (KGA Enhancement) – Establishes the first trigger towards an undesirable result, defining the condition by which the management area could likely contribute to an undesirable result for the entire basin. A Management Area Exceedance occurs when a management area exceeds minimum thresholds at 40% or more of representative monitoring wells within a management area over four (4) consecutive bi-annual SGMA monitoring events, referred to as the Minimum Threshold Trigger. This also establishes a process for the Subbasin entities to collaborate on corrective measures to address further degradation of groundwater conditions and potential impacts to beneficial users. This proactive approach allows the KGA to collaboratively work amongst KGA member and with other GSAs in the Subbasin to identify and address causes of degrading groundwater conditions to prevent reaching an Subbasin-wide undesirable result.
- Undesirable Results (SGMA Requirement) – In the Kern Subbasin an undesirable result is defined as the geographic extent of minimum threshold exceedances across the entire Subbasin, measured by the accumulation of management area exceedances. During the development of the undesirable results for the Kern basin, it became apparent that the basin's hydrology and geography is so diverse that it would be necessary to have a management project called a "Basin Study". The Kern subbasin has just recently been granted $2.9 million dollars to move forward with the basin study to assist in achieving an understanding of complexity of the basin.
- Minimum Thresholds (SGMA Requirement) – Minimum thresholds have been set at each representative monitoring well as the point at which impacts to beneficial uses and users become significant and unreasonable and that cannot be mitigated. Minimum thresholds are collaboratively set with all Subbasin GSAs and are set within each management area with the overlying managing entity to ensure that the diversity of geographic conditions and distribution of beneficial users are considered and represented. In setting the minimum thresholds, the KGA members considered all beneficial users and uses by having a water well analysis as the foundation to work from. This provided an understanding of water depths of existing wells.
- Measurable Objectives (SGMA Requirement) – Similar to the minimum thresholds, the measurable objectives have been set at each representative monitoring well to represent a condition of sustainability. All KGA members have agreed and have management actions to operate their respective management areas at or above their measurable objectives. But note that SGMA is a 20-year process and the ability to manage to the measurable objectives is the goal of the KGA members with their respective management actions and projects to assist in that endeavor however at this time, most KGA members are achieving that goal.

- As described above and demonstrated in Figure 3-1, in the Kern Subbasin, Sustainable Management Criteria are more robust than the SGMA prescribed Undesirable Results, Measurable Objective and Minimum Threshold. Sustainable management begins with early identification of potential minimum threshold exceedances (one exceedance) and coordinated actions to address those early exceedances.

- An undesirable result is a condition that occurs throughout the Subbasin, demonstrating that the Subbasin is not sustainably managing groundwater conditions in the aggregate and that impacts to beneficial users are occurring on a scale (spatially and temporally) that is significant and unreasonable to beneficial users and groundwater managers alike. However, the KGA and other GSAs of the Subbasin, recognize that as groundwater approaches an undesirable result condition, exceedances of minimum thresholds will likely progressively occur in the absence of intervention, beginning with isolated exceedances which could impact beneficial users. A proactive approach to identifying and working with management areas to address these conditions will help address and mitigate degrading groundwater conditions. This approach is shown in Figure 3-1 and more fully detailed in the remainder of this section.

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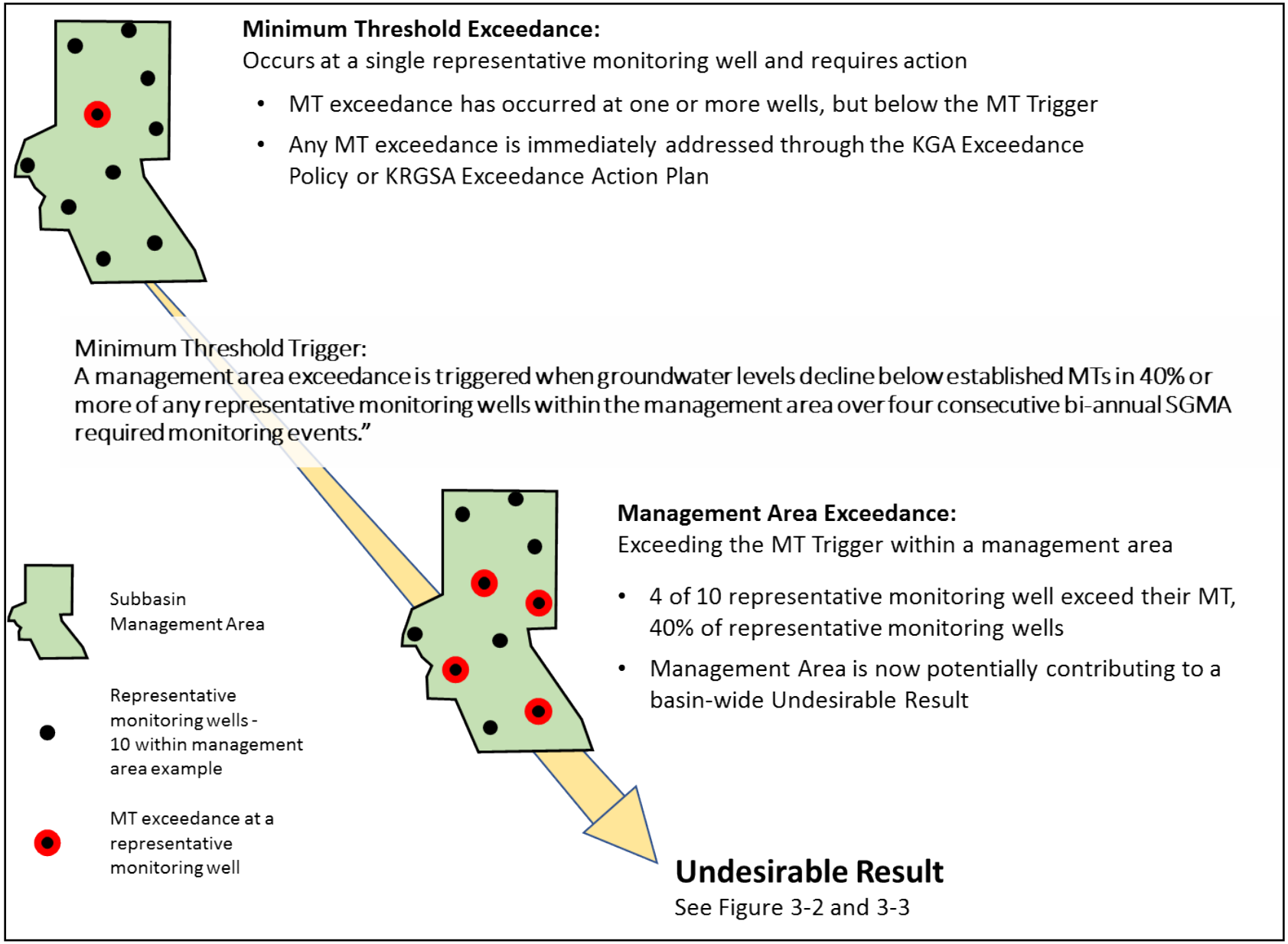

Figure 3-1 NEW. Representation of KGA Minimum Threshold Exceedance Management Policy.

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3.1 Sustainability Goal

SGMA requires that a sustainability goal be defined for the basin (23-CCR § 354.22), and that the sustainability goal be defined on a basin-wide basis. As introduced in Section 1.3, the KGA, working with all GSAs and its member agencies in the Subbasin have developed the following sustainability goals for the Kern County Subbasin:

- *Collectively bring the Subbasin into sustainability and to maintain sustainability over the implementation and planning horizon.*
- *Achieve sustainable groundwater management in the Kern County Subbasin through the implementation of projects and management actions at the member agency level of each GSA.*
- *Maintain its groundwater use within the sustainable yield of the basin as demonstrated by monitoring and reporting groundwater conditions.*
- *Operate within the established sustainable management criteria, which are based on the collective technical information presented in the GSPs in the Subbasin.*
- *Protect beneficial users for municipal and domestic drinking water supply wells.*

In addition, sustainability within the KGA will focus on maintaining the economic viability of agricultural while also balancing the needs of all beneficial users that rely on groundwater resources. To achieve this, KGA members manage to checkbook water budgets as well as implement projects and management actions within their respective management areas to sustain water levels at or above the measurable objectives to mitigate impacts to beneficial users.

3.2 Minimum Threshold Exceedances

To manage potential impacts to beneficial users from lowering groundwater levels the KGA has developed the KGA Exceedance Action Plan into its sustainable management practices. The Exceedance Policy calls for immediate action to address single minimum threshold exceedances at representative monitoring wells. While a single or isolated exceedance of a minimum threshold will not, by itself, cause a management area exceedance or undesirable result, an exceedance may be indicative of future or trending exceedances which could result in a management area exceedance – contributing to the undesirable results criterion. Therefore, early action to address such exceedances is important to prevent potential continued degradation of groundwater conditions.

The KGA Exceedance Action Plan directly addresses the chronic lowering of groundwater levels since beneficial users in the Subbasin are most impacted by groundwater levels. Within the management areas of the KGA, the Exceedance Policy also addresses reduction in groundwater storage and degradation of water quality, as a proxy.

The following four-step action plan has been developed to address a minimum threshold exceedance for the chronic lowering of groundwater levels at a single representative monitoring well, including coordination between KGA management areas and/or other GSAs.

1. **Identify Exceedance and Investigate the Representative Monitoring Well Area:** After each annual report, the KGA managers team will review data and identify any exceedances of minimum thresholds for each RMW and will compile a summary of minimum threshold exceedances, as noted in the annual report, for review by the KGA Board.

   Various conditions surrounding the representative monitoring well will be considered. For example: Are water levels declining in nearby wells? If so, how large of an area is affected? Has a new well been installed nearby or localized groundwater extraction increased? Is the problem related to area-wide drought conditions? Has local demand increased? If increased demand is responsible for the exceedance, then is a sustainable water budget needed and/or being adhered to in the area?
2. **Evaluate Outside Management Area Plan Contributing Factors:** Provided that aquifer connectivity exists between MAP areas and groundwater impacts cross MAP boundaries, declining groundwater levels in an area may be the result of operations in an adjacent MAP and/or an adjacent GSA. In this situation, the KGA member may not be able to resolve any exceedances unilaterally. KGA members in adjacent MAPs agree to coordinate. Updates or proposals will be reported back to the KGA board at a regular board meeting thus providing transparency.
3. **Consider Developing Management Actions and/or Projects:** Any KGA member with a minimum threshold exceedance may develop or modify existing management actions or projects to mitigate a minimum threshold exceedance and avoid undesirable results ("mitigation plan"). Any mitigation plan should be submitted to the KGA managers team for review. The mitigation plan along with any KGA managers team comments will be submitted to the KGA Board. To the extent the mitigation plan includes any new management actions, any proposed modifications to an existing management action or new projects, the KGA will consider how those changes will be incorporated into any update to the KGA GSP and the annual report.
4. **Consider Enforcement Plan:** In the event of a management area exceedance the KGA member or contributing member(s) will consider developing and/or implementing policies and programs intended to eliminate or mitigate the exceedance (enforcement plan). The enforcement plan(s) must be submitted to the KGA and the KGA will have 90 days to determine whether the enforcement plan is sufficient to demonstrate the avoidance of undesirable results. If no enforcement plan is submitted to KGA, the KGA Board may recommend policies or programs to the member(s) that could, in its discretion, take to remedy the existence of a management area exceedance(s) and to avoid undesirable results.

3.3 Management Area Exceedance

Within the Kern Subbasin a Management Area Exceedance occurs when a management area exceeds minimum thresholds at 40% or more of representative monitoring wells within a management area over four (4) consecutive bi-annual SGMA monitoring events, referred to as the Minimum Threshold Trigger. Once a management area triggers the Management Area

Exceedance, the management area will be counted towards the calculation of an undesirable result for the entire Subbasin.

The Management Area Exceedance criteria applies to Chronic Lowering of Groundwater Levels and by proxy to Reduction of Groundwater Storage, and Degraded Water Quality. Land Subsidence is considered as the rate of subsidence at California Aqueduct and the Friant-Kern Canal, as explained Section 3.4.5. Table 3-1 shows the total number of representative monitoring wells in each Subbasin management area for groundwater levels and the number of which would have to exceed their respective minimum threshold to for the management to trigger a Management Area Exceedance.

3.4 Undesirable Results

Undesirable results for each sustainability indicator have been developed through a collaborative process with all the GSAs in the Subbasin, compliant with GSP emergency regulations, which state that undesirable results are to be defined consistently throughout the basin (23-CCR § 354.20). Seawater intrusion and depletion of interconnected surface water were determined not to be present in the Subbasin; therefore, undesirable results for these sustainability indicators were not defined. Justification for these determinations is provided in Sections 3.2.4 and 3.2.5.

The undesirable results developed for this Subbasin represent a condition of significant and unreasonable impacts to the beneficial uses and users of groundwater over a broad area of the Subbasin. The undesirable results definition for the Subbasin allows flexibility for each management area within the Subbasin to define minimum thresholds that protect against significant and unreasonable impacts to the beneficial uses and users of groundwater within specific management areas and as was stated in Section 3, the KGA members used as a foundation a water well impact analysis for all beneficial users and uses. The minimum thresholds within a management area have also been coordinated with other management areas and/or other GSAs to ensure coordination and reasonable operating conditions between management areas.

Table 3-1 NEW. Kern Subbasin Management Area Exceedances Information

KGA Management Area	# of Representative Wells	# of Well Exceedances to Trigger Management Area Exceedance Criteria	Acres in Management Area	Percentage of Subbasin
Cawelo GSA	7	3	62,616	3.5
Eastside Water Management Agency	6	2	38,222	2.1
Kern-Tulare Water District (in Kern)	6	2	11,219	0.6
North Kern WSD				
MA-1 (Old District)	8	4	61,741	3.4
MA-2 (RRID)	2	1	5,802	0.3
KCWA-Pioneer GSA	5	2	2,233	0.1
Kern Water Bank Authority	0	0	20,490	1.1
Rosedale-Rio Bravo WSD	19	8	48,610	2.7
Southern San Joaquin MUD	10	4	65,693	3.7
Shafter-Wasco Irrigation District	7	3	39,980	2.2
7th Standard Annex	3	2	10,045	0.6
Semitropic GSA				
MA-1 (Pond Poso)	6	2	82,638	4.6
MA-2 (Buttonwillow)	5	2	92,633	5.2
MA-3 (Undeveloped)	2	1	49,140	2.7
West Kern GSA				
North Project MA	6	2	521	0.0
South Project MA	17	7	889	0.0
Western Watch Area [1]	n/a	n/a	183,128	10.2
Lake Watch Area [1]	n/a	n/a	653	0.0
LSMV Watch Area [1]	n/a	n/a	1,947	0.1
Westside Districts Water Authority				
Westside District MA	3	1	195,263	10.9
Lost Hills Watch Area [1]	n/a	n/a	33,191	1.9
Southwest Watch Area [1]	n/a	n/a	48,739	2.7
Non-District White Lands Watch Areas [1]	n/a	n/a	210,034	11.7

2. "Watch Areas" are areas with no significant groundwater use and no planned groundwater use as documented by the management area member agency. Water areas will be monitored for land use changes and groundwater conditions which could change its designation to a "management area" with specified SMCs.

Undesirable results for each sustainability indicator have been developed through a collaborative process with all the GSAs in the Subbasin, compliant with GSP emergency regulations, which state that undesirable results are to be defined consistently throughout the basin (23-CCR §

354.20). Seawater intrusion and depletion of interconnected surface water were determined not to be present in the Subbasin; therefore, undesirable results for these sustainability indicators were not defined. Justification for these determinations is provided in Sections 3.2.4 and 3.2.5.

The undesirable results developed for this Subbasin represent a condition of significant and unreasonable impacts to the beneficial uses and users of groundwater over a broad area of the Subbasin. The undesirable results definition for the Subbasin allows flexibility for each management area within the Subbasin to define minimum thresholds that protect against significant and unreasonable impacts to the beneficial uses and users of groundwater within specific management areas and as was stated in Section 3, the KGA members used as a foundation a well impact analysis for all beneficial users and uses. The minimum thresholds within a management area have also been coordinated with other management areas and/or other GSAs to ensure coordination and reasonable operating conditions between management areas.

3.4.1 Criteria Used to Define Undesirable Results

Defining the point of a Subbasin level undesirable result begins with a defined level of significant and unreasonable impacts to beneficial users, both spatially and temporally, within each management area of the Subbasin. The accumulation of impacts to beneficial users throughout the Subbasin, and across multiple management areas, representing a persistent and prevalent occurrence of impacts to beneficial users is considered an undesirable result.

For Chronic Lowering of Groundwater Levels, Reduction of Groundwater Storage and Degraded Water Quality the Kern Subbasin has defined the occurrence of an undesirable results as the level of impacts affecting either:

- 15% of the Subbasin area, measured as the combined acres of three adjacent management areas with Management Area Exceedances, or
- 30% of the Subbasin area, measured as the combine acres of any management area with Management Area Exceedances.

The criterion of three adjacent management areas of at least 15% of the Subbasin was developed to recognize a condition where degrading groundwater conditions from one management area spreads to adjacent management areas. This criterion recognizes that even the lesser percentage of the Subbasin (15%) as a contiguous area is significant with regards to the potential for further degradation of groundwater conditions across the Subbasin. The criterion of 30% of the Subbasin (generally noncontiguous management areas) recognizes a condition of widespread degradation of groundwater conditions across the whole of the Subbasin and across a diverse demographic of beneficial users, operational and geologic landscape.

Figure 3-2 provides an example of the occurrence of an undesirable result when Management Area Exceedances have occurred in at least three (3) adjacent management areas that represent at least 15% of the Subbasin (as measured by the acreage of each management area). In this example three management areas which are adjacent to each other are designated as

Management Area Exceedances (defined in Section 3.3) and whose management areas account for more than 15% of the Subbasin.

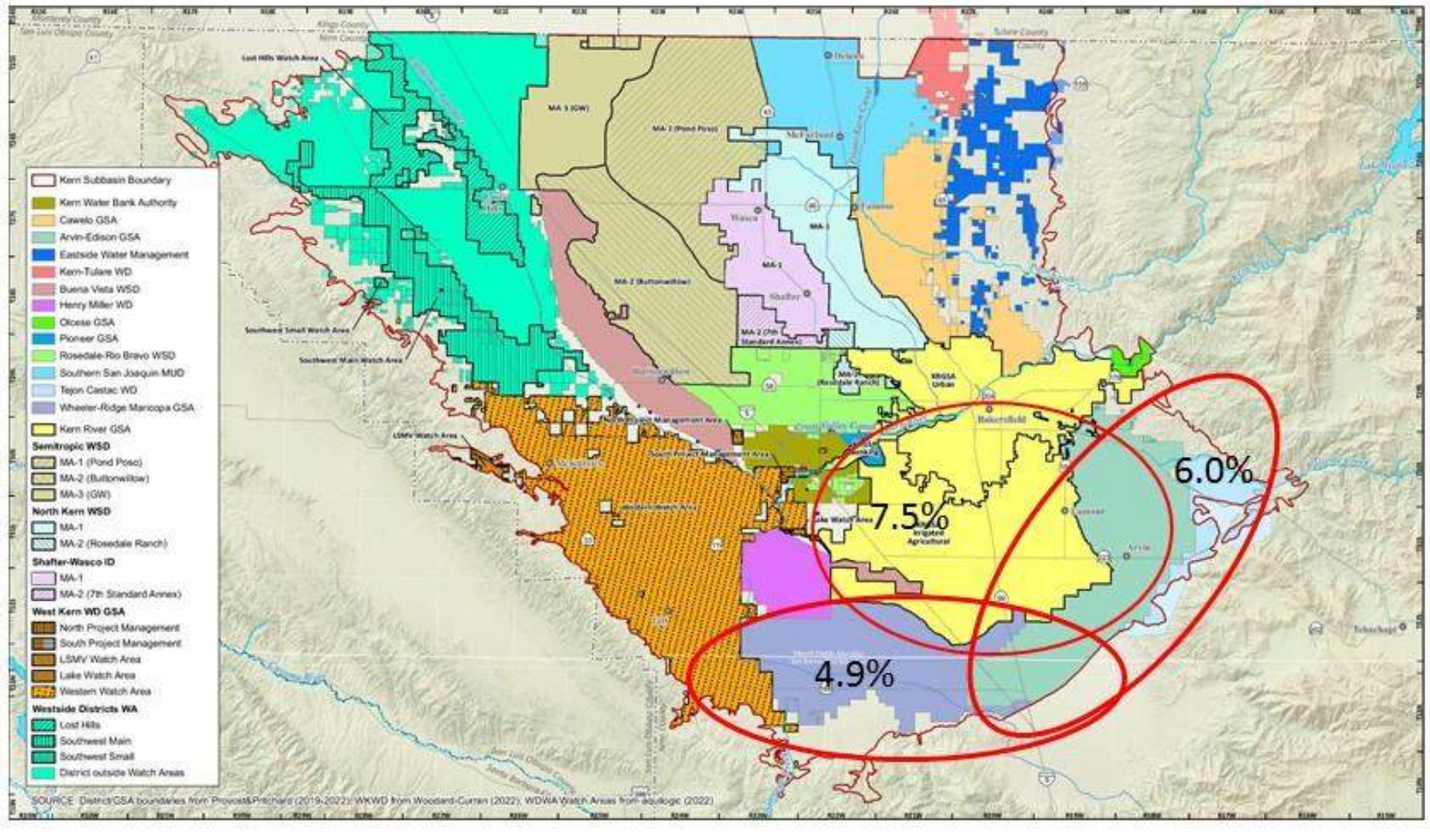
Figure 3-3 provides an example of the occurrence of the undesirable result criteria when Management Area Exceedances have occurred in greater than 30% of the Subbasin (as measured by the acreage of each management area). In this illustrative example seven (7) separate management areas are experiencing Management Area Exceedance areas (defined in Section 3.3) and the combined acreage accounts for more than 30% of the Subbasin. This criterion recognizes a large spread degraded of groundwater conditions across the whole of the Subbasin and across a diverse demographic of beneficial users, operational and geologic landscape. As the Kern subbasin GSAs were working through the criteria to define undesirable results, key characteristics of the basin that played an important role in the definitions were:

1. One important characteristic is the size of the basin and variation in hydrology and geology from the west side of the basin differs from the east side, as does the north boundary line to the south, and neither direction responds exactly the same to groundwater activities.
2. Another important characteristic is the scattering of beneficial users and uses as well as in some cases having no beneficial users and uses in some areas. This characteristic in some cases is even diverse between adjacent management areas. For example, one area has domestic beneficial users and the adjacent management area might have no beneficial users.

As the development of the definitions was moving forward, it became very apparent that there exist data gaps where the Basin Study would assist in more accurate approach and direction for the update GSPs in 2025.

Management Area	Acres	Percent of Subbasin
Cawelo GSA	62,616	3.5%
Eastside Water Management Area	38,222	2.1%
Kern-Tulare WD *(in Kern County)*	11,219	0.6%
North Kern WSD		
MA-1	61,741	3.4%
MA-2 (Rosedale Ranch)	5,802	0.3%
KCWA - Pioneer GSA	2,233	0.1%
Kern Water Bank Authority	20,490	1.1%
Rosedale-Rio Bravo WSD	48,610	2.7%
Southern San Joaquin MUD	65,693	3.7%
Shafter-Wasco ID		
MA-1	39,980	2.2%
MA-2 (7th Standard Annex)	10,045	0.6%
Semitropic GSA		
MA-1 (Pond Poso)	82,638	4.6%
MA-2 (Buttonwillow)	92,633	5.2%
MA-3 (Undeveloped)	49,140	2.7%
West Kern WD GSA		
North Project Management Area	521	0.0%
South Project Management Area	889	0.0%
Western Watch Area	183,128	10.2%
Lake Watch Area	653	0.0%
LSMV Watch Area	1,947	0.1%
Westside District WA		
Westside District WA	195,263	10.9%
Lost Hills Watch Area	33,191	1.9%
Southwest Watch Area	48,739	2.7%
Non-District White Lands Watch Areas	210,034	11.7%
South of Kern River Districts		
Arvin Edison WSD GSA	107,728	6.0%
Tejon Castac WD GSA	19,280	1.1%
Wheeler Ridge-Maricopa WSD GSA	87,391	4.9%
Kern River GSA		
KRGSA - AG	134,104	7.5%
KRGSA - Banking	5,045	0.3%
KRGSA - Urban	93,350	5.2%
Buena Vista GSA	50,414	2.8%
Henry Miller GSA	26,055	1.5%
Olcese GSA	3,206	0.2%
TOTALS:	1,792,000	100.00%

"..least three (3) adjacent management areas that represent at least 15% of the Subbasin ..."

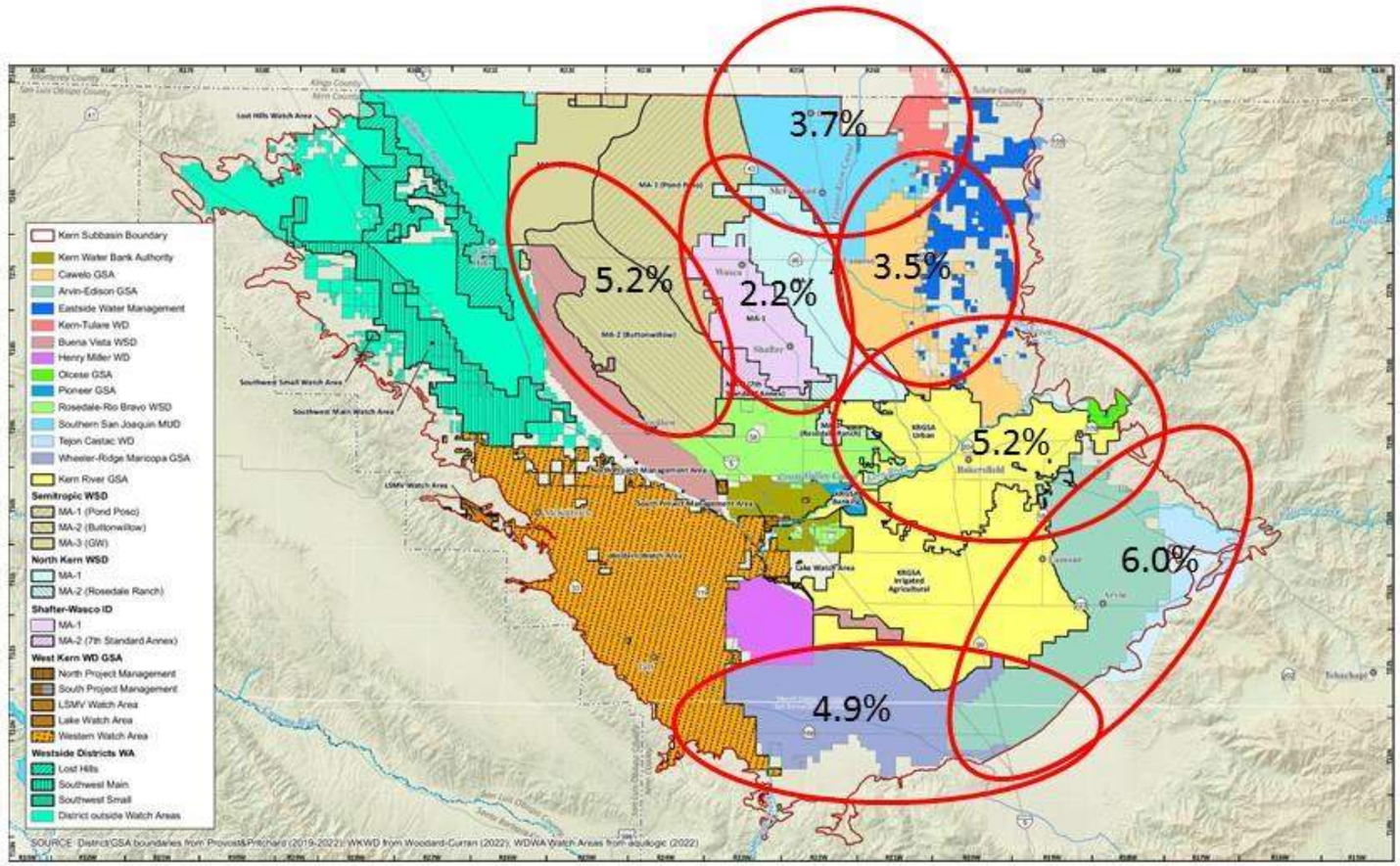


18.4 % of the Subbasin

Figure 3-2 NEW. Example of Undesirable Results Criteria for 15% of Subbasin.

Management Area	Acres	Percent of Subbasin
Cawelo GSA	62,616	3.5%
Eastside Water Management Area	38,222	2.1%
Kern-Tulare WD *(in Kern County)*	11,219	0.6%
North Kern WSD		
MA-1	61,741	3.4%
MA-2 (Rosedale Ranch)	5,802	0.3%
KCWA - Pioneer GSA	2,233	0.1%
Kern Water Bank Authority	20,490	1.1%
Rosedale-Rio Bravo WSD	48,610	2.7%
Southern San Joaquin MUD	65,693	3.7%
Shafter-Wasco ID		
MA-1	39,980	2.2%
MA-2 (7th Standard Annex)	10,045	0.6%
Semitropic GSA		
MA-1 (Pond Poso)	82,638	4.6%
MA-2 (Buttonwillow)	92,633	5.2%
MA-3 (Undeveloped)	49,140	2.7%
West Kern WD GSA		
North Project Management Area	521	0.0%
South Project Management Area	889	0.0%
Western Watch Area	183,128	10.2%
Lake Watch Area	653	0.0%
LSMV Watch Area	1,947	0.1%
Westside District WA		
Westside District WA	195,263	10.9%
Lost Hills Watch Area	33,191	1.9%
Southwest Watch Area	48,739	2.7%
Non-District White Lands Watch Areas	210,034	11.7%
South of Kern River Districts		
Arvin Edison WSD GSA	107,728	6.0%
Tejon Castac WD GSA	19,280	1.1%
Wheeler Ridge-Maricopa WSD GSA	87,391	4.9%
Kern River GSA		
KRGSA - AG	134,104	7.5%
KRGSA - Banking	5,045	0.3%
KRGSA - Urban	93,350	5.2%
Buena Vista GSA	50,414	2.8%
Henry Miller GSA	26,055	1.5%
Olcese GSA	3,206	0.2%
TOTALS:	1,792,000	100.00%

"... greater than 30% of the Subbasin (as measured by each management area)."



30.7 % of the Subbasin

Figure 3-3 NEW. Example of Undesirable Results Criteria for 30% of Subbasin.

3.4.2 Undesirable Result for Chronic Lowering of Groundwater Levels

The basin-wide definition for undesirable results for chronic lowering of groundwater levels is as follows:

> *The point at which significant and unreasonable impacts over the planning and implementation horizon, as determined by depth/elevation of water, affect the reasonable and beneficial use of, and access to, groundwater by overlying users.*
>
> *This is determined when the minimum threshold for groundwater levels are exceeded in at least three (3) adjacent management areas that represent at least 15% of the Subbasin or greater than 30% of the Subbasin (as measured by each management area). Minimum thresholds shall be set by each of the management areas through their respective management area plans or Groundwater Sustainability Plans.*

This undesirable result definition at the Subbasin level provides flexibility at the management area level to identify the appropriate users and uses of groundwater and the levels of impacts important in that area of the Subbasin. Consistent with DWR's Draft BMP for Sustainable Management Criteria, the Subbasin recognizes that: "overdraft during a period of drought is not sufficient to establish a chronic lowering of groundwater levels if extractions and groundwater recharge are managed as necessary to ensure that reductions in groundwater levels or storage during a period of drought are offset by increases in groundwater levels or storage during other periods." The Subbasin has agreed that a drought period of greater than 10-years would constitute prolonged drought and the lowering of groundwater levels or groundwater storage to below minimum thresholds resulting from a prolonged drought will not constitute an undesirable result.

The Subbasin is trying to avoid widespread occurrence of groundwater levels declining below the minimum thresholds, which indicates the Subbasin is not sustainably managing groundwater conditions in the aggregate and that beneficial users could be affected on a spatial and temporal scale that it too substantial to mitigate. If groundwater levels approach the minimum threshold, isolated exceedances will likely occur and is expected to progressively occur in multiple wells if there is no intervention. To avoid a widespread occurrence of MT exceedances, the KGA established an *Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater*, which is a proactive approach to identifying and working with management areas to address a single, isolated exceedance. If intervention at a single MT exceedance is unsuccessful, a Management Area Exceedance may be triggered, which could trigger a Subbasin-wide undesirable result.

As described above, an undesirable result for chronic lowering of groundwater levels occurs when a combination of management areas reaches Management Area Exceedance status, totaling 15% or 30% of the Subbasins acreage. This undesirable results criterion recognizes a large spread of chronic groundwater level declines across the whole of the Subbasin and across a diverse demographic of beneficial users, operational, and geologic landscape that significantly and unreasonably impacts beneficial users.

3.4.2.1 Potential Cause of Chronic Lowering of Groundwater Levels

Section 354.26(b)(1) of the GSP Regulations requires identification of potential causes of an undesirable result for each sustainability indicator. Potential causes of undesirable results for chronic lowering of groundwater levels vary throughout the Subbasin. Lowering groundwater levels can be attributed to increased groundwater pumping, reduced imported water supplies, reduced groundwater inflows from adjacent areas, and/or climate change that results in more frequent and extreme droughts and dry periods. Because of the size of the Kern subbasin and the geology and hydrology, each management area is not created equally and thus for more specific information regarding their specific cause of chronic lowering of groundwater levels in the regions of the Subbasin, refer to the management area plans. None of the KGA management areas have any other causes of chronic lowering of groundwater levels other than what are mentioned in this section however some management areas have different beneficial users and uses that are more dominate and have indicated that in their specific management area plans as well as how their will limit impacts to those users and uses.

3.4.2.2 Potential Effects of Chronic Lowering of Groundwater Levels

Section 354.26(b)(3) of the GSP regulations requires identification of potential effects of an undesirable result for chronic lowering of groundwater levels. Potential effects of an undesirable result due to the chronic lowering of groundwater levels is the potential to affect the reasonable and beneficial use of, and access to, groundwater by overlying beneficial users. As previously mentioned, the beneficial uses and users of water varies across the Subbasin and each management area plan address the potential effects on those uses and users. Also, as previously mentioned, these plans are coordinated to avoid impacts to the neighboring GSAs or management areas. As mentioned in Section 2.5 Management Areas and the reason why management areas were established, for more detailed information on how the effects or impacts to the beneficial users concerning the chronic lowering of groundwater levels in specific areas refer to the individual management area plans.

3.4.3 Undesirable Result for Reduction of Groundwater Storage

The basin-wide definition of an undesirable result for reduction of groundwater storage is as follows:

> *The point at which significant and unreasonable impacts, as determined by the amount of groundwater in the basin, affect the reasonable and beneficial use of, and access to, groundwater by overlying users over an extended 10-year drought period.*
>
> *This is determined when the volume of storage (above the groundwater level minimum threshold) is depleted to an elevation lower than the groundwater level minimum threshold in at least three (3) adjacent management areas that represent at least 15% of the subbasin or greater than 30% of the subbasin (as measured by the acreage of each management areas). Minimum thresholds shall be set by each of the management area through their respective management area plans or Groundwater Sustainability Plans.*

Groundwater storage is coordinated and collaborated across the Subbasin, based on groundwater modeling budgets (historical, baseline and projected). To protect groundwater in storage, KGA Members are managing to their MO, which provides sufficient groundwater to manage through a 10-year drought condition before water levels decline to the MT. Considering the Kern Subbasin's capacity to store water is plentiful, and that the MT for chronic lowering of groundwater levels was set to avoid significant and unreasonable impacts to beneficial users, when used as a proxy for groundwater in storage, groundwater levels are inherently protective of the groundwater storage. An undesirable result in the Kern Subbasin has been defined for the reduction of groundwater storage as a condition that occurs throughout the Subbasin which represents unsustainable management of basin-wide groundwater resources. This begins with a defined level of significant and unreasonable impacts to beneficial users from reduced groundwater storage, both spatially and temporally, in the Kern Subbasin as well as within each management area of the Subbasin. The accumulation of impacts to beneficial users throughout the Subbasin, and across multiple management areas, representing a persistent and prevalent occurrence of impacts to beneficial users that is considered an undesirable result. Refer to Figures 3-2 and 3-3 for applied examples of the undesirable results criteria for reduction of groundwater storage.

Because of the history of the Kern subbasin actively recharging the basin since the early 1950s and being the first agricultural county to execute contracts on the State Water Project back on November 16, 1963, groundwater storage is vital to the Kern subbasin. The Kern subbasin has a history of storing millions of acre feet of water in wet water years to limit the reduction of groundwater storage. This practice has allowed all beneficial users and uses the benefit of costs associated to power costs that are associated to extraction of groundwater, meaning that with recharging activities the beneficial users will pay less in power extraction costs. Using the new developed website from DWR called California Groundwater Live: reported dry wells, the Kern subbasin since 2015 (SGMA start date) has seen only 18 wells that have been reported, and no municipal well in that number. This provides some insight into the ability to store and thus limit the reduction of groundwater stored. Note that this timeline, covered the last drought period.

Another item to note, is the hydrology and geology of the Kern subbasin is so complex that data gaps are very apparent. The Kern subbasin's base of fresh water is below the set of the minimum thresholds and the Basin Study will assist in providing concrete data to support that assumption during the development and submittal of the updated 2025 GSP. Also, during the development and submittal of the annual reports, the Kern subbasin re-evaluates the groundwater storage in volume amount and with the grant funds now available to begin the Basin Study, the Kern subbasin is working to have in the updated 2025 GSPs, volume data on groundwater storage that is accurate. During the development of the 2020 GSPs, the Kern subbasin acknowledged the data gaps and thus the updated GSPs will provide groundwater storage in volume based on the new calibrated water model that will come from the Basin Study.

3.4.3.1 Potential Cause of Reduction of Groundwater Storage

Section 354.26(b)(1) of the GSP regulations requires identification of potential causes of undesirable results for each sustainability indicator. Potential causes of an undesirable result for reduction of groundwater storage vary throughout the Subbasin, specifically the volume of storage needed to manage to a 10-year drought condition while maintaining groundwater levels at or above the minimum threshold for chronic lowering of groundwater levels. Although the SGMA regulations state drought conditions cannot trigger an undesirable result, the KGA members developed undesirable result definitions with consideration of how best to manage to a 10-year drought condition. To protect groundwater storage, the KGA members are using their water budgets to manage at or above the measurable objective and sustainably manage through a 10-year drought. Thus, difference between the measurable objective and minimum threshold equates to the volume of groundwater storage needed to sustainably manage through a 10-year drought. Reduction of groundwater storage can be attributed to increased groundwater pumping; reduced imported water supplies; reduced surface water and banking; reduced groundwater inflows from adjacent areas; and/or climate change that results in more frequent and extreme droughts and dry periods. Similar to the chronic lowering of groundwater levels, for more specific areas of the Subbasin and to determine the potential cause of reduction of groundwater storage, refer to the management area plan for the specific area.

3.4.3.2 Potential Effects of Reduction of Groundwater Storage

Section 354.26(b)(3) of the GSP regulations requires identification of potential effects of an undesirable result for reduction of groundwater storage. Potential effects of reduction of groundwater storage could lead the limited groundwater availability during a prolonged drought with impacts to beneficial users and uses in high power costs, construction of wells to accommodate the reduction and possible relocation of some water wells.

3.4.4 Undesirable Result for Degraded Water Quality

The basin-wide definition of an undesirable result for degraded water quality is as follows:

> *The point at which significant and unreasonable impacts over the planning and implementation horizon, as caused by water management actions, that affect the reasonable and beneficial use of, and access to, groundwater by overlying users.*
>
> *This is determined when the minimum threshold for a groundwater quality constituent of concern is exceeded in at least three (3) adjacent management areas that represent at least 15% of the subbasin or greater than 30% of the designated monitoring points within the basin. Minimum thresholds shall be set by each of the management areas through their respective management area plans or Groundwater Sustainability Plans.*

As with chronic lowering of groundwater levels, the above basin-wide definition allows for local definition, within each management area of the Subbasin, of the minimum thresholds that constitute a significant and unreasonable impact to the beneficial users within each management area. Due to the hydrology and geology of the basin as well as the size of the basin this approach

provides more accurate specific setting of the minimum thresholds that will accomplish compliance with SGMA.

Similar to reduction of groundwater storage, groundwater levels are also used as a proxy for degraded water quality in some management areas. As with the previous sustainability indicators, an undesirable result in the Kern Subbasin for the degraded water quality represents a condition that occurs throughout the Subbasin representing unsustainable management of basin-wide groundwater resources. This begins with a defined level of significant and unreasonable impacts to beneficial users from degraded water quality conditions, both spatially and temporally, within each management area of the Subbasin. The accumulation of defined water quality impacts to beneficial users throughout the Subbasin, measured as a Management Area Exceedance, representing a persistent and prevalent occurrence of impacts to beneficial users is considered an undesirable result. Refer to Figures 3-2 and 3-3 for applied examples undesirable results criteria for reduction of reduction of water quality.

Establishment of specific measurable objectives and minimum thresholds based on the above definition for this undesirable result can be found in Section 3.3.

An overview of the existing water quality conditions in the Subbasin is provided in the basin setting section of this GSP. Additionally, details of the water quality monitoring in the KGA can be found in Section 3.6.7.2.

3.4.4.1 Potential Cause of Degraded Water Quality

Section 354.26(b)(1) of the GSP regulations requires identification of potential causes of undesirable results for each sustainability indicator. Potential causes of an undesirable result for degraded water quality vary throughout the Subbasin. Water quality in the Subbasin has been historically sustainable with few exceptions. In the future, water quality can be degraded by significant increase in groundwater pumping or unforeseen point source contamination issues caused by natural or human activity. Each management area plan addresses the cause of degraded water quality in their management area differently since the Subbasin has dynamic differences in hydrology and water supplies and uses. For detailed causes of degraded water quality in a specific area, refer to the management area plans.

3.4.4.2 Potential Effects of Degraded Water Quality

Section 354.26(b)(3) of the GSP regulations requires identification of potential effects of an undesirable result for degraded water quality. An undesirable result for degraded water quality could affect beneficial users. This could potentially reduce the amount of usable supply delivered to groundwater users and require the need for treatment systems, which could potentially have a negative economic effect. As mentioned above for the cause of degraded water quality, the effects or impacts vary in the Subbasin and the management area plans provide more detailed information for their specific areas.

3.4.5 Undesirable Result for Land Subsidence

The basin-wide definition of an undesirable result for land subsidence is as follows:

The point at which significant and unreasonable impacts, as determined by a subsidence rate and extent in the basin, that affects the surface land uses or critical infrastructure.

This is determined when subsidence results in significant and unreasonable impacts to critical infrastructure as indicated by monitoring points established by a basin wide coordinated GSP subsidence monitoring plan.

An undesirable result for land subsidence is further identified as the occurrence of a single minimum threshold exceedance along either the Aqueduct or the Friant-Kern Canal. The minimum thresholds for the Aqueduct are detailed in the white paper in Attachment E3. See the Friant-Kern white paper (Attachment 4) for a detail discussion the minimum thresholds for that facility.

CA Aqueduct

The California Aqueduct (Aqueduct) has been identified as regional critical infrastructure on the west side of the Subbasin. The Subbasin definition of an undesirable result for land subsidence is the point at which the amount of inelastic subsidence, if caused by SGMA-related Subbasin groundwater extractions, creates a significant and unreasonable impact (requiring either retrofitting or replacement to a point that is economically unfeasible to the beneficial users) to surface land uses or critical infrastructure. A significant loss in functionality that could be mitigated through retrofitting and is considered economically feasible to the beneficial users would not be considered undesirable.

Friant-Kern Canal

An undesirable result for land subsidence is defined as the point at which the amount of inelastic subsidence, if caused by Subbasin groundwater extractions, creates a significant and unreasonable impact to surface land uses or critical infrastructure. A significant and unreasonable impact to the FKC is determined when the flow capacity through the Lower Reach is reduced to capacities below historical operational flow capacities over the previous 10 years, impacting surface land uses of available water supplies, as a result of groundwater extractions from agricultural, domestic, municipal, or urban beneficial users within the Kern County Subbasin.

Establishment of specific measurable objectives and minimum thresholds based on the above definition for this undesirable result can be found in Section 3.5 and within each management area plan. Additional details on subsidence monitoring can be found in 3.6.7.4.

3.4.5.1 Potential Cause of Land Subsidence

Section 354.25(b)(1) of the GSP regulations requires identification of potential causes of an undesirable result for land subsidence. Potential causes of land subsidence vary throughout the Subbasin. A variety of subsurface conditions and mechanisms, not all completely understood, can cause subsidence. A relatively minor amount of subsidence over a wide area can be insignificant and/or imperceptible, whereas a significant amount of localized subsidence can create an unreasonable impact to overlying infrastructure. Although groundwater extractions for agricultural or other uses have potential under limited conditions to cause subsidence, recent

studies conducted by Management Areas on the west side and the KGA have identified soluble soils, natural differential compaction and oil and gas production activities as potential contributors to subsidence along the Aqueduct. None of the subsidence modes besides groundwater extraction for agricultural and other Management Area beneficial uses are within the control or jurisdiction of Subbasin GSAs. Identifying the subsurface conditions and mechanisms causing subsidence in the Subbasin will be a critical first step to managing current and future impacts and identifying appropriate management actions. Recent reports of damage to critical infrastructure due to land subsidence are provided in detail in the management area plans. Data gaps and challenges to setting sustainable management criteria and monitoring for undesirable results due to land subsidence are presented in Section 3.4. Potential Effects of Land Subsidence

Section 354.26(b)(3) of the GSP regulations requires identification of potential effects of an undesirable result for land subsidence. Potential effects of land subsidence include damage to critical infrastructure including pipelines, roads, building, water conveyance systems, and flood control facilities. In the Kern Subbasin, the most sensitive infrastructure is the California Aqueduct and Friant-Kern Canal. Damage to these systems could impact surface water deliveries, resulting in increased groundwater use.

3.4.6 Seawater Intrusion

The Subbasin is located approximately 60 miles from the Pacific Ocean, separated by the Coastal Range and other geologic features that prevent seawater from migrating into the Subbasin. Details of the geologic structure of the Subbasin can be found in the basin setting of this GSP. Based on the separation of the Subbasin from any source of seawater, the Subbasin has not developed sustainable management criteria for this sustainability indicator.

3.4.7 Interconnected Surface Water

As defined in the California Code of Regulations (§ 351. Definitions), “Interconnected Surface Water” refers to water that is hydraulically connected at any point by a continuous saturated zone to the underlying aquifer and the overlying surface water is not completely depleted.” A discussion on interconnected surface water is included in Section 2.3.5. As there are no known natural interconnected surface water systems within the KGA boundary, this sustainability indicator is not included in this GSP.

3.5 Minimum Thresholds and Measurable Objectives

The SGMA planning effort began in 2013, prior to the enactment of SGMA, as districts in the Subbasin recognized the need to begin coordination of groundwater management activities. The initial efforts focused on developing an understanding of the significant issues facing groundwater management at the Subbasin and at the district level. Particularly important to this process was understanding the unique conditions that existed in the Subbasin. These conditions include, but are not limited to:

- Not all management areas have equal access to groundwater resources (quantity or quality).
- Each management area has variable imported or local water supplies (State Water Project, Friant Project, Kern River) each with their own management and reliability challenges.
- The ability to implement water management programs within management areas varies by the authorities of the managing entity and in some cases challenges coordination between districts.
- The beneficial uses and users of groundwater varied across the Subbasin.

Despite these unique conditions, the management areas within the Subbasin understood the need to coordinate the development of groundwater management activities and common technical methods on which to develop future management activities.

The KGA was formed under a JPA in 2017 and through that process the KGA/GSA Managers Group was formalized. The KGA/GSA Managers Group includes representatives from all KGA member agencies, typically the district general managers and technical experts, as well as representatives from each of the other GSAs developing a GSP in the Subbasin; Kern River GSA, Buena Vista GSA, Henry Miller GSA, Olcese GSA and South of Kern River GSAs. The measurable objectives and minimum thresholds within the Subbasin were developed in a collaborative process, starting with the KGA/GSA Managers Group. The Manager's Group has been meeting on a weekly basis to address coordination issues; develop and share technical information; identify and resolve potential conflicts; the development of all the annual reports: and, where appropriate, elevated issues to the Board of Directors of their respected GSAs and/or the Kern SGMA Coordination Committee comprised of representatives of all GSAs in the Subbasin.

Through the Managers Group, the process for developing minimum thresholds and measurable objectives for the entire subbasin was initiated. This process involved review of the SGMA requirements for thresholds and objectives, including their relationship and coordination to management areas; presentation of technical methods for establishing thresholds and objectives; and coordination between districts and GSAs through the establishment of draft and final thresholds and objectives.

The process was facilitated by the KGA/GSA Planning Manager and technical team with input and identification of issues from member agencies and GSA representatives. The general process for developing minimum thresholds and measurable objectives is outlined below:

Step 1: Regulatory and technical review of minimum threshold and measurable objectives requirements.

- **KGA/GSA Managers Group:** Provided overview of regulatory and technical requirements.
- **Member agencies and GSA representatives and technical consultants:** Sharing of technical approaches to establishing thresholds and objectives for their respective management areas.

Step 2: Defining roles and responsibilities for GSAs and management areas (district areas).

- **KGA/GSA Managers Group:** Presentations on roles and responsibilities for managing resources through proposed thresholds and objectives.
- **Member agencies and GSA representatives and technical consultants:** Identification of potential management area conflicts and opportunities for joint resource management strategies.

Step 3: Development of first draft minimum thresholds and measurable objectives for all Subbasin management areas.

- **KGA/GSA Managers Group:** Facilitate review of draft thresholds and objectives, including development of contour maps and cross-sections of thresholds and objectives.
- **Member agencies and GSA representatives and technical consultants:** Develop and execute technical approach for developing thresholds and objectives with presentation to the KGA Managers Group for review.

Step 4: Development of second draft thresholds and objectives for all Subbasin management areas.

- **KGA/GSA Managers Group:** Facilitate review of draft minimum thresholds and measurable objectives, including development of contour maps and cross-sections of thresholds and objectives.
- **Member agencies and GSA representatives and technical consultants:** Develop and execute technical approach for developing thresholds and objectives and presentation to the KGA Managers Group for review. Identify areas of potential conflicting minimum thresholds and measurable objectives in adjacent management areas and coordinate resolution with adjacent management area.

Step 5: Adoption of final minimum thresholds and measurable objectives.

- **KGA/GSA Managers Group:** Facilitate review of final thresholds and objectives and presentation of thresholds and objectives to KGA Board of Directors.
- **Member agencies and GSA representatives and technical consultants:** Resolve any outstanding conflicts and review thresholds and objectives with management area Boards of Directors and stakeholder groups
- **GSA Boards:** KGA/GSA managers presented to their specific boards for policy board approval

As demonstrated in the steps above, the KGA/GSA Managers Group facilitated the coordination and review of the Subbasin's minimum thresholds and measurable objectives. The technical work required to establish thresholds and objectives at the management area level was completed by the member agencies or GSAs. For the details of the technical processes utilized by KGA member agencies see their respective management area plans. One item to note, that during this

entire process the KGA held several stakeholder/beneficial users workshops to roll-out the minimum thresholds and measurable objectives for their input at each step. Also, at the KGA Board meetings, the minimum thresholds and measurable objectives appeared as discussion items.

All KGA Management Areas used a Well Impact Study to identify beneficial uses and users within each management area that reflects the types of users that actively rely on local groundwater resources and those that can be directly affected by groundwater management, impacts of operating at proposed Measurable Objectives (MO), and impacts of exceeding Minimum Thresholds (MT). Each MAP provides the details of the data and methodology applied to the Well Impact Study specific to that management area and identifies an estimate of potential impacts to beneficial users (in terms of dewatered wells) if groundwater elevations reach the MO and MT in the management area. Table 3-2 provides a tabular summary and Figure 3-4 shows a graphic summary of the number of wells for each beneficial use category (M-municipal, D-domestic, A-agricultural) and the potential impact to each category as a percent of wells that could be dewatered at the measurable objective. Table 3-3 shows a tabular summary of Figure 3-5 shows a graphic summary of the percent of wells that could be dewatered at the minimum threshold.

KGA Representative Monitoring Wells

Table 3-4 provides a list of the KGA groundwater level Representative Monitoring Wells with the MT and MO, as approved in June 2022. This table also shows where groundwater level is a representative proxy for water quality and land subsidence. Across the Subbasin, water levels are used as a proxy for groundwater in storage. There is also a column with a brief summary from each management area describing their definition of a MT Exceedance for each sustainability indicator. The purpose of this table is to show consistency amongst the KGA, and where there is a difference, there is an explanation of why a different threshold is most applicable to the management area. Figures 3-6 provides a map showing the RMW locations. Figures 3-7 and 3-8 show the MT and MO contours.

RMWs presented in Table 3-4 and Figures 3-4 through 3-6 do not include proposed changes in the amended Management Area Plans. The Monitoring Network will be updated to reflect management area revisions before the fall seasonal water level monitoring period begins. Table 3-5 summarizes the management areas that proposed changes.

Table 3-2. Tabular Summary of Wells Potentially Dewatered at the Measurable Objective

	Number of Wells				Number of Dewatered Wells			
	M	D	A	% M/D Wells	M	D	A	% M/D Wells
CWD	0	93	197	32%	0	0	0	0%
EWMA	2	11	41	24%	0	0	0	0%
NK	1	22	161	13%	0	0	2	0%
KTWD	0	18	94	16%	0	0	0	0%
RRB	24	149	156	53%	0	0	0	0%
SWID	16	68	118	42%	0	8	7	10%
SSJMUD	19	67	243	26%	0	13	11	15%
SWSD	4	138	763	16%	0	10	4	7%
WDWA	0	2	35	5%	0	0	0	0%
WKWD	13	0	0	100%	0	0	0	0%
7th Standard	2	9	19	37%	0	2	0	18%
Total	**81**	**577**	**1827**	**26%**	**0**	**33**	**24**	**5%**

0 Municipal wells going dry at the MT's
Anyone over 5% of Domestic wells dewatered required to put together a mitigation plan

M= Municipal, D= Domestic, and A=Agricultural

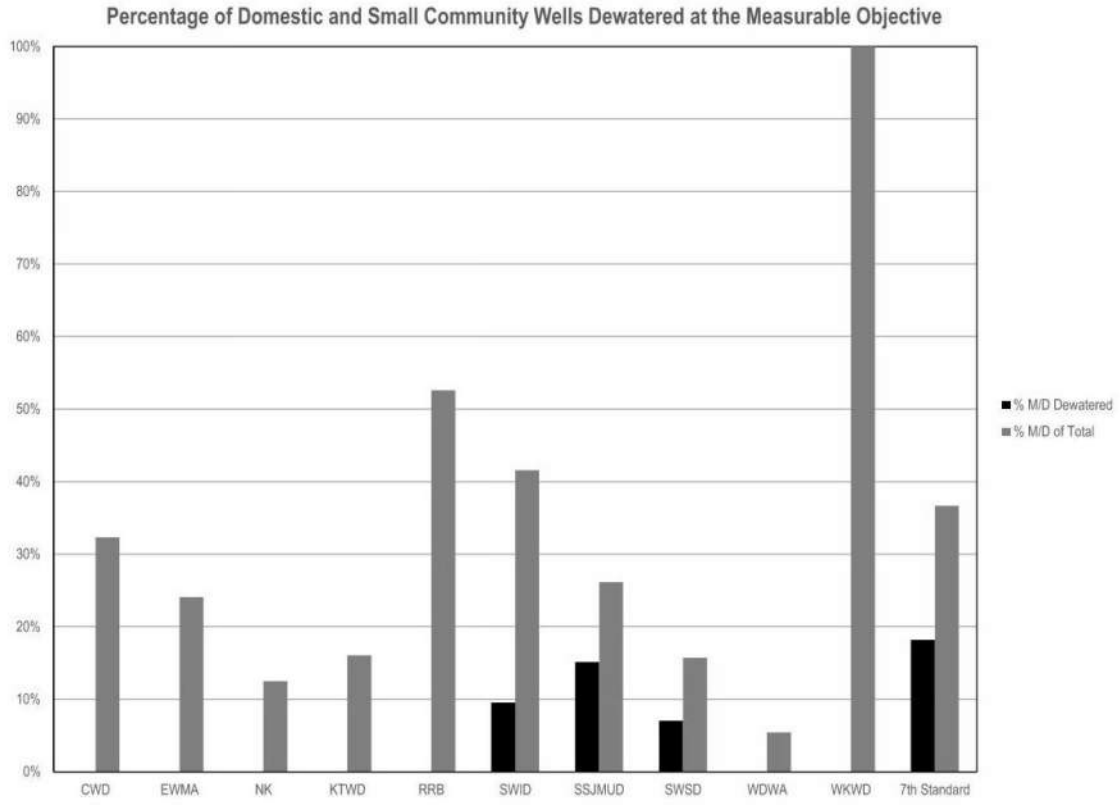


Figure 3-4. Graphic Summary of Wells Potentially Dewatered at the Measurable Objective

Table 3-3. Tabular Summary of Wells Potentially Dewatered at the Minimum Threshold

	Number of Wells				Number of Dewatered Wells			
	M	D	A	% M/D Wells	M	D	A	% M/D Wells
CWD	0	93	197	32%	0	3	1	3%
EWMA	2	11	41	24%	0	3	0	23%
NK	1	22	161	13%	0	2	5	9%
KTWD	0	18	94	16%	0	0	0	0%
RRB	24	149	156	53%	0	21	0	12%
SWID	16	68	118	42%	0	22	13	26%
SSJMUD	19	67	243	26%	0	29	25	34%
SWSD	4	138	763	16%	0	41	52	29%
WDWA	0	2	35	5%	0	0	0	0%
WKWD	13	0	0	100%	0	0	0	0%
7th Standard	2	9	19	37%	0	5	2	45%
Total	81	577	1827	26%	0	126	98	19%

0 Municipal wells going dry at the MT's
Anyone over 5% of Domesiic wells dewatered required to put together a mitigation plan

M= Municipal, D= Domestic, and A=Agricultural

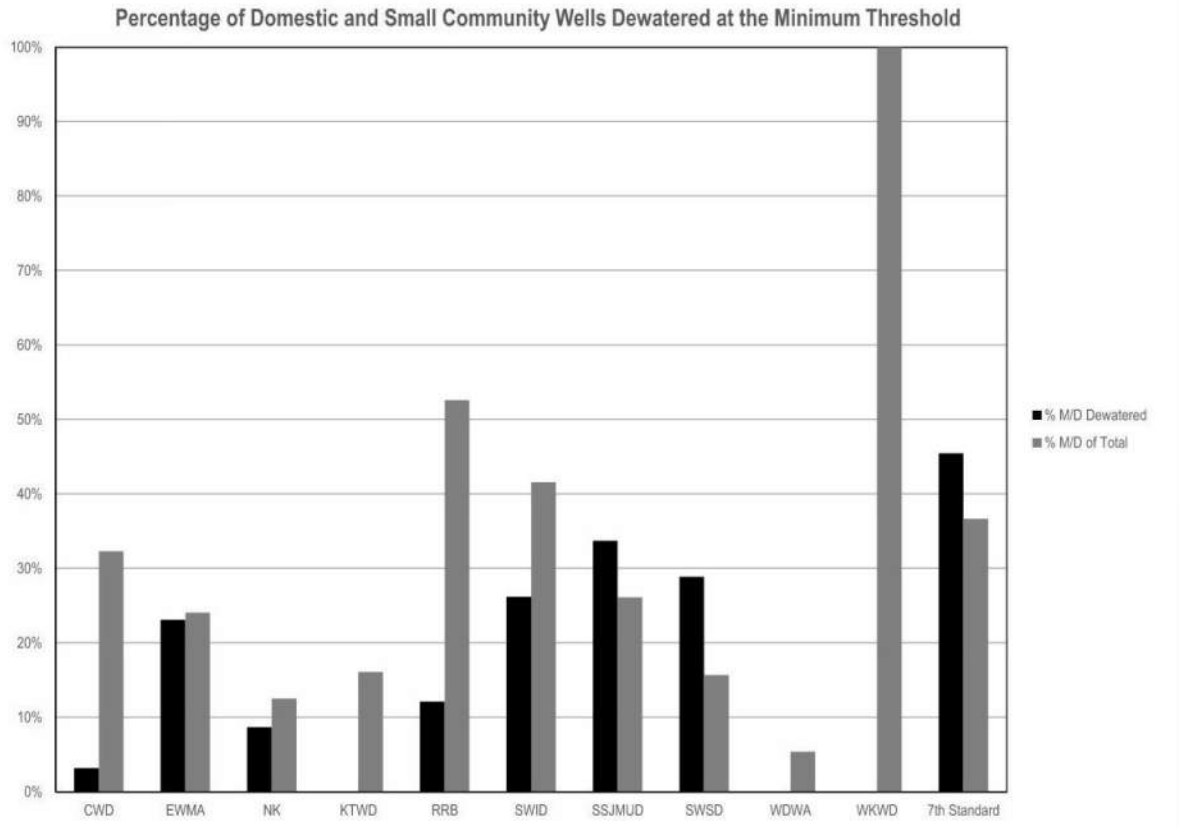


Figure 3-5. Graphic Summary of Wells Potentially Dewatered at the Minimum Threshold

KGA Representative Monitoring Wells

Table 3-4 provides a list of the KGA groundwater level Representative Monitoring Wells with the MT and MO, as approved in June 2022. This table also shows where groundwater level is a representative proxy for water quality and land subsidence. Across the Subbasin, water levels are used as a proxy for groundwater in storage. There is also a column with a brief summary from each management area describing their definition of a MT Exceedance for each sustainability indicator. The purpose of this table is to show consistency amongst the KGA, and where there is a difference, there is an explanation of why a different threshold is most applicable to the management area. Figures 3-6 provides a map showing the RMW locations. Figures 3-7 and 3-8 show the MT and MO contours.

RMWs presented in Table 3-4 and Figures 3-4 through 3-6 do not include proposed changes in the amended Management Area Plans. The Monitoring Network will be updated to reflect management area revisions before the fall seasonal water level monitoring period begins. Table 3-5 summarizes the management areas that proposed changes.

Table 3-4. Management Area Proposed Changes to the Regional Monitoring System

Management Area	Summary of Proposed Changes
North Kern WSD MA-1 (Old District)	MTs for RMWs in the southern portion of NKWSD will be raised 50-ft to reduce impacts to beneficial users and to coordinate with neighboring districts, MOs are also raised as appropriate. Refer to MAP Section 4.4, Table 4-3.
North Kern WSD MA-2 (Rosedale Ranch)	Two new wells were identified to serve as RMWs to represent this Management Area. MTs and MOs were set to be coordination with neighboring districts and with consideration for impacts to beneficial user. Refer to MAP Section 4.4, Table 4-3.
Shafter-Wasco Irrigation District (MA-1)	MTs for RMWs in the southern portion of SWID will be raised 50-ft to reduce impacts to beneficial users and to coordinate with neighboring districts. Refer to MAP Section 4.4, Table 4-4.
Shafter-Wasco 7th Standard Annex	Will raise the MTs and MOs for Chronic Lowering of Groundwater Levels by 50-ft to reduce impacts to beneficial users and to coordinate with adjacent Management Areas. Refer to Section 13.1.
Rosedale-Rio Bravo WSD	To provide clarity and to better coordinate with neighboring MAs, RRBMA prepared multiple groundwater level and MT cross-sections in the general direction of groundwater flow and crossing multiple MAs. MTs and MOs were compared and adjusted to the projected water levels for consistency across the coordinating MA's. Refer to MAP Section 5.7 for further details.
Semitropic Water Storage District	Added two RMW's to MA-2 (Buttonwillow) to coordinate and interpret groundwater responses with management areas on the Districts south and southeastern boundaries. MOs and MT with Rosedale-Rio Bravo. Refer to Chapter MAP Section 4.3.4 and Figure 4.1.

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Table 3-4. Summary of Minimum Thresholds and Measurable Objectives

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
Cawelo GSA		Well 12H	RMW-167	25	ft msl	103	ft msl	X		X	~~The undesirable result will be triggered when 30 percent or more of the monitoring wells in the Cawelo GSA fall below the MT during three (3) successive spring measurements.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The undesirable result will be triggered when 30 percent or more of the monitoring wells in the Cawelo GSA fall below the MT during three (3) successive spring measurements.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The undesirable result will be triggered when 30 percent or more of the monitoring wells in the Cawelo GSA have TDS concentrations rising above the MT for two continuous years.~~ A management area exceedance is considered to occur when more than 40% of representative monitoring wells used to monitor TDS concentrations exceed their minimum thresholds for two consecutive annual monitoring periods.	Since groundwater elevations below historical lows may lead to localized land subsidence undesirable results, the exceedance of the land subsidence MT at a single representative monitoring well will be considered a management area exceedance.
		Well 24R	RMW-170	-43	ft msl	35	ft msl	X		X				
		Well 11M	RMW-171	-81	ft msl	3	ft msl	X		X				
		Well 6C	RMW-172	-85	ft msl	-1	ft msl	X		X				
		Well 33C	RMW-173	-64	ft msl	20	ft msl	X		X				
		Well 28L	RMW-169	26	ft msl	110	ft msl	X		X				
		Well 4R	RMW-168	-24	ft msl	60	ft msl	X		X				
Eastside Water Management Authority		EWMA #04 *(added July 2020)*	RMW-283	-133.21	ft msl	87.79	ft msl	X			~~Measurement of water levels below minimum thresholds, in four (4) consecutive semiannual monitoring periods, in no less than 50% of the Representative monitoring network wells, rounded down to the nearest whole number, i.e., four (4) wells. (Sec 12.1.2)~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Same as GW levels criteria (Sec 12.2.2)~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	Chronic lowering of groundwater levels or changes in storage may potentially draw saline water into the area of groundwater production in these units in the EWMA, thus monitoring for TDS will be necessary to foresee and avoid Undesirable Results related to degradation of groundwater quality. (Sec 12.4).	There have been no known occurrences of significant (i.e., magnitude more than one foot) land subsidence within the EWMA (Figure GWC-4) and no observed negative effects. Since no "critical infrastructure" are located within the EWMA, no Undesirable Results are defined within the EWMA.. (Sec 12.5.3)
		EWMA #21	RMW-185	-110	ft msl	136	ft msl	X						
		EWMA #23	RMW-278	-71	ft msl	132	ft msl	X						
		EWMA #30	RMW-187	-228	ft msl	-71	ft msl	X						
		EWMA #10 *(added July 2020)*	RMW-280	-43	ft msl	175.8	ft msl	X						
		EWMA #41	RMW-189	-41	ft msl	230	ft msl	X						
		EWMA #49 *(added April 2022)*	RMW-	312.0	ft msl	381.9	ft msl	X						
Kern-Tulare Water District		Well 4P1	RMW-175	-150	ft msl	20	ft msl	X			~~An Undesirable Result for the KTWD would be lowering the groundwater levels to the extent that the minimum threshold for groundwater levels are exceeded in 30% of the monitoring wells located within the District. The 30% criteria was chosen to be consistent with criteria used throughout the Kern Subbasin.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The Undesirable Result and Minimum Threshold for reduction of groundwater storage shall be the same threshold associated with chronic lowering of groundwater levels.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	A management area exceedance is triggered when the MT for groundwater quality is exceeded in 40% or more of any representative monitoring wells within the management area. KTWD believes that the main constituent of concern associated with the chronic lowering of groundwater levels is TDS. Immediately west of the District, the Santa Margarita Formation becomes saline. The District has established a minimum threshold for TDS as 750 mg/L.	KTWD has not established any management area critical infrastructure. The District is unaware of any loss of functionality or incurred costs to replace or repair infrastructure due to subsidence within the Dsitrict.
		Well 20C1	RMW-176	-150	ft msl	20	ft msl	X						
		Well 15P1	RMW-177	-150	ft msl	20	ft msl	X						
		Well 24Q1	RMW-178	-150	ft msl	20	ft msl	X						
		Well 32M1	RMW-179	-150	ft msl	20	ft msl	X						
		Well 8L1	RMW-180	-150	ft msl	20	ft msl	X						

Table 3-4. Summary of Minimum Thresholds and Measurable Objectives – CONTINUED.

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
Rosedale-Rio Bravo Management Area		1 Bushnell	RMW-050	-33.1	ft msl	48	ft msl	X			~~The RBMA will seek to maintain at least two water level monitoring points for each monitoring zone. To the extent that average water levels in of designated monitoring points has exceeded the minimum threshold of the monitoring zone, it will be considered an undesirable result. To the extent that two of the North, Central, and South of River zones exceed this criterion, the RBMA will consider it an undesirable result to the extent that either the South or East zones exceed this criterion, the RBMA will consider it an undesirable result.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The Minimum Threshold for the RRB MA groundwater storage as calculated by its cumulative balance (Appendix D) will be 0 AF and its Measurable Objective is 663,000 AF. The storage level with respect to the calculated water surface calculations will assume the level Minimum Threshold to be 0.~~ The RRBMA will coordinate with the other KGA MAP's and utilize groundwater levels as a proxy until such time as a basin study can be completed and volumetric metholodogies are adopted. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The Measurable Objective will be any applicable beneficial use COC value that is less than the MCL and a value increase less than 10 percent of the 2015-2020 value. An undesirable result will exist if any applicable beneficial use COC value that is greater that the current MCL and value increase of greater than 10 percent from the 2015-2020 value.~~ A Management Area exceedance is triggered when groundwater quality rises above the established minimum threshold in 40% or more of any representative monitoring wells within the respective Management Area over two-consecutive annual SGMA required monitoring events.	~~Until a regional program is developed, a threshold of 2 feet will be assigned given that there is not a history of subsidence in the RBMA. A measurable objective of less than 1 foot will be assigned and a 2030 milestone of less than 1.5 feet will be assigned.~~ A Management Area exceedance is triggered when the average measured subsidence rate at the representative monitoring sites exceeds the established minimum threshold over a six-year rolling average.
		3 L.R. Stout	RMW-052	-2.7	ft msl	78	ft msl	X						
		5 RBG School	RMW-053	3.5	ft msl	85	ft msl	X						
		18 Cauzza	RMW-057	8.3	ft msl	82	ft msl	X						
		6 P. Enns Domestic	RMW-054	41.9	ft msl	116	ft msl	X						
		16 Section 18	RMW-055	16.0	ft msl	90	ft msl	X						
		17 Blacco HQ	RMW-056	9.0	ft msl	83	ft msl	X						
		19 Parsons	RMW-058	28.3	ft msl	127	ft msl	X						
		20 West I-5	RMW-059	44.0	ft msl	143	ft msl	X						
		22 Virgil Bussell	RMW-060	49.0	ft msl	148	ft msl	X						
		27N_Mayer	RMW-061a	55.0	ft msl	154	ft msl	X						
		30 Enos	RMW-062a	69.0	ft msl	168	ft msl	X						
		9 Chet Reed	RMW-063	101.0	ft msl	209	ft msl	X						
		13 Home Place	RMW-064	88.4	ft msl	196	ft msl	X						
		32 Greeley	RMW-065a	84.0	ft msl	192	ft msl	X						
		36 Harvest Ranch	RMW-066	91.0	ft msl	199	ft msl	X						
		37 RRBWSD Shop	RMW-067a	107.0	ft msl	215	ft msl	X						
		28J Triple	RMW-069b	129.0	ft msl	196	ft msl	X						
		32N Triple	RMW-068a	127.0	ft msl	189	ft msl	X						
		Frito Lay	RMW-?						X					
		Brock South	RMW-?						X					
		Nord Road Water	RMW-?						X					
		I-5 and Stockdale Hwy	RMP-?					X		X				
		Stockdale Hwy and Hwy 43	RMP-?					X		X				
		Allen Road and Hwy 58	RMP-?					X		X				
		Hwy 58 and Hwy 43	RMP-?					X		X				
		Hwy 43 and 7th Standard Rd	RMP-?					X		X				

Table 3-4. Summary of Minimum Thresholds and Measurable Objectives – CONTINUED.

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
Kern County Water Agency - Pioneer		30S26E04J002M	J002	-12.5	ft msl	186.3	ft msl	X	X		~~N/A~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~N/A~~ N/A-Pioneer is a banking program in which all withdrawals recover previously stored water, and therefore does not contribute to the basin's change in storage.	~~N/A~~ Degraded Water Quality is monitored by proxy using groundwater levels. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	Within the Pioneer GSA Area there is no Management Area Critical Infrastructure, defined as infrastructure located within a particular Subbasin Management Area whose loss of significant functionality due to inelastic subsidence if caused by Subbasin groundwater extractions would have significant impacts to beneficial users within that Subbasin Management Area. Therefore, no subsidence thresholds have been established for the Pioneer MAP.
		30S26E04J003M	RMW-259	-147	ft msl	156	ft msl	X	X					
		30S26E10P004M	RMW-048	-24.8	ft msl	92.7	ft msl	X	X					
		30S26E15N003M	RMW-049	-24.8	ft msl	92.7	ft msl	X	X					
		30S26E04D003M	RMW-045	-51.4	ft msl	111	ft msl	X	X					
North Kern Water Storage District and Shafter Wasco Irrigation District	NKWSD MA-1 (Old District)	88-03-009	RMW-145	-127	ft msl	-52	ft msl	X	X		~~A management area will be considered an undesirable watch area when 51% of the representative monitoring sites in a management area violate their minimum thresholds for groundwater levels. If multiple undesirable results watch areas meet the criteria for a Subbasin undesirable result, the Subbasin would be considered to be experiencing an undesirable result.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~A management area will be considered an undesirable results watch area for reduction in groundwater storage when 51% of the representative monitoring sites in a management area violate their MT for groundwater levels, since water elevations serve as a proxy for reduction of groundwater storage. If multiple undesirable results watch areas meet the criteria for a Subbasin undesirable result, the Subbasin would be considered to be experiencing an undesirable result.~~ Groundwater levels are used as a proxy for storage. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~A management area will be considered an undesirable results watch area for degraded water quality when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels, since groundwater levels serve as a proxy for degraded water quality. If multiple undesirable results watch areas meet the criteria for a Subbasin undesirable result, the Subbasin would be considered to be experiencing an undesirable result.~~ Groundwater levels are used as a proxy for water quality. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events	The Lower Reach of the Friant-Kern Canal, defined as Regional Critical Infrastructure for the Subbasin, crosses through the MAP area. An undesirable result is triggered when the six-year rolling average annual subsidence rate exceeds the established MT rate. No other local infrastructure have been identified as Management Area Critical Infrastructure and any adverse impacts to district structures will be mitigated by the respective district.
		88-09-009	RMW-146	-141	ft msl	-66	ft msl	X	X					
		88-21-005	RMW-147	-131	ft msl	-56	ft msl	X	X					
		88-29-014	RMW-148	-133	ft msl	-57	ft msl	X	X					
		99-00-003	RMW-149	-52	ft msl	24	ft msl	X	X					
		99-00-081	RMW-150	-192	ft msl	-114	ft msl	X	X					
		99-22-084	RMW-151	-213	ft msl	-135	ft msl	X	X					
		Shafter Well 18	RMW-271	-128	ft msl	-54	ft msl	X	X					
	NKWSD MA-2 (RRID)													
	SWID MA-1	Shafter Well 7	RMW-205	-163	ft msl	-85	ft msl	X	X					
		Shafter Well 12	RMW-254	-159	ft msl	-81	ft msl	X	X					
		Shafter Well 15	RMW-204	-146.9	ft msl	-68	ft msl	X	X					
		Wasco 8 *(added July 2020)*	RMW-263	-235	ft msl	-153	ft msl	X	X					
		Wasco 11 *(added July 2020)*	RMW-276	-229	ft msl	-147	ft msl	X	X					
		Wasco 12	RMW-256	-242.9	ft msl	-159	ft msl	X	X					
		Shafter Well 14	RMW-257	-144	ft msl	-67	ft msl	X	X					

Table 3-4. Summary of Minimum Thresholds and Measurable Objectives – CONTINUED.

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
Shafter-Wasco Irrigation District	MA-2 7TH Standard Annex	28S/25E 19G	RMW-269	-137	ft msl	-79	ft msl	X			~~Undesirable Results are triggered if the MT is exceeded at one or more of the three RMSs over three consecutive monitoring periods (events).~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Undesirable Results are triggered if and when groundwater storage is reduced by an amount that could cause the groundwater levels in one or more RMSs to exceed their MTs for Chronic Lowering of Groundwater Levels.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Undesirable Results for Degraded Water Quality are not defined.~~ Until additional groundwater level and groundwater quality information is available to refine the correlation analysis, it is considered a local undesirable results for degraded water quality within the management area if the arsenic concentrations exceed the MTs in 40% or more of the representative monitoring wells within the management area over two consecutive annual SGMA required monitoring events, such that it cannot be managed to provide drinking water supply (i.e., that treatment or blending is not possible or practicable).	Based on the limited to no historical subsidence observed in the management area, the lack of regional critical infrastructure (i.e., the California Aqueduct and the Friant Kern Canal), and mapping of the Corcoran clay in the basin which suggests that it does not extend in the management area, undesirable results for land subsidence are not defined.
		Well 31J	RMW-248	-137	ft msl	-79	ft msl	X						
		28S/24E-35C	RMW-249	-137	ft msl	-79	ft msl	X						
Southern San Joaquin Municipal Utility District		McFarland Taylor Ave. Well	RMW-208	-117	ft msl	-42	ft msl	X	X		~~The SSJMUD management area will be considered an undesirable results watch area when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels. If multiple undesirable results watch areas meet the criteria for a Subbasin undesirable result, as defined by the basin-wide definition, the Subbasin would be considered to be experiencing an undesirable result.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The SSJMUD management area will be considered an undesirable results watch area for reduction in groundwater storage when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels, since water elevations serve as a proxy for reduction of groundwater storage. If multiple undesirable results watch areas meet the criteria for a Subbasin undesirable result, the Subbasin would be considered to be experiencing an undesirable result.~~ Groundwater levels are used as a proxy for storage. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~The SSJMUD management area will be considered an undesirable results watch area for degraded water quality when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels, since groundwater levels serve as a proxy for degraded water quality. If multiple undesirable results watch areas meet the criteria for a Subbasin undesirable result, as defined above, the Subbasin would be considered to be experiencing an undesirable result.~~ Groundwater levels are used as a proxy for water quality. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~As no impacts to critical infrastructure have been identified and because it is not clearly understood how groundwater pumping in different areas of the basin affects subsidence, SSJMUD has identified land subsidence as a data gap. As a result, no minimum thresholds for local infrastructure are established for land subsidence at this time.~~ The Lower Reach of the Friant-Kern Canal, defined as Regional Critical Infrastructure for the Subbasin, crosses through the MAP area. An undesirable result is triggered when the six-year rolling average annual subsidence rate exceeds the established MT rate. No other local infrastructure have been identified as Management Area Critical Infrastructure and any adverse impacts to district structures will be mitigated by the respective district.
		Delano 34	RMW-281	-216	ft msl	-118	ft msl	X	X					
		Delano 30	RMW-252	-100	ft msl	-6	ft msl	X	X					
		SSJMUD-8	RMW-157	-329	ft msl	-227	ft msl	X	X					
		SSJMUD-14	RMW-158	-136	ft msl	-57	ft msl	X	X					
		SSJMUD-23	RMW-159	-278	ft msl	-183	ft msl	X	X					
		SSJMUD-42	RMW-163	-123	ft msl	-48	ft msl	X	X					
		SSJMUD-53	RMW-160	-131	ft msl	-55	ft msl	X	X					
		SSJMUD-59	RMW-161	-112	ft msl	-37	ft msl	X	X					
		SSJMUD-62	RMW-162	-83	ft msl	-7	ft msl	X	X					

Table 3-4. Summary of Minimum Thresholds and Measurable Objectives – CONTINUED.

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
Semitropic WSD GSA	MA-2 Buttonwillow	S-02	RMW-119	-200	ft msl	-127	ft msl	X	X		~~Within the Semitropic GSA, a management area will be considered an undesirable result watch area when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Within the Semitropic GSA, a management area will be considered an undesirable result watch area for reduction in groundwater storage when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels, since water elevations serve as a proxy for reduction of groundwater storage.~~ Groundwater levels are used as a proxy for storage. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~Within the Semitropic GSA, a management area will be considered an undesirable result watch area for degraded water quality when 51% of the representative monitoring sites in a management area violate their minimum threshold for groundwater levels, since groundwater levels serve as a proxy for degraded water quality.~~ Groundwater levels are used as a proxy for water quality. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	Semitropic has identified land subsidence as a data gap. The SWSD GSA has not historically experienced impacts to local infrastructure from the levels of subsidence historically experienced. As such no minimum thresholds for local infrastructure are established for land subsidence at this time.
		S-04	RMW-121	-144	ft msl	-76	ft msl	X	X					
		S-05	RMW-122	-242	ft msl	-161	ft msl	X	X					
		S-1 *(added February 2020)*	RMW-277	-165	ft msl	-80	ft msl	X	X					
		948L02 Cluster 1 of 2	RMW-139	-180	ft msl	-101	ft msl	X	X					
	MA-3 Undeveloped	S-11	RMW-130	-258	ft msl	-195	ft msl	X	X					
		S-12	RMW-131	-264	ft msl	-194	ft msl	X	X					
	MA-1 Pond-Poso	S-06	RMW-123	-306	ft msl	-209	ft msl	X	X					
		S-09A Cluster 1 of 2	RMW-128	-227	ft msl	-146	ft msl	X	X					
		S-13A Cluster 1 of 2	RMW-132	-371	ft msl	-269	ft msl	X	X					
		S-14B Cluster 2 of 2	RMW-135	-335	ft msl	-233	ft msl	X	X					
		26S-23E-15A1	RMW-137	-345	ft msl	-244	ft msl	X	X					
		S-8A Cluster 1 of 2	RMW-126	-331	ft msl	-229	ft msl	X	X					
Westside Districts Water Authority		S#14 *(added November 2020)*	RMW-279	150	ft msl	200	ft msl	X			~~There has been little historical pumping for irrigation in the interior areas of the WDWA due to naturally degrade ground water. The WDWA maintains two sentry coordination zones with adjacent groundwater management areas to the east and will expand its network of monitor wells as part of PMA #1. An undesirable result is identified if a sentry zone records a measured GW level falls below its MT over three consecutive monitor events.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~See response to Lowering of GW Levels.~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	Water quality in the WDWA is known to be naturally degraded due to local geology. As a result over 95% of water used in the WDWA is surface water.	Land subsidence is an identified data gap, as such interim MOs/ MTs have been identified for regional critical infrastructure and associated management area infrastructure pursuant to the Basin-wide coordinated GSP subsidence plan. The interim MOs/MTs are valid until 2025 at which time they may be updated based on additional data. Areas of InSAR identified subsidence in the WDWA include the Lost Hills and Belridge oilfields. Recent subsidence studies by the WDWA to assess impacts to the Aqueduct (MP 195-215) have identified sources other than agricultural pumping as the likely primary cause. This material was shared with the subsidence experts within the DWR in early 2020 subsequent to GSP submittal. The WDWA is coordinating with adjacent water districts to assess interim MOs/MTs pending acquiring additional subsidence data as described in the KGA GSP Subsidence Management Plan.
		7108-66 *(added March 2020)*	RMW-275	-115	ft msl	-62	ft msl	X						
		7106-63	RMW-203	59	ft msl	101	ft msl	X						

Table 3-4. Summary of Minimum Thresholds and Measurable Objectives – CONTINUED.

Monitoring Sites				Lowering of Groundwater Levels				Groundwater Level Used as Proxy?			Description of Sustainable Management Criteria in Each KGA Management Area and Definition of a Trigger to a Management Area Exceedance			
Member Agency	Sub-Management Area	Monitoring Site/ Parameter	RMW Number	Minimum Threshold		Measurable Objective		Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence	Lowering of Groundwater Levels	Reduction of Groundwater Storage	Degraded Water Quality	Land Subsidence
				Value	Unit	Value	Unit							
West Kern Water District	North Project MA	NWM1-S	RMW-088	56	ft msl	110	ft msl	X	X		~~N/A~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~N/A~~ A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~N/A~~ Degraded Water Quality is monitored by proxy using groundwater levels. A management area exceedance is triggered when groundwater levels decline below established MTs in 40% or more of any representative monitoring wells within the management area over four consecutive bi-annual SGMA required monitoring events.	~~N/A~~. Within the WKWD GSA Area there is no Management Area Critical Infrastructure, defined as infrastructure located within a particular Subbasin Management Area whose loss of significant functionality due to inelastic subsidence if caused by Subbasin groundwater extractions would have significant impacts to beneficial users within that Subbasin Management Area. Therefore, no subsidence thresholds have been established for the WKWD MAP.
		NWM1-M	RMW-266	27	ft msl	71	ft msl	X	X					
		NWM1-D	RMW-267	4	ft msl	60	ft msl	X	X					
		NWM2-S	RMW-089	49	ft msl	93	ft msl	X	X					
		NWM2-M	RMW-264	39	ft msl	80	ft msl	X	X					
		NWM2-D	RMW-265	0	ft msl	78	ft msl	X	X					
	South Project MA	Well 6-04	RMW-087	-82	ft msl	125	ft msl	X	X					
		Well 7	RMW-074	-42	ft msl	106	ft msl	X	X					
		21L-D	RMW-082c	-61	ft msl	105	ft msl	X	X					
		21L-M	RMW-082b	-54	ft msl	115	ft msl	X	X					
		21L-S	RMW-082a	-26	ft msl	159	ft msl	X	X					
		21R-D	RMW-076c	-46	ft msl	90	ft msl	X	X					
		21R-M	RMW-076b	-72	ft msl	121	ft msl	X	X					
		21R-S	RMW-076a	-107	ft msl	109	ft msl	X	X					
		22K-D	RMW-079c	95	ft msl	104	ft msl	X	X					
		22K-M	RMW-079b	37	ft msl	163	ft msl	X	X					
		22K-S	RMW-079a	2	ft msl	139	ft msl	X	X					
		23M-D	RMW-085c	23	ft msl	166	ft msl	X	X					
		23M-M	RMW-085b	-8	ft msl	132	ft msl	X	X					
		23M-S	RMW-085a	4	ft msl	133	ft msl	X	X					
		28E-D	RMW-072c	0	ft msl	122	ft msl	X	X					
		28E-M	RMW-072b	68	ft msl	162	ft msl	X	X					
		28E-S	RMW-072a	90	ft msl	163	ft msl	X	X					

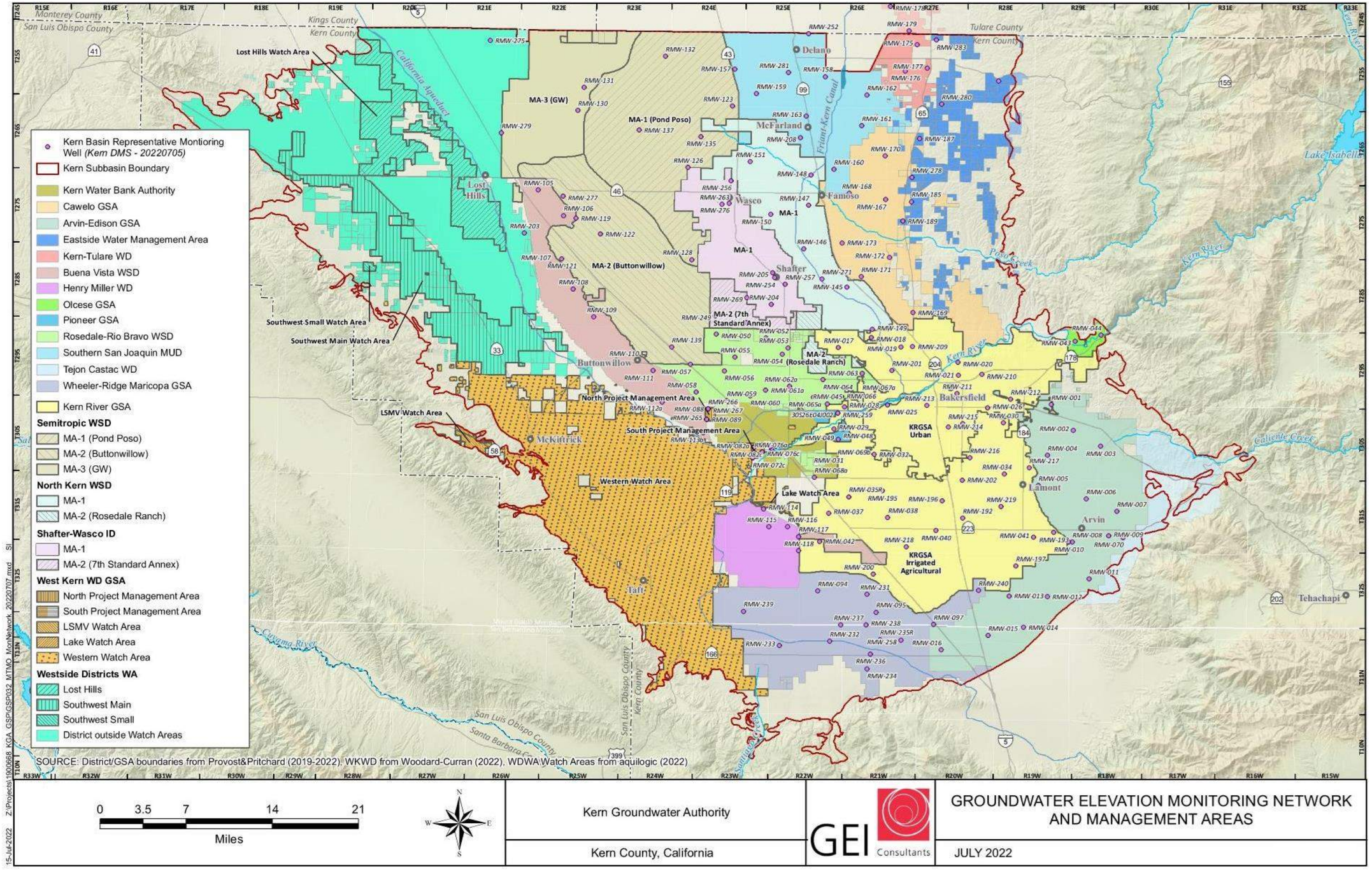

Figure 3-6R. REVISED Regional Groundwater Level Monitoring Network

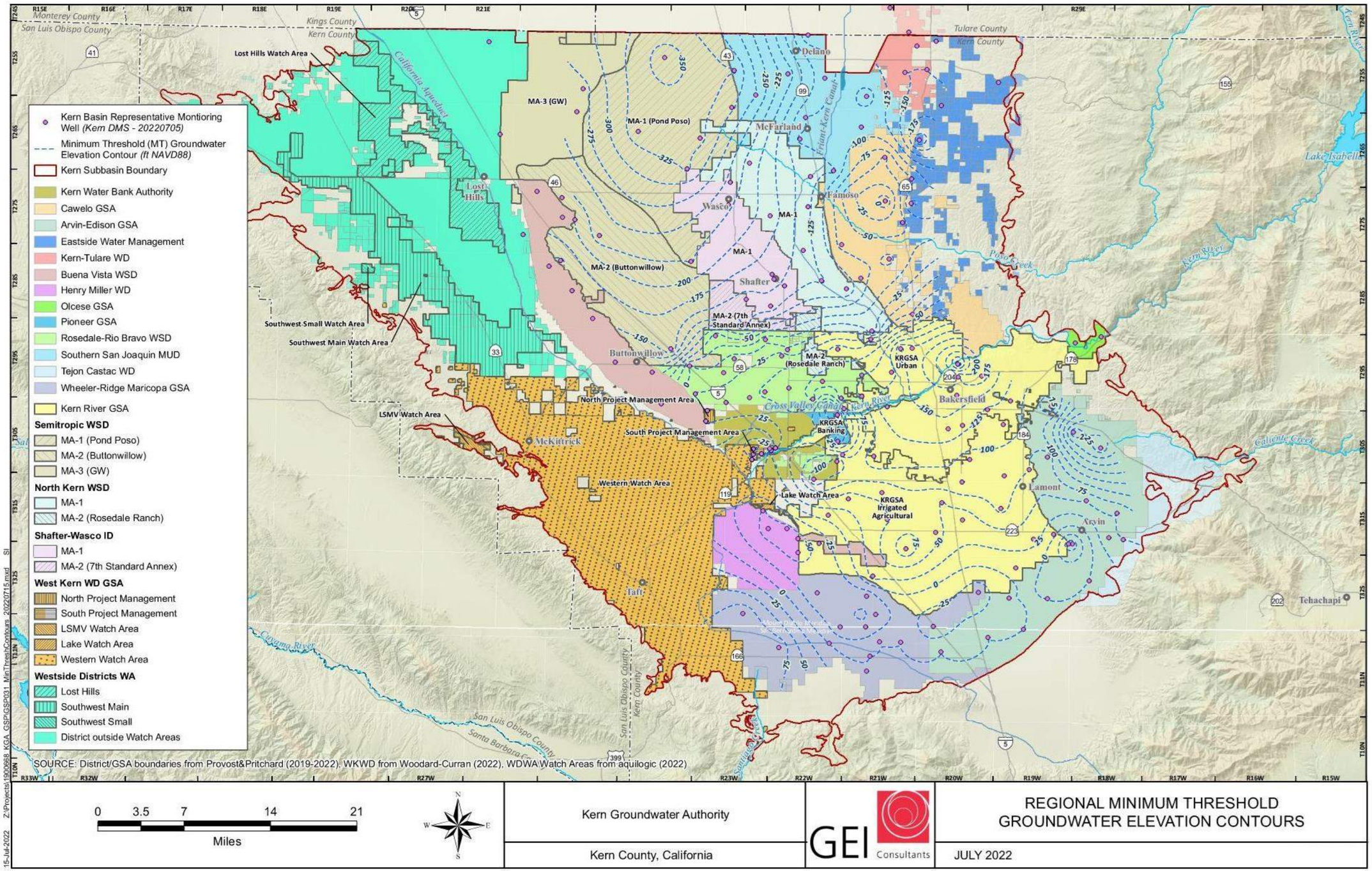

Figure 3-7R REVISED Regional Minimum Threshold Contours for Groundwater Levels

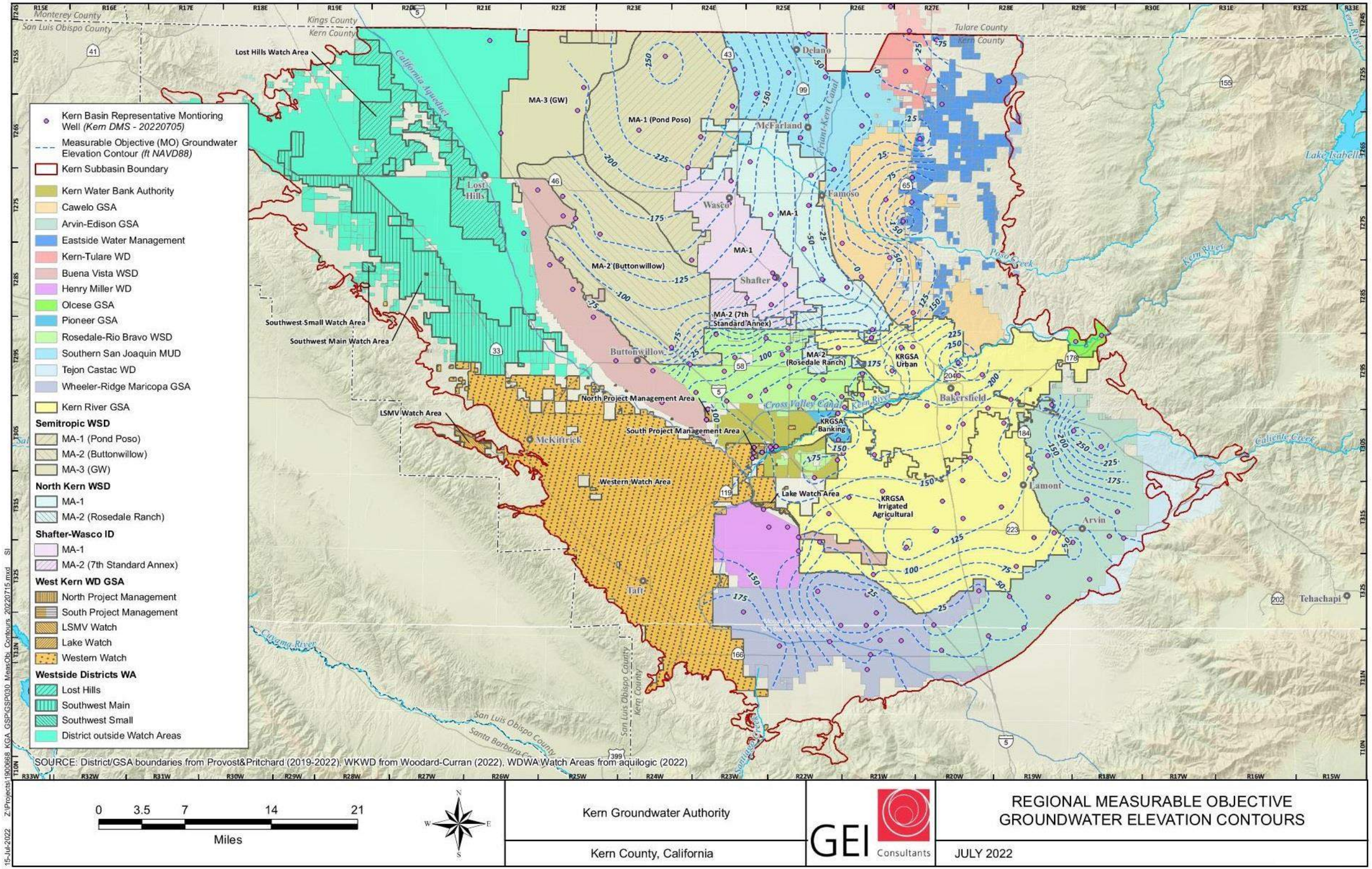

Figure 3-8R. REVISED Regional Measurable Objective Contours for Groundwater Levels

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3.5.1 Chronic Lowering of Groundwater Levels and Reduction of Groundwater Storage

The final Subbasin minimum thresholds and measurable objectives values for the chronic lowering of groundwater levels sustainability indicator at each representative monitoring well are presented in Table 3-4 with an indication of whether that RWM is used as a proxy for reduction of groundwater storage or degraded water quality. The location of the representative monitoring well are shown in Figure 3-6. Figure 3-7 show only the minimum thresholds for the groundwater levels sustainability indicator with elevation contours between each of the representative monitoring sites. This figure provides an indication of how the thresholds values at each representative monitoring site relate to adjacent monitoring site values. Contour maps such as these were used in the review of draft thresholds to determine areas of potential conflicting thresholds between neighboring management areas, such as drastically differing threshold values, elevation gradients steeper than typically observed gradients, or elevation gradients contrary to typically observed gradients.

Figure 3-8 shows only the measurable objective values for groundwater levels sustainability indicator at each representative monitoring site, with elevation contours between monitoring site. The draft measurable objectives were reviewed in the same manner as minimum thresholds.

Through the KGA/GSA Managers Group coordination meetings, it was generally agreed that the withdrawal of groundwater from the Subbasin would not create impacts to beneficial uses or users of groundwater in the Subbasin if groundwater elevations are maintained above the minimum threshold values. The chronic lowering of groundwater level minimum thresholds and measurable objective values serve as proxy for the reduction of groundwater storage and in some case water quality and subsidence for the KGA Member Agencies. Table 3-4 show the measurable objectives and minimum threshold for chronic lowering of groundwater levels for each KGA Member Agency RMW; provides an indication of whether groundwater levels are used as a proxy for reduction of groundwater storage, degraded water quality, or land subsidence; and how the minimum threshold of each sustainability indictor has been changed to address DWR comments. The process for re-establishing consistent minimum threshold triggers (which identify Management Area Exceedances, leading to contributions to an undesirable result as explained above) involved collaboration and negotiation with all GSAs in the Kern Subbasin.

3.5.2 Degraded Water Quality

The minimum thresholds and measurable objectives for degraded water quality were established by each of the management areas. All the representative monitoring sites for water quality are summarized in Table 3-4. In many instances, the minimum threshold and measurable objectives values for groundwater levels serves as a proxy for water quality. In other words, no water quality degradation, migration of contaminate plumes, or other indicators of water quality impairment would be experienced at the groundwater level minimum threshold value at that representative monitoring site.

3.5.3 Land Subsidence

Because of the variability of subsidence in time, we have examined the temporal variation in rates for the entire region, as well as for the four sub-domains (central, east, west, and south, as shown in Figure 3-9). These are area-wide averages and, as noted below, do not capture the spatial variability in rates. Still, the averages provide an indication of the temporal variability in rates. The large-scale (spatially) rates indicate a background 'floor" of subsidence values of around -0.4 inches/year for the eastern, western, and southern regions, interrupted by decreases in subsidence in wetter years leading to net uplift. The central region, with its greater exposure to the large-scale subsidence bowl to the north, has a larger background rate that is higher, around -0.6 inches/year. Again, during wet years the subsidence is arrested and can even reverse to uplift. This indicates the potential for water-banking or some other mitigation technique to reduce subsidence if applied on a large scale. There are indications that the subsidence rate has increased since 2020, most dramatically in the central region. Perhaps the easiest way to visualize the temporal changes in the four regions is to examine. The time series of displacements for the three regions (east, west, south) is roughly linear, then interrupted by a rather abrupt shift upward, likely due to the effects of the wet years, availability of surface water, existing water banking programs and a pause or end of the drought around 2017. As noted above, this shift occurs at different times for the central and western regions. Factors contributing to this temporal difference may include proximity to areas of natural recharge, such as in the west (the central region is more distal), groundwater dependence (the central region has higher dependence), and availability of surface water. In the two other regions s (southern and eastern), the shift might represent natural recharge of deeper aquifers. The shift is then followed by a linear behavior in time, at roughly the same slope as before, suggesting a return to the previous subsidence rate. The behavior for the central region is different in that the curve does not return to a linear trend, but rather seems to indicate an increase in the rate of subsidence after 2020 or so. One take-away from these results is that when calculating rates, it can be important to consider the temporal changes in rates. A rate calculation incorporating the rapid shift during the wet time interval, can significantly skew the rate estimates.

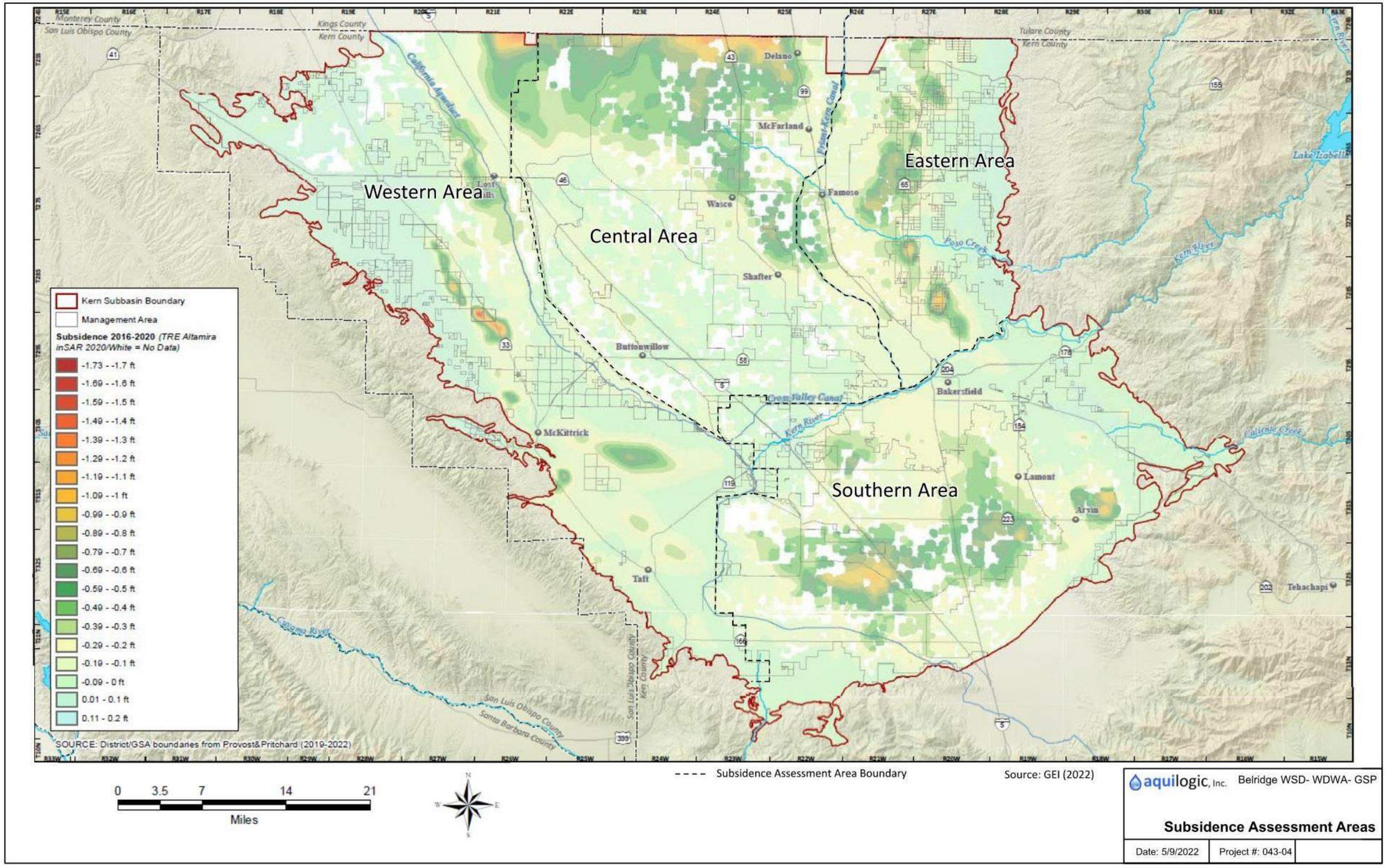

Figure 3-9. Kern Subbasin Subsidence Sub-Regions

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The spatial distribution of surface displacement, and hence subsidence, is highly variable and typically concentrated within the various sub-regions. This concentration is most notable for oil and gas fields. These regions can have dramatic changes, both subsidence and uplift, over short periods (Vasco et al. 2017), and probably cannot be characterized accurately by a single rate. Still, it is possible to examine yearly averages that measure accumulated surface deformation. In this study, we considered the deformation rate for the year 2020, and the spatial variability in rates that can occur within the four sub-domains. The yearly rates of change in 2020 were calculated for all points of the four regions. In order to capture the spatial variability within each region, we scanned the rates and determined the locations with the maximum subsidence and the minimum rate of subsidence (typically uplift), as well as computing the mean of all of the rates for the given sub-domain. The resulting maximum rates of subsidence were around 2-3 inches/year with an anomalously large value of -7.7 inches/year in the western sub-area. At the northeastern corner of the western sub-region. The activities in this area should probably be examined in more detail, as the subsidence rate is significant and fairly concentrated. Outside of this anomalous area, the western sub-domain has relatively moderate subsidence in 2020, though there are concentrations in selected oil and gas fields. We should note that the yearly rates of -3.2, -2.6, and -2.4 inches/year for the central, southern, and eastern areas are in line with estimates in the March 2021 report by Earth Consultants International, who found subsidence rates of 2-3 inches/year in the northern edge of the Kern County Subbasin and 3-4 inches/year south of Bakersfield.

Again, peak rates for specific areas are subject to dramatic temporal changes as local activities vary. When focusing on specific infrastructure we can derive more detailed and specific estimates along the given paths of the canals, pipelines, and transmission lines. Given current rates of subsidence buried infrastructure, like pipelines, would not experience significant adverse effects provided “hinge line” factors (stream crossings, faults, changes in elevation and grade etc.) were minimal. However, further study is needed to quantify and confirm the types of stresses that may be present. In addition, the line-of-sight displacements are dominated by subsidence but there will also be notable horizontal displacement, particularly from the subsidence bowl at the northern edge of the subbasin. Such north-south displacement can be estimated from an inversion for volume change, as in Vasco et al. (2019), followed by a forward geomechanical calculation of three-dimensional displacements, as in Vasco et al. (2017).

3.5.3.1 Interim Measurable Objectives and Interim Minimum Thresholds

At the June 17, 2022, meeting with DWR, the Kern subbasin presented the findings of two important subsidence studies that were conducted subsequent to the January 2020 submission of the GSPs. DWR staff indicated their understanding of the studies/data and appreciated the challenge of setting sustainable management criteria in the face of data gaps thus stated that an interim SMC with caveats would be better than setting no SMC. The caveats for subsidence are the following which may not be inclusive:

- The sustainable management criteria can be interim, will only be valid until 2025, and will be updated in the 2025 GSP update;

- Due to the complexity of the Kern Subbasin, setting of an interim SMC for subsidence, does not require GSAs take responsibility, manage, regulate or otherwise be liable for impacts resulting from actions outside the authority of the GSA or outside the GSA's ability to manage sustainability under SGMA; and
- That the Kern Subbasin GSAs are not responsible for addressing subsidence caused by activities outside of the jurisdiction of SGMA i.e., extractions from exempt aquifers, or caused by activities other than extraction of water on behalf of the beneficial users under the purview of SGMA.

The Interim Measurable Objective for land subsidence for the California Aqueduct is defined as the avoidance of a permanent loss (associated with inelastic subsidence) of conveyance capacity as attributable to subsidence as limited by remaining concrete liner freeboard for a specific Aqueduct Pool that exceeds the average observed rate from 2016-2022. Using the 2022 CASP survey data, the average observed rate was calculated to be -0.05 ft/yr for all Pools of the Aqueduct within the Kern Subbasin.). The MO rate of subsidence is calculated and assessed as an average annual rate over a rolling 6-year monitoring period.

The Minimum Threshold for land subsidence for the California Aqueduct is defined as the avoidance of a permanent loss (associated with inelastic subsidence) of conveyance capacity as attributable to subsidence as limited by remaining concrete liner freeboard for a specific Aqueduct Pool that exceeds twice the average observed rate from 2016-2022. Using the 2022 CASP survey data, twice the average observed rate was calculated to be -0.10 ft/yr for all Pools of the Aqueduct within the Kern Subbasin.). The MT rate of subsidence is calculated and assessed as an average annual rate over a rolling 6-year monitoring period.

3.5.3.2 California Aqueduct

The above methodology for developing MOs and MTs, recognizing the baseline subsidence rate as calculated from the latest CASP survey data, is supported by the findings of the KGA Subsidence Study and Lawrence Livermore Study. The Subsidence Rate for the MO and MT as described below are interim, pending the collection and analysis of additional data, and will be updated in the 2025 GSP. Table 3-6 presents an interim MO and MT by Pool in the Kern Subbasin.

Table 3-6. Subsidence (INTERIM) MO and (INTERIM) MTs for CA Aqueduct Pools in Kern Subbasin

CA Aqueduct Pool	[1]Measurable Objective Rate (INTERIM) from 2022-2025 (Ft/Yr)	*[2]Measurable Objective Total Extent (INTERIM) from 2022-2040 (Ft)*	[1]Minimum Threshold Rate (INTERIM) from 2022-2025 (Ft/Yr)	*[2]Minimum Threshold Total Extent (INTERIM) from 2022-2040(Ft)*
Pool 23	-0.05	*-0.9*	-0.1	*-1.8*
Pool 24	-0.05	*-0.9*	-0.1	*-1.8*
Pool 25	-0.05	*-0.9*	-0.1	*-1.8*
Pool 26	-0.05	*-0.9*	-0.1	*-1.8*
Pool 27	-0.05	*-0.9*	-0.1	*-1.8*
Pool 28	-0.05	*-0.9*	-0.1	*-1.8*
Pool 29	-0.05	*-0.9*	-0.1	*-1.8*
Pool 30	-0.05	*-0.9*	-0.1	*-1.8*
Pool 31	-0.05	*-0.9*	-0.1	*-1.8*
Pool 32	-0.05	*-0.9*	-0.1	*-1.8*
Pool 33[3]	-0.07	*-1.35*	-0.15	*-2.7*
Pool 34[3]	-0.07	*-1.35*	-0.15	*-2.7*
Pool 35[3]	-0.07	*-1.35*	-0.15	*-2.7*
[1]The MO & MT rate are calculated over a rolling 6-yr period, averaging Pools 23-32 and Pools 33-35; the interim rate identified for the MO and MT is for subsidence due to activities under the purview of SGMA. The interim rate is established based upon findings from the 2022 CASP survey data, and the InSAR Study and LBL preliminary study (KGA 2021). **The Interim Rate will be updated in the 2025 GSP Update.**				
[2]The extent of subsidence (INTERIM) for the term 2022 – 2040 utilizes the Interim MO and MT Rate and will be updated as the MO and MT rates for subsidence are updated in the 2025 GSP Update. [3]Information regarding the SMC for Pools 33, 34, and 35 can be found in the South of Kern River GSP.				

The Interim Measurable Objectives and Minimum Thresholds are only valid until 2025 and they will be updated in the 2025 GSP Update, and only apply when the permanent loss of freeboard is a result of subsidence due to SGMA-related groundwater extractions from the following beneficial uses/users: agricultural, domestic, municipal, or urban. Permanent loss of freeboard from land subsidence due to other causes including but not limited to due to oil or gas production, natural compaction of shallow underlying soils beneath or near the Aqueduct, or any other cause that is not within the jurisdiction of a GSA, shall not be considered as a loss of freeboard that contributes to the amount specified for any MO or MT. When considering Measurable Objective and Minimum Threshold rates beyond 2025 it will be critical to fully understand design considerations of the identified critical infrastructure. It is typical that major infrastructure designs incorporate assumptions for natural settling, subsidence of any type, service life, repair and replacement cycles, etc. It is expected that when selecting Minimum Threshold rates of subsidence beyond the interim 2025 period that MO and MT rates may require reduction based on these and other critical elements as the basin approaches its 2040 sustainability goal.

For example, if the MT for subsidence for a particular pool of the Aqueduct within a Management Area was determined to be 0.10 ft/yr over a 6-year period, and SGMA-related beneficial uses within the jurisdiction of a GSA were deemed to cause 0.07 ft /yr of subsidence within that pool while non-jurisdictional uses were deemed to cause 0.15 ft/yr, the Management Area would only consider the 0.07 ft/yr subsidence rate (and related loss of pool freeboard) when evaluating MT compliance, and in that case would not determine that an MT exceedance has occurred. Friant-Kern Canal.

Interim Measurable Objectives and Interim Minimum Thresholds - Friant-Kern Canal

Refer to *Attachment E4 for the Friant-Kern Canal White Paper*. The methodology to determine and set minimum thresholds is defined as the avoidance of permanent loss of historical operational flow capacities for the Lower Reach as a result of groundwater extractions from agricultural, domestic, municipal, or urban beneficial users within the Kern County Subbasin. In order to set an appropriate MT, additional studies and subsidence modeling is necessary to understand the cause of subsidence, identify appropriate management actions, and develop a mitigation plan. However, as noted above, the Subbasin GSAs will establish an interim MT.

The interim MT for the entire Lower Reach within the Kern Subbasin is defined as the average annual rate of subsidence over the last 6 years and the corresponding total interim extent from 2022 until 2040. Based on information provided by the DWR's California Groundwater Live website, the annual rate of subsidence is presented as a range and MT is set at the average of lower elevation of the subsidence ranges. The MT rate of allowable subsidence is -0.2 feet per year and MT extent is -3.6 ft until the 2040. A new MT rate and extent will be established in the 2025 GSP updates based on data from the previously discussed basin study and subsidence modeling. Tables 3-7 summarizes the MO, MT and temporal extent.

Table 3-7. FKC Lower Reach Interim Measurable Objectives, Minimum Thresholds and Extent

Measurable Objectives Rate from 2022 to 2025 (Ft/Yr)	Measurable Objective Total Extent from 2022 to 2040 (Ft)	Minimum Threshold Rate from 2022 to 2025 (Ft/Yr)	Minimum Threshold Total Extent from 2022 to 2040 (Ft)
-0.1	-1.8	-0.2	-3.6

3.5.4 Seawater Intrusion

As described above, the Subbasin is located approximately 60 miles from the Pacific Ocean, separated by the Coastal Range and other geologic features that prevent seawater from migrating into the Subbasin. Details of the geologic structure of the Subbasin can be found in the basin setting of this GSP. Based on the separation of the Subbasin from any source of seawater, the Subbasin has not developed sustainable management criteria for this sustainability indicator.

3.5.5 Depletions of Interconnected Surface Water

As described above the Subbasin, has not identified any areas of interconnected surface waters. Though many studies have been conducted in the Subbasin, including in areas such as the Kern River and Poso Creek, results do not show evidence of surface water within the Subbasin to be interconnected. As there are no known natural interconnected surface water systems within the KGA boundary or the Subbasin, this sustainability indicator is not included in this GSP. Additional information can be found in basin setting section of this GSP and in the management area plans.

3.6 Monitoring Network

The monitoring networks, protocols, and standards described within this section and in the respective management area plans meet the requirements of §352.2, and §354.32 to §354.40 of the California Code of Regulations. The Kern subbasin collaboratively developed the monitoring network for the Kern subbasin as well as coordinating the setting of the SMC for water levels at the same time. The monitoring network for the Kern subbasin also include monitoring protocols that stipulated the time frames for collecting the SMC data and how that data is used in preparing the annual report. The monitoring protocols have been updated to provide more accountability on confirming that SMC data is collected, see 3.6.7.

3.6.1 Monitoring Network Description

Management areas within the KGA generally align with member agency boundaries and represent areas of common water management practices. Management areas are designated and managed by KGA member agencies (Table 3-7) and shown in Figures 3-5 and 3-6. KGA members are best suited to leverage existing relationships with water users for local groundwater monitoring and site access.

The monitoring network for the KGA represents the coordination of the monitoring networks and activities of the KGA member agencies within their respective management areas as well as the coordination with the other GSAs in the Kern subbasin. The KGA and the other GSAs in the Kern subbasin will coordinate the annual collection and reporting of monitoring data to DWR and will ensure the monitoring network and protocols are compliant with SGMA.

Monitoring Network is capable of collecting sufficient data to demonstrate short-term, seasonal, and long-term trends in groundwater and related surface conditions, and yield representative information about groundwater conditions as necessary to evaluate Plan implementation. The monitoring network objectives accomplish the following:

1) Demonstrate progress toward achieving measurable objectives described in the management area and throughout the Subbasin
2) Monitor impacts to the beneficial uses and users of groundwater
3) Monitor changes in groundwater conditions relative to measurable objectives and minimum thresholds
4) Quantify annual changes in water budget components

3.6.2 Monitoring Network Objectives

The objectives of the KGA monitoring network are to:

- demonstrate progress toward achieving measurable objectives summarized in this GSP and detailed in the attached management area plans;
- monitor impacts to the beneficial uses of groundwater and stakeholders within the Subbasin; monitor changes in groundwater conditions relative to measurable objectives and minimum thresholds; quantify annual changes in water budget components; and
- monitor changes for the following pertinent sustainability indicators in the Subbasin;
    - Groundwater Potentiometric Surfaces, or Groundwater Levels,
    - Groundwater Storage,
    - Groundwater Quality, and
    - Land Subsidence.

And to coordinate with the other GSAs in the basin to consider all beneficial users and uses. Seawater intrusion and depletions of interconnected surface water are not pertinent to the monitoring network as they were not considered pertinent sustainability indicators, as described in the basin setting.

3.6.3 Monitoring Data Quality Objectives

As described in DWR's *Groundwater Monitoring Protocols, Standards, and Sites BMP* (DWR, 2016c), the processes for maintaining quality control and quality assurance are iterative, and, as such, will be evaluated every 5 years for effectiveness. The monitoring networks implemented as part of this GSP include the analytical approaches to obtain acceptable data that can monitor the sustainability indicators against minimum thresholds and interim milestones. Where necessary, revisions can be made every 5 years as this GSP is updated.

The monitoring network (see Figures 3-6 and Table 3-4) will be capable of collecting sufficient data to demonstrate seasonal, short-term (1 to 5 years), and long-term (5 to 10 years) trends in groundwater and related surface conditions and yield representative information about groundwater conditions as necessary to evaluate Plan implementation. The frequency at which data will be collected for each network will be described herein.

3.6.4 Monitoring Progress Toward Measurable Objectives

As described in the above section, groundwater levels in the KGA are the key sustainability indicator to monitor undesirable results. Seasonal groundwater levels in selected monitoring wells will be used to monitor progress towards identified measurable objectives. While most of the management areas have used groundwater level as a proxy to monitor other sustainability indicators, certain management areas have defined specific interim milestones for other primary sustainability indicators such as degraded water quality and groundwater storage. The details of these milestones can be found in the management area plans.

After adopting this GSP, the KGA and its member agencies will monitor the progress towards reaching interim milestones for groundwater levels. This progress will be compared with

monitoring data for storage, land subsidence, and water quality as well as their respective minimum thresholds, to evaluate the effectiveness of groundwater level as proxies for these other the sustainability indicators. Where needed, interim milestones for groundwater levels or other sustainability indicators may be adjusted to maintain the objectives of the GSP.

The proposed monitoring networks will provide data used to monitor impacts of sustainable groundwater management to beneficial uses and users of groundwater. The proposed approach for monitoring impacts to beneficial uses and users of groundwater are described in Table 3-8.

Table 3-8. Monitoring Impacts to Beneficial Uses and Users

Potential impacts on beneficial uses and users of groundwater	Monitoring Network	Notes
Groundwater elevation decline may result in increased pumping costs and or dry wells.	Groundwater Level Monitoring	Groundwater levels will be compared with well screen construction and pump depth settings
Groundwater storage is reduced to less than minimum threshold affecting future supplies for use.	Groundwater Level Monitoring	Data will be incorporated into the Subbasin model to quantify and monitor storage outlooks and minimum thresholds and interim milestones.
Land subsidence due to overdraft results in infrastructure damage and loss in aquifer storage.	Groundwater Level and Land Subsidence Monitoring	Groundwater levels and land subsidence data will be evaluated against minimum thresholds and interim milestones.
Groundwater quality is degraded and is not suitable for use without additional treatment costs.	Groundwater Quality Monitoring	Data from all water quality reporting sources will be evaluated for the Subbasin to compare against minimum thresholds and objectives.

3.6.5 Coverage of Sustainability Indicators

As mentioned previously, the monitoring plan for Kern Subbasin addresses all pertinent sustainability indicators of the Subbasin: chronic lowering of groundwater levels, reduction in groundwater storage, degraded water quality, and land subsidence. Figure 3-4 provides the current distribution of representative monitoring wells for water elevations included in the monitoring network for the KGA. Based on the BMP for monitoring networks, the well density goal is to be between 4 to 10 wells per 100 square miles (DWR, 2016c). In the Subbasin, the KGA covers approximately 1,980 square miles of which approximately 83% (or ~1,650 square miles) is reliant on some level of groundwater production and has active groundwater wells. Based on DWR's BMP recommended density goal, the KGA monitoring network should contain between 66 to 165 monitoring wells base in the area that is reliant on groundwater. The KGA's proposed monitoring network includes 118 well locations for groundwater elevation and storage.

3.6.6 Scientific Rational for Site Selection

The monitoring network for the KGA member agencies was designed using the following scientific rational for site selection:

- Aquifer representation –Per DWR's Emergency Regulations CCR § 354.34 (c) (1), monitoring wells were chosen to adequately represent each underlying aquifer within the KGA.
- Potential impacts to beneficial users of groundwater
- Availability of site-specific historical data and technical information
- Spatial and vertical representation of the underlying aquifers
- Precedence of dedicated monitoring wells over production wells
- Site accessibility
- Coordination with the other GSAs in the Kern subbasin

While this outlines the general procedure followed by the KGA member agencies to identify their respective monitoring networks, the detailed scientific rational for each monitoring network can be found in the respective management area plan.

3.6.7 Monitoring Protocols for Data Collection and Monitoring

3.6.7.1 Groundwater Level Monitoring Network Protocol and Standards

The existing monitoring network in the KGA includes production wells and dedicated monitoring wells. Until enough dedicated monitoring wells are installed to fill data gaps, production wells will be used to expand the spatial coverage of the existing network.

As referenced in §352.4 of the regulations, monitoring sites/wells will conform to best management practices for geographic locations, identification, and details on well construction. Table 3-9 provides the requested standards.

Table 3-9 Standards for Required Monitoring Well Information

Well Identification	Use the CASGEM well identification number. If a CASGEM well identification number has not been issued, appropriate well information shall be entered on forms made available by DWR.
Well/Site Location	Geographic locations shall be reported in GPS coordinates by latitude and longitude in decimal degree to five decimal places, to a minimum accuracy of 30 feet, relative to NAD83, or another national standard that is convertible to NAD83. Reference point elevations shall be measured and reported in feet to an accuracy of at least 0.5 feet, or the best available information, relative to NAVD88, or another national standard that is convertible to NAVD88, and the method of measurement described.
Well Type and Construction Details	A description of the well use/type, whether the well is active or inactive, and whether the well is a single, clustered, nested, or other type of well. Casing perforations, borehole depth, and total well depth shall be reported. Well completion reports will be provided, if available, from which the names of private owners have been redacted. Geophysical logs, well construction diagrams, or other relevant information will be provided, if available, including any other relevant well construction information, such as well capacity, casing diameter, or casing modifications.
Monitoring Zone	Identification of principal aquifer or aquifer zones monitored.

Requirements for well selection

- A long-term access agreement that includes year-round site access to allow for increased monitoring frequency
- A unique identifier that includes a general written description of the site location, date established, access instructions and point of contact, type of information to be collected, latitude, longitude and elevation
- Monitoring location should also track all modifications to the site in a modification log

Monitoring Protocols

As referenced in §352.4 of the GSP regulations, "monitoring protocols shall be developed according to BMP. Monitoring protocols shall be reviewed at least every five years as part of the periodic evaluation of the Plan and modified as necessary." As mentioned above, the Kern Subbasin developed and coordinated the monitoring protocols as well as the monitoring locations.

As per DWR's Monitoring Protocol BMP (DWR, 2016c) and the Subbasin's Coordination Agreement for Groundwater Elevation Data:

- Groundwater level data shall be sufficient to produce seasonal maps of potentiometric surfaces or water table surfaces throughout the basin that clearly identify changes in groundwater flow direction and gradient.
- Use the Kern Subbasin Well Data form.
- Groundwater level data shall be collected from each principal aquifer in the basin.
- Collection of data between the approved time frames only.
    - January 15th to March 30th
    - September 15th to November 15th
- If attempts have been made and a measurement cannot be collected from a representative monitoring well during the approved timeframe, one of the following is to occur:
    - A measurement from a nearby well with similar water level trends can be used as a proxy.
    - If no substitute well is available, the static water level can be estimated based on trending for Spring and Fall levels from the previous four or more bi-annual measurements; estimates are used for purposes of comparing to the established thresholds for each Management Area only.
    - If the water level is estimated, the entry must be flagged with a DWR No Measurement Code using the DWR pull-down menu options and described in the Water Level Measurements Comments field as "Estimated groundwater level based on trending for Spring or Fall levels from the previous four or more bi-annual measurements."
- If an existing representative monitoring well cannot be measured during two bi-annual timeframes, a plan to replace or repair the well in the monitoring network shall be made prior to the subsequent monitoring period or annual report, whichever occurs first.
- A weighted water level meter will be used to measure the depth to groundwater.

- Depth to groundwater must be measured relative to an established Reference Point on the well casing. If no mark or reference point is apparent, the person performing the measurement should measure the depth to groundwater from the north side of the top of the well casing.
- The elevation of the Reference Point of the well must be surveyed to the North American Vertical Datum of 1988. The elevation must be accurate to within 0.1 foot.
- Each well's Reference Point will be cataloged to ensure identical procedures are followed for subsequent measurements.
- The data collector should remove the appropriate cap, lid or plug that covers the monitoring access point listening for pressure release. If a release is observed, the measurement should follow a period of time to allow the water level to equilibrate.
- Depth to groundwater must be measured to an accuracy of 0.1 foot below the Reference Point.
- The water level meter shall be decontaminated after measuring each well.
- The data collector shall calculate the groundwater elevation as:
    - GWE = RPE – DTW
    - GWE = Groundwater Elevation
    - RPE = Reference Point Elevation
    - DTW = Depth to Water
- The data collector must ensure that all measurements are consistent units of feet, tenths of feet or hundredths of feet. Measurements and Reference Point Elevations should not be recorded in feet and inches.
- Seasonal measurements must be submitted to the Kern Data Management System, reviewed for Quality Control, and approved by the management area administrator for upload to the SGMA Portal.

Pressure Transducers

As per DWR's Monitoring Protocols BMP (DWR, 2016c), groundwater levels and/or calculated groundwater elevations may be recorded using pressure transducers equipped with data loggers installed in monitoring wells. When installing pressure transducers, care will be exercised to ensure that the data recorded by the transducers is confirmed with hand measurements.

The following general protocols will be followed when installing a pressure transducer in a monitoring well:

- The sampler will use an electronic sounder or chalked steel tape and follow the protocols listed above to measure the groundwater level and calculate the groundwater elevation in the monitoring well to properly program and reference the installation.
- The sampler will note the well identifier, the associated transducer serial number, transducer range, transducer accuracy, and cable serial number.
- Transducers will be able to record groundwater levels with an accuracy of at least 0.1 foot. Consideration of the battery life, data storage capacity, range of groundwater level fluctuations, and natural pressure drift of the transducers will be included in the evaluation.

- The sampler will note whether the pressure transducer uses a vented or non- vented cable for barometric compensation. Vented cables are preferred, but non- vented units provide accurate data if properly corrected for natural barometric pressure changes. This requires the consistent logging of barometric pressures to coincide with measurement intervals.
- Follow manufacturer specifications for installation, calibration, data logging intervals, battery life, correction procedure (if non-vented cables used), and anticipated life expectancy to assure that data quality objectives are being met for the GSP.
- Secure the cable to the well head with a well dock or another reliable method. Mark the cable at the elevation of the reference point with tape or an indelible marker. This will allow estimates of future cable slippage.

The transducer data will periodically be checked against hand measured groundwater levels to monitor electronic drift or cable movement. This will happen during routine site visits, at least annually or as necessary to maintain data integrity.

The data will be downloaded as necessary to ensure no data is lost and entered into the basin's DMS following the QA/QC program established for the GSP. Data collected with non-vented data logger cables will be corrected for atmospheric barometric pressure changes, as appropriate. After the sampler is confident that the transducer data have been safely downloaded and stored, the data will be deleted from the data logger to ensure that adequate data logger memory remains.

As mentioned above, for specific details regarding the monitoring network for groundwater level and change in groundwater storage for each management area, please refer to the respective individual management area plans. The data gaps and steps for improvement of the respective monitoring networks have also been identified in those management area plans.

3.6.7.2 Water Quality Monitoring Network Protocol and Standards

Groundwater Quality Monitoring Network Protocol and Standards

The existing monitoring network in the KGA includes production wells and dedicated monitoring wells. Until enough dedicated monitoring wells are installed to fill data gaps, production wells will be used to expand the spatial coverage of the existing water quality network.

As referenced in §352.4 of the GSP emergency regulations, monitoring sites/wells will conform to best management practices for geographic locations, identification, and details on well construction.

Requirements for Well Selection

- A long-term access agreement that includes year-round site access to allow for increased monitoring frequency
- A unique identifier that includes a general written description of the site location, date established, access instructions and point of contact, type of information to be collected, latitude, longitude and elevation

- Monitoring location should also track all modifications to the site in a modification log
- The use of existing water quality data within the basin should be done to the greatest extent possible
- Monitoring network should consist largely as a supplemental monitoring locations where known groundwater contamination plumes are under existing regulatory management

Monitoring Protocols

The monitoring protocols will follow, at a minimum, the sampling guidelines as provided in DWR's *Groundwater Monitoring Protocols, Standards, and Sites BMP* (2016c).

Groundwater quality sampling protocols will ensure that:

- Groundwater quality data are taken from the correct location,
- Groundwater quality data are accurate and reproducible,
- Groundwater quality data represent conditions that inform appropriate basin management and are consistent with the data quality objectives,
- All important information is recorded to normalize, if necessary, and compare data, and
- Data are handled in a way that ensures data integrity.

The following points are general guidance in addition to the techniques presented in the previously mentioned USGS *National Field Manual for the Collection of Water Quality Data.*

Standardized protocols include the following:

- Monitor groundwater quality data from each principal aquifer in the basin.
- Data should be sufficient for mapping movement of degraded water quality.
- Data should be sufficient to assess groundwater quality impacts to beneficial uses and users.
- Data should be sufficient to evaluate whether management activities are contributing to water quality degradation.
- All analyses should be performed by a laboratory certified under the State Environmental Laboratory Accreditation Program.
- Samples will be collected according to the standards listed in the Standard Methods for the Examination of Water and Wastewater, USGS National Field Manual for the Collection of Water Quality Data.
- Prior to sampling, the sampler must contact the laboratory to schedule laboratory time, obtain appropriate sampler containers, and clarify any sample holding times or sample preservation requirements.
- Each well used for groundwater quality monitoring must have a unique identifier. This identifier must appear on the well housing or the well casing to avoid confusion.
- In the case of wells with dedicated pumps, samples should be collected at or near the wellhead. Samples are not to be taken/collected from storage tanks, at the end of long pipe runs or after any water treatment infrastructure.

- Samples will be taken/collected only after the appropriate volume of water has been purged from the casing and field parameters have stabilized.
- Sampler will clean the sampling port and/or sampling equipment. The sampling port and/or sampling equipment must be free of any contaminants.
- Groundwater elevation in the well should be measured following the protocols described in the groundwater level measuring protocols.
- Field parameters of pH, electrical conductivity and temperature should be collected for each sample. Lab pH analysis are typically unachievable due to short hold times.
- All field instruments should be calibrated daily and evaluated for drift throughout the day.
- Sample containers should be labeled prior to sample collection. The sample label must include:
    - Sample ID (well ID)
    - Sample date and time
    - Sample personnel
    - Sample location
    - Preservative used
    - Analytes and analytical method
- Samples shall be collected under laminar flow conditions. This may require reducing pumping rates prior to sample collection.
- Samples requiring preservation must be preserved as soon as practically possible.
- Samples to be analyzed for metals should be field-filtered prior to preservation. Do not collect an unfiltered sample in a preserved container.
- Samples will be chilled and maintained at 4 C to prevent degradation of the sample
- Samples will be shipped under a chain of custody documentation to the appropriate laboratory promptly to avoid violating holding time restrictions.
- Custody Seal will be used by the field technician if a third-party transportation service is used.
- A Field Sampling Log will be maintained for each sampling event and will include:
    - Sampler’s identification
    - Well identification
    - Climatic conditions
    - Depth to water prior to purging
    - Type of purging and sampling device
    - Purging rate and volume

- Relative well yield volume
- Field parameter measurements (pH, temperature, EC, DO)
- Type and number of samples collected
- Date and time collected

As mentioned above, for specific details regarding the monitoring network for groundwater quality for each management area, please refer to the respective individual management area plans. The data gaps and steps for improvement of the respective monitoring networks have also been identified in those chapters.

3.6.8 Reduction of Groundwater Storage

The reduction of groundwater storage provides an estimate of the change in annual groundwater storage. Since the groundwater storage is not a directly measurable condition, it relies heavily on the collection of accurate groundwater level data. The changes in groundwater levels reflect changes in storage and can thus be estimated with assumptions of thickness of subsurface geologic units, porosity, and connectivity. These observations will be essential for use in calculating the water budget.

A water budget is a foundational tool used to compile water flows (supplies) and outflows (demands). It is an accounting of the total groundwater and surface water entering and leaving a basin or user-defined area. The difference between flows and outflows is a change in the amount of water stored.

Coordination of water budget data to comply with groundwater storage include:

- Surface water supply
- Total water use
- Water budget
- Sustainable yield

The change in the annual volume of groundwater storage between seasonal high conditions shall be quantify in the water budget calculations.

3.6.9 Land Subsidence Monitoring Network

The current regional subsidence monitoring network includes regional subsidence screening by InSAR conducted by the USGS and monitoring points at existing continuous GPS (CGPS) stations and available data from SOPAC, as described in the basin setting. These monitoring points include: P544, P545, P563, P564, P565, BFLD, ARM1/2, TAFT, and BVPP. In addition, local extensometers for Semitropic Water Storage District (25S22E35B001M) and Kern Water Bank (30S25E16L) and benchmark monuments of North Kern Water Storage District are included in the network. Data from leveling surveys of the California Aqueduct and Friant-Kern Canal are also valuable points that have some historical data, but which have not been formally incorporated into the local Subbasin network.

3.6.9.1 CA Aqueduct Monitoring Plan

Subsidence will be assessed in a five-mile-wide monitoring corridor (i.e., 2.5 miles on either side of the Aqueduct). Since physical access to surveying benchmarks along the Aqueduct for independent parties is limited, the Aqueduct subsidence monitoring reports produced by DWR will be one of the sources to identify the rate and magnitude of subsidence (i.e., change in freeboard) on the Aqueduct. The DWR reports provide complete coverage of each Pool within the Subbasin and represent one method to monitor subsidence for the Aqueduct. Below, Table 3-10b provides the latest range of available freeboard by pool using the latest DWR survey data through 2022. The amount of remaining concrete liner was calculated relative to the original as-built liner elevations or subsequent liner raises where applicable.

As a supplement to the DWR subsidence monitoring reports, InSAR data will, at a minimum, be reviewed on an annual basis to inform Management Areas of whether subsidence rates could lead to an undesirable result. InSAR data will be ground-truthed by comparison to NOAA CORS station P545, SOPAC CGPS location P544, and available local existing extensometers in or adjacent to the subsidence monitoring corridor for the Aqueduct, in addition to any future CORS, CGPS, extensometer, or other pertinent facilities that may be constructed in the future in or adjacent to the monitoring corridor discussed below in coordination with DWR-CASP staff.

3.6.9.2 Monitoring Corridor

The subsidence monitoring corridor for the Aqueduct will include lands within 2.5 miles on either side of the Aqueduct (i.e., total of five miles wide centered on the Aqueduct). The width of the monitoring corridor was based on a review of Subbasin hydrogeology, historical InSAR datasets, the 2019 DWR-CASP report, and current land use along the Aqueduct.

3.6.9.3 Areas of Interest (AOIs)

Pools that have experienced subsidence which has significantly reduced freeboard and, in some cases, impacted flow capacity will be identified as “Areas of Interest” and be subject to focused monitoring by the collection and ground-truthing of InSAR data on an annual basis and the preparation of focused studies or investigations to assess the cause of subsidence in consultation with the adjacent Management Areas and DWR. If it is determined that the sole or principal cause of subsidence in a particular AOI is groundwater extraction for SGMA-related beneficial use, these sites will be identified for additional Subbasin monitoring stations in the future and/or management actions based on the data. Current AOIs for the Subbasin include the Kern bowl (a portion of Pool 23, all of Pools 24, 25 and a portion of Pool 26), Maricopa bowl (a portion of Pool 30, all of Pools 31 and 32), and Pleito bowl (a portion of Pool 34 and all of Pool 35). Studies conducted by the Management Areas on the west side have concluded that subsidence between Aqueduct Mile Post 195 to approximately 214 (i.e., Pools 23 through 25) is attributable to oil and gas activities. As such, the subsidence attributable to oil and gas activities at the Kern Bowl is beyond the ability of the Subbasin to control or mitigate. Further, additional study of the Maricopa and Pleito bowls is required to more fully understand potential causes of identified subsidence.

3.6.9.4 Watch Areas (WAs)

The 2019 DWR-CASP Report and 2022 CASP survey data show that subsidence in several pools has been minimal with top of concrete liner elevations in 2017 being comparable to those measured when the Aqueduct was constructed over 50 years ago, accordingly, neither freeboard nor capacity has been significantly impacted (i.e., undesirable results have not been experienced). Any significant loss of conveyance capacity from design specifications was found to be caused from aging concrete liner with increased hydraulic roughness and other factors. Pools that have experienced minimal subsidence historically will be identified as “Watch Areas”. Watch Areas will be monitored utilizing annual ground-truthed InSAR data and the most current DWR-CASP Aqueduct report. In the event that future monitoring determines that conditions have changed, the subject Watch Area may be redesignated as an AOI. Table 10a summarizes the Pool specific Monitoring Classification, and Management Areas associated with each Pool.

3.6.9.5 Friant-Kern Canal Monitoring Plan

Kern Subbasin is in contact with the FWA and will continue to work with FWA on filling data gaps as well as coordinate on a monitoring network. The Friant Water Authority (in conjunction with the Bureau of Reclamation) is developing a system-wide Friant-Kern Canal Capacity Correction Program (Program). Both entities have already begun the correction phase of the Middle Reach, which experienced significant capacity loss (over 40 percent) as a result of regional subsidence. The proposed monitoring program includes identifying impacts to water supplies from the loss of flow capacity in the Lower Reach. Several Kern Subbasin representatives are involved in the Program and will continue to monitor the Program with respect to SGMA compliance and implementation.

In addition to FWA’s subsidence monitoring reports, InSAR data will, at a minimum, be reviewed on an annual basis to inform Management Areas of whether subsidence rates could lead to an undesirable result. InSAR data will be ground-truthed by comparison to NOAA CORS station P564 (at Wasco-Kern County Airport) and P565 (at Delano Municipal Airport). In addition to any future CGPS, extensometer, or other pertinent facilities that may be constructed in the future in or adjacent to the monitoring corridor.

Table 3-10a. CA Aqueduct Pools in Kern Subbasin and Associated Management Areas

CA Aqueduct Pool	Management Area Within 5-Mile Corridor	Pool Monitoring Classification
Pool 23	KGA (WDWA)	AOI/WA
Pool 24	KGA (WDWA, SWSD), BVGSA	AOI
Pool 25	KGA (WDWA), BVGSA	AOI
Pool 26	KGA (WDWA), BVGSA	AOI/WA
Pool 27	KGA (WKWD), BVGSA	WA
Pool 28	KGA (WKWD, KWB), BVGSA	WA
Pool 29	KGA (WKWD, KWB), HMGSA	WA
Pool 30	KGA (WKWD), HMGSA	AOI/WA
Pool 31	KGA (WKWD), HMGSA, SOKR	AOI
Pool 32	KGA (WKWD), SOKR	AOI
Pool 33	SOKR, KGA	WA
Pool 34	SOKR, KGA	AOI/WA
Pool 35	SOKR, KGA	AOI

Table 3-10b. CA Aqueduct Pools in Kern Subbasin and Monitoring Classification Extent

CA Aqueduct Pool	2022 Range of Available Freeboard by Pool (Ft)[4]	Watch Area Mile Post (MP) Extent	Area of Interest Mile Post (MP) Extent
Pool 23	1.48 to 3.74	MP-184.5 to MP-194	[1]MP 194 to MP 197
Pool 24	0 to 2.19	N/A	[1]MP-197 to MP 208
Pool 25	0 to 3.43	MP-216 to MP-218	[1]MP-208 to MP-216
Pool 26	1.67 to 4.01	MP-216 to MP-222.5	[2]MP-222.5 to MP-223.5
Pool 27	3.62 to 4.32	MP-223.5 to MP- 231.5	N/A
Pool 28	1.51 to 4.35	MP-231.5 to MP-238	N/A
Pool 29	2.18 to 2.92	MP-238 to MP-244.5	N/A
Pool 30	2.65 to 8.11	MP-249.5 to MP-251	[2]MP-244.5 to 249.5
Pool 31	0.97 to 4.61	N/A	[3]MP-249.5 to MP-256.5
Pool 32	3.20 to 4.86	N/A	[3]MP-256.5 to MP 261.5
Pool 33	5.72 to 6.53	MP-261.5 to 267.5	[3]N/A
Pool 34	5.07 to 6.01	MP- 267.5 to 269.5	[3]MP-269.5 to MP- 271.5
Pool 35	3.59 to 6.64	N/A	[3]MP- 271.5 to MP- 278.5

[1]Vicinity of Lost Hills Oil Field; [2]Potential geotechnical effects; [3]Potential oil and other effects;
[4] California Aqueduct Adjusted NGVD29 Kettleman-Edmonston+Lat Long (CASP) Report, June 2022

3.6.9.6 Monitoring Corridor

The subsidence monitoring corridor for the FKC will include lands within 2.5 miles on either side of the FKC (i.e., total of five miles wide centered on the FKC). The width of the monitoring corridor was based on a review of Subbasin hydrogeology, historical InSAR datasets, and current land use in the area.

3.6.9.7 Areas of Interest (AOIs)

The Subbasin was recently awarded a $7.6 million DWR grant that includes funding for basin-wide proposals includes subsidence monitoring in 2 areas of interest along the FKC, which are identified as AOI-1 and -3.

- AOI-1 is situated east-northeast of the City of McFarland, along the FKC between Mileposts 120 and 130. The lithology presented on the cross sections indicate the presence of multiple clay layers below the water table. The completion report for a nearby well (approximately 1 mile west of the FKC) indicates there is a roughly 50-foot-thick clay layer at a depth of approximately 350 feet and two other clay layers at depths between approximately 900 to 1,000 feet.
- AOI-3 is situated west-southwest of the community of Famoso, along the FKC between Mileposts 130 and 137. Geologic cross sections show substantive clay units are present beneath the majority of AOI-3 at depths of approximately 250 to 300 feet (referred to as the 300-Foot Clay) and 750 to 800 feet (referred to as the 700-Foot Clay).

Data from DWR's California Groundwater Live website will be used to determine the annual subsidence rate and reporting purposes.

Subsidence monitoring is needed to understand the causes of subsidence, the potential risk of damaging critical infrastructure, and how to set minimum thresholds to avoid significant impacts to critical infrastructure in the Subbasin. Regional coordination of monitoring is key to the design of the network in the Subbasin because regional groundwater extraction is a main driver for regional-scale subsidence, along with subsurface geologic conditions. In addition, if significant impacts to critical infrastructure due to subsidence associated with oil and gas activities identified through regional monitoring, they will be communicated to DOGGR to address as appropriate pursuant to Public Resources Code 3315.

The basis for the design of land subsidence monitoring in the Subbasin is CWC 23 CCR § 354.34. Below are excerpts of the code with pertinent requirements to the Subbasin monitoring network.

Based on 23 CCR § 354.34, the following are some of the key criteria considered for Subbasin monitoring:

- The monitoring will collect sufficient data for seasonal, short-term, and long-term trends in groundwater and related surface conditions.

- The monitoring network will focus on collecting subsidence data (rate and extent) to avoid undesirable results, which for subsidence is defined as "…the point at which significant and unreasonable impacts, as determined by a subsidence rate and extent in the basin, affects the surface land uses or critical infrastructure…".
- The monitoring network will be based on scientific rationale.

§ 354.34. Monitoring Network

(a) Each Agency shall develop a monitoring network capable of collecting sufficient data to demonstrate short-term, seasonal, and long-term trends in groundwater and related surface conditions, and yield representative information about groundwater conditions as necessary to evaluate Plan implementation.

…

(c) Each monitoring network shall be designed to accomplish the following for each sustainability indicator:

…

(5) Land Subsidence. Identify the rate and extent of land subsidence, which may be measured by extensometers, surveying, remote sensing technology, or other appropriate method.

…

(g) Each Plan shall describe the following information about the monitoring network:

(1) Scientific rationale for the monitoring site selection process.

….

(j) An Agency that has demonstrated that undesirable results related to one or more sustainability indicators are not present and are not likely to occur in a basin, as described in Section 354.26, shall not be required to establish a monitoring network related to those sustainability indicators.

3.6.9.8 Monitoring Protocols

The preliminary monitoring network is based on the following decision-making process (Figure 3-10), which represents continuous screening for land subsidence in the Subbasin by InSAR and ground truthing where necessary. Where critical infrastructure is potentially susceptible to regional subsidence and subsidence is evident, then a determination is needed as to whether groundwater extraction is causing the subsidence. If groundwater extraction is causing the subsidence, then the following actions should be taken:

1. groundwater level monitoring,
2. additional ground-truthing of subsidence, and
3. monitoring of the critical infrastructure.

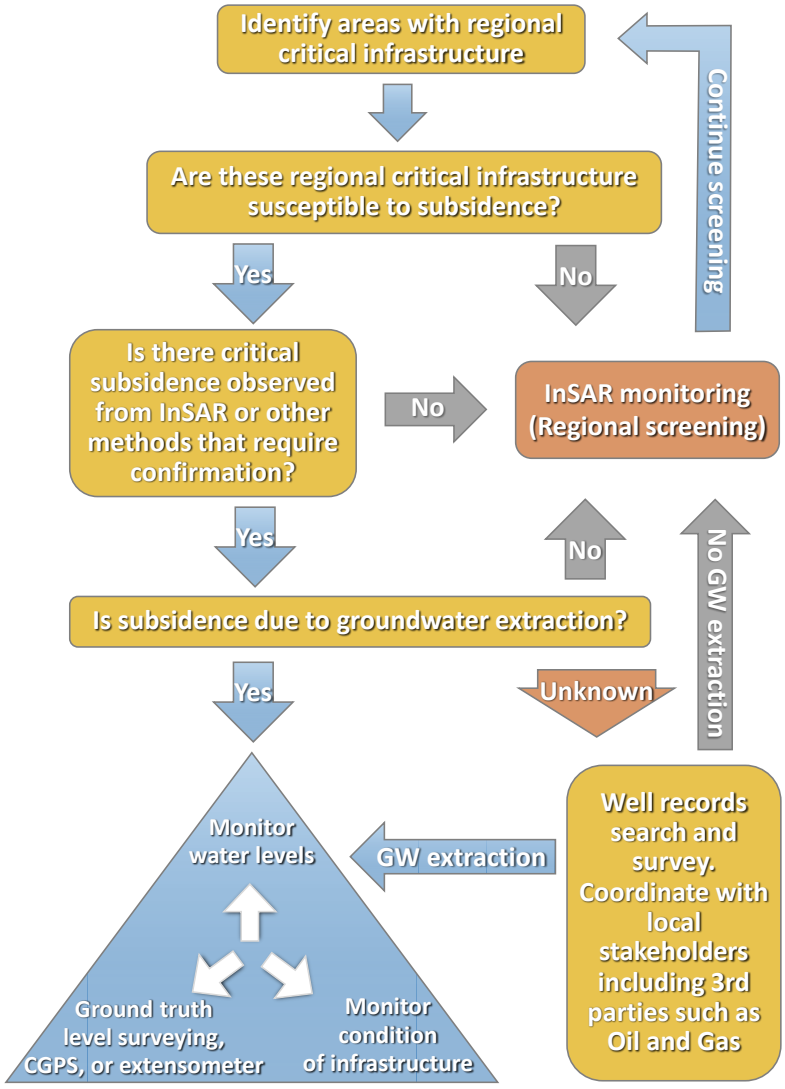

Figure 3-10. Subsidence Monitoring Design Approach

Subsidence Monitoring Network within Areas of Interest

The subsidence monitoring network areas of interest (AOI) are shown in Figure 3-11. Five AOIs were identified, in order of priority, to improve the subbasin monitoring network (AOI-1 to AOI-5). Two of these areas are located along the Friant-Kern Canal, two are along the California Aqueduct, and one area is for monitoring changes in land surface elevation along the northern boundary of the subbasin where a significant amount of subsidence has been reported in the InSAR data.

Water Level Elevations

The collection of water level elevations should be coordinated with subsidence monitoring points. If no wells within the water level monitoring network of the Subbasin are located near AOIs then monitoring wells at these locations will be identified for installation.

Five Areas of Interest

Based on the above monitoring design approach and recent InSAR and level surveying data from State Water Project, Central Valley Project, and North Kern Water Storage District as scientific rationale, four subsidence AOIs associated with critical infrastructure have been identified. In addition, a fifth AOI has been identified at the north boundary of the Subbasin. These AOIs will be covered by the monitoring network. Of these five, the stretch along CA Aqueduct MP 196 to 215 and MP 267 to 271 will be investigated to confirm if groundwater extraction is the cause of subsidence.

Where groundwater extraction is not causing subsidence in an AOI, groundwater management will not be a mitigating factor; therefore, the area will be removed from the AOI list for subsidence monitoring.

Friant-Kern Canal (AOI 1)

This high priority area is located along the Friant Kern Canal between Mileposts 120 to 130, east-northeast of the City of McFarland. The purpose of this AOI is to monitor subsidence along the Friant Kern Canal and its related infrastructure. At times, InSAR monitoring has reported up to 5 inches per year of subsidence in areas surrounding this segment of the Friant Kern Canal. At present, no significant impacts to the Friant Kern Canal have been reported along this portion of the canal's alignment. According to leveling survey data from Friant Water Authority (FWA, 2019), the Friant Kern Canal invert may have subsided from 2 ft to 3 ft below original as-built elevations between mileposts 120 to 135. Continued lowering of the canal invert can decrease freeboard from the original as-built conditions, which may contribute to reduction in emergency storage capabilities and delivery options of the Canal.

In contrast, beyond the Subbasin's northern boundary, subsidence has caused significant impacts to the Friant Kern Canal conveyance capabilities between mileposts 101 to 108.

Existing Monitoring

Currently, this area is screened by InSAR, and previous level surveying was performed by Friant Water Authority at mileposts 120 to 135. There are no other active monitoring points except for InSAR along this stretch.

New Monitoring Approach

A new CGPS station that monitors at the ground surface any subsurface subsidence, regardless of the depth interval, is recommended in this area. Monitoring at this location will assist in the KGA and its member to determine the causes of subsidence. If is it is reasonability determined that local agricultural extractions are the cause of subsidence at this location, the appropriate management area will work towards establishing appropriate measurable objectives and

minimum thresholds. This CGPS data will complement any manual level surveys that may incorporate the Friant Water Authority reported measuring points. CGPS data may also provide on-demand data as needed.

Coordination of Monitoring

Subsidence monitoring along the Friant Kern Canal benefits local stakeholders, CVP contractors, and the Friant Water Authority. It is anticipated that this monitoring can be coordinated with Friant Water Authority to share data as well as potentially share resources and cost.

Any level surveying along the canal from the United States Bureau of Reclamation Friant-Kern benchmarks will require coordination with the Friant Water Authority.

CA Aqueduct Milepost 196 to 215 (AOI 2)

This high priority area is the segment of the California Aqueduct where an embankment failure occurred at Milepost 208 in June 2011 (DWR, 2017c). This failure is partially attributed to subsidence. The cause of this subsidence is unknown and is therefore a subject of monitoring at this location. This area is along the Aqueduct between Mileposts 196 to 215 in the western central subbasin (Figure 3-11). In addition to embankment failure, other consequences of subsidence include loss in freeboard in the Aqueduct. This area has experienced at least 2 feet of subsidence since the Aqueduct was constructed.

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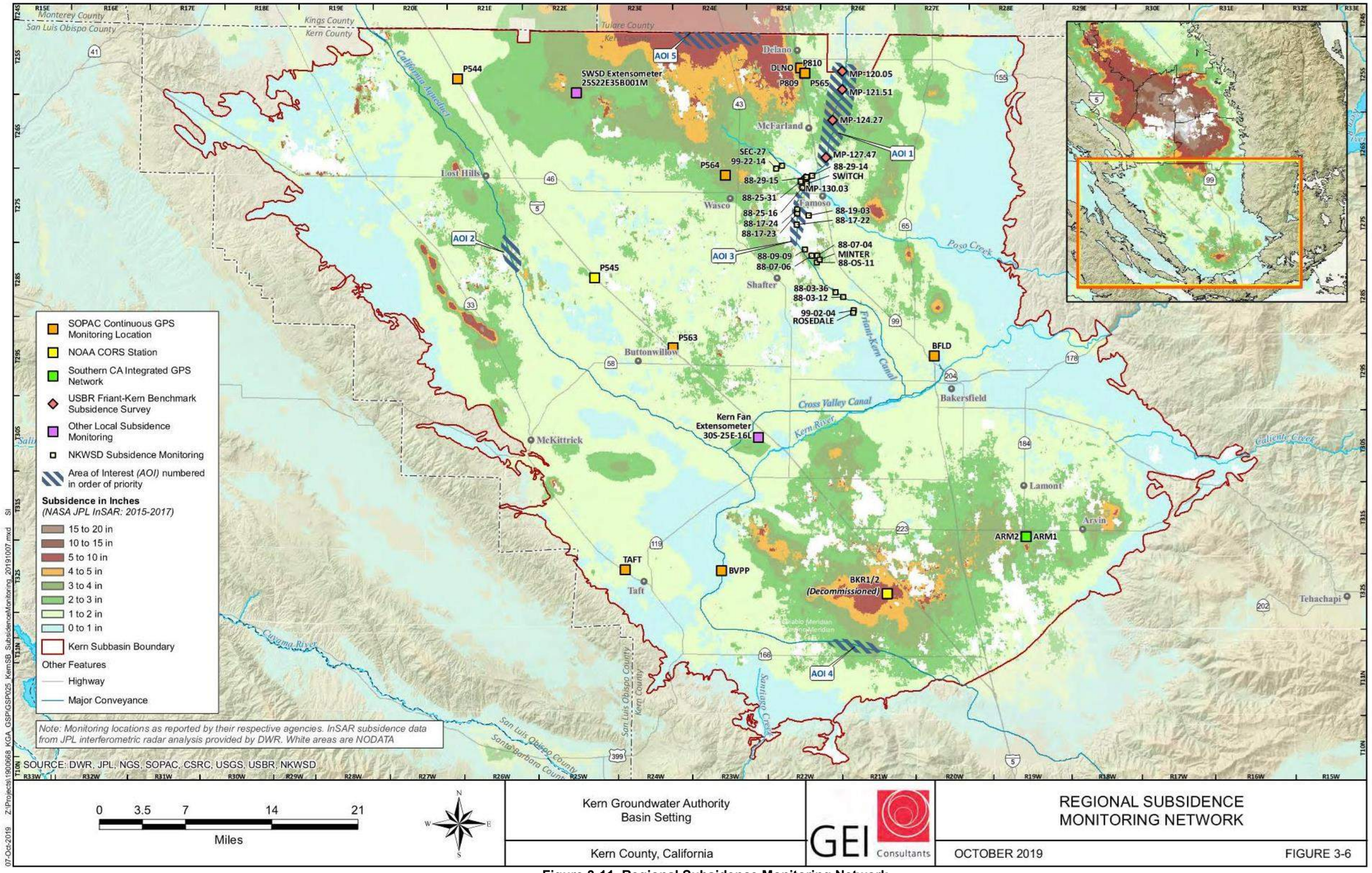

Figure 3-11. Regional Subsidence Monitoring Network

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Existing Monitoring

Currently, this area is screened by InSAR and is monitored with level surveys every three to seven years by the DWR's DOE. There are no other active monitoring points along this stretch.

New Monitoring Approach

The source of subsidence, either by groundwater extraction activities or oil activities, will be investigated by performing well records searches from DWR well completion records, the Kern County Public Health Department well permit records, and the DOGGR's databases. If necessary, a field well survey may be performed. Coordination may be needed with local stakeholders to confirm the magnitude of groundwater extracted within 1 mile of this portion of the Aqueduct's alignment and the volume of fluids extracted and injected by oil and gas activities within 1 mile of this alignment. A third potential source for subsidence in this area could be hydrocompaction, which was identified during the initial design and construction of the Aqueduct. Pre-consolidation of soil was performed during initial construction so hydrocompaction is likely not significant, however, it cannot be ruled out at this time.

If it is determined that groundwater extraction is playing a role in subsidence for this area, a monitoring point should be installed away from the footprint of the Aqueduct to avoid potential signatures of hydrocompaction if any exist. If there is question of whether some of the subsidence is related to nearby oil and gas activities, then an extensometer should be installed in the interval where groundwater production occurs. An extensometer will provide data of subsidence pertaining to intervals with groundwater production, whereas a CGPS would capture any subsidence regardless of the depth interval.

Coordination of Monitoring

Subsidence monitoring along the Aqueduct benefits local stakeholders, State Water Project (SWP) contractors, and the DWR's DOE. It is anticipated that this monitoring can be coordinated with DWR to share data as well as potentially share resources and cost.

Friant-Kern Canal Milepost 130 to 137 (AOI 3)

This medium priority area is located along the Friant Kern Canal between Mileposts 130 to 137, southwest of Famoso and Poso Creek. The purpose of this AOI is to monitor subsidence along the Friant Kern Canal infrastructure where InSAR and local stakeholders have reported subsidence in the surrounding area. As with AOI-1, no significant impacts to the Friant Kern Canal have been reported along this stretch. According to leveling survey data from the Friant Water Authority (2019), the Friant Kern Canal invert may have subsided from 2 ft to 3 ft below original as-built elevation between Mileposts 120 to 135. Continued lowering of the canal invert can decrease freeboard from the original as-built conditions, which may contribute to reduction in emergency storage capabilities and delivery options of the Canal.

Existing Monitoring

Currently, this area is screened by InSAR, and previous level surveying was performed by the Friant Water Authority at Mileposts labeled on Figure 3-11. Local districts monitor this stretch regularly. Currently there are no continuous monitoring points along this stretch.

New Monitoring Approach

A CGPS station that monitors from the ground surface, any subsurface subsidence regardless of the depth interval, is recommended because the only known cause of subsidence in this area is attributed to groundwater extraction. This CGPS data will complement manual level surveys from local district surveys. CGPS data will also provide nearly on-demand data as needed.

Where possible, this station should be tied in to benchmark surveys performed by local districts.

Coordination of Monitoring

Subsidence monitoring along the Friant Kern Canal benefits local stakeholders, CVP contractors, and the Friant Water Authority. It is anticipated that this monitoring can be coordinated with Friant Water Authority to share data as well as potentially share resources and cost.

Any level surveying along the canal from the Friant-Kern Canal benchmarks will require coordination with the Friant Water Authority.

CA Aqueduct Milepost 267 to 271 (AOI 4)

This medium priority area is located along the Aqueduct between Milepost 267 to 271 near Old River Road. InSAR data report subsidence southwest and along I-5 and southwest toward the Aqueduct along Old River Road. A former CGPS station (BKR1/2) located about 5 miles north of the Aqueduct along Old River Road also reported significant subsidence; however, this station has since been decommissioned (2016).

Existing Monitoring

Currently, this area is screened by InSAR, and is monitored by level surveying every three to seven years by the DWR's DOE. There are no other active monitoring points along this stretch.

New Monitoring Approach

Groundwater extraction is potentially the source of subsidence, so a continuous monitoring station such as a CGPS or extensometer will be installed. Other potential sources could be oil and gas extraction and hydrocompaction. A DOGGR records search may provide sufficient information to understand the extent of oil and gas extraction in this area. Although hydrocompaction may not be significant because of pre-consolidation practices during Aqueduct construction, nonetheless, in order to avoid potential signatures of hydrocompaction, a monitoring point should be installed away from the footprint of the Aqueduct. If feasible during the siting study, the site location may be selected to the north between the Aqueduct and former BKR1/2.

Where possible, this station should be tied to benchmark surveys performed by local districts.

Coordination of Monitoring

Subsidence monitoring along the Aqueduct benefits local stakeholders, SWP contractors, and the DWR's DOE. It is anticipated that this monitoring can be coordinated with DWR to share data as well as potentially share resources and cost.

North Boundary of Subbasin (AOI 5)

This medium priority area is in the northern quarter of T25S-R24E and T25S-R25E. Currently, this AOI does not have recognized susceptible critical infrastructure. It has significant subsidence reported both historically (USGS level surveys) and recently (InSAR). A CGPS station in this area will provide a needed ground truthing point to confirm InSAR readings and will act as a useful monitoring point to gauge progress of groundwater management along the border of the subbasin in relation to neighboring subbasins to the north.

Existing Monitoring

Currently, this area is screened by InSAR. There are no other active monitoring points along this stretch.

New Monitoring Approach

Monitoring at this location will assist in the KGA and its members to determine the causes of subsidence. If is it is reasonability determined that local agricultural extractions are the cause of subsidence at this location, the appropriate management area will work towards establishing appropriate measurable objectives and minimum thresholds. If local groundwater extraction is determined to be the source of subsidence more detailed subsidence monitoring will be undertaken. a CGPS or extensometer monitoring station should be installed. Where possible, this station should be tied in to benchmark surveys performed by local districts.

Coordination of Monitoring

Subsidence monitoring along the subbasin boundary benefits local stakeholders in Kern County subbasin and adjacent subbasins. In the future, data may be shared with neighboring GSAs for coordination.

3.6.10 Assessment and Improvement of Monitoring Network

The following section describes data gaps and improvements for groundwater elevations, groundwater quality, and land subsidence. While this section provides the overall data gaps observed within the KGA, details for each management area can be found in the respective management area plan.

3.6.10.1 Groundwater Elevation and Storage

As referenced in § 352.4 of the regulations, "*If an Agency relies on wells that lack casing perforations, borehole depth, or total well depth information to monitor groundwater conditions as part of a Plan, the Agency shall describe a schedule for acquiring monitoring wells with the necessary information, or demonstrate to the Department that such information is not necessary to understand and manage groundwater in the basin."*

Well types and construction details will need to be determined to improve on the monitoring network. Downhole well surveys and desktop surveys will be utilized for existing wells to fill in the well construction details gap. New dedicated monitoring wells and converted monitoring wells from production wells will be utilized to fill in the monitoring network spatial extent and density. Plans for improvement will be developed during the next few years to be ready for proposal.

Currently, groundwater elevation and sampling measurements are not scheduled according to the 1 to 2-week period during the middle of Spring and middle of Autumn, as recommended by DWR's Monitoring Protocol BMP. Consequently, groundwater elevations and hydraulic gradients in the Subbasin are reported according to a broader range of time between Spring and Fall.

To minimize the effects of a temporal data gap in the future, it will be necessary to coordinate the collection of groundwater elevation data such that it occurs within a two-week window during the key reporting periods of mid-March and mid-October.

3.6.10.2 Groundwater Quality

New dedicated monitoring wells and converted monitoring wells from production wells will be utilized to fill in the monitoring network spatial extent and density. Plans for improvement will be developed during the next few years to be ready for proposal.

3.6.10.3 Land Subsidence

As described above, the Subbasin has agreed to a joint effort of monitoring subsidence at critical location in the Subbasin. The proposed monitoring program is to understand the causes of subsidence, the potential risk of damaging critical infrastructure, and how to set minimum thresholds to avoid significant impacts to critical infrastructure in the Subbasin.

3.6.11 Monitoring Summary

The monitoring networks as described above will leverage existing networks for groundwater elevations and storage, groundwater quality, and land subsidence. The networks will be improved upon with data reported semiannually to meet the objectives of this plan. The networks will be evaluated as often as possible to consider improvements and adjustments, and at a minimum, every 5 years, the network reports will summarize the results against measurable objectives. The network improvement plan is provided below.

4 Projects and Management Actions

4.1 Proposed Projects and Management Actions

Projects and management actions for the KGA have been developed at the management area level. Table 4-1 (provided at the end of this section) provides a summary list of all projects and management actions being considered for implementation by each member agency, including the project title, implementation status, a brief description of the project, and benefits associated with the project. The details of each proposed project and management action can be found in each member agency's management area plan.

In addition to the projects and management actions that are proposed by the KGA members, the KGA has identified projects and management actions that it will implemented to further the coordination of groundwater management in the Subbasin. Table 4-2 list these proposed projects and management actions. These efforts will be managed by the KGA and will be cost share through agreements with KGA members, other GSAs in the Subbasin, and grants, as appropriate.

Table 4-2: Kern Groundwater Authority Projects and Management Actions

Project Name	Project Description
Subsidence Monitoring (basin-wide)	Improve the understanding of the causes and impacts of subsidence in the Subbasin. Installation of subsidence monitoring stations in 2023 with funding from the Budget Act of 2021 Sustainable Groundwater Management (SGM) Grant Program SGM Act Implementation – Round 1 Grant. Work with the DWR CA Aqueduct staff and Friant staff to continue the studies and exchange of data to improve the sustainable management criteria for each critical regional infrastructure Implementation Period: 2020 to 2025
Groundwater Modeling (basin-wide)	Improve the understanding of groundwater reactions to the implementation of projects and management actions, relationship to minimum thresholds and measurable objectives, determination of the native yield of the Subbasin, and subsurface flow within and out of the Subbasin. Continue the development of the Kern subbasin data management system that will assist in improving the understanding as well as provide access to the data to stakeholders and beneficial users. Enhancing the transparency of the data as well as addressing any minimum threshold exceedances. Implementation Period: 2020 to 2025. Funding provided through the Budget Act of 2021 Sustainable Groundwater Management (SGM) Grant Program SGM Act Implementation – Round 1 Grant.
Study of Native Yield of the Subbasin	Studies to refine the understanding and allocation of the available native groundwater yield within the Subbasin. Implementation Period: 2020 to 2025. Funding provided through the Budget Act of 2021 Sustainable Groundwater Management (SGM) Grant Program SGM Act Implementation – Round 1 Grant.
Kern County Subbasin, Basin-wide Study	• **Basin Study:** Basin Study to develop a systematic technical analysis to better represent and understand the flow of groundwater and surface water into, through and out of the Kern Subbasin. • **Evapotranspiration Analysis & Study:** Field by Field Project compliments the Basin Study by groundwater truthing the water demand part of SGMA. The Component will provide data on the soil types and farming methods to further investigate the different crops planted and best way to meet water demands, providing a more accurate account of water usage.

Project Name	Project Description
	• **Subsidence Investigation and Study:** Priority Area #1 Data collection: Data to set the SMC for Kern subsidence. Strategically placed extensometers would provide the data necessary to set SMC as well as considering the other activity of extractions occurring in the basin, oil extractions. • **New or Converted Monitoring Wells**: Improve existing monitoring network throughout the Kern subbasin. Implementation Period: 2022 to 2005. Funding provided through the Budget Act of 2021 Sustainable Groundwater Management (SGM) Grant Program SGM Act Implementation – Round 1 Grant.
Subbasin Wide Consumptive Use Monitoring	Development of basin-wide consumptive use data to support water budget analyses, basin-wide modeling, groundwater native yield analysis and allocation, and annual reporting requirements Implemented in 2023. Funding provided through the Budget Act of 2021 Sustainable Groundwater Management (SGM) Grant Program SGM Act Implementation – Round 1 Grant.
Managing to Measurable Objectives	KGA members manage to checkbook water budgets as well as implement projects and management actions within their respective management areas to sustain water levels at or above the established measurable objectives. Implementation: 2020 to ongoing
Domestic Well Mitigation Program	A Domestic Well Mitigation Program will be developed and implemented by all KGA members. The purpose of this program is to mitigation the potential impact of declining groundwater elevations resulting from groundwater management actions. Implementation Period: 2020 to ongoing. Funding will be determined by individual members within their respective management areas.
KGA Monitoring Network Improvement Program	The KGA will work with its member entities, and other Subbasin GSAs, to continue to improve and reach SGMA compliance for identified representative monitoring sites. The KGA will work to identify joint projects and programs to ensure efficient installation and/or rehabilitation of monitoring wells and data collection and reporting efforts. Implementation Period: 2020 to 2025.
Basin-wide Coordination	Continuation of the Kern Subbasin Managers Group to coordinate water management activities in the Subbasin, including technical analysis, project management and coordination, identification of joint management opportunities and coordination of SGMA reporting requirements to DWR. Implementation Period: 2020 to ongoing
Annual Reporting	Coordination and facilitation of annual SGMA reporting requirements. The Kern subbasin to continue to address minimum threshold exceedances in the annual report. Implementation Period: 2020 to ongoing

The Subbasin includes a complex environment of various local and imported surface water supplies; variable access to groundwater supplies based on quantity and quality; water management authorities; extent and capacity of water management infrastructure; and fiscal relationship with local landowners for participation in water management programs. Each of the member agencies within the KGA has identified projects and management actions best suited to meet the conditions of sustainability within their respective management areas within the water management and authorities of its entity. Collectively these projects and management actions are designed to maintain or achieve sustainability and the avoidance of undesirable results, first within the management area and then collaboratively throughout the Subbasin. The KGA, the

KGA/GSA Managers Group and the Kern SGMA Coordination Committee will monitor the progress of project and management action implementation against reported groundwater conditions and performance to measurable objectives and interim milestones. Through this coordination effort opportunities will be explored for collaboration in implementing projects and management actions, as has been historically accomplished in the Subbasin, for joint conveyance as well as recharge and banking projects, as an example.

Table 4-1 list more than 140 projects and management actions either planned for, underway, or completed as of 2022. This includes management projects ranging from expansion of local and regional conveyance and recharge facilities to take advantage of surplus supplies; new conveyance and recharge projects; and participation in the Delta Conveyance Project or other thru-Delta improvement projects. Management actions range from implementing district level fee structures to incentive reduced groundwater pumping; participation in local, regional, and state-wide water markets; and setting allocation for groundwater use by landowner, based on the sustainable yield of the management area.

Table 4-1 also demonstrates the tremendous capacity of the entities in the Subbasin to implement projects and management actions to manage the Subbasin sustainably. As the KGA and the other Subbasin GSAs progress to 2040, the implementation of projects and management actions will be adaptively managed to ensure that the proper mix of projects or management actions are developed to avoid undesirable results. Each management area plan as developed its own adaptive management strategy, which often entails some level of groundwater pumping reductions if proposed project or management action are not realized or are not as effective as anticipated.

4.2 Projected Future Water Budgets with SGMA Implementation

Projected water budgets with implementation of the projects and management actions described in the previous section were developed using the C2VSimFG-Kern to evaluate the performance with respect to achieving groundwater sustainability. Proposed projects and management actions were simulated under Baseline conditions, 2030 Climate Conditions and 2070 Climate Conditions using the C2VSimFG-Kern. Detailed description of proposed SGMA projects, and management actions are provided in *Attachment H: Historical and Projected Future Water Budget Development with C2VSimFG-Kern*.

4.2.1 Future Baseline Water Budget with SGMA Implementation

The Baseline Scenario with Projects simulates the implementation of proposed projects and management actions applied to the Baseline Scenario. No other changes were made except for the addition of the projects to provide a direct comparison of the relative benefits of the over 400,000 AFY of proposed SGMA projects and management actions. The change in groundwater storage for projected future baseline with SGMA Projects improves by about 409,904 AFY. This change results in a net gain in groundwater in aquifer storage over the WY2041 to WY2070 sustainability period of about 85,578 AFY.

Figure 4-1 shows the comparison of the average annual water budget components for the two different Baseline Scenarios. Over this period, the average groundwater pumping of 1,354,000 AFY for the Baseline Scenario with SGMA Projects (which includes agricultural pumping, urban pumping and exported water) is over 270,000 AFY less than the Baseline Scenario.

4.2.2 2030 Climate Change Water Budget with SGMA Implementation

The 2030 Climate Scenario with SGMA Projects simulates the implementation of proposed projects and management actions applied to the 2030 climate change conditions. No other changes were made to this scenario. A comparison of the average annual water budget components for the two 2030 Climate Scenarios is presented in Figure 4-2. The change in groundwater storage for projected 2030 Climate Scenarios condition with SGMA Projects improves by about 418,949 AFY. This change results in a net deficit in groundwater in aquifer storage over the WY2041 to WY2070 sustainability period of about 46,829 AFY. Over this period, the average groundwater pumping of 1,444,300 AFY for the 2030 Climate Scenario with SGMA Projects, which includes agricultural pumping, urban pumping and exported water, is over 290,000 AFY less than the 2030 Climate Scenario without SGMA Projects.

4.2.3 2070 Climate Change Water Budget with SGMA Implementation

The 2070 Climate Scenario with SGMA Projects simulates the implementation of proposed projects and management actions applied to the 2070 climate change conditions. No other changes were made to this scenario. A comparison of the average annual water budget components for the two different 2070 Climate Scenarios is presented in Figure 4-3. The change in groundwater storage for projected 2070 Climate Scenarios condition with SGMA Projects improves by about 426,367 AFY. This change results in a net deficit in groundwater in aquifer storage over the WY2041 to WY2070 sustainability period of about 45,969 AFY. Over this period, the average groundwater pumping of 1,559,000 AFY for the 2070 Climate Scenario with SGMA Projects, which includes agricultural pumping, urban pumping and exported water, is over 307,000 AFY less than the 2070 Climate Scenario without SGMA Projects.

A comparison of the annual change in groundwater storage over the 50-year hydrologic period for the baseline conditions, 2030 and 2070 climate condition for with and without projects is presented in Figure 4-4. The time series shows that change in groundwater storage has stabilized to slightly increasing over the period from WY2041 to WY2070 for with Projects condition.

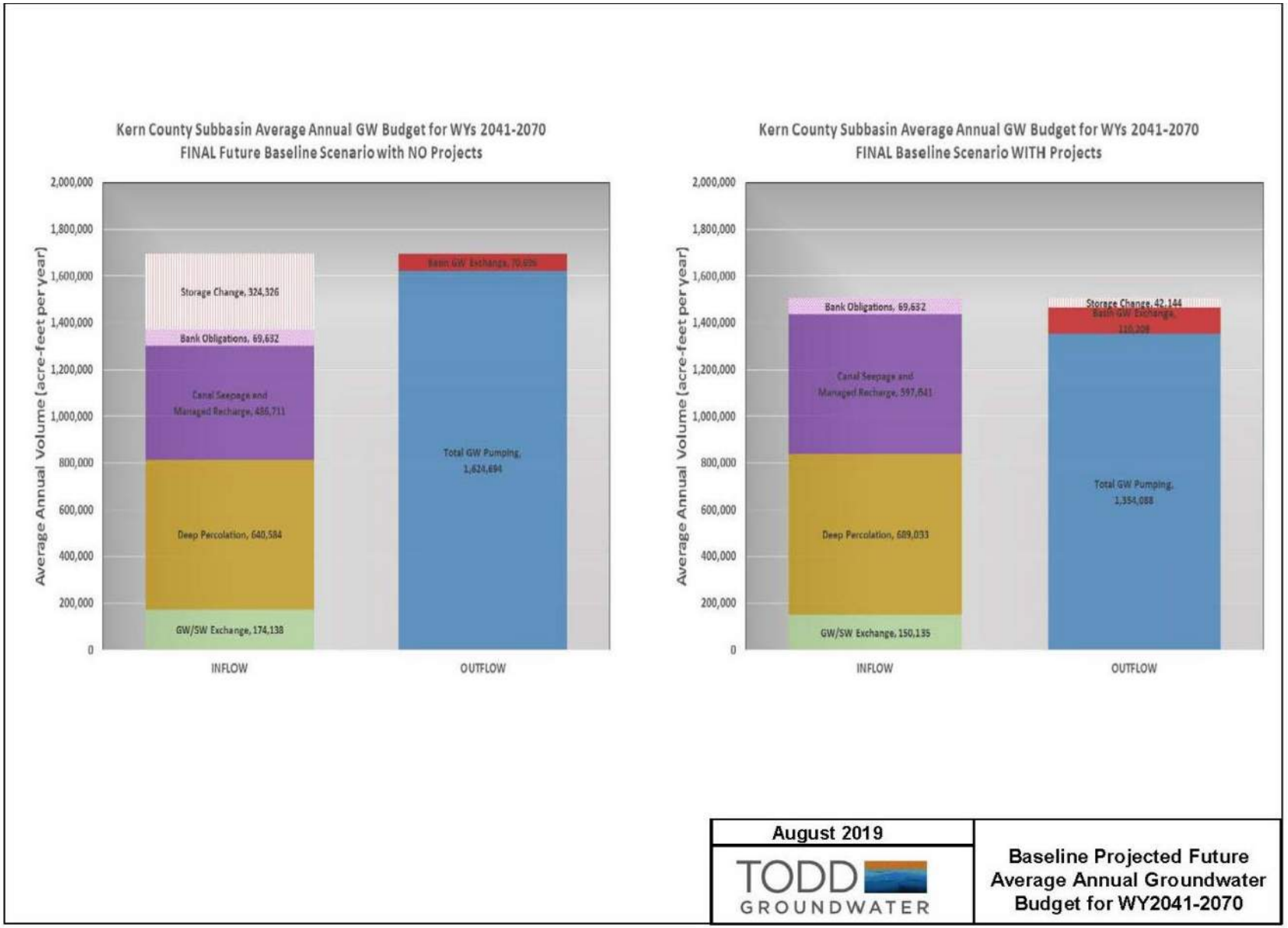

Figure 4-1. Baseline Projected Future Average Annual Groundwater Budget for WY2041-2070

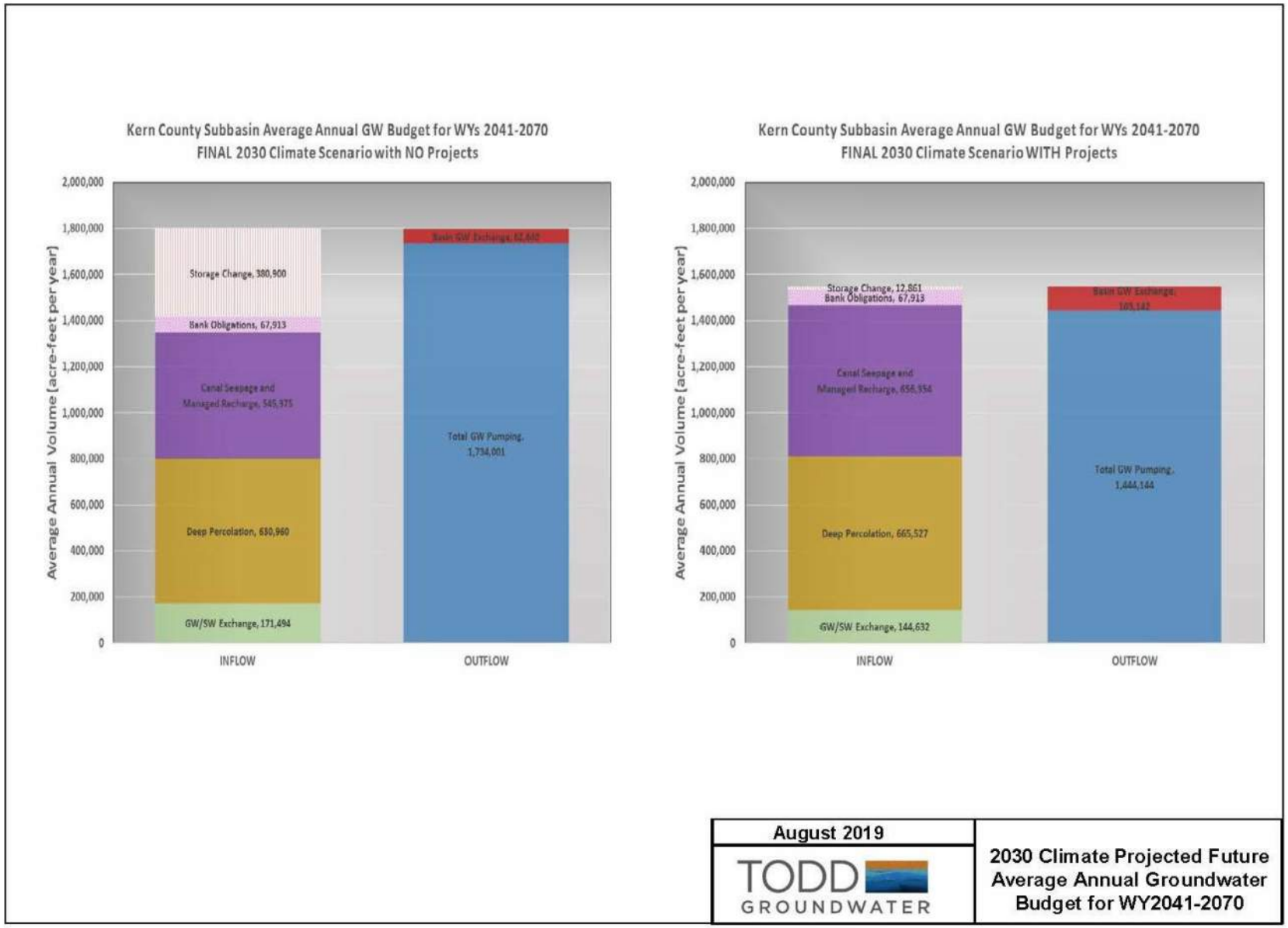

Figure 4-2. 2030 Climate Projected Future Average Annual Groundwater Budget for WY2041-2070

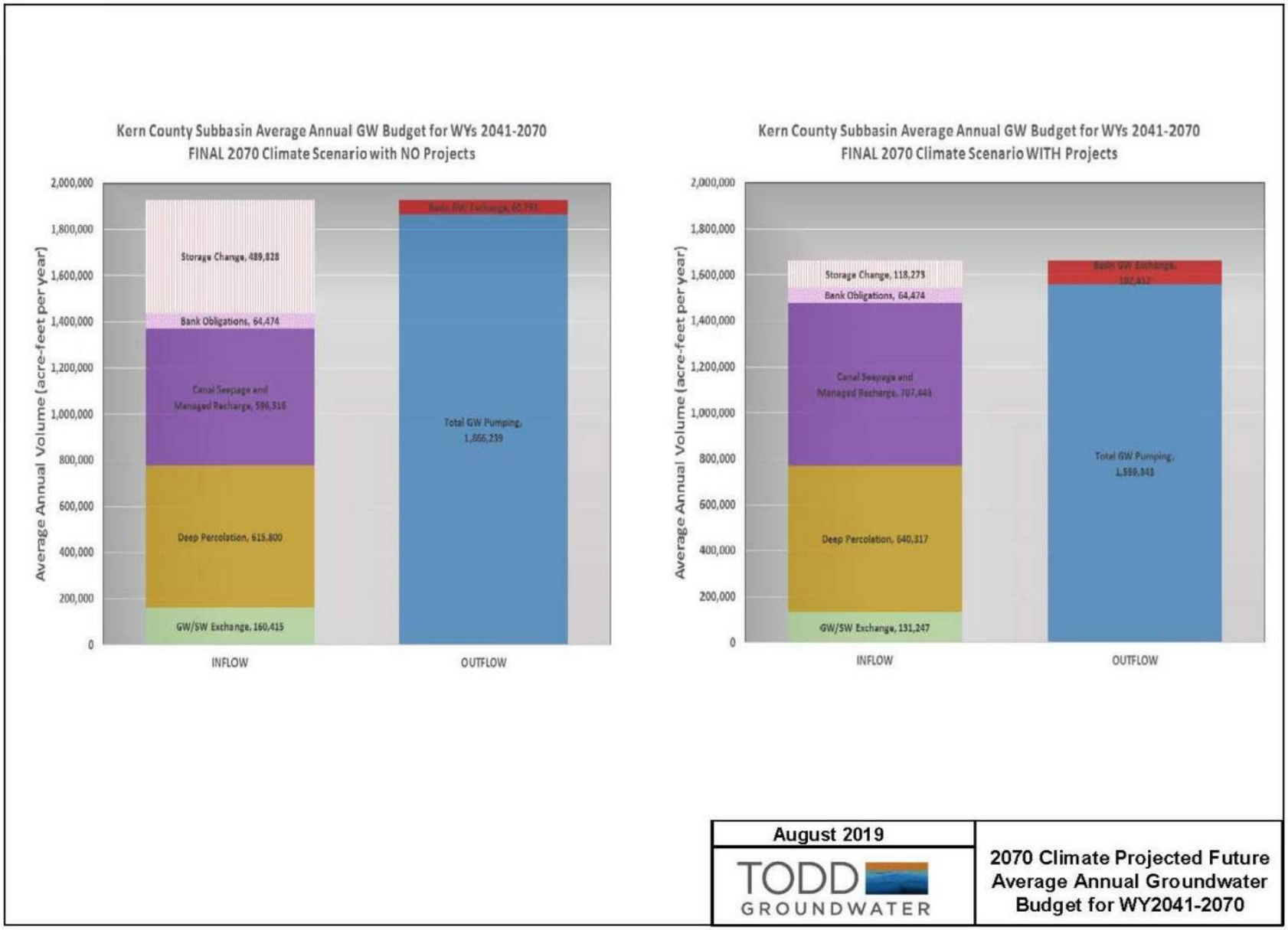

Figure 4-3. 2070 Climate Projected Future Average Annual Groundwater Budget for WY2041-2070

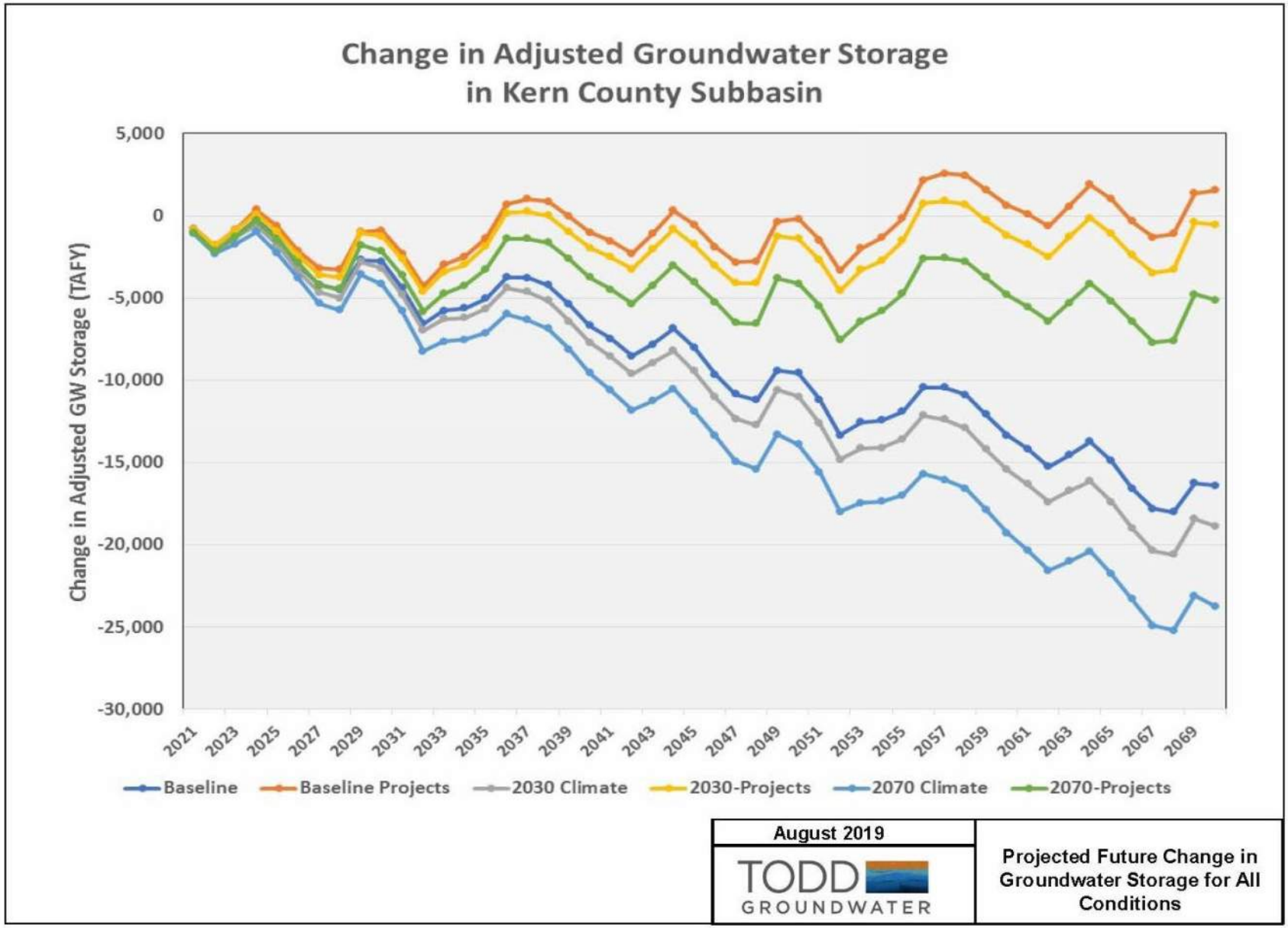

Figure 4-4. Projected Future Change in Groundwater Storage for all Conditions.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions

Entity	Project Title	Implementation Status	Description	Benefits
Cawelo Water Storage District				
CWD	NEW Management Action #1: Kern Groundwater Authority Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater	2020 to 2040 Implementation	The Cawelo GSA has adopted the Kern Groundwater Authority Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater Levels (Action Plan). Under the Action Plan, the Cawelo MAP will assess the cause of any single minimum threshold (MT) exceedance to better understand whether the underlying cause may be a potential precursor to an undesirable result or if it is the result of temporary or localized conditions. This proactive approach will provide an opportunity for the early implementation of other management actions or projects, as necessary, to address a potential emerging undesirable result.	The Action Plan allows for a proactive approach to assess the cause of any single MT exceedance providing an opportunity for the early implementation of other management actions or projects, as necessary, to address a potential emerging undesirable result.
CWD	NEW Management Action #2: Domestic Well Mitigation Program	2020 to 2040 Implementation	The Cawelo GSA Board will consider, if deemed necessary and appropriate, to adopt a Domestic Well Mitigation Program to assist in offsetting costs for domestic well issues related to dewatering of pumps or dewatering of well screens to the point of significant reduction in production. The Domestic Well Mitigation Program may be developed whereby a potential remedy will be provided to the domestic well owner in the event that the domestic wells are demonstrably unreasonably impacted by groundwater conditions, as defined within the program. Funding for such a program may be sourced from the CWD general funds or from a Cawelo GSA fund supported by a fee on owners of agricultural and industrial supply wells. The program may be modeled after similar programs developed elsewhere in the Kern Subbasin or around the state (e.g., Joint Operations Plan on the Kern Fan), and may include, but not limited to, remedies such as lowering pumps, deepening of wells, drilling new wells, and support for access to alternative water sources. The program will be developed in coordination with and in consideration of the interests of local stakeholders within the Cawelo GSA.	The domestic well mitigation program will benefit potentially effected beneficial users in the instance their domestic well is demonstrably unreasonably impacted by groundwater conditions.
CWD	Management Action #3: Voluntary Land Conversion	2020 to 2040 Implementation	The Cawelo GSA will develop a program to incentivize landowners to reduce their total crop demand by converting farmed land to groundwater recharge areas. This would reduce demands and the increased recharge capability could increase supplies. It could also reduce the potential of currently fallow land being used for future crops. This Management Action could be implemented conjunctively with Project #2: Increase GW Recharge and Banking Capacity	Range of annual benefit is 2,000 AFY with an average annual benefit at 2040 of 2,000 AFY.
CWD	Management Action #4: Crop Conversion and Irrigation Efficiency	2020 to 2040 Implementation	The Cawelo GSA will evaluate potential programs to incentivize growers to convert from relatively high water demands crops to crops that require less water and to improve the efficiency of irrigation practices. The Cawelo GSA will partner with Federal, State and local organizations such as the California Department of Food and Agriculture, U.S. Department of Agriculture, and Natural Resources Conservation Service to provide landowners information and access to conservation programs. The programs would educate the landowners on the potential economic savings from conversion to lower water demand crops and increased irrigation efficiencies and incentivize them to seek improved economically viable agricultural operations.	Range of annual benefit is less than 2,000 AFY with an average annual benefit at 2040 of 3,8000 AFY.
CWD	Management Action #5: Land Acquisition	2020 to 2040 Implementation	The Cawelo GSA will evaluate and potentially implement a program to acquire land that is actively farmed to reduce irrigated acreages within the Cawelo GSA. This would directly eliminate demands and free up the associated water supplies to meet other demands. This could be a very long-term program seeking to acquire appropriate land when available or to reduce the financial burden. Another method for pot ential conservation programs will be developed that could place certain easements on land that would minimize potential future increased water demands. These programs could also be implemented by contracts or other types of agreements.	Range of annual benefi is 2,500 AFY with an average annual benefit at 2040 of 2,400 AFY.
CWD	Management Action #6: Secure Access to Additional Monitoring Locations	2023 to 2025	The Cawelo GSA will continue to pursue an access agreement for a monitoring well location in the southeastern portion of the GSA. At the time of the completion of this GSP, access to the eighth location had not been secured, so it is listed as To-Be-Determined (TBD). Negotiations are ongoing for this location in the southeastern part of the GSA.	This management action would provide a monitoring location in the southeastern portion of the GSA where Cawelo GSA does not currently have a monitoring location. However, the regional monitoring network does include monitoring locations south of this area in the Kern River GSA area.
CWD	Projtect #1: New Water Supply Purchases	Begin program in 2020.	The Cawelo GSA would implement programs that will acquire long-term new water purchase contracts and/or establish a water purchase fund if contracts are difficult to secure because of high demand and competition and resulting high costs. The main goal would be to secure long-term new water contracts but compliance with SGMA will impact future water management practices and could make the availability of new long-term contracts scarce. If long-term contracts can't be secured then a new water fund would be established to build funding reserves for water purchases. These purchases could occur during favorable times such as hydrologically wet years when water will be more readily available at lower costs. While the Cawelo GSA would likely not need this water in wet years, these types of purchases could be in the form of banked water that the Cawelo GSA could request at a future date. Alternatively, the funds could be used to make annual water purchases and the revenue for the fund would be consistent from year to year regardless of the hydrological conditions. Therefore, during wet or average hydrologic years the water would cost less and reserves would be built up for more costly water purchases during the drier years. It is estimated that an additional 5,000 AFY to 23,000 AFY of water could be imported into the Cawelo GSA area through new long-term contracts or establishing a new water purchase fund or both.	Securing new long-term contracts or establishing a water purchase fund or both could result in an additional 5,000 AFY to 23,000 AFY of water that could be imported into the Cawelo GSA area. This additional water would increase the amount of water in the basin and decrease overdraft.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
CWD	Project #2: Increase Groundwater Recharge and Banking Capacity	Target 2030 Implementation	The Cawelo GSA will implement projects or programs to increase recharge capacity to capture and recharge additional wet year high flow waters to store for future use. The Cawelo GSA has limited groundwater recharge facilities and has not been able to capture and recharge all available water under wet hydrological conditions. This project would entail building additional Cawelo GSA-owned recharge facilities and/or improve the distribution system to increase the capacity to capture more water, especially during wet hydrologic events. Some facilities could be strategically located to capture storm runoff that may otherwise leave the Cawelo GSA area. It is estimated that approximately 200 to 570 acres of new recharge and banking facilities could be developed. Additionally, the Cawelo GSA will consider implementing a program to incentivize landowners to use their land for recharge. This could provide an opportunity for landowners to bank their privately-owned water for future recovery and possibly allow the Cawelo GSA access to their lands for additional recharge. This program would not only increase recharge capacities during wet years but could also reduce water demand by replacing crops with recharge facilities. The privately-owned water could be purchased under Project #1, New Water Supply Purchases, described above.	There are significant regions within the Cawelo GSA with soil properties that could achieve percolation rates of up to 0.5 AF per day. Assuming an average percolation rate of 0.35 AF/day and approximately 200 to 570 acres of potential new recharge and banking land, about an average of 500 AFY to 1,500 AFY of new water could be recharged for future recovery. It is not clear what magnitude landowner-owned recharge facilities would have on importing additional waters into the Cawelo GSA area. It could be anywhere between an average of 50 AFY to 500 AFY.
CWD	Project #3: New Cawelo GSA Banking Partners	Begin program in 2020.	The Cawelo Water District benefits from a banking program partnership with the Zone 7 Water Agency. Located in the Livermore-Amador Valley, which is outside of the Kern County Subbasin. The District stores water for Zone 7 and keeps half of the water that it stores. For example, for every 2 AF feet of water delivered to District recharge facilities, the District is obligated to only return 1 AF. The currently banking program with Zone 7 could be modified to increase the amount of water stored for Zone 7 and/or a new banking programs and partners could be considered to fund the construction of new facilities and/or to improve existing facilities. It is estimated this could increase the annual average water supply up to 500 AFY.	The expansion of the existing banking contract with Zone 7 and/or the development of additional banking partners would be a beneficial way the Cawelo GSA could increase its groundwater supply by the portion of water each partner agrees to essentially leave in the Cawelo GSA area. Zone 7 has agreed to leave 50 percent of all that is spread. It is estimated that this program would generate about 500 AFY.
CWD	Project #4: Water Treatment Facilities	Begin program in 2020.	The Cawelo GSA is currently evaluating projects to install water treatment facilities that will allow the Cawelo GSA to acquire wastewater and treat it to a level that is safe for crop irrigation. Wastewater is exempt from SGMA regulation and the treated wastewater would be considered new water. There is a substantial volume of oilfield produced water (OPW), a byproduct of oil production, available in the vicinity of the Cawelo GSA. The salinity of OPW can range from moderate to high, although even the best quality still requires some level of blending with fresh water before it can be used on crops. Reverse osmosis or distillation would generally be needed to remove enough salts to make the OPW usable for irrigation. Near the Cawelo GSA, approximately 20,000 AFY of wastewater is injected into exempt groundwater aquifers well below the base of fresh water. The Cawelo GSA is evaluating potential projects to treat anywhere from 7,500 AFY to 20,000 AFY of OPW.	The treated OPW would be a new source of about 7,500 AFY to 20,000 AFY of water for irrigation.
CWD	Project #5: Friant Pipeline Project	Construction in 2019.	The Cawelo GSA is currently developing the Friant Pipeline Project that would increase water importation capacity into the Cawelo GSA area. Currently, the amount of imported water that the Cawelo GSA can import into the area is limited by conveyance capacity, not by irrigation demand or recharge basin capacities. The Friant Pipeline Project would increase the total capacity by 100 cubic feet per second (cfs) and connect Cawelo's Famoso Recharge Basins directly to the Friant-Kern Canal. The increased capacity would allow greater access to high flow water and support banking programs with Friant Contractors. The Friant Pipeline Project would result in an additional 1,500 AFY to 2,500 AFY of water brought into the Cawelo GSA area on an average annual basis.	The Friant Pipeline Project would increase the total capacity into the Cawelo GSA by 100 cfs and increase access to CVP high flow waters and allow for banking programs with Friant Contractors. It would result in an additional 1,500 AFY to 2,500 AFY of water brought into the Cawelo GSA area on an average annual basis.
CWD	Project #6: Poso Creek Flood Water Capture	Target 2030 Implementation	The CWD has appropriative rights to divert water from Poso Creek, an ephemeral stream, when there are flows into the Cawelo GSA area. Additionally, there are downstream districts that also have subsequent appropriative rights and certain adjacent landowners that exercise their riparian rights. CWD also has additional diversion rights to divert supplementary water when high flows occur. The Poso Creek Flood Water Capture Project would consist of the construction of additional facilities to take advantage of those additional rights and divert supplementary water from the creek during times of high flow. In addition to making more water available to the Cawelo GSA, this capture of additional high flows could reduce potential downstream flooding impacts. Participation from downstream right holders would be needed due to potential water right impacts. The estimated net water gain is up to 150 AFY on average.	The Poso Creek Flood Water Capture Project would provide up to 150 AFY on average of additional water and could reduce potential downstream flooding impacts.
CWD	Project #7: Surface Water Storage	Target 2030 Implementation	The Cawelo GSA has several existing reservoirs with a combined storage capacity of 800 AF. This project would consist of constructing a new 5,000 AF reservoir within the Cawelo GSA boundary. This would provide additional storage capacity to bring more water into the Cawelo GSA area during wet years. It is estimated that this new reservoir would provide approximately 500 AFY on average. This program would likely only be implemented conjunctively with other water management programs.	A new reservoir would provide approximately 500 AFY on average.
CWD	Project #8: Out of Cawelo GSA Banking	Begin program in 2020.	The Cawelo GSA will evaluate groundwater banking projects that are outside the Cawelo GSA but within the Kern County Subbasin and also groundwater banking projects outside of the Kern County Subbasin. Potential banking projects outside of the Cawelo GSA are likely to have multiple participants and therefore offer a limited share of project benefits.	This Project could yield an average annual benefit of 500 AFY to 4,000 AFY through out of Cawelo GSA banking programs.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
Eastside Water Management Area				
EWMA	Project-1	Not yet initiated; Timetable TBD.	Development of oilfield produced-water supplies to potentially reduce groundwater demand.	Potential additional external source of water for the basin (annual volume TBD).
EWMA	Project-2	Not yet initiated; Timetable TBD.	Construction of aquifer-specific monitoring wells in locations with data gaps, to better understand hydraulic heads and gradients.	Improved ability to monitor groundwater conditions in specific aquifers or areas.
EWMA	Project-3	Not yet initiated; Timetable TBD.	Installation of pressure transducers in selected wells of the monitoring network, to collect high-resolution cost-effective data.	Improved ability to monitor groundwater conditions in EWMA.
EWMA	Project-4	Not yet initiated; Timetable TBD.	Surface runoff capture and enhanced infiltration in impoundments.	Reduced groundwater pumping (annual volume TBD) to meet sustainability goals, as needed.
EWMA	Management Action-1	Not yet initiated; Timetable TBD.	Exceedence Policy (see GSP Section 16.2)	Actionable information regarding causes and effects of MT exceedance
EWMA	Management Action-2	Not yet initiated; Timetable TBD.	Reduction of irrigated acreage, or modification of irrigation techniques or crop types to reduce water usage.	Reduced groundwater pumping (annual volume TBD) to meet sustainability goals, as needed.
EWMA	Management Action-3	Not yet initiated; Timetable TBD.	Assess fees for groundwater use to encourage reduced pumping or curtailment.	Reduced groundwater pumping (annual volume TBD) to meet sustainability goals, as needed.
EWMA	Management Action-4	Not yet initiated; Timetable TBD.	Establish a system of transferrable water credits.	Reduced groundwater pumping (annual volume TBD) to meet sustainability goals, as needed.
Kern Water Bank Authority				
KWB	Operations Plans	Ongoing	KWB operations can cause a temporary lowering of groundwater levels in adjacent areas toward the end of extended droughts. In order to mitigate the potential impacts that might arise from those temporary changes, DWR has developed mitigation measures for the project, which have now been coordinated with other adjacent water banking projects and incorporated into a Joint Operations Plan. The Joint Operations Plan designates measures to prevent, eliminate or mitigate significant adverse impacts resulting from project recovery operations.	Potential impacts from project operations on adjoining domestic, small community, and agricultural groundwater wells are avoided.
KWB	Groundwater Storage Improvement	Ongoing	Water recovered by KWB provides water supplies to KWB participants in dry years significantly reducing their need to pump groundwater. KWB also provides up to 4% of the water stored to adjoining Management Areas to reduce overdraft in those areas. KWBA cannot recover water beyond those volumes previously stored less appropriate losses.	KWB operations help both our members and adjoining management areas reduce groundwater pumping thereby minimizing the potential for a reduction of groundwater storage in those areas. KWB recovery operations will also never result in a reduction of groundwater storage because recovery ceases when stored water accounts reach zero.
KWB	Water Quality Protection	Ongoing	Groundwater monitoring from 1994 through 2018 indicates groundwater quality is not being degraded by KWB water banking activities, and in fact the removal of salts is benefitting the aquifer. DWR developed mitigation measures to ensure that continued KWB operations do not degrade groundwater quality.	Historical KWB operations have removed salts from the Kern Fan aquifer and provided improvements to water quality for some constituents in the California Aqueduct. These benefits will continue.
KWB	Subsidence Monitoring	Ongoing	The KWB supports the repair and continued monitoring of the extensometer located on KWB property.	The KWB extensometer provides important subsidence data for the Kern Fan region.
KWB	KWB Recharge Enhancement Project	Completed	KWBA has constructed an additional 1,025 acres of recharge basins.	Project will allow KWBA capture more water in the future, furthering the conservation goals of SGMA.
Kern Tulare Water District				
KTWD	Action 1: Modify District Pricing Structure	ction 1 could be executed during the first 5 years of implementing the Plan (2020-2025).	The most affordable way to reduce groundwater pumping is to provide a pricing mechanism that causes groundwater to cost more than surface water. This could be accomplished by implementing a "groundwater charge" for every acre-foot pumped. Water Code §35533 provides the District the authority to collect groundwater charges. Revenue from the groundwater charge could be used to implement management actions or to reduce the cost to deliver surface water from the District.	5,580 AF/yr reduction in groundwater pumping.
KTWD	Action 2: CRC Pipeline Project - Produced Water Project	The District and CRC are in the process of acquiring permits, preparing an anti-degradation analysis and acquiring a WDR from the Regional Board. Project pipelines have been designed and plan and profile drawings have been prepared. The District is negotiating an agreement with CRC and obtaining rights-of-way. The pipeline construction is expected to be completed prior to 2025.	The District has historically accepted produced water to provide surface water to the District and is in the process of obtaining an additional source of produced water from California Resources Corporation (CRC). Produced water from CRC will be transported through 12 miles of 15-inch pipeline to the Guzman Reservoir. From the Guzman Reservoir, water will be transported through 1.8 miles of 30-inch pipeline to the District's existing Big 4 Reservoir, from which it will be blended with water from the Friant-Kern Canal and distributed in existing facilities to existing irrigated agriculture located within the District.	3,000 AF/yr of additional surface supplies (results in a reduction of 1,440 AF/yr in groundwater pumping).

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
KTWD	Action 3: In-District Surface Storage	The project is still in the preliminary design phase and will require additional steps before construction. The District has selected two potential reservoir sites, completed exploratory borings, and conducted a geotechnical evaluation of the two potential sites. The District has yet to acquire land and rights of way, permits, environmental documentation, or project financing. It is estimated that these facilities will be constructed between 2025 and 2030 if they are determined to be feasible and found to be necessary.	There are times when affordable water supplies are available, but the District has little to no irrigation demand and no available spreading capacity in its existing out-of-district banking programs. Construction of off-stream surface storage will allow the District to acquire water when it is available and store it to meet future irrigation demands. The District has selected two potential reservoir sites with a total capacity of 8,000 AF to capture wet year water. The sites are located to the east of the District in both the north and south portions. A location map of facilities and detailed description is not provided due to the confidential nature of the property and rights of way acquisition.	Based upon annual water supply modeling herein, the project yields only 530 AF/yr. However, a monthly analysis will need to be conducted to provide a better estimate of project yield, which could be as much as 2,000 AF/yr (assumes the reservoirs are used once every 4 years).
North Kern Water District & Shafter-Wasco Irrigation District				
NKWSD	Calloway Canal Improvements: Lining Snow Rd. to 7th Standard Rd.	Calloway Canal Lining is an ongoing project. NKWSD is in the process of acquiring adequate funding to complete the next one-mile lining of the project. The proposed project schedule includes a start date of October 2019 and completion within 36-months.	Calloway Canal Improvements is part of NKWSD's continued effort of the recently completed 1.1-mile long canal lining. The first phase of this project consists of concrete lining approximately 2,200 LF of currently unlined portion of the Calloway Canal to increase surface water reliability and prevent seepage.. Phase two of this project includes water delivery improvements (WDI) that consist of installing magnetic flowmeters (or magmeters) at a total of 50 of the District owned production wells. Each magmeter will include a totalizer capable of measuring the volume of groundwater pumped through the wells. Further, water level sensors will also be installed in each of the 50 production wells and four additional monitoring wells to quantify the depth-to-water data. Additionally, the District proposes to implement telemetry upgrades at each of the production well sites, each of the monitoring well sites, and 14 remote Terminal Unity (RTUs-used to measure canal levels) sites. The final part of the water delivery improvements integrating these sites with NKWSD's Supervisory Control and Data Acquisition (SCADA) setup.	Lining the canal will reduce the irrecoverable losses that result when high quality surface water seeps to poor quality groundwater, which cannot be recovered for later use without substantial treatment. Reducing these losses enhances NKWSD's capability to deliver increased volumes of water from the Kern River to irrigators for existing demand. The integration of the telemetry system with the SCADA setup will enable the District to control well operation and access their groundwater pumping data remotely. Water conserved by lining the canal and implementing WDI is estimated at 1,576 AFY.
NKWSD	Expanded Water Banking Program	This program is an expansion of the District's ongoing groundwater banking program. Environmental documents are being prepared to carry out the program in a timely manner.	Due to historically low groundwater levels, requirements under SGMA, and potential reductions in its historical water supplies, NKWSD is proposing a new program to increase its existing conjunctive use (or water banking) facilities and subsequently expand these facilities. Phase I of this program would primarily rely on unused capacity in existing facilities which is available from time to time (with some additional conveyance) and would seek to increase the utilization of the District's proven recharge and recovery assets. Phase II would involve the construction of additional direct recharge and recovery facilities to further expand water banking in the District. Both the District and District landowners will receive water supply benefits from this program.	Implementation of this program would bring additional water supplies that would help offset potential losses of the District's historical supplies, support the District's mission of maintaining economic pumping lifts for its landowners, and maintain supplies to be used for municipal and industrial purposes by the city of Shafter. Quantitative benefits include 50,000 AFY (Phase I) and 72,000 AFY (Phase II) for a total of 122,000 AFY of water for the District.
NKWSD	Groundwater Banking Conveyance Improvements to NKWSD Recharge and Recovery	NKWSD is in the process of acquiring adequate funding to complete this project. The proposed project schedule includes a start date of October 2019 and completion by the end of 2021.	The proposed project involves the drilling and equipping of three replacement wells and connecting two other deeps wells (five total) to NKWSD's existing network to improve return capacity of recharged water for the District's neighbors. Proposed project is to construct the necessary pipelines to connect five deep wells to the District's recovery network system that improves the capacity to return water supplies multiple districts in the region during dry years.	Implementation of this project is anticipated to return previously stored water into the FKC and NKWSD's conveyance system at a rate of approximately 27 cfs. This equates to a total estimated average of 1,660 acre-feet per month, or an annual capacity of 9,961 acre-feet per year for the seasonal use of the wells (six months in a year) to improve the return capacity for the Poso Creek IRWM CVP Contractors to meet irrigation demands during a critically dry year. Two of the five wells will discharge into the District's canals and the remaining three will connect to the District's manifold pipeline, which ultimately discharges to the FKC.
NKWSD	Beneficial Reuse of Oilfield Produced Water	This is an ongoing project. NKWSD is interested in expanding the amount of oilfield produced water being brought into the district; however, no decision has been made at this time.	Since 2015, NKWSD has made beneficial reuse of oilfield produced water by blending produced water with other surface supplies for irrigation use. The California Resources Corporation (CRC) discharges 58 acre-feet per day of produced water from CRC's Kern Front Oil Field to NKWSD. The blended water is used directly for irrigation or is discharged to spreading basins in NKWSD for groundwater recharge.	Currently, this project has an important beneficial impact on water resources in the local area. One impact of the project is the annual recycling of up to 11,000 AF of oilfield produced water to the District. This flow is blended with other water sources and used for irrigation and groundwater recharge. Produced water increases the District's water supply and partially replaces groundwater that would otherwise be pumped. During the winter season, produced water is discharged to the Rosedale Spreading Basins along with any available Kern River water to recharge groundwater supplies. This has the added benefit of decreasing the rate of groundwater decline and lowering pumping costs.
NKWSD	SCADA Automation and Evapotranspiration Measurement Improvements	This is an ongoing project. The District is in the process of switching from SCADA to Wonderware Software and plans to implement upon approval from Reclamation.	The proposed project includes the installation of Supervisory Control and Data Acquisition (SCADA) Automation software along with Evapo-transpiration (ET) measurement stations. This project is divided into two components, the purpose of the first component is to remotely monitor and control the District owned and operated groundwater wells and Canal level transmitters. The second component of this project is to install evapo-transpiration (ET) stations in strategic locations within the District. The District anticipates that the crop specific ET measurements will help the District and its growers to correlate the ET and the applied water with the crop yield.	With these modernization efforts, the District can automatically record the instantaneous groundwater pumping rate, depth to groundwater, canal level, water quality parameters, and ET data.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
NKWSD	Poso Creek Weir	Currently, this project is in preliminary stages. This project is part of the projects planned to meet the sustainability goal of the District by 2040. NKWSD may implement this at any time over the planning horizon to reach its sustainability goal.	NKWSD plans to construct a weir on the Poso Creek Flood channel to divert water into their facilities. The District currently has an earthen plug that works to divert water; however, the plug is not reliable and has proven to be inefficient for the District. Implementation of this project will provide a more reliable management of flows, allow water to be measured as it is diverted, and reduce the velocity and sediment loading prior to diversion. Diverted water will be used to increase groundwater banking activities in NKWSD to help prevent further lowering of groundwater levels.	Construction of a weir will provide the ability to drop out sediment prior to flood water entering the District's distribution system or direct spreading facility. By slowing the velocity and allowing sediment to drop out, higher water quality is diverted into the district.
NKWSD	Spreading Pond Facility	No Data	No Data	No Data
RRID	Expanded Recharge	Project is in the conceptual phase; however, the pre-existing conveyance pipeline allows for swift project implementation if needed.	RRID will expand their recharge to include on-farm spreading to maximize recharge capability. To ensure adequate delivery of supplies, water delivery infrastructure improvements will be included in this project. Improvements to the CRC pipeline will be made before on-farm recharge occurs.	An estimated 6,000 AFY would be added to the already 5,000 AFY provided by CRC for the purposes of beneficial reuse.
RRID	Allocation of Available NKWSD Supplies	This project is ongoing as NKWSD already allocates produced water to their facility; however, water spread in the Rosedale facility will now exclusively benefit RRID.	Oilfield produced water will be allocated to North Kern's Rosedale spreading facility for RRID's exclusive benefit.	
SWID	Diltz Intertie Lateral Piping and WMI	Design plan specifications have been completed for the proposed later improvements coinciding with the Diltz Intertie mainline design. Project is in its pre-construction phase and will be fully implemented in 2020.	The proposed project includes installing pressurized pipe laterals to connect the Diltz Intertie mainline to serve 380 acres of irrigated land. Project will consist of a 1.5-mile long, 30 cfs, 36- inch diameter, bi-directional, intertie pipeline, which will allow for the efficient conveyance of surface water supplies to spreading ground facilities located in SWID.	Component 1 is expected to decrease groundwater pumping in the SWID by providing growers with pressurized surface water deliveries at a greater capacity and frequency. Decreased groundwater pumping in SWID will all for the recovery of groundwater elevations. This project will save 1,927 AFY of water following project completion.
SWID	Bell Recharge Project	Project is currently in planning phase and still requires final pipeline alignment selection to begin other project components such as easement acquisition, final design, and bidding.	Implementation of this project includes the construction of a 12 cfs conveyance improvement along SWID's existing distribution system that will allow CVP-Friant supply to be delivered from the FKC to the Bell Recharge site. Bell project will allow for delivery of surface water to the new Bell Recharge facilities form the CVP, for increased water storage.	Proposed Bell Project pipeline connection is anticipated to convey CVP wet period water into SWSD at a rate of 12 CFS with estimated annual benefits of 1,728 AFY.
SWID	Kimberlina Recharge Project	Already being implemented. To be completed by 2022.	Construction of a 285-acre recharge site for CVP surface water.	Water suuply augmentation of approximately 19,000 AFY
SWID	Leonard Avenue Conveyance Improvement Project	Project is currently in planning phase and still requires final pipeline alignment selection to begin other project components such as easement acquisition, final design, and bidding.	This project involves the construction of 1.5 miles of pipeline to connect SWID with Semitropic Water Storage District (SWSD). Implementation of a new pipeline will provide SWID with the operational flexibility to absorb surface water when it is available for delivery to SWSD's distribution system, connecting the supply to in-lieu and direct recharge facilities in SWSD, generally during wet periods, so that water delivered can later be recovered for irrigation in peak demand months, or dry periods.	When implemented, this project will provide added capacity to absorb surplus water from the CVP during wet periods. It is estimated that this project will capture 2,880 AFY of surface supply, predominately from the CVP surface floodwater conveyed via the FKC, through SWID and into SWSD. Additional water absorbed into the groundwater basin will be split 50/50 between SWID and SWSD. The total average annual water saving to SWID is 1,440 AFY. Captured water will directly offset SWID's reliance on San Joaquin River supplies to the Bay-Delta and help conserve local groundwater supplies.
SWID	Improved Water Level Measurement of District Recharge Facility	This project is in the planning phase. Implementation of this project may begin as soon as 2020.	Proposed project includes the construction of a 400 to 500-feet deep, 8-inch diameter PVC monitoring well and the conversion of an existing older well to an 800-feet deep, 6-inch diameter monitoring well both equipped with both water-level sensors and located within the District's recharge facility. Both monitoring wells will help manage and collection information on groundwater levels which can be used to document site performance as well as monitor the effects on the groundwater aquifer levels.	Implementation of this project will contribute to improving the district's drought resiliency and preserving groundwater levels by monitoring groundwater levels in the facility and improving efficiency of recharge operations.
SWID	Expanded Water Banking Program	Ongoing	The expanded water banking program will optimize of the district's existing conjunctive use program that recharges groundwater during wet-periods (banked water) and recovers the banked water during times of need (typically dry periods). The expanded banking program consists of various projects that will increase use of existing facilities and development of additional recharge and recovery facilities. Associated projects will involve the construction of direct recharge facilities and on-farm spreading to maximize recharge capability. To ensure adequate delivery of supplies, water delivery infrastructure improvements will be needed.	Implementation of this program would bring additional water supplies that would help offset potential losses of the District's historical supplies, support the District's mission of maintaining economic pumping lifts for its landowners, and maintain supplies to be used for municipal and industrial purposes.
NKWSD	Refinement of Water Budget Components	Ongoing	Improvement of monitoring and measurements to refine the accuracy of measurement or calculation of inflow and outflow components of district level water budget. Will also refine Subbasin Model and water budget.	This management action is conceptual; a volume of water associated with this management action has not been calculated.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
NKWSD/SWID	"Surface Water First" Incentive Program	This Management Action is in the preliminary stages of consideration by the districts. It has not been formally adopted but is under consideration.	Both NKWSD and SWID have access to imported surface water to supply their respective jurisdictional areas. However, there instances in which growers have historically opted to pump groundwater, rather than receiving deliveries of surface water from the district which services their properties. When this occurs, the district must either use that water for groundwater recharge or enter into exchanges with other districts (either in the KCS or in another basin). While this may be an economic decision for the grower, it has the potential to cause local impacts to groundwater in the district over the long-term. To prevent local impacts to groundwater due to the use of groundwater over available surface water, the districts may explore a fee structure in which growers with access to surface water may be assessed for the use of groundwater when surface water is available for use. The fees collected for such activities would be applied to the expansion of existing recharge projects or the development of new recharge projects to accommodate the additional surface water that would be brought into the district to replace the additional groundwater pumped.	A reduction of groundwater extraction would result from the implementation of this incentive program. The fees collected in this incentive program have not been quantified but would also provide a source of funding for the expansion of existing recharge or the development of new recharge projects within the districts.
NKWSD/SWID	On-Farm Efficiency/Deficit Irrigation Practices Incentive Program	The provisions of the conservation laws are being complied with by both NKWSD and SWID. Ag water management plans, as required by SB 7, are being regularly updated by these districts for submittal to DWR. Plans will be updated to include the applicable requirements of AB 1668 and SB 606.	As agricultural water service providers, both NKWSD and SWID comply with all provisions of SB 7 (amending Division 6, Part 2.55 of the Water Code) passed into law in November 2009 regarding agricultural water conservation and management. Efficient management practices in the law, related to SGMA objectives, include volumetric water pricing, incentives for conjunctive use and increased groundwater recharge, and development of an overall water budget. AB 1668 and SB 606 passed in 2018 did not materially add to these objectives, save for those districts serving between 10,000 and 25,000 acres who must now prepare water management plans under the newer laws.	There are no direct benefits to be derived and quantified from compliance with the aforementioned agricultural conservation laws at the present time. The districts will continue to divert for beneficial use all local and imported water supplies to which it is entitled. Should agricultural demands for irrigation water diminish as a result of some of the conservation provisions, a larger portion of diverted supplies will be devoted to groundwater recharge in the future.
NKWSD/SWID	On-Farm Recharge Activities Incentive Program	This Management Action is in the preliminary stages of consideration by the districts. It has not been formally adopted but is under consideration.	In wet years, when the districts have utilized the full capacity of their respective recharge basins and spreading grounds, it may be necessary for the districts to seek other locations for the application of available surface water for groundwater recharge. The districts will develop an incentive program to encourage landowners to take delivery of available water that is in excess of customer demand and the districts' capacity for recharge projects for application to fallow land and/or over-irrigation of crops to facilitate further groundwater recharge. Landowners will receive a groundwater credit in exchange for participation in this program, for their use within the district which has provided the water for on-farm recharge activities.	A increase of groundwater recharge would result from theimplementation of this incentive program.
NKWSD/SWID	Subsurface Recharge Feasibility Study	This Management Action is in the preliminary stages of consideration by the districts. It has not been formally adopted but is under consideration.	Both NKWSD and SWID have been approached by landowners within their respective districts about the efficacy and use of subsurface recharge methods. While subsurface recharge is being tested in neighboring districts, neither NKWSD nor SWID have taken an official position on the use of such methods. Before the implementation of any program which would supply water to landowners for use in subsurface recharge practices, the districts will conduct a feasibility study to evaluate whether or not these practices are appropriate for the hydrogeologic conditions and/or land uses within their respective jurisdictions. The scope of the feasibility study is yet to be determined, but it will include an evaluation of subsurface recharge methods, the soil types located within each district, the effectiveness of subsurface recharge compared to other recharge methods, and its compatibility with existing land uses.	No benefits have been quantified for this Management Action at this time. Potential benefits gained through the use of subsurface recharge will be determined as a result of this Management Action.
NKWSD/SWID	Land Conversion from Agricultural Use to Urban Use	The conversion of land use from agricultural to urban is an ongoing process, the pace of which is determined by external factors such as the demand for land based on each city's growth and need for additional housing and/or property to support business, industrial, or municipal use. The projected growth for each city is based upon the current General Plans and may be subject to change when the cities update their respective plans.	As described in the General Plans for the cities of Shafter and Wasco, anticipated population growth is expected to lead to changes in land use within the limits of each city and in the Sphere of Influence for each city. The conversion of land use from agricultural to urban use generally leads to an overall reduction in groundwater use due to the decreased demand, in terms of volume per unit area.	For NKWSD's jurisdiction, there is an anticipated reduction of water by 2030, based on the conversion of land use as the city of Shafter expands. In SWID's jurisdiction, the anticipated reduction of water by 2030 reflects the anticipated growth of both Shafter and Wasco.
NKWSD/SWID	Urban Water Conservation Program	The cities of Shafter and Wasco are currently evaluating their respective compliance measures for indoor use and are awaiting additional information and guidelines concerning regional outdoor and landscape compliance measures. The cities presently are complying with the 2020 mandates contained in SB 7X-7 and as embodied in their respective UWMPs. As the SWRCB establishes its compliance deadlines for both indoor and outdoor usage, anticipated to occur by 2025, the municipal KGA Members will have a clearer picture of an implementation schedule.	As referenced in the Umbrella Basin Setting (Chapter 2), urban water usage in the future is expected to comply with the conservation mandates contained in SB 606 and AB 1668, both bills signed into law in May 2018. Based on that legislation, indoor residential use is to be capped at 55 gpcd in 2019 and ramp down to 50 gpcd by 2030, and outdoor residential use is to be capped in the future based on local climate and size of landscaped areas. Standards for outdoor usage are to be defined in a SWRCB rule-making process to be completed by June 2022.	Given the early implementation stages of AB 1668 and SB 606, its benefits in terms of reduced groundwater pumping by Shafter and Wasco can only be roughly approximated. The Pacific Institute, in its 2014 report "Urban Water Conservation and Efficiency Potential in Calif." estimated that indoor usage could be reduced by 33-40 gpcd, and that outdoor/landscape usage could be reduced by 20-50 gpcd. These values are on a statewide basis and likely unrealistic in some regions; however, the report postulates that total urban water usage could be reduced by as much as 30-60%. Savings of this magnitude would represent a significant reduction in groundwater pumping by both cities. The Measurable Objectives to be partially met with additional urban conservation include groundwater level stabilization and, by proxy, groundwater storage stabilization.
SWID	Mitigation Program for Potential Impacts to Domestic Wells	Upon implementation of the law.	In coordination with other KGA members, develop a mitigation program to offer financial assistance for the replacement of domestic wells which are impacted by groundwater management to the proposed SMCs. Coordinate development of eligibility criteria for participation in mitigation program.	Since this management action is conceptual, a volume of water associated with this management action has not been calculated.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
NKWSD/SWID	In-District Allocation Structure	This Management Action is in the conceptual stages, having been discussed with various stakeholder groups. However, an actual structures and fee schedules have yet to be devised for either district.	At the time of this draft of the GSP, neither NKWSD nor SWID have an established allocation structure and fee schedule for groundwater extraction. As SGMA is implemented throughout the KCS, the districts are required to manage to the Sustainable Management Criteria (SMCs). One of the ways to manage for the SMCs is to allocate the Sustainable Yield for their respective districts to the landowners within their districts. While the specifics of such an allocation structure may vary between the districts, a baseline groundwater extraction volume would be allocated to each parcel based on its size and the Sustainable Yield for the district. If a landowner were to extract more water than the baseline volume for that parcel or for the aggregate of all of their parcels within the district, they would be required to pay an extraction fee which would be applied toward projects and programs implemented by the district to reach and/or maintain sustainability.	The benefits to sustainable groundwater management have not been quantified at this time. However, the development and implementation of an allocation structure for each district would allow for the districts to utilize their Sustainable Yield as a management tool for reaching and maintaining their SMCs.
NKWSD/SWID	Voluntary Land Fallowing	At this time, this Management Action is conceptual. The districts will develop their respective fallowing programs during the SGMA implementation period.	In the event of a drought, the districts may not be able to entirely meet in-district demand by increasing the volume of imported water. The combination of decreased availability in surface water to supply to the district and decreased recharge from other sources in the subbasin has the potential to lead to violations of SMCs at the Representative Monitoring Sites, in the absence of decreased demand. To facilitate the districts' ability to maintain sustainability at their respective monitoring sites, the districts will develop and implement their own voluntary land fallowing programs for their jurisdictions.	The decrease in water demand will be dependent upon the land being fallowed and its existing land use at the time of fallowing. Agricultural demand for water is generally estimated to be 3 AF/acre. Fallowing or land retirement would reduce the demand to zero for the lands participating in the program.
NKWSD/SWID	Pumping Restrictions	At this time, this Management Action is conceptual. The districts will develop their respective processes to implement pumping restrictions within their jurisdictions.	In the event that the districts or the entire subbasin are nearing a condition where they are at risk of triggering an Undesirable Result, even with the implementation of the projects and management actions described in this Plan, it may be necessary for the districts to limit groundwater pumping. The volume of groundwater extraction permitted under this Management Action would be determined by the districts based on the Sustainable Yield for the district and the SMCs at the Representative Monitoring Sites.	Pumping restrictions based on the Sustainable Yield of the district, could decrease groundwater demand if applied to NKWSD. If applied to SWID, pumping restrictions could decrease groundwater demand.
NKWSD/SWID	Coordinate with Existing Water Quality Programs	NKWSD and SWID are actively participating in the ILRP and CV-SALTS programs.	NKWSD and SWID are actively participating in the ILRP and CV-SALTS programs; coordination and data sharing will continue to facilitate improved groundwater management and to mitigate degraded water quality attributable to SGMA implementation. As requested, NKWSD/SWID will also coordinate with the SAFER program and its projects.	A coordinated approach to managing water quality for groundwater dependent communities.
NKWSD/SWID	NEW Domestic Well Survey	NKWSD and SWID intend to conduct a domestic well survey before the 2025 Management Area Plan is updated	NKWSD and SWID will conduct a domestic well survey to verify wells in the District and validate the Well Impact Study completed using DWRs well completion report database	Develop an accurate count of domestic wells in each Management Area, status of each well, and potential impacts of water level declining to the MT.
NKWSD/SWID	NEW KGA Exceedance Policy	The KGA Exceedance Policy has been adopted by the Board of Directors.	A standard policy to address the exceedance of minimum thresholds for the chronic lowering of groundwater levels sustainability indicator. This Policy, "KGA Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater" (referred to as Exceedance Policy) was adopted by the KGA Board of Directors in April 2022.	Coordinated action to address an MT exceedance at a single representative monitoring well.
NKWSD/SWID	NEW Ongoing Evaluation of Groundwater Levels and Water Quality Trends	Implemented in 2020 at each Regional Monitoring Well	Groundwater quality samples are collected for the constituents of concern in the Management Areas within 2 weeks of seasonal water level measurements. If a correlation develops indicating that declining water levels are causing unmitigated impacts to beneficial users, stakeholders will be consulted, and appropriate corrective actions or mitigation will be considered.	Mitigate degraded water quality caused by declining groundwater levels.
Pioneer Groundwater Sustainability Agency				
Pioneer	Project 1: Install Monitoring Well in North Pioneer	Implementation of this project entails planning, permitting, design and currently, construction of the monitoring well cluster. KCWA and/or its consultants will secure necessary permits and plan, design and construct the wells. KCWA will monitor the wells as part of normal Pioneer Project operations.	A data gap for groundwater monitoring north of the Kern River was identified during development of this Chapter GSP, and a monitoring well cluster is being constructed in the northwest triangle-shaped parcel of the Pioneer Project (i.e., the area of the GSA north of Kern River). The triangle shaped parcel is in the northwest portion of the North Pioneer Area, and does not include a recharge pond. This area is in the southeast quarter of section 6, T 30S/R26E. The monitoring well cluster will allow groundwater monitoring at multiple depths using three separate boreholes.	The new monitoring well cluster will address an identified data gap in the Pioneer GSA Area. The monitoring well cluster will also help Pioneer GSA evaluate maintenance of its sustainability goals and monitor groundwater conditions in that portion of the Pioneer GSA Area.
Pioneer	Management Action 1: Continued Balanced Pumping and Recharge	This management action would be accomplished through continuation of existing groundwater recharge and recovery operations. Surplus water would be banked either for overdraft recovery or future use. Banked groundwater would be used to supplement water supplies in dry years or during years of shortages	Continued balanced pumping and recharge is the standard operating procedure for the Pioneer GSA. Under this management action, long-term pumping would be balanced by long-term recharge activities in the Pioneer GSA Area. Pioneer GSA would continue to closely monitor water that is pumped from the Subbasin and water that recharges the Subbasin with the goal of a balanced groundwater budget over the long term.	The Pioneer Project is operated in a manner that results in more water being recharged than recovered from the Subbasin in the Pioneer GSA Area. Therefore, continuing operation of the Pioneer Project in the same manner would provide a net positive increase of groundwater volume in the Pioneer GSA Area. Full benefits of this management action would be evaluated through accounting of water recharge volumes compared to groundwater pumping.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
Pioneer	Management Action 2: Continued Participation in Basin-Wide Coordination with other GSAs	This management action would be accomplished through continued attendance at KGA coordination meetings and by arranging periodic coordination meetings with the Kern River GSA, the Henry Miller GSA, the WKWD GSA and the Buena Vista GSA. Meetings would be attended by one or more representatives of Pioneer GSA and may include the GSA manager or their designated staff. Decisions made in coordination meetings would not be binding until approved by the appropriate authority, such as the Pioneer GSA manager or by KCWA's Board of Directors.	Pioneer GSA is one of several GSAs in the Subbasin. Sustainable management of the Subbasin as a whole requires coordination among GSAs and their respective GSPs. During development of the GSPs in the Subbasin, GSAs have been discussing sustainability thresholds, potential projects and management actions and specific issues and concerns. The KGA is a JPA composed of member agencies that was established in 2014 to develop and implement a groundwater management plan in the Subbasin and the neighboring Tulare Lake Groundwater Basin (KGA, 2017). This management action would involve attending monthly KGA manager and coordination meetings, as well as KGA stakeholder meetings, which are held as needed. Quarterly coordination meetings would be held with the Kern River GSA, and annual coordination meetings would be held with the Henry Miller GSA, the WKWD GSA and the Buena Vista GSA.	This management action would continue existing coordination activities between GSA managers, and help to build and maintain relationships with neighboring GSAs. Through coordination activities and ongoing communication, potential conflicts among GSAs regarding groundwater management would be mitigated because GSAs would better understand the challenges facing each other and how these challenges are being addressed. It will also provide an opportunity for GSAs to inform each other of potential issues that may require intra-Subbasin coordination, and to inform neighboring GSAs of management actions and projects under way that may affect decisions of other GSAs.
Pioneer	Adaptive Management Strategy: Increase Surface Spreading Losses from 6 to 10 Percent	Coordination would be initiated by KCWA with the Pioneer Project Participants.	Under the *Pioneer Project Participation Agreement* , all surface water diverted to the Pioneer Project for spreading is assessed a 6 percent loss factor. All losses assessed are non-recoverable. This provision was set up to "prevent, eliminate or mitigate significant adverse impacts" resulting from project recovery operations. The intent of losses assessed is to assist in mitigating impacts to adjoining entities. This adaptive management strategy would explore feasibility of increasing the fixed loss rate from 6 percent to a fixed loss rate of 10 percent.	This adaptive management strategy would provide KCWA and the Pioneer Project Participants an understanding of the feasibility of increasing lossess assessed to diverted surface water. If increasing losses is deemed feasible, it would provide the Pioneer Project and the opportunity to mitigate and avoid undersirable results and support the for sustainability indicators relevant to the Pioneer GSA as follows: chronic lowering of groundwater levels (direct), reduction of groundwater storage (proxy), degraded water quality (proxy), and subsidence (proxy).
Rosedale Rio Bravo Management Area				
RRBMA	West Basin Improvements	RRBWSD purchased the properties in 2009-2015. Project construction was completed in 2016	The improvement of existing recharge ponds and development of an additional 50-acre project west of Bakersfield designed to recharge, store and recover water to provide a cost-effective and reliable water supply for landowners within the RRBWSD.	This project has the potential to recharge up to 5,000 AF of water in wet years. This could provide the RRBWSD with up to 1,000 AFY.
RRBMA	Stockdale East Groundwater Storage and Recovery Project	RRBWSD purchased the property in 2010. Project is 90% complete, it will be operational by 2020.	Project is a developed 200-acre project west of Bakersfield designed to recharge, store and recover water to provide a cost-effective and reliable water supply for landowners within the RRBWSD.	This project has the potential to recharge up to 25,000 AF of water in wet years. This could provide the RRBWSD with up to 4,000 AF per year on average.
RRBMA	Pilot Projects	These continued GRAT projects could be on-line as early as 2025.	In 2017 the RRBWSD developed four pilot recharge projects under which it leased properties for temporary recharge activities. Since that time the District has invested in a Groundwater Recharge Assessment Tool (GRAT) in order to identify similar projet sites in the future.	Approximately 10,000 AF was recharged during that year of implementation in these four projects. The GRAT implementation could provide RRBWSD up to 2,000 AF per year.
RRBMA	Onyx Ranch	The project is currently undergoing a feasibility and environmental analysis. The project could be on-line as early as 2025.	The RRBWSD owns several parcels of land and the associated water rights for the Onyx Ranch and the Smith Ranch. These parcels are located along the South Fork of the Kern River in the Kern River Valley, in and around the communities of Weldon and Onyx, in an unincorporated area of northeastern Kern County. These parcels together comprise the 4,109.18-acre project site. The RRBWSD is currently conducting an analysis of a proposed change in the point of diversion and place of use of the water rights associated with these parcels so that the water can be delivered in the RRBWSD service area on the San Joaquin Valley floor and used for irrigation and groundwater recharge. The project would reduce the diversion of water on the project site and convert the irrigated fields to lower water use crops, or allow the fields to return to their native vegetative state. With the proposed project, RRBWSD would allow the water that would have been diverted on the project site to remain in the South Fork of the Kern River and flow downstream. This could result in a net increase in flows within the South Fork of the Kern River, and the Isabella Reservoir where the water would be released through the Isabella Dam and flow downstream in the lower Kern River until the water is diverted at the RRBWSD diversion point. From there, the RRBWSD would deliver the water to recharge basins and channels within and near its service area west of the City of Bakersfield (City) in unincorporated Kern County within the San Joaquin Valley.	The net increase in water supplies to the RRBWSD's service area as a result of the proposed project would help mitigate the shortages in RRBWSD's contracted State Water Project (SWP) water supply from the State of California, which has steadily reduced due to environmental constraints in the Sacramento/San Joaquin Delta. The proposed project would provide the RRBWSD with approximately 6,500 AF per year.
RRBMA	James Groundwater Storage and Recovery Project	Rosedale and Buena Vista Water Storage District jointly purchase the property in 2011. Current project status is feasibility and environmental analysis. This project could be online as early as 2025.	The James Groundwater Storage and Recovery Project is a proposed 2,070-acre project in southwest Bakersfield designed to recharge, store and recover water to provide a cost-effective and reliable water supply for landowners within the RRBWSD (and elsewhere).	This project has the potential to recharge up to 150,000 AF of water in wet years. This could provide the RRBWSD with up to 3,000 AF per year.
RRBMA	Kern Fan Groundwater Storage Project.	Project status is feasibility analysis. This project could be on-line as early as 2030.	The District has evaluated a conceptual Kern Fan Groundwater Storage Project (Kern Fan Project). This project would serve to develop a regional water bank in the Kern Fan to capture and store Article 21 water via the State Water Project (SWP) during conditions when surface water is abundant. A twophased approach would be taken to the development of the Kern Fan Project. The first phase would be to develop a project site, including the purchase of approximately 640 acres of land in the Kern Fan area. The first phase would also include constructing conveyance facilities, recharge facilities, and recovery facilities as necessary to develop a fully functioning water banking project. The second phase of the Kern Fan project would involve acquiring an additional 640 acres of land for expansion of the water banking facilities and developing the associated recharge and recovery facilities.	This could provide the RRBWSD with up to 10,000 AFY.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
RRBMA	Western Rosedale In-Lieu Service Area	Project status is shovel ready; feasibility and environmental analysis is complete. This project could be on-line as early as 2035.	The Western Rosedale Lands In-Lieu Service Area Project (the Project) includes construction and operation of up to ten miles of water conveyance pipelines, including appurtenant facilities (such as pumps and valves), and a joint service area agreement between RRBWSD and BVWSD in order to provide surface water to agricultural water users within the portion of RRBWSDs service area located westerly of Interstate 5 in close proximity to Buena Vista Water Storage Districts East Side Canal.	This could provide the RRBWSD with up to 1,000 AFY.
RRBMA	Ten Section Water Recharge Project	No implementation date is known at this time.	The owners of Ten Section located within the South of the River Monitoring Zone are currently studying the feasibility of a 200+ acre groundwater recharge, storage and recovery project.	It is estimated that approximately 2,200 AF/month could be recharged into the aquifer.
RRBMA	Water Charge Demand Reduction	This management action could be on-line as early as 2025.	The Water Charge would be expected to result in demand reduction in the RRBWSD. For market reasons it is probable that landowners will opt to fallow ground in order to trade water supplies to other District landowners, as well as fallow lands (or limit double cropping) to avoid the Water Charge all together.	With an agricultural water consumptive-use demand of about 84,000 AF per year we conservatively expect a 5% demand reduction as a result of the water charge which results in about 4,000 AFY of reduced demand
RRBMA	RRBWL (White Land) Water Supplies and Demand Imbalance Reduction	This management action could be on-line as early as 2020.	White Lands (non-RRBWSD lands) within the RRBMA that are not used for groundwater banking will correct the water supply imbalance on a linear basis over the planning period of 2020-2040. Like RRBWSD lands, the white lands will start with the native yield of 0.15 AF/acre. The total annual demand for white lands in the RRBMA is about 10,307 AFY with a water supply imbalance (or deficit) of 3,618 AFY. The average agricultural demand is 2.6 AF/acre according to METRIC studies. While agricultural demands in the White Lands range from 1.4-4.9 AF/acre the initial allowable demand will be the average demand of 2.6 AF/acre. It is expected that white lands would seek to acquire water supplies for in-lieu and direct groundwater recharge via banking agreements with RRBWSD or others to offset demands.	Demand reduction will occur as follows over the 2020-2040 period; the imbalance will be reduced by 1/20 of the current imbalance each year (5%). This approach will result in about 217 AF of imbalance reduction each year and 2,170 AFY by 2030 and a total of 4,335 AFY by the 2040 sustainability planning period.
RRBMA	RRBWD 3rd Party Recharge and Storage Program	This management action could be on-line as early as 2020.	The RRBWSD will assist 3rd parties (white lands, districts, and private parties) in recharging water supplies for use in the RRBMA or other down gradient areas in the Kern Sub-basin. RRBWSD would offer existing conveyance and recharge facilities in exchange for a portion of the imported water supply and payments of yet-to-be developed costs and/or fees.	It is expected that the RRBWSD would provide this service in exchange for 20-33% of the imported water supply and that an average amount of 5000 AFY would be imported. This management action could bring an additional supply of 1,250 AFY to RRBDL lands.
RRBMA	NEW Emergency Domestic Water Response	This management action could be on-line as early as 2020.	Deployment of emergency water services to assist domestic well users that is dispatched within 24 hours of notification of a well issue. Financial assistance for bottled drinking water is also offered.	Protects domestic water users from pump and well failures allowing time for employing longterm solution.
RRBMA	NEW Coordination with State Regulatory Programs	waiting on KGA language	waiting on KGA language	waiting on KGA language
RRBMA	NEW KGA Action Plan Related to Exceedance of MT's for Chronic Lowering of Groundwater	This management action could be on-line as early as 2022.	Five-step action plan is proposed to address a minimum threshold exceedance for the chronic lowering of groundwater levels at a single representative monitoring well (RMW), including coordination between KGA member districts.	Protect beneficial users from an undesirable results.
RRBMA	NEW Unmitigated Domestic Well Replacements	Adaptive Management Action	Approximately 3 of the approximately 149 domestic wells in the RRBMA could require replacement if levels drop to the established Minimum Threshold. Should that occur and the Long-term Operations Plan not addressed per its routine mitigation process the RRBWSD will establish a similar well mitigation program to the Long-term Operations Plan so that potential impacts are addressed.	Protect beneficial users from an undesirable results.
Southern San Joaquin Municipal Utility District				
SSJMUD	REVISED In-District Spreading and Recovery Facility	The district has purchased land, secured funding for construction, and is expected to begin construction in July 2022.	This project will include construction of 80-acres of spreading ponds and the installation of one recovery wells within district boundaries. The proposed recharge ponds have an anticipated annual capacity of 3,240 AFY. Prior to this project, the district has not had any in-district direct recharge facilities. Implementation of this project will allow SSJMUD the opportunity to capitalize on wet period storage of CVP supplies and allow them to bypass less favorable out-of-district banking agreements to store water that would increase the District's and the subbasin's water reliability and drought resiliency.	The proposed recharge ponds have an anticipated annual capacity of 3,240 AFY. Estimated amount of water to deliver to recharge is at least 4,200 AFY. If the available surplus is delivered to an out-of-district facility, it is expected that North Kern will keep one-third of the water as part of banking agreements and SSJMUD will realize an average water benefit of 2,800 AFY. Captured water will directly offset the District's reliance on the San Joaquin River supplies to the Bay-Delta and help conserve local groundwater.
SSJMUD	NEW Regan Recharge Facility	Implementation of project upon completion of CEQA. Construction is expected to begin at the end of 2022 with implementation in 2023.	This project willl include construction of 75-acres of spreading ponds with the recovery through an existing recovery well within the district boundaries. The proposed recharge ponds have an anticipated annual capacity of 6,120 AFY.	The proposed recharge ponds have an anticipated annual capacity of 6,120 AFY.
SSJMUD	SSJMUD and Semitropic Schuster Intertie	This project is in the conceptual stage of development and is included in the 2019 Poso Creek IRWM Plan Update.	The proposed project is to construct an intertie in coordination with SWSD. This pipeline will allow for SSJMUD to bank or return water to Semitropic previously delivered to Semitropic's groundwater banking program. SSJMUD could deliver wet period water from the FKC for groundwater banking to Semitropic or return water for irrigation purposes during dry years. This Project removes the need to involve a third-party in an agreement with Semitropic for banking since it establishes a direct connection to return water to SSJMUD from Semitropic, thereby increasing operational flexibility and reliability to deliver previously stored water from groundwater storage at times of drought.	Considering the frequency of surplus 'Other Water' in the Central Valley Project and the existing design limit of 50 cfs, the Project will allow for an expected average annual amount of 3,622 AF to be put into storage with 1,811 AF credited to SSJMUD for return. Given that recently the District became a member of the Poso Creek Integrated Regional Water Management Group (IRWM) in spring 2016, interties such as this pipeline were identified as the first step in the District's efforts towards banking water with their neighboring districts to add drought resiliency.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
SSJMUD	SSJMUD and CWD Intertie Pipeline	This project is in the conceptual stage of development and is included in the 2019 Poso Creek IRWM Plan Update.	SSJMUD and CWD propose to construct a bidirectional intertie connecting their respective water conveyance systems. This pipeline is a regional opportunity to improve flexibility, reliability, and conjunctive use of water supplies.	The estimated annual yield of this project is approximately 50 to 500 AF, depending on the selected project size. Project size will be determined by greatest benefit yielded that is economically feasible and sustainable.
SSJMUD	SSJMUD and North Kern WSD 9-28 Intertie Pipeline	This project is in the planning stage of development, in conjunction with NKWSD, and is defined in the Poso Creek IRWM Plan.	Project proposal includes the construction of the 9-28 Intertie pipeline with NKWSD. This pipeline will allow for the return of CVP Class I, Class II, and surplus floodwater that was previously delivered to the District's groundwater banking partner (NKWSD) from the FKC for groundwater banking or irrigation purposes during wet years. The pipeline is the conveyance mechanism for return of previously stored water to the District during dry years. This project removes the need to involve a third-party in an agreement with North Kern for banking since it established a direct connection to return water to SSJMUD from NKWSD, thereby increasing operational flexibility and reliability to deliver previously stored water from groundwater storage during times of drought.	This project would allow for SSJMUD to better capture and utilize wet period supplies by increasing the District's capacity to return banked wet period water during dry periods. Considering the frequency of surplus Other Water in the Central Valley Project, the Project will allow for an expected annual amount of 10,000 AF to be put into storage with 6,667 AF credited to SSJMUD for return. The pipeline capacity to return water from North Kern to SSJMUD is 4,284 AFY, which will require roughly 1.5 years to return the water for each 10,000 AF of water banked and 6,667 AF credited.
SSJMUD	Southeast Delano Spreading Grounds	This project is in the planning stage of development. SSJMUD has already begun the process of developing a CEQA document to assess the potential impacts of the construction and operation of spreading grounds in the areas identified by the district.	SSJMUD proposes the purchasing of land holdings, with possible partnering agencies (to be identified later), in and around the eastern most portion of the District. The District is currently exploring the potential for capturing excess surface water deliveries in the FKC. Excess surface supply, or those flows beyond the quantity of water that satisfies immediate water demand, typically occur in wet years where precipitation in applicable watersheds is large enough to induce surface water available above Class I contract supplies. Potential captured flows consist of water which is currently discharged during wet year and flood conditions.	Implementation of this project has the potential for contributing water supplies to SSJMUD, the City of Delano (which qualifies as a DAC), and Poso Creek IRWM water users. Specifically, SSJMUD will use a portion of these captured flows to offset their groundwater use in dry years by moving the surplus water to this banking facility using either the Friant Kern Canal or other existing infrastructure. Wet year water supplies captured in the spreading grounds and storage locations will be utilized by SSJMUD, City of Delano, and potentially other Poso Creek stakeholders, during years where other water supplies are limited.
SSJMUD	REVISED City of Delano Spreading Grounds	Implementation upon completion of design. Consturction expected to being in Fall 2022.	SSJMUD proposes identifying and evaluating potential land suitable for developing recharge basins, with possible purchase with private and/or public partnering agencies within the City of Delano. The purpose of this project is to capture surface water deliveries that are delivered through the FKC. Excess available surface supply, or those flows beyond the quantity of water that satisfies immediate water demand within a service area, typically occurs in wet years when precipitation in contributing watersheds is large enough to induce surface water available above Friant Class 1 contract supplies. Potential flows to capture consists of water which is currently discharged during wet years, during flood conditions and for water that needs to be delivered due to changes in timing to meet environmental water management goals for the San Joaquin River Restoration.	Implementation of this project has the potential for contributing water supplies to SSJMUD, the City of Delano (which is classified as DAC), and Poso Creek IRWM water users. Specifically, SSJMUD will use a portion of these captured flows to offset their groundwater use in dry years by moving the surplus surface water to this banking facility from the FKC or other existing infrastructure. Wet year water supplies captured in the spreading grounds and storage locations will be utilized by SSJMUD, City of Delano, and potentially other Poso Creek stakeholders, during years where other water supplies are limited.
SSJMUD	Pond Road Spreading Grounds	This project is in the planning stage of development. SSJMUD has already begun the process of developing a CEQA document to assess the potential impacts of the construction and operation of spreading grounds in the areas identified by the district.	SSJMUD proposes identifying and evaluating potential land holdings to be purchased, with possible private and/or public partnering agencies. The District is currently exploring the potential for capturing excess surface water deliveries in the Friant-Kern Canal. Excess surface supply, or those flows beyond the quantity of water that satisfies immediate water demand, typically occur in wet years where precipitation in applicable watersheds is large enough to induce surface water available above Class 1 contract supplies. Potential captured flows consist of water which is currently discharged during wet year and flood conditions.	Implementation of this project has the potential for contributing water supplies to SSJMUD, the City of Delano, and Poso Creek IRWM water users. Specifically, SSJMUD will use a portion of these captured flows to offset their groundwater use in dry years by moving the surplus water to this banking facility using either the California Aqueduct or other existing infrastructure. Wet year water supplies captured in the spreading grounds and storage locations will be utilized by SSJMUD, City of Delano, and potentially other Poso Creek stakeholders, during years where other water supplies are limited.
SSJMUD	In District Spreading Grounds	This project is in the planning stage of development. SSJMUD has already begun the process of developing a CEQA document to assess the potential impacts of the construction and operation of spreading grounds in the areas identified by the district.	SSJMUD proposes identifying and evaluating potential land holdings to be purchased, with possible private and/or public partnering agencies. The District is currently exploring the potential for capturing excess surface water deliveries in the FKC. Excess surface supply, or those flows beyond the quantity of water that satisfies immediate water demand, typically occur in wet years where precipitation in applicable watersheds is large enough to induce surface water available above Class 1 contract supplies. Potential captured flows consist of water which is currently discharged during wet year and flood conditions.	Implementation of this project has the potential for contributing water supplies to SSJMUD, the City of Delano, and Poso Creek IRWM water users. Specifically, SSJMUD will use a portion of these captured flows to offset their groundwater use in dry years by moving the surplus water to this banking facility using either the California Aqueduct or other existing infrastructure. Wet year water supplies captured in the spreading grounds and storage locations will be utilized by SSJMUD, City of Delano, and potentially other Poso Creek stakeholders, during years where other water supplies are limited.
SSJMUD	Conversion of Dairy to Recharge Facility	This project is in the conceptual stage of development, with potential sites being evaluated based on data available through the RWQCB's GAMA Geotracker program, the district's recharge feasibility study, and other state and local agencies.	SSJMUD proposes identifying and evaluating potential purchase of a dairy, with possible private and/or public partnering agencies. The District is currently exploring the potential for capturing excess surface water deliveries in the FKC. Excess surface supply, or those flows beyond the quantity of water that satisfies immediate water demand, typically occur in wet years where precipitation in applicable watersheds is large enough to induce surface water available above Class 1 contract supplies. Potential captured flows consist of water which is currently discharged during wet year and flood conditions.	Implementation of this project has the potential for contributing water supplies to SSJMUD, the City of Delano, and Poso Creek IRWM water users. Specifically, SSJMUD will use a portion of these captured flows to offset their groundwater use in dry years by moving the surplus water to this banking facility using either the California Aqueduct or other existing infrastructure. Wet year water supplies captured in the spreading grounds and storage locations will be utilized by SSJMUD, City of Delano, and potentially other Poso Creek stakeholders, during years where other water supplies are limited.
SSJMUD	"Surface Water First" Incentive Program	This Management Action is in the preliminary stages of consideration by the districts. It has not been formally adopted but is under consideration.	SSJMUD has access to imported surface water to supply its jurisdictional area. However, there instances in which growers have historically opted to pump groundwater, rather than receiving deliveries of surface water from the district which services their properties. When this occurs, the district must either use that water for groundwater recharge or enter into exchanges with other districts (either in the KCS or in another basin).	An estimated reduction of 1,800 AFY of groundwater extraction would result from the implementation of this incentive program. The fees collected in this incentive program have not been quantified but would also provide a source of funding for the expansion of existing recharge or the development of new recharge projects within the districts.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
SSJMUD	On-Farm Efficiency/Deficit Irrigation Practices Incentive Program	The provisions of the conservation laws are being complied with by both NKWSD and SWID. Ag water management plans, as required by SB 7, are being regularly updated by these districts for submittal to DWR. Plans will be updated to include the applicable requirements of AB 1668 and SB 606.	As an agricultural water service provider, SSJMUD complies with all provisions of SB 7 (amending Division 6, Part 2.55 of the Water Code) passed into law in November 2009 regarding agricultural water conservation and management. Efficient management practices in the law, related to SGMA objectives, include volumetric water pricing, incentives for conjunctive use and increased groundwater recharge, and development of an overall water budget. AB 1668 and SB 606 passed in 2018 did not materially add to these objectives, save for those districts serving between 10,000 and 25,000 acres who must now prepare water management plans under the newer laws.	There are no direct benefits to be derived and quantified from compliance with the aforementioned agricultural conservation laws at the present time. The districts will continue to divert for beneficial use all local and imported water supplies to which it is entitled. Should agricultural demands for irrigation water diminish as a result of some of the conservation provisions, a larger portion of diverted supplies will be devoted to groundwater recharge in the future.
SSJMUD	On-Farm Recharge Activities Incentive Program	This Management Action is in the preliminary stages of consideration by the districts. It has not been formally adopted but is under consideration.	In wet years, when the district has utilized the full capacity of their respective recharge basins and spreading grounds, it may be necessary for the districts to seek other locations for the application of available surface water for groundwater recharge. The district will develop an incentive program to encourage landowners to take delivery of available water that is in excess of customer demand and the district's capacity for recharge projects for application to fallow land and/or over-irrigation of crops to facilitate further groundwater recharge. Landowners will receive a groundwater credit in exchange for participation in this program, for their use within the district which has provided the water for on-farm recharge activities.	An estimated increase of 1,200 AFY of groundwater recharge would result from the implementation of this incentive program.
SSJMUD	Conversion of Agricultural Land to Urban Use	The conversion of land use from agricultural to urban is an ongoing process, the pace of which is determined by external factors such as the demand for land based on each city's growth and need for additional housing and/or property to support business, industrial, or municipal use. The projected growth for each city is based upon the current General Plans and may be subject to change when the cities update their respective plans.	As described in the General Plans for the cities of Delano and McFarland, anticipated population growth is expected to lead to changes in land use within the limits of each city and in the Sphere of Influence for each city. The conversion of land use from agricultural to urban use generally leads to an overall reduction in groundwater use due to the decreased demand, in terms of volume per unit area. The City of Delano and the surrounding areas have a projected increase of 2,100 acres in urban use; the City of McFarland and its surrounding areas have a projected increase of 1,100 acres.	For SSJMUD's jurisdiction, there is an anticipated reduction of 900 AF of water by 2030, based on the conversion of land use as the cities of Delano and McFarland expand. By 2040, the projected reduction is 1750 AF.
SSJMUD	Urban Water Conservation Program	The cities of Delano and McFarland are currently evaluating their respective compliance measures for indoor use and are awaiting additional information and guidelines concerning regional outdoor and landscape compliance measures. The cities presently are complying with the 2020 mandates contained in SB 7X-7 and as embodied in their respective UWMPs. As the SWRCB establishes its compliance deadlines for both indoor and outdoor usage, anticipated to occur by 2025, the municipal KGA Members will have a clearer picture of an implementation schedule.	As referenced in the Umbrella Basin Setting (Chapter 2), urban water usage in the future is expected to comply with the conservation mandates contained in SB 606 and AB 1668, both bills signed into law in May 2018. Based on that legislation, indoor residential use is to be capped at 55 gpcd in 2019 and ramp down to 50 gpcd by 2030, and outdoor residential use is to be capped in the future based on local climate and size of landscaped areas. Standards for outdoor usage are to be defined in a SWRCB rule-making process to be completed by June 2022.	Given the early implementation stages of AB 1668 and SB 606, its benefits in terms of reduced groundwater pumping by Delano and McFarland can only be roughly approximated. The Pacific Institute, in its 2014 report "Urban Water Conservation and Efficiency Potential in Calif." estimated that indoor usage could be reduced by 33-40 gpcd, and that outdoor/landscape usage could be reduced by 20-50 gpcd. These values are on a statewide basis and likely unrealistic in some regions; however, the report postulates that total urban water usage could be reduced by as much as 30-60%. Savings of this magnitude would represent a significant reduction in groundwater pumping by both cities. The Measurable Objectives to be partially met with additional urban conservation include groundwater level stabilization and, by proxy, groundwater storage stabilization.
SSJMUD	Coordinate with Existing Water Quality Programs	SSJMUD is actively participating in the ILRP and CV-SALTS programs.	SSJMUD is actively participating in the ILRP and CV-SALTS programs; coordination and data sharing will continue to facilitate improved groundwater management and to mitigate degraded water quality attributable to SGMA implementation. As requested, SSJMUD will also coordinate with the SAFER program and its projects.	A coordinated approach to managing water quality for groundwater dependent communities.
SSJMUD	NEW KGA Exceedance Policy	The KGA Exceedance Policy has been adopted by the Board of Directors.	A standard policy to address the exceedance of minimum thresholds for the chronic lowering of groundwater levels sustainability indicator. This Policy, "KGA Action Plan Related to Exceedance of Minimum Thresholds for Chronic Lowering of Groundwater" (referred to as Exceedance Policy) was adopted by the KGA Board of Directors in April 2022.	Coordinated action to address an MT exceedance at a single representative monitoring well.
SSJMUD	REVISED Domestic Well Mitigation Program	Upon final adoption by the SSJMUD Board of Directors, the Domestic Well Mitigation Program will be implemented. The Program Guidelines are currently in draft (included in management area plan) and is expected to be adopted and implemented by the end of 2022.	A domestic well mitigation program to mitigate the potential impact of declining groundwater elevations resulting from SSJMUD's groundwater management actions	There are no quanitifiable benefits to sustainable groundwater management. This is a mitigation based management action to be implemented if SSJMUD groundwater management activities impact a domestic well.
SSJMUD	In-District Allocation Structure	This Management Action is in the conceptual stages, having been discussed with various stakeholder groups. However, an actual structures and fee schedules have yet to be devised for either district.	At the time of this draft of the GSP, SSJMUD does not have an established allocation structure and fee schedule for groundwater extraction. As SGMA is implemented throughout the KCS, the districts are required to manage to the Sustainable Management Criteria (SMCs) established in Section 5 of this Chapter GSP. One of the ways to manage for the SMCs is to allocate the Sustainable Yield for their respective districts to the landowners within their districts. The allocation structure would allow for the transfer of groundwater pumping credits within each district's jurisdiction, provided that it does not lead to localized impacts to at the Representative Monitoring Sites defined in Sections 4 and 5 of this Chapter GSP.	The benefits to sustainable groundwater management have not been quantified at this time. However, the development and implementation of an allocation structure for each district would allow for the districts to utilize their Sustainable Yield as a management tool for reaching and maintaining their SMCs.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
SSJMUD	Voluntary Land Fallowing	At this time, this Management Action is conceptual. The district will develop its fallowing program during the SGMA implementation period.	In the event of a drought, the district may not be able to entirely meet in-district demand by increasing the volume of imported water. The combination of decreased availability in surface water to supply to the district and decreased recharge from other sources in the subbasin has the potential to lead to violations of SMCs at the Representative Monitoring Sites, in the absence of decreased demand. To facilitate the district's ability to maintain sustainability at its monitoring sites, the district will develop and implement a voluntary land fallowing program.	The decrease in water demand will be dependent upon the land being fallowed and its existing land use at the time of fallowing. Agricultural demand for water is generally estimated to be 3 AF/acre. Fallowing or land retirement would reduce the demand to zero for the lands participating in the program.
SSJMUD	Pumping Restrictions	At this time, this Management Action is conceptual. The district will develop its process to implement pumping restrictions within the plan area.	In the event that the districts or the entire subbasin are nearing a condition where they are at risk of triggering an Undesirable Result, even with the implementation of the projects and management actions described in this Plan, it may be necessary for the district to limit groundwater pumping. The volume of groundwater extraction permitted under this Management Action would be determined by the district based on the Sustainable Yield for the district and the SMCs at the Representative Monitoring Sites.	The benefits of mandatory pumping restrictions have not yet been quantified, as the guidelines for such a management action have not been established.
Shafter-Wasco Irrigation District - 7th Standard				
SWID - 7th Standard	Evaluation of Potential to Utilize SWID Kimberlina Ponds for Recharge or other Facilities	Status: Conceptual, have begun initial discussions; Initiation: 2020-2024 Completion: Ongoing Accrual of Benefits: Annual-basis	SWID operates the Kimberlina Ponds groundwater recharge facility. The Annex Area will evaluate opportunities with SWID to utilize Kimberlina Pond storage capacity for recharge. The Annex Area will evaluate opportunities to purchase non-SWID water for recharge in the Kimberlina Ponds facilities, when the Ponds have unused capacity (i.e., likely in nonwet and non-drought years).	Up to 4,500 AFY of imported supply, in combination with other recharge projects. Increased groundwater levels.
SWID - 7th Standard	Evaluation of Potential to Partner in Kern Fan Groundwater Storage Project	Status: Conceptual, have begun initial discussions with RRBWSD; Initiation: 2030 Completion: 2035 Accrual of Benefits: 50 vears after construction	The Kern Fan Groundwater Storage Project is under development by RRBWSD and would serve to develop a regional water bank in the Kern Fan to capture and store Article 21 water via the State Water Project (SWP) during conditions when surface water is abundant. The Annex Area could potentially become a funding partner in this project and have access to recharge and storage capacity in the Project.	Up to 4,500 AFY of imported supply, in combination with other recharge projects. Increased groundwater levels.
SWID - 7th Standard	7th Standard Annex Management Area Storage Pond Project	Status: Conceptual, have begun initial discussions with RRBWSD; Initiation: 2030 Completion: 2035 Accrual of Benefits: 50 years after construction	This project would improve water supply reliability and groundwater conditions in the Management Area. Benefits of developing a groundwater recharge facility within the Mangement Area include effective conveyance of surface water supplies when they are available, facilitation of water banking and exchange arrangements, and avoidance of direct water quality impacts. A conveyance mechanism, such as the Flat Rocks Canal would be necessary to bring such water to the Mangement Area.	Up to 1,463 AFY of recharge capacity for purchased surface water within the Management Area (assumes 320-acre basin). Increased groundwater levels.
SWID - 7th Standard	Identify Opportunities to Utilize Existing Infrastructure	Status: Conceptual, have begun initial discussions; Initiation: 2020-2024 Completion: ongoing Accrual of Benefits: annual	Several entities in the vicinity of the Annex Area have existing groundwater recharge infrastructure, which have unused capacity, particularly in nonwet years. The Annex Area will evaluate potential opportunities with these entities to utilize the unused capacity for recharge of purchased water.	Up to 4,500 AFY of imported supply, in combination with other recharge projects. Increased groundwater levels.
SWID - 7th Standard	On-Farm Groundwater Recharge	Status: Conceptual, have begun initial discussions; Initiation: 2020-2024 Completion: ongoing Accrual of Benefits: annual	In May 2019, the SWID Board adopted a new Buried Recharge policy that will allow for on-farm water banking, which will allow Annex Area landowners to purchase and recharge non-SWID water on their own properties, as well as those within the original SWID boundary.	Up to 4,500 AFY of imported supply, in combination with other recharge projects. Increased groundwater levels.
SWID - 7th Standard	Flat Rock Canal Extension	Status: Conceptual, have begun initial discussions; Initiation: 2030 Completion: 2035 Accrual of Benefits: 50 year period following construction	The Management Area will assess the feasibility of this project and seek partnership with other interest entities. This project would provide connection from the Annex Area to the Kern Water Bank Canal, Cross Valley Canal, and Goose Lake Slough. Phase 1 of this project is to distribute Kern River water to the north using gravity from Goose Lake Slough.	Improve ability to delivery surface water supplies to the District for irrigation or recharge. Benefits to neighboring entities, who would be key partners in this regional project.
SWID - 7th Standard	Develop New Interconnections Within SWID's Conveyance System (and Improve "Bottleneck" Issues)	Status: Conceptual, will require evaluation of options and benefits; Initiation: TBD Completion: TBD Accrual of Benefits: TBD	The Annex Area can work with SWID to increase the capacity and flexibility of SWID's current conveyance system, to allow access to additional supplies.	Improve operational flexibility within the SWID conveyance system to allow for increased capacity to accept surface water supplies when available.
SWID - 7th Standard	Increased Recycled Water Deliveries and Recharge	Status: In discussions for increased purchases; Initiation: In progress Completion: Anticipated 2019-2020 Accrual of Benefits: Annual	Secondary-treated municipal wastewater is from the North of the River Sanitary District is currently used for irrigation and infiltrated into groundwater within the Annex Area. The Annex Area is discussion options to increase recycled water deliveries and recharge of groundwater with secondary-treated wastewater within the Annex Area. Growth rate is projected at 2% and output expected to increase to 14,000 AFY.	Up to 8,180 AFY of treated effluent (based on project increased WWTP flows), to be used for irrigation to offset groundwater demand.
SWID - 7th Standard	On-farm Water Conservation	Status: not yet initiated; Initiation: Upon stakeholder interest Completion: TBD Accrual of Benefits: 1-3 years after initiation	The NRCS is offering landowner incentive programs to assist in implementing various conservation activities, including but not limited to: irrigation system improvements, water/nutrient/pest management, and pump engine replacement. Interested landowners can call (661) 336-0967 or visit the website (www.ca.nrcs.usda.gov) for more information.	Reduce on-farm water demands.
SWID - 7th Standard	Voluntary Rotational Land Fallowing Program	Status: not yet initiated; Initiation: Upon approval of funding mechanism Completion: Anticipated 2020-2024 Accrual of Benefits: 1 years after initiation	In order to reduce demand within the Management Area, this project would incentivize landowners to fallow their previously farmed lands voluntarily on a rotational basis. This potential project would be implemented on a voluntary rotational basis. Incentives have not yet been established, but would be anticipated to be funded by the Annex Area landowners through the same funding mechanism used for other SGMA related activities.	Up to 1,443 AFY of reduced water demand (assumed 430 acres fallowed per year).

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
SWID - 7th Standard	Education of Groundwater Use per Acre	Status: not yet initiated; Initiation: Upon GSP implementation Completion: Until overdraft ends/other programs initiated Accrual of Benefits: 1 year after initiation	This program would provide groundwater users an expected groundwater volume, as an education tool, prior to enforcement actions on groundwater allocations, with the goal of providing awareness of overdraft conditions. This information would be provided in an annual letter, along with average crop demand, GSA average extraction, GW overdraft, and reminders of GSA powers and authorities.	Reduce on-farm water demands.
Semitropic Water Storage District				
SWSD	Landowner Water Budgets	Implemented	Establish individual water budget for landowners by landowner classes	Water demand reduction of an estimated 60,000 af total (3,000 af/yr to 2040)
SWSD	Tiered Pricing for Groundwater Pumping	Under development with adoption in 2022	Develop pricing structure to incentize groundwater users to manage groundwater extractions to MA1 water Budgets	Water demand reduction consistent with MA1 (Landowner Water Budgets)
SWSD	District Fallowing Program	Not yet started; to be implemented in 2020 after implementation of MA 1	Support land fallowing as a District action and by individual landowners or groups of landowners.	Water demand reduction consistent with MA1 (Landowner Water Budgets)
SWSD	Enhanced Groundwater Recharge	Status is ongoing and expected to be initiated in 2020 upon adoption of Semitropic GSP.	Development of surface and subsurface recharge projects underlying developed agricultural lands to increase groundwater recharge capacity	Water supply augmentation up to 20,000 af average annual
SWSD	Monitoring Network Improvement Plan	Ongoing, initiated planning.	Assess and identify monitoring network requirements for full compliance with SGMA and development of an implementation plan for achieving full compliance.	Improved groundwater monitoring in support of SGMA
SWSD	Evaluation and Assessment of GDEs within the Semitropic Area	Not yet started; Expected to be initiated in 2020 upon adoption of Semitropic GSP.	Conduct additional analysis to verify the prescence and extent of GDE's in the Semitropic and, if present, develop appropriate monitoring protocols.	
SWSD	Brackish Water Desalination	Initiated planning; expected to be initiated in 2022 upon completion of environmental and regualtory requirements.	Development of a braackish water treatment facility to treat locally sourced brackish water for District use.	Expected water supply augmentation of 1,800 af/year
SWSD	In-District Water Markets and Transfers	Not yet started; Expected to be initiated in 2022 upon adoption of Semitropic GSP.	District will allow for the development of market for in-district transfers	Water supply augmentation TBD.
SWSD	Poso Creek MAR	Upon completion of feasibility and permitting requirements; Expected initiation in 2020	Development of floodwater capture and recharge program ffrom Poso Creek flood flows	Water supply augmentation of 1,200 af average annual
SWSD	Tulare Lake Project	Under Development since 2018; Initiated upon completion of water rights determination	Development of conveyance facilities to divert Kings River flood flows for direct use and recharge in the SWSD	Water supply augmentation of 70,000 af average annual
SWSD	Water Market Acquititions	Status is ongoing and expected to be initiated in 2020 upon adoption of Semitropic GSP.	Increased participation in state-wide water markets for spot market and long-term water transfers	Water supply augmentation of 4,000 af average annual
SWSD	Stored Water Recovery Unit	Initiated; 2025 Upon approve by SWSD BOD and identification of funding	Development of water storage to expand in-lieu service areas	Increases capacity & flexibility of conveyance for recharge
SWSD	Pond-Poso Spreading Grounds, Phase II	Inititated; Upon adotion of Semitropic SWSD; 2020.	Development of spreading facilities to increase groundwater recharge capacity	Increases groundwater recharge capacity
SWSD	Pond-Poso Entrance Ponds	Initiated; 2024 upon approval by SWSD BOD and identification of funding.	Development of spreading facilities to increase groundwater recharge capacity	Increases capacity & flexibility of conveyance for recharge
SWSD	Multi-District Conveyance (CA to Friant-Kern Canal)	Ongoing; Implementation upon approval by SWSD BOD and identification of funding.	Development of a conveyance system to deliver surface water for groundwater recharge and irrigation	Increases capacity & flexibility of conveyance for recharge
SWSD	Schuster Spreading Grounds	Initiated; Expected initiation 2023 upon approval by SWSD BOD and identification of funding	Development of spreading facilities to increase groundwater recharge capacity	Increases groundwater recharge capacity
SWSD	Leonard Avenue System	Inititated 2019; Upon adotion of Semitropic SWSD. To be completed by 2023.	Development of an intertie system to provide east to west surface water conveyance to for supply in groundwater dependent areas	Increases capacity & flexibility of conveyance for recharge
SWSD	Diltz Intertie	Completed	Connection of an intertie to provide surface water converyance for agricultural irrigation	Increases capacity & flexibility of conveyance for recharge
SWSD	Cox Canal	Completed	Developed canal for the conveyance of surface water for groundwater recharge	Increases capacity & flexibility of conveyance for recharge
SWSD	Stored Water Recovery Unit- XYZ	Completed		Increases capacity & flexibility of conveyance for recharge

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
West Kern Water District				
WKWD	Project 1: Automatic Meter Reading Project	The circumstance of implementation for this project would be current conditions, once funding is secured or committed and the project approved by WKWD's Board of Directors, it could be implemented.	In 2015, WKWD began installing AMR systems for all industrial and outlying customers. To further achieve sustainability goals, WKWD would install AMR systems on the remainder of its primarily residential customer meters. The AMR system selected by WKWD for its industrial and outlying customers uploads data every 24 hours to a website where customers can access their accounts and view water use data, compare their current water use to their historical water use, and receive leak alerts.	AMR provides potential water savings through early leak detection and increased awareness of water use among customers. Upgrading meters also reduces unaccounted-for losses related to accuracy degradation in older meters. WKWD estimates that AMR will save an average 8 percent of water for each metered connection, based on savings experienced by nearby agencies. The City of Sacramento had an average 4 percent water savings based on a pilot AMR project, while the Golden Hills Community Services District realized 12 percent in average savings (WKWD, 2014). WKWD's 2015 UWMP shows residential water use ranges between 2,169 AF in 2015 to a projected high of 2,597 AF in 2040, and applying the projected 8 percent conservation, anticipated water savings from this project is estimated to be 173 to 208 AFY (WKWD, 2016). Conservation achieved by the AMR project would be measured by the reduction in water deliveries to customers with AMR meters.
WKWD	Project 2: Participation in California WaterFix	Long-term	California WaterFix is intended to address the challenges of pumping water from the Delta by diverting water upstream of the current diversion points and conveying it to existing pump stations for the SWP and the Central Valley Project (CVP). Under current operation, the SWP and CVP are unable to consistently deliver state and federal water contractors their full contract supplies. California WaterFix is intended to address some of the conditions that impact the ability to export water from the Delta.	The primary benefit of this project would be the increased reliability of imported water supplies and to expand groundwater banking opportunities to meet customer demands. Additional supplies could be 1) banked in WKWD's recharge facilities, 2) used for GWE protection if monitoring shows unexpected declines in elevation, or 3) transferred to neighboring agencies to help offset groundwater pumping in the Subbasin.
WKWD	Project 3: Buena Vista Recreation Area Water Supply Management Coordination	Implementation of this project is already underway and is likely to remain an ongoing project until such time as the BVARA no longer requires water from the GSA area.	BVARA is in and adjacent to the WKWD GSA area. The 1,585-acre BVARA is home to two manmade lakes, Lake Webb and Lake Evans, boating facilities, playgrounds and volleyball courts, camp sites, and picnic areas. The lakes lie outside of the GSA area but the park facilities such as picnic areas, restrooms, and parking areas are within the GSA area. When constructed, the lakes had a combined storage capacity of over 6,800 AF. Shoreline camping and picnic areas are landscaped with grass and are irrigated during the dry season (County of Kern Parks and Recreation Department, 2019). With no outlet, water from the lakes either evaporates or percolates into the groundwater basin. Kern County pumps groundwater from wells located within the GSA area to supplement losses at the lake. Supplemental water delivered to the lakes is not metered and is not included in WKWD GSA's water balance.	Managing water supply for the BVARA would include a focused effort on monitoring pumping in that portion of the GSA area, and identifying which projects or management actions are needed to eliminate undesirable results in the Subbasin. Securing additional supplemental supplies would reduce the potential impacts to groundwater levels, storage, and water quality for this portion of the GSA area. Improved management of the BVARA water supply would also support ongoing use of the BVARA, a popular recreation area. The project does not have a directly measurable benefit unless implementation actions arise from these meetings.
WKWD	Management Action 1: Continued Balanced Pumping and Recharge	The circumstance of project implementation would be current conditions and would remain unless conditions indicated a different management approach was needed to achieve sustainability indicators.	Continued balanced pumping of groundwater and recharge of imported supplies has and will continue to be the operational norm for WKWD. Under this management action, recharge and recovery activity will continue to be monitored closely by WKWD to maintain balanced conditions.	This management action would allow WKWD to continue operating groundwater recharge and recovery in balance, resulting in a long-term net-zero balance in the Subbasin for the areas under WKWD's control.
WKWD	Management Action 2: Implement Water Shortage Response Plan	The circumstance of implementation for this project would be times of water shortage, supply interruption, or drought, as declared by WKWD's Board of Directors. Implementation would cease when shortages are no longer being experienced, and as approved by the WKWD's Board of Directors.	WKWD's Water Shortage Response Plan (WSRP) is incorporated into the 2015 UWMP and includes triggers for when the WSRP would be implemented. The WSRP describes management actions and use restrictions that would be implemented if water shortages were declared. Because current operation of groundwater recharge and recovery in the GSA area has shown a long-term increase in banked groundwater, and normal water years are projected to have a surplus of supply that can be banked, it is not expected that the WSRP would go into effect during normal or wet years. During extended dry periods, groundwater pumping would increase, and WKWD would use banked supplies to meet demands in excess of available imported and surface water supplies.	The WSRP is designed to reduce customers' overall water use by implementing restrictions on when and how water may be used. As a result, implementation of this management action would reduce overall demand, which offsets demand for imported water and groundwater. Each Response Level is designed to help achieve a specific conservation target, and would reduce overall demands between 0 and 6,900 AF (i.e., 0 to 50 percent conservation) (Table 8-3). Conservation achieved by this management action would be measured by the reduction in metered water deliveries after this management action is implemented.
WKWD	Management Action 3: Continued Participation in Basin-Wide Coordination	The circumstance of implementation for this project is ongoing.	The WKWD GSA is one of several GSAs in the Subbasin. Coordination among these GSAs is necessary for sustainable management of the Subbasin as a whole and has been ongoing during development of their respective GSPs. Coordination during GSP development has included regular in-person meetings and calls to discuss sustainability thresholds, potential projects and management actions, and to discuss specific issues and concerns. As described in this Chapter GSP, the KGA is developing an Umbrella GSP for the Subbasin, while the other GSAs in Kern County are developing Chapter GSPs.	This management action would continue existing coordination activities among GSA managers, helping to build and maintain relationships with neighboring GSAs. Potential conflicts between GSAs regarding groundwater management would be reduced because GSAs would better understand the challenges experienced in each GSA area, and how these challenges are being addressed. Coordination meetings will also provide an opportunity for GSAs to inform each other of potential issues that may require intra-Subbasin coordination to address, and to notify neighboring GSAs of management actions or projects that might affect a decision made by another GSA.
WKWD	Adaptive Management Strategy 1: Taft Recycled Water Program	This project would be implemented through an agreement between WKWD, the City of Taft, and FCTHSD.	The Taft Recycled Water Program would create up to 423 AFY of tertiary recycled water suitable for Title 22-approved applications for recycled water. This project would be implemented in partnership between WKWD, the City of Taft, and the Ford City-Taft Heights Sanitation District (FCTHSD). WKWD provides water within the WKWD GSA area, but sanitation services are provided by the City of Taft and FCTHSD, which jointly own the Taft Wastewater Treatment Facility (WWTF). The Taft WWTF currently produces undisinfected secondary effluent that is suitable for and applied to feed crops, specifically alfalfa. This effluent is not suitable for wider recycled water use, but through upgrade to tertiary treatment, it could be used more widely for non-potable applications, such as landscape irrigation, which currently use potable water to meet demands (WKWD, 2018).	The project would create up to 423 AFY of tertiary recycled water, offsetting an equal volume of potable water (WKWD, 2018). Available and unused potable water is currently banked for future use during imported and surface water supply shortages. This project would both reduce demand for groundwater pumping during dry years and allow for additional water to be banked during wet years. Tertiary recycled water would be a local supply with high supply reliability, even during drought years. The volume of water offset by this project would be measured by quantifying the amount of tertiary recycled water both produced and delivered.

Table 4.1R. REVISED Kern Groundwater Authority Member Entities List of Projects and Management Actions (CONTINUED)

Entity	Project Title	Implementation Status	Description	Benefits
WKWD	Adaptive Management Strategy 2: Shift Balance of Pumping between North and South Wellfields	Implementation would require easy-to-implement operational changes and could be implemented quickly once triggered.	In 2010, WKWD's North Wellfield (wells within the North Project Management Area) was constructed in response to falling groundwater levels at the South Wellfield (wells within the South Project Management Area). Despite a surplus of banked groundwater, local levels at the South Wellfield showed a trending decline associated with groundwater recovery activities. A single wellfield for recovery activities also limited WKWD's operational flexibility. To combat these two management challenges, the North Wellfield was constructed along with additional recharge basins. Under current operation of the two wellfields, 11,300 AFY are pumped from the South Wellfield and 12,700 AFY are pumped from the North Wellfield. The North Wellfield has an annual pumping capacity of 24,000 AFY (WKWD, 2010).	This adaptive management strategy would reduce groundwater pumping in a localized area, allowing water levels in that area to recover or to decline less sharply during times of drought. Minimizing groundwater level declines reduces the potential for localized subsidence and long-term decrease in groundwater storage capacity. It also helps to maintain well efficiency, allowing for improved wellfield longevity. Local recovery of GWEs would be determined by standard monitoring activities that are part of regular wellfield management. Local groundwater level recovery from this strategy would be measured by monitoring of groundwater levels in the vicinity of the two wellfields.
WKWD	Adaptive Management Strategy 3: Implement Permanent Demand Management Measures	As needed	According to the 2016 WSRP, Response Level 1 is ongoing, and all water use restrictions are strictly voluntary. These actions only become mandatory if a Response Level 2 is declared, which requires a declaration by the WKWD's Board of Directors. This adaptive management strategy would convert the Response Level 1 actions in the WSRP from voluntary to mandatory. These water restrictions would require a 25 percent reduction in large landscape watering from 2007 levels, prohibit water waste, and reduce non-contracted industrial water use by 15 percent from 2007 levels. WKWD may choose to implement these or a different set of permanent demand management measures as appropriate at the time this adaptive management strategy is approved.	Project benefits are expected to be like those achieved under Management Action 2 (Implement WSRP), though they will have long-term benefits because they are permanent measures rather than temporary ones under the WSRP. Conservation achieved by this management action would be measured by the reduction in metered water deliveries after this management action is implemented.
Westside District Water Authority				
WDWA	Collect Representative Hydrogeologic Data	The PMA No.1 will be implemented beginning with acceptance of the MNP, and directly support WDWA MT/MOs by providing foundational data to monitor and manage adaptive management projects that are designed and implemented to ameliorate the potential for significant reduction of ground water elevations and groundwater in storage	Historically, because of the brackish and naturally degraded quality of groundwater in the WDWA, growers have relied almost exclusively on surface water from the SWP for their irrigation needs. Groundwater is used primarily for blending when annual SWP deliveries are less than expected. As a result, there is currently little representative hydrogeologic data in the WDWA. This lack of data represents a significant data gap that must be addressed in order to refine the current understanding of the WDWA Conceptual Hydrogeologic Model, including key elements such as groundwater elevations, pumping and changes to groundwater in storage and the overall water budget. As a first step, the WDWA will conduct a review of groundwater wells to inventory their number, type, and location in relation to groundwater watch areas and critical regional and management area and infrastructure within the WDWA. In addition, the WDWA will find or install at least two additional representative monitoring wells by 2025.	The ability to generate representative data for use in updating water budget elements; Improved numerical groundwater modeling results; and Better forecasting and planning of adaptive management projects and management actions.
WDWA	Water Resource Coordination	The implementation of the disparate Water Resource Coordination Programs vary, some as described above are already in place and ongoing. Others, like a KCS-wide coordination program would likely begin with planning during the first five-year reassessment period after KCS Plan implementation. Coordination between the WDWA and its immediately adjacent GMAs would likely be structured to begin with meetings shortly after Plan approval.	The member growers in the WDWA have historically made significant investment in efficient irrigation technologies and methods that promote water conservation and sustainable management. They have also coordinated amongst themselves as individuals or via the various Water Districts to implement focused reduction demand measures, trade or purchase surplus water when deliveries from the SWP have been reduced. It is assumed that these effective ad hoc arrangements will continue after Plan implementation. In addition, the WDWA will work cooperatively and in close consultation with its members, the KGA and adjacent GMAs to coordinate water resource monitoring, testing and future water trading as part of its overall strategy for the sustainable management of all its available water resources.	More reliability and flexibility in water availability; Drought resiliency; and Sustainable water strategies for both short- and long-term planning horizons.
WDWA	Conjunctive Reuse of Naturally Degraded Brackish Groundwater	Preliminary planning for a Project Engineering FS for the first phase of the project has already begun. It is expected there will be at a minimum two phases of distributed treatment facility construction.	To further enhance the sustainable and adaptive management strategies for the Westside, the WDWA is evaluating the feasibility of an innovative phased project that will integrate the treatment and conjunctive reuse of naturally degraded brackish groundwater and oilfield produced water for multiple beneficial uses.	When operational, the Project will result in multiple potential beneficial uses, including many of the "One Water" concepts enumerated in the State's California Water Action Plan.

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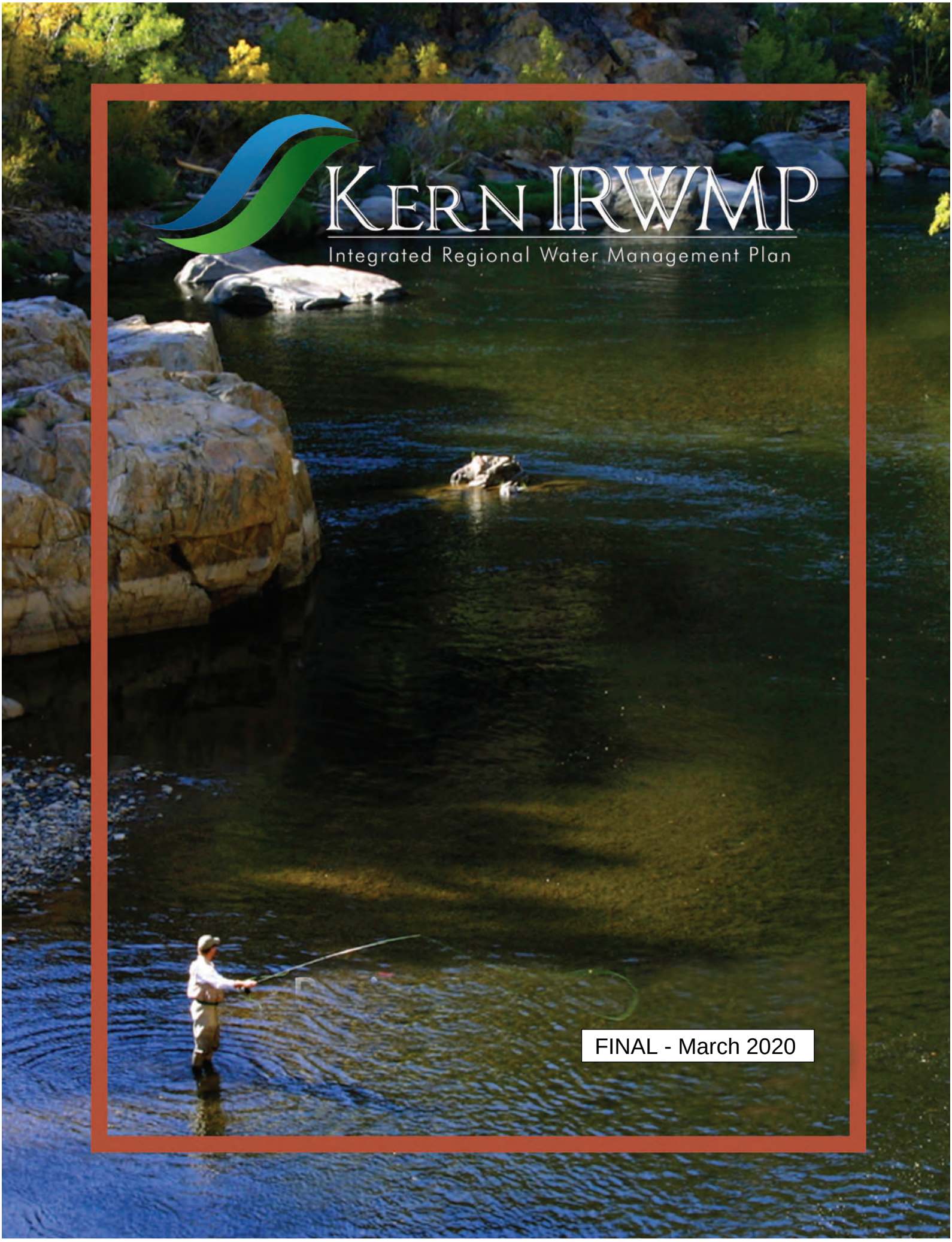

KERN IRWMP

Integrated Regional Water Management Plan

FINAL - March 2020

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan

Final Update

March 11, 2020

Plan Update Prepared by:
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Section 1: Introduction

1.1 Introduction to the Region

The Tulare Lake Basin hydrologic region consists of approximately 17,000 square miles, and includes all of Tulare and Kings Counties, and most of Fresno and Kern Counties (see **Figure 1-1**). Significant geographic features include the southern half of the San Joaquin Valley, the Temblor Range to the west; the Tehachapi Mountains, Transverse Ranges, and San Emigdio Range to the south; and the southern Sierra Nevada to the east.

The Tulare Lake Basin Portion of Kern County Region (Kern Region), as defined for the purposes of this Integrated Regional Water Management Plan (IRWMP), consists of that portion of the Tulare Lake Basin hydrologic region that is within Kern County, with small additional areas that are included for hydrologic reasons (see **Figure 1-2**). The Kern Region boundary is consistent with the Tulare Lake Hydrologic Basin Planning Area boundary delineated by the Central Valley Regional Water Quality Control Board (CVRWQCB), and the California Water Plan (Bulletin 160) Hydrologic Region, and Integrated Regional Water Management Program "Funding Area" boundary.

The Kern Region covers approximately 5,690 square miles of Kern County and a small portion of southern Kings County. The Kern Region is separated into nine (9) subregions, which acknowledge the variation in geography, agency boundaries, and resource management strategies within the greater region (see **Figure 1-4**). These subregions are: (1) Greater Bakersfield, (2) Kern Fan, (3) Mountains/Foothills, (4) Kern River Valley, (5) North County, (6) South County, (7) West Side, (8) KCWA1 and (9) the County of Kern.[1]

Water demands within the Kern Region are serviced by a variety of water purveyors, including the large wholesale agency, the Kern County Water Agency (KCWA) and its member districts (both agricultural, and municipal and industrial [M&I]), irrigation districts, investor-owned water companies, mutual water companies, municipalities and private well owners. Water supplies utilized in the region are the State Water Project (SWP) via the California Aqueduct, the Central Valley Project (CVP) via the Friant-Kern Canal, and local surface supplies from the Kern River and other local streams, as well as the largest common groundwater basin, the San Joaquin Valley groundwater basin, covering the majority of the managed resources in the Kern Region. Other groundwater basins in the Kern Region include the Kern River Valley groundwater basin to the east; Walker Basin Creek Valley groundwater basin to the southeast; Cummings Valley and Tehachapi Valley West on the eastern side of the Region, Brite Valley to the southwest; and Cuddy Canyon Valley, Cuddy Ranch Area, Cuddy Valley; and Mil Potrero Area basins to the south. All of these groundwater basin boundaries are within the watershed boundary of the Kern Region (see Figure 2-7 for basin locations).

Increasing development and environmental demands on water availability and quality for agricultural and M&I purposes, coupled with curtailments of imported SWP and CVP deliveries due to prolonged drought and regulatory restrictions, have intensified the competition for

[1] KCWA and the County of Kern were chosen to be separate subregions because they each overlap the entire Kern Region, as well as represent the interests of their subregion, whether for water supply management or land use planning purposes.

available water supplies in the Kern Region. Consensus was needed to develop a water resources management plan and strategy that addresses the needs of both M&I purveyors to reliably provide the quantity and quality of water necessary to serve the continually expanding urban needs and the needs of agricultural water users that require adequate and reliable supplies of reasonably-priced irrigation and groundwater recharge water. In addition, the Tulare Lake hydrologic region is a "closed basin." Water that enters the basin is not 'lost to' or 'returned to' a salt sink after use – with the exception of a few areas in the Westside Subregion. Thus, opportunities for recycling and conjunctive use programs are magnified. For these reasons, the Kern Region is an appropriate area for integrated regional water management.

1.1.1 Relationship with Neighboring IRWMPs

The Kern Region is adjacent to nine other existing or developing IRWM planning regions: Poso Creek, Southern Sierra, Inyo-Mono, Antelope Valley, Fremont Basin, Upper Santa Clara River, the Watersheds Coalition of Ventura County (Ventura), Santa Barbara, and San Luis Obispo. Overlapping areas exist with three of these Regions: (1) San Luis Obispo, (2) Antelope Valley, and (3) Poso Creek.

Coordination with each of these planning regions, as well as a discussion of these identified overlaps and an explanation of their basis is documented below. See **Figure 1-3** for a map of these planning regions.

1.1.1.1 Poso Creek IRWMP

Prior to the formation of the Kern IRWMP region, the only IRWMP region that existed within the Tulare Lake Basin portion of Kern County was the Poso Creek IRWMP, which is located in the northerly portion of the Kern County and southerly portion of Tulare County (see **Figure 1-3**). The Poso Creek region, which currently continues to exist as an IRWMP Region, includes Semitropic Water Storage District (SWSD), Cawelo Water District, Delano-Earlimart Irrigation District (DEID), Kern-Tulare Water District (KTWD), North Kern Water Storage District (NKWSD), Shafter-Wasco Irrigation District (SWID), and North West Kern Resource Conservation District as their Regional Management Group (RMG).

The Kern Region overlaps the Poso Creek region as a result of the respective boundaries of each IRWMP's participants. Many members of the Kern and Poso Creek IRWMPs have a long history of open communication and coordination of surface water and groundwater management on regional and local scale, which predates the IRWM program. Regional coordination and communication are evident in the numerous joint groundwater banking programs, routine exchanges and transfers of water supplies between urban and agricultural purveyors, participation in local and state programs and participation in a multitude of local water management committees and meetings. In addition to the regular communication between the Kern and Poso Creek regions, the two regions have executed a "Letter Agreement on Region Boundaries and Coordination of Water Management Strategies for the Poso Creek Integrated Regional Water Management Plan and the Kern Integrated Regional Water Management Plan" (Agreement). The Agreement defines the Poso Creek IRWMP's boundaries within the Kern IRWMP and identifies the area of overlap. Additionally, the Agreement identifies the need for continued collaboration and five main water management issues of mutual interest, including: restoration of water supplies, protection of water quality, preservation of local management, protection and/or restoration of habitat and improving the relationship between land use planning and water resources. During the 2011 Region Acceptance Process (RAP) the Kern

and Poso Creek Regions were both fully approved by the California Department of Water Resources (DWR).

1.1.1.2 Southern Sierra IRWMP

The Southern Sierra IRWMP is a primarily watershed-based region, covering a large portion of the southern Sierra Nevada Mountains. Originally, the Southern Sierra IRWMP and the Kern IRWMP boundaries overlapped in the lower portion of the Kern River watershed, located in northeastern Kern County. Beginning in late 2008, representatives of the two regions worked together to determine if such a large area of overlap was necessary and/or beneficial to the region and arrived at a mutual set of boundaries. At that time it was determined that the Kern IRWMP had already conducted extensive outreach in the area to communities (including Disadvantaged Communities [DACs] and tribal groups), water purveyors, environmental and conservation organizations, recreational groups, land use planning entities, and many more potential stakeholders, and that those stakeholders were actively participating in the Kern IRWMP process. After discussing the overlapping boundary with stakeholders in the region and their option to participate in either IRWMP, it was determined that the stakeholder preference in the area was to remain a part of the Kern IRWMP. Therefore, representatives of the Southern Sierra and Kern Regional Water Management Groups (RWMGs) decided it was in the best interest of stakeholders and both IRWMPs to adjust the boundaries to eliminate the overlapping region. After multiple discussions during 2008-2009, both groups agreed that the Kern-Tulare County line would serve as the northern and southern boundaries of the Kern and Southern Sierra IRWMPs, respectively, in order to eliminate the unnecessary overlap. Additionally, as both regions had already identified several watershed-wide issues and objectives (e.g., protection of the headwaters of the Kern River, removal of invasive aquatic species, etc.), it was mutually agreed that the two regions would work collaboratively on these objectives and any potential watershed projects that may arise from either IRWMP effort.

Representatives of both IRWMPs have executed a letter agreement detailing the boundary decision, cross-boundary resource management issues and objectives, and strategies for collaboration between the two groups. The letter is provided in **Appendix A**.

1.1.1.3 Inyo-Mono IRWMP

The Kern RWMG has been in communication with the Inyo-Mono IRWMP planning region since late 2008. The Inyo-Mono IRWMP extends from the southern portion of the North Lahontan hydrologic region into the northern portion of the South Lahontan hydrologic region. Currently the Kern Region shares a watershed boundary in the northeast portion of Kern County, along the crest of the Sierra Nevada. Open lines of communication exist between the Kern and Inyo-Mono IRWMP regions, and facilitation of any cross-boundary issues, objectives, and/or projects will be collaborative. A letter agreement regarding the mutual boundary between the two regions has been executed and is provided in **Appendix A**.

1.1.1.4 Antelope Valley IRWMP

A small portion of the Kern Region's southeast boundary departs from the Tulare Lake Basin watershed boundary to overlap with the northern portion of the Antelope Valley watershed-based boundary in order to be inclusive of the entire Tehachapi-Cummings County Water District (TCCWD) service area. TCCWD is a member unit of the KCWA and provides imported water supplies and groundwater management services to its service area. Due to these

infrastructure and contractual relationships, TCCWD chose not to participate in the Antelope Valley IRWMP planning effort and is currently involved in the Kern IRWMP planning effort.

Both the Kern RWMG and Antelope Valley RWMG acknowledge the existence of an overlap of boundaries and have agreed to work collaboratively to address issues of common interests in this area as both regions advance their respective efforts. A letter of agreement in support of this mutual boundary was executed and is provided in **Appendix A**.

1.1.1.5 Fremont Basin IRWMP

The Fremont Basin IRWMP covers the Fremont groundwater basin and abuts the Kern Region's eastern boundary. Representatives of the Kern Region have been in communication with the Fremont Basin IRWM group and have provided assistance with boundary development and information regarding starting an IRWM program. The Fremont Basin IRWMP was approved during the 2011 RAP.

In 2018, The Fremont IRWM Group requested a boundary change to encompass the entirety of the Fremont Valley Groundwater Basin, which results in an overlap with a small portion of the eastern Kern IRWM Region. Both the Kern RWMG and Fremont Basin RWMG acknowledge the overlap of boundaries and have agreed to work collaboratively to address issues of common interests in this area as both regions advance their respective efforts. A letter of agreement in support of this mutual boundary was executed and is provided in **Appendix A**. .

1.1.1.6 Ventura IRWMP, Santa Barbara IRWMP, San Luis Obispo IRWMP

At the southernmost portion of the Kern Region boundary a small overlap occurs with the Upper Santa Clara River IRWMP; with much of the northern boundary of the Ventura IRWMP; and if extended to the County line, there is a very small shared boundary with the Santa Barbara IRWMP (see **Figure 1-3**). Coordination among these four planning regions occurred in early 2009 during the RAP to discuss mutual boundary lines and possible letters of agreement. It was determined by the parties that there was little likelihood for water resources to be managed across the shared boundaries; however, there would continue to be open lines of communication should any jurisdictional issues and/or projects arise. Everyone was supportive of the boundaries as they had been delineated.

As shown on **Figure 1-3**, a small portion of the Kern Region boundary, comprising the southwestern corner of the West Kern Water District (WKWD), extends into San Luis Obispo County in order to include the entire WKWD service area in the Kern Region. WKWD is a member unit of the KCWA, provides imported water supplies to its service area, and is currently participating in the Kern IRWMP planning effort. This area of overlap was discussed between the two IRWMP Regions, and it was determined that because no water resources within those areas of overlap need to be managed, the overlapped areas in question were not areas of significance that would cause any confusion or controversy, and it is acceptable to both planning regions.

1.1.1.7 Upper Santa Clara River IRWMP

At its southernmost portion the Kern Region shares a very small piece of boundary with the Upper Santa Clara River IRWMP. The consultant team for the Kern Region, which also prepared the Upper Santa Clara River IRWMP, has consulted with the RWMG for the Upper Santa Clara River IRWMP regarding this small shared area, and has determined that it is not a significant issue needing further coordination between the two planning regions.

1.2 Purpose of the Tulare Lake Basin Portion of Kern County IRWMP

The purpose of the Kern IRWMP is to develop a cooperative regional framework, implementation plan, and context for managing water resources in the Kern Region. As stated above, this IRWMP aims to address as much of the Kern County portion of the Tulare Lake Basin as possible and includes a wide Stakeholder base. A collaborative approach for the Kern IRWMP will help strengthen regional influence, reduce conflict, increase benefits across the region and may reduce costs for individual agencies, many of which are economically disproportionate compared to other more urbanized funding regions in the State.

A goal of this IRWMP is also linkage or nexus to IRWMPs prepared by other regions, if appropriate. For example, it may be that issues of importance to the entire Tulare Lake hydrologic region, or to the San Joaquin Valley as a whole, could be addressed by linking multiple IRWMPs to solve common problems. Linkage of these IRWMPs will provide mutual benefits and potential joint funding partnership opportunities for entities within the Tulare Lake hydrologic region.

Stakeholders from the Tulare Lake Hydrologic Region, including the Kern, Upper Kings Basin, Tule, Kaweah Basin, Poso Creek and Southern Sierra, have been meeting regularly to discuss IRWM program and planning issues of mutual concern. This forum has been used to develop mutual boundaries, discuss grant applications, collaborate on regional planning topics (such as addressing climate change), and create a watershed coordinator position for the Tulare Lake Basin.

This IRWMP effort is funded entirely by local participating agencies. A number of individuals have contributed to the development of this IRWMP, including representatives of local agencies, city and county staff, and consultants. This IRWMP is a comprehensive plan that primarily addresses Region-wide water management and related issues. This IRWMP complies with the 2016 IRWM Guidelines for an IRWMP and provides for integration of project and program implementation strategies that best address the needs and objectives of the Region.

1.3 Stakeholder Involvement

This IRWMP benefits from active participation by a wide range of Stakeholders. Members of the RWMG Executive Committee and other Stakeholders have participated in monthly Stakeholder meetings, reviewed draft document materials, and provided extensive collaborative input to shape the formation of this IRWMP. By participating in Stakeholder meetings to develop this Plan, participants have created opportunities for establishing and developing mutually beneficial partnerships. Participating Stakeholders are listed in Section 1.3.3.

1.3.1 Regional Water Management Group

The Kern Region RWMG was established by a Participation Agreement, a document similar in nature to a Memorandum of Understanding (MOU) that prescribes the preliminary roles and responsibilities for the RWMG, including complying with the IRWMP sections of the Water Code. The members of the RWMG that signed the Participation Agreement in October 2008, referred to as “Participants”, are listed in **Table 1-1**. The Participation Agreement is discussed in Section 12.5 provided in **Appendix B**.

Table 1-1 also identifies how each agency is responsible for statutory authority over water supply or water management within the Kern Region by noting whether the agency has authority over any of the following: water supply, water quality management, wastewater treatment, flood management/control, or stormwater management.

Table 1-1: Roles and Responsibilities of the Regional Water Management Group Participants

Agency	Subregion	Roles And Responsibility	Statutory Authority Over Water Supply Or Water Management
City of Arvin	South County	Municipal government that provides open space and land use planning as well as stormwater capture and treatment, and creek restoration within City borders. Wastewater treatment is also provided to residents.	Water supply, water quality management, flood management/control, stormwater management
Arvin Community Services District	South County	Provides groundwater for drinking water in the Arvin area.	Water supply
Arvin-Edison Water Storage District	South County	Delivers CVP and other water to the services are and for the operation of conjunctive use banking program; recharge, store, and recover water to improve water supply and stabilize groundwater levels for local agricultural lands; provide water management to others, typically for drought protection.	Water supply
City of Bakersfield Water Resources	Greater Bakersfield	Municipal government that provides groundwater, surface water from Kern River, and purchased water from KCWA Improvement District 4 (ID4) to a portion of the Bakersfield area. Also operates recharge ponds and canals.	Water supply, water quality management, flood management/control, stormwater management
Bear Valley Community Services District	Mountains/ Foothills	Provides police protection, groundwater, road maintenance, wastewater treatment, and solid waste disposal services to the Bear Valley Springs community.	Water supply, wastewater treatment, water quality management

Agency	Subregion	Roles And Responsibility	Statutory Authority Over Water Supply Or Water Management
Belridge Water Storage District	West Side	Provides surface water from the State Water Project and imported groundwater from local exchange programs to agricultural lands and petroleum production facilities within its service area.	Water supply
Berrenda Mesa Water District	West Side	Provides groundwater, surface water from Kern River, and purchased water from KCWA to agricultural lands within its service area.	Water supply
Buena Vista Water Storage District	Kern Fan	Provides groundwater, surface water from Kern River, and purchased water from KCWA to agricultural lands within its service area.	Water supply
Buttonwillow County Water District	Kern Fan	Provides groundwater to the community of Buttonwillow.	Water supply
California Water Service, Bakersfield	Greater Bakersfield	Provides groundwater, surface water from Kern River, and purchased water from KCWA ID4 to a portion of the Bakersfield area.	Water supply
California Water Service, Kern River Valley District	Kern River Valley	Provides groundwater and surface water from Kern River to its service area.	Water supply
Casa Loma Water Company	Greater Bakersfield	Provides drinking water supply to its service area.	Water supply
City of Delano	North County	Municipal government that provides open space and land use planning as well as stormwater capture and treatment, and creek restoration within City borders. Also provides drinking water and wastewater treatment services to its residents.	Water supply, wastewater treatment, water quality management, flood management/control, stormwater management
Desert Mountain Resource Conservation and Development Council	Kern River Valley	Develop partnerships to enhance economic growth while protecting the natural resources in the Kern Region.	Water quality management, flood management/control
Dudley Ridge Water District	West Side	Provides surface water from State Water Project and imported groundwater from local banking and exchange programs to agricultural lands within its service area.	Water supply
East Niles Community Services District	Greater Bakersfield	Provides groundwater and purchased water from KCWA ID4 to the East Bakersfield area.	Water supply

Agency	Subregion	Roles And Responsibility	Statutory Authority Over Water Supply Or Water Management
Frazier Park Public Utility District	Mountains/ Foothills	Provides local spring water and groundwater to the Frazier Park community.	Water supply
Golden Hills Community Services District	Mountains/ Foothills	Provides groundwater via adjudicated water rights and recharge projects to the Golden Hills community for drinking water.	Water supply
Greenfield County Water District	Greater Bakersfield	Provides groundwater to its service area for drinking water.	Water supply
Henry Miller Water District	Kern Fan	Provides groundwater, surface water from Kern River, and purchased water from KCWA to agricultural lands within its service area.	Water supply
Kern County Water Agency (KCWA)	Kern County Water Agency	Wholesale water supplier.	Water supply
Kern County Resource Management Agency	County of Kern	Municipal government that provides environmental and land use planning as well as permitting and planning for future supply and new transportation projects.	Flood management, stormwater management
KCWA Improvement District No. 4 (ID4)	Greater Bakersfield	Provides a supplemental water supply to the urban Bakersfield area through (1) direct recharge and (2) treatment and delivery of water to its member agencies.	Water supply, water quality management
Kern Delta Water District	South County	Provides groundwater, surface water from Kern River, and purchased water from KCWA to its service area.	Water supply
Kern Water Bank Authority	Kern Fan	Operation of the Kern Water Bank; recharge, store, and recover water to improve water supply for its participants during periods of water shortage.	Water supply
Lamont Public Utility District	South County	Special purpose district that provides water, sewer, and street lighting services to the town of Lamont.	Water supply, wastewater treatment, water quality management
Lamont Stormwater Utility District	South County	Provides and plans for stormwater control and diversion projects within the Caliente Canyon watershed.	Stormwater management
Lebec County Water District	Mountains/ Foothills	Provides groundwater to the community of Lebec.	Water supply
Long Canyon Water Company	Mountains/ Foothills	Provides groundwater to its service area.	Water supply
Lost Hills Utility District	West Side	Provides groundwater for municipal and commercial services and wastewater collection and treatment services to the community of Lost Hills and the I-5/Hwy 46 interchange.	Water supply, wastewater treatment, water quality management

Agency	Subregion	Roles And Responsibility	Statutory Authority Over Water Supply Or Water Management
Lost Hills Water District	West Side	Provides groundwater and purchased water from KCWA to agricultural lands within its service area.	Water supply
City of Maricopa	Kern Fan	Municipal government that provides open space and land use planning as well as stormwater capture and treatment, and creek restoration within City borders.	Water supply, water quality management, flood management/control, stormwater management
City of McFarland	North County	Municipal government that provides open space and land use planning as well as stormwater capture and treatment, and creek restoration within City borders. Also provides drinking water and wastewater services to its residents.	Water supply, water quality management, flood management/control, stormwater management
Mettler County Water District	South County	Provides groundwater to the rural community of Mettler.	Water supply
Mountain Mesa Water Company	Kern River Valley	Provides groundwater to its service area.	Water supply
North of the River Municipal Water District	Greater Bakersfield	Provides groundwater, surface water from Kern River and purchased water from KCWA ID4 to its service area. Wholesales water to Oildale Mutual Water Company.	Water supply
North West Kern Resource Conservation District	North County	Manages resource conservation projects on public and private lands.	Water quality, flood management/control
Oildale Mutual Water Company	Greater Bakersfield	Provides groundwater and purchased water from North of the River Municipal Water District to its service area.	Water supply
Olcese Water District	Kern Fan	Provides groundwater and surface water from Kern River to agricultural lands within its service area.	Water supply
Rainbird Valley Mutual Utility Company	Kern River Valley	Provides groundwater to its service area for drinking water.	Water supply
Rosedale-Rio Bravo Water Storage District	Kern Fan	Operation of conjunctive use banking program; recharge, store, and recover water to improve the water supply for its participants during periods of water shortage. Provides surface water from KCWA and Kern River, and water from City of Bakersfield.	Water supply
City of Shafter	North County	Municipal government that provides open space and land use planning as well as stormwater capture and treatment, and creek restoration within City borders. Also provides drinking water and sewer treatment for its residents.	Water supply, water quality management, flood management/control, stormwater management

Agency	Subregion	Roles And Responsibility	Statutory Authority Over Water Supply Or Water Management
Stallion Springs Community Services District	Mountains/ Foothills	Provides potable groundwater, and wastewater services to its service area.	Water supply, wastewater treatment, water quality management
City of Taft	Kern Fan	Municipal government that provides open space and land use planning as well as stormwater capture and treatment, and creek restoration within City borders.	Water supply, water quality management, flood management/control, stormwater management
City of Tehachapi	Mountains/ Foothills	Municipal government that provides open space and land use planning as well as stormwater capture and treatment, and creek restoration within City borders.	Water supply, water quality management, flood management/control, stormwater management
Tehachapi-Cummings County Water District	Mountains/ Foothills	Provides purchased water from KCWA and flood protection services to its service area.	Water supply, flood management/control
Tehachapi Resource Conservation District	Mountains/ Foothills	Manages resource conservation projects on public and private lands.	Water quality, flood management/control
Tejon-Castac Water District	Mountains/ Foothills	Provides groundwater, surface water from local streams, and purchased water from KCWA to its service area.	Water supply
Valley Estates Property Owners Association	Kern River Valley	Provides road system and groundwater to Valley Estates.	Water supply
Vaughn Water Company	Kern Fan	Provides groundwater to the Rosedale area of Bakersfield.	Water supply
City of Wasco	North County	Municipal government that provides groundwater, open space and land use planning, stormwater capture and treatment, and creek restoration within City borders.	Water supply, water quality management, flood management/control, stormwater management
West Kern Water District	Kern Fan	Provides groundwater, surface water from Kern River, and purchased water from KCWA to its service area.	Water supply
Wheeler Ridge-Maricopa Water Storage District	South County	Provides purchased surface water from KCWA to agricultural lands within its service area.	Water supply

As part of the Participation Agreement, RWMG members have agreed to:

- Provide facilities to hold stakeholder meetings
- Appoint one representative and one alternate to participate in the Executive Committee
- Share data necessary for development of the IRWMP
- Attend stakeholder and subregion meetings
- Review and comment upon draft and final versions of the IRWMP

As is evident from the extensive list of RWMG participants in **Table 1-1**, the RWMG represents the majority of water authorities and stakeholders in the region.

1.3.2 Executive Committee

To develop an IRWMP that identifies and addresses those issues specific to the Kern Region, while recognizing and honoring local conditions and preferences over a large geographic area, the Kern IRWMP was organized to solicit input from nine (9) “subregions”. This “subregion” stakeholder structure acknowledges the variation in geographic and water management strategies in a region of over 8,000 square miles. The Executive Committee is a subgroup of the RWMG Participants consisting of one representative and one alternate from each of the nine subregions that comprise the Kern Region. Aligning the Executive Committee with the subregions ensures that their roles and responsibilities will support this regional planning effort.

Responsibilities of the Executive Committee as outlined in the Participation Agreement include:

- Collaborate with the RWMG, Stakeholder Group, and other entities
- Call and conduct Participant and Executive meetings as necessary
- Recommend to the Stakeholder Group, hire, and manage consultants as needed
- Approve or disapprove expenditures of contingency funds
- Approve or disapprove agendas and materials for meetings related to plan development
- Coordinate with KCWA management (or assignees) on matters related to development of the IRWMP
- Determine the appropriate timeframe for the completion and submission of data, executed agreements, and other relevant information and actions
- The Executive Committee will pick two (2) of its members as co-chairs, one (1) from the agricultural sector and one (1) from the urban sector
- The co-chairs will conduct and direct meetings of the RWMG
- The co-chairs, acting as signatories for the RWMG, may execute third-party agreements for integration with other RWMGs with the approval of at least 51 percent of the Participants
- Coordinate with a legal entity willing to act on behalf of the Stakeholder Group to execute and manage contracts and oversee financial transactions As part of this approach, the Executive Committee was the governing body and invited Stakeholder involvement (i.e., beyond the Participation Agreement signatories), through frequently scheduled Executive Committee meetings.

1.3.3 Stakeholders

The Kern IRWMP was prepared through a collaborative process of many agencies and organizations with an interest in improving water supply, operational efficiency, water quality, flood management, and promoting land use planning and resource stewardship in the Kern Region. A broad stakeholder outreach process was crucial to ensure that this IRWMP identified local issues, reflected local needs, promoted the formation of partnerships, and encouraged coordination with State and Federal agencies.

Table 1-2 provides a list of all of the Stakeholders that were involved in the development of the Kern IRWMP, and the subregion they represent. The broad array of stakeholders includes the agencies that comprise the RWMG, as well as an extensive mix of town councils, regulatory, environmental, agricultural, tribal and land use planning entities that represent all areas of the Kern Region. They are grouped into several categories per California Water Code (CWC)

§10541(g) and their roles in the planning process are briefly described below. A brief discussion of coordination efforts with local planning, State, and Federal agencies is also provided where appropriate.

Table 1-2: Stakeholder List

Organization	Subregion
Wholesale and Retail Water Purveyors/Wastewater Agencies/Flood Management Agencies/Special Districts	
Arvin Community Services District	South County
Arvin-Edison Water Storage District	South County
Bear Valley Community Services District	Mountains/Foothills
Belridge Water Storage District	West Side
Berrenda Mesa Water District	West Side
Buena Vista Water Storage District	Kern Fan
Buttonwillow County Water District	Kern Fan
California Water Service	Greater Bakersfield
California Water Service, Kern River Valley District	Kern River Valley
Casa Loma Water Company	Greater Bakersfield
Desert Mountain Resource Conservation and Development Council	Kern River Valley
Dudley Ridge Water District	West Side
East Niles Community Services District	Greater Bakersfield
Frazier Park Public Utility District	Mountains/Foothills
Golden Hills Community Services District	Mountains/Foothills
Greenfield County Water District	Greater Bakersfield
Henry Miller Water District	Kern Fan
KCWA Improvement District No. 4	Greater Bakersfield
Kern County Water Agency	Kern County
Kern Delta Water District	South County
Kern Water Bank Authority	Kern Fan
Lamont Public Utility District	South County
Lamont Stormwater Utility District	South County
Lebec County Water District	Mountains/Foothills
Long Canyon Water Company	Kern River Valley
Lost Hills Utility District	West Side

Organization	Subregion
Lost Hills Water District	West Side
Mettler County Water District	South County
Mountain Mesa Water Company	Kern River Valley
North Kern Water Storage District	North County
North of the River Municipal Water District	Greater Bakersfield
North West Kern Resource Conservation District	North County
Oildale Mutual Water Company	Greater Bakersfield
Olcese Water District	Kern Fan
Rainbird Valley Mutual Utility Company	Kern River Valley
Rosedale-Rio Bravo Water Storage District	Kern Fan
Semitropic Water Storage District	North County
Shafter-Wasco Irrigation District	North County
Stallion Springs Community Services District	Mountains/Foothills
Tehachapi-Cummings County Water District	Mountains/Foothills
Tejon-Castac Water District	Mountains/Foothills
Valley Estates Property Owners Association	Kern River Valley
Vaughn Water Company	Kern Fan
West Kern Water District	Kern Fan
West Side Mutual Water Company	West Side
Wheeler Ridge-Maricopa Water Storage District	South County
Municipal and County Governments and Special Districts	
County of Kern	Kern County
County of Kern Development Services Agency	Kern County
Kern County Water Agency	Kern County Water Agency
Kern Council Of Governments	Region-wide
Kern River Valley Chamber of Commerce	Kern River Valley
City of Arvin	South County
City of Arvin Planning Department	South County
City of Bakersfield Planning Department	Greater Bakersfield
City of Bakersfield Water Resources	Greater Bakersfield
City of Delano	North County
City of Delano Planning Department	North County
City of Maricopa	Kern Fan
City of McFarland	North County
City of Shafter	North County
City of Taft	Kern Fan
City of Tehachapi	Mountains/Foothills
City of Tehachapi Planning Commission	Mountains/Foothills
City of Wasco	North County
State and Federal Prisons	Region-Wide
Regulatory and Resource Agencies – State and Federal	
California Department of Public Health/Drinking Water	Region-wide
California Department of Water Resources	Region-wide

Organization	Subregion
California Department of Fish and Game	Region-wide
Central Valley Regional Water Quality Control Board	Region-wide
United States Bureau of Reclamation	Region-wide
United States Forest Service	Region-wide
United States Bureau of Land Management	Region-wide
United States Fish and Wildlife Service	Region-wide
United States Army Corps of Engineers	Region-wide
United States Department of Agriculture	Region-wide
Recreational and Environmental Entities	
Tulare Basin Wildlife Partners	Region-wide
Kern County Parks and Recreation	Region-wide
Tulare Lake Basin Working Group	Region-wide
Kern River Valley Revitalization	Mountains/Foothills
Kern National Wildlife Refuge (USFW)	North County
Sequoia Riverlands Trust	Mountains/Foothills
Kern River Preserve	Mountains/Foothills
Kern Audubon Society	Region-wide
Sierra Club – Kern-Kaweah Chapter	Region-wide
Wind Wolves Preserve	West Side
Tulare Basin Wetlands Association	Region-wide
Great Valley Center	Region-wide
Kern Valley Resource Conservation District	Mountains/Foothills
Tehachapi Resource Conservation District	Mountains/Foothills
Community Representatives/Social Justice Organizations/Public and Private Interests	
Tubatulabals of Kern Valley (Tribe)	Kern River Valley
Self-Help Enterprises	Region-wide
Community Water Center	Region-wide
Tulare Basin Watershed Coordinator	Region-wide
AERA Energy	N/A
Chevron	N/A
Oxy (Occidental Petroleum)	N/A
California State University, Bakersfield	Region-wide
California State University, Fresno	Region-wide
Agricultural Interests	
Kern County Farm Bureau	Region-wide
California Farm Water Coalition	Region-wide

1.3.3.1 Wholesale and Retail Water Purveyors/Wastewater Agencies/Flood Management Agencies/Special Districts

The wholesale and retail water purveyors, wastewater agencies, flood management agencies, and special districts of the Kern Region are involved in the development and implementation of the objectives and projects for this IRWMP. Their participation was focused particularly on the water supply and flood management issues pertaining to the region. These agencies include, but are not limited to SWP districts (KCWA and its 13 member units), Kern River districts (i.e., NKWSD, Kern Delta Water District [KDWD], etc.), CVP districts (i.e., Arvin-Edison Water

Storage District (AEWSD), SWID, etc.), groundwater supplier districts (smaller water suppliers like the Vaughn Water Company (VWC) and Casa Loma Water Company [CLWC], and community services districts such as Bear Valley Community Services District [BVCSD] and Golden Hills Community Services District [GHCSD]).

1.3.3.2 Municipal and County Governments and Special Districts

Municipal and county governments and special districts include local jurisdictions and land use planning agencies that were involved in the identification of issues, formation of objectives, and development of projects of this IRWMP. Their participation provided a link between local planning agencies and this IRWMP by offering discussion in meetings, providing accurate, consistent land use planning information, and incorporating local planning documents and goals into the project objectives. The cities of Bakersfield, Arvin, Tehachapi, the County of Kern, Kern County Resource Management Agency (KCRMA), and Kern Council of Governments are examples of land use agencies and entities participating in the meetings.

1.3.3.3 Regulatory and Resource Agencies - State and Federal

Several State and Federal regulatory and resource agencies were involved in the identification of issues, formation of objectives, and development of projects for this IRWMP. Coordination with these regulatory agencies is essential to the development and implementation of all recommended objectives and projects due to the need for regulatory and environmental approval prior to implementation. The fact that resource and environmental stewardship is a cornerstone of this IRWMP also makes close collaboration with these resource agencies imperative to effectively promoting and addressing local environmental needs. These agencies have had the opportunity to address items of concern relating to these topics at the stakeholder meetings. Their roles and responsibilities were to ensure that this IRWMP considers resource management, resource enhancement, and regulatory compliance standards. The agencies include: State Water Resources Control Board (SWRCB), SWRCB Division of Drinking Water (DDW), DWR, California Department of Fish and Wildlife (CDFW), the United States (US) Bureau of Reclamation, US Fish and Wildlife Service (USFWS), and the US Forest Service (USFS).

1.3.3.4 Recreational and Environmental Entities

The role and responsibility of recreational and open space entities was to ensure that issues and goals related to conservation, protection, and restoration of the natural resources and habitat within the Kern Region were incorporated in this IRWMP and into projects when appropriate. They also sought opportunities for integrating restoration and enhancement into projects addressing water supply, water quality and flood management needs. Some of those involved are the Tulare Basin Wildlife Partners, the Kern National Wildlife Refuge (KNWR) of the USFWS, Sequoia Riverlands Trust, Sierra Club, USFS, and the Kern County Department of Parks and Recreation.

1.3.3.5 Community Representatives/Public and Private Interests

Other stakeholders involved in the development of this IRWMP include other community representatives such as the Kern River Valley Chamber of Commerce as well as public and private interests including non-profit organizations. The Tubatulabal Tribe of Kern Valley, Self-Help Enterprises, and California State University Fresno are participating stakeholders and have provided input into the development of this IRWMP. It is noted that Tribes are sovereign nations, and as such coordination with Tribes is on a government-to-government basis.

1.3.3.6 Public Outreach

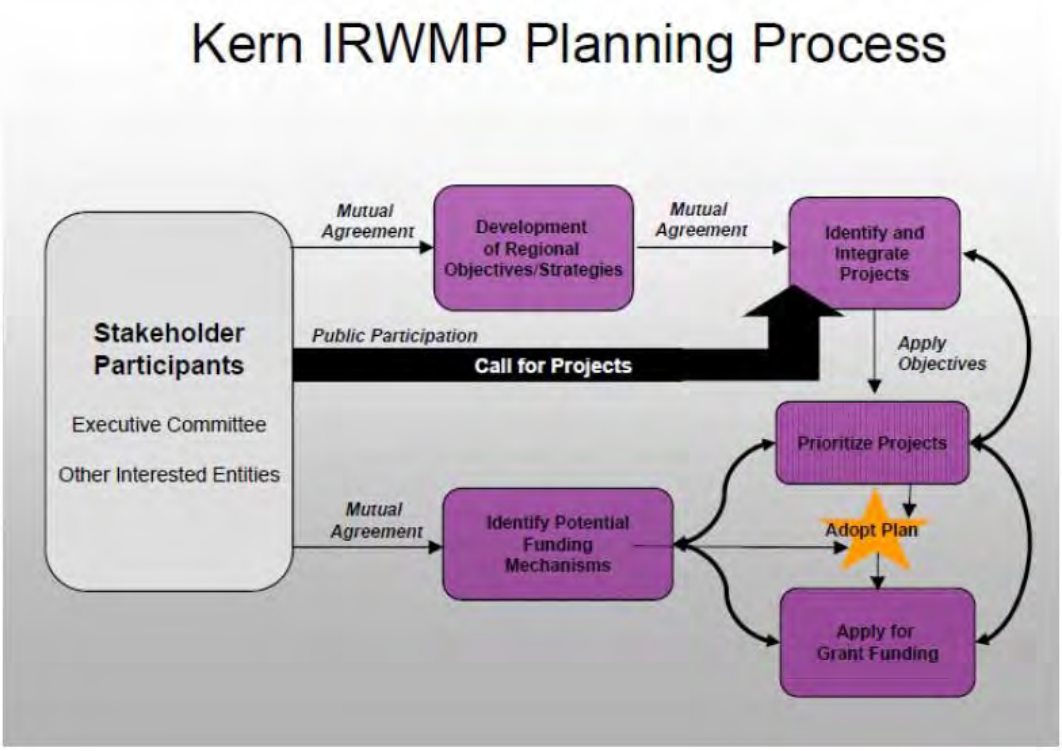
The Kern RWMG contracted with a professional facilitation consultant to identify, contact, and coordinate with potential stakeholders and the general public. By working through the professional facilitator, the region was able to get the input from a broad range of stakeholders, including representatives of, or entities that work on behalf of, DACs (such as Self-Help Enterprises).

1.4 Participation and Outreach

This IRWMP was developed to identify and address those issues specific to the Kern Region, while recognizing and honoring local conditions and preferences over a large geographic area. In order to accomplish this, an effective process to involve stakeholders and incorporate their input was necessary. The development of the IRWMP aimed to create as many opportunities for the public to be both part of and aware of regional water management and the IRWMP efforts. A schematic of the Kern IRWMP planning process is shown in **Figure 1-5**. The Kern IRWMP planning process included the following key steps:

1. Identify Issues and Needs in the Kern Region: Illustrate the issues and needs of the region related to water resources in a manner that reflects the majority of Stakeholder concerns. These issues and needs are what drive the stakeholders into taking action.
2. Develop Regional Objectives and Strategies: Collectively establish the quantifiable objectives that the regional entities will work together to accomplish and identify the resource management strategies available to meet those objectives.
3. Identify and Integrate Projects: Identify and integrate projects within the water management strategy areas that satisfy the IRWMP objectives of water supply, operational efficiency, water quality, flood management, and promoting land use planning and resource stewardship. This step also includes a “Call for Projects” in which stakeholders submit projects and project concepts for inclusion in the IRWMP.
4. Evaluation and Prioritization: This step in the planning process includes developing a prioritization process for evaluating and ranking Stakeholder-identified projects in order to identify which projects the group will take “action” on first. This prioritization process was developed concomitant with the identification of projects.
5. Identify Potential Funding Mechanisms: There are many opportunities for grant funding available to the stakeholders in the Kern Region that are well suited to stakeholder projects. These opportunities are being identified concurrently with development of the IRWMP.
6. Apply for Grant Funding: As funding becomes available the prioritization process will be used to select projects appropriate for each opportunity.

FIGURE 1-5: Kern IRWMP Planning Process



The planning process for the Kern IRWMP is designed to provide a forum for assured and effective dialogue among the various stakeholders. Each stakeholder meeting contains a public comment period whereby the public is afforded the time to comment on record to the RWMG about the IRWMP process. Public hearing announcements and monthly meeting notices were noticed via the project website (www.kernirwmp.com) and through electronic and written communications. These avenues for public access to the RWMG and Kern IRWMP are discussed in greater detail below.

- Stakeholder Meetings: The Kern IRWMP process centered on monthly stakeholder meetings open to the public where attendees were invited to participate in several ways. Attendees were asked to participate in facilitated discussions of major items of interest, to develop objectives and identify strategies, and to provide input on the agenda for upcoming stakeholder meetings. These meetings were announced to a broad distribution list via e-mail and all materials developed for use in stakeholder meetings were made available on the project website (see **Appendix C** for meeting materials). In addition, special evening meetings were publicly advertised and held to encourage additional participation by members of the general community. Meeting minutes were developed for each meeting and were provided on the project website prior to the next meeting for public review. In this manner all public comments are kept on record, as part of the IRWMP administrative record.
- Subregion Meetings: Subregions were encouraged to meet independently, to discuss content provided at the Stakeholder meetings, and to brainstorm project concepts and

ideas. The subregions ensure that the IRWMP reflects the geographic and water management differences that exist within the larger Kern Region.

- Review of Plan Sections: The Kern IRWMP is a comprehensive, living body of work related to water resources within the Kern Region. The IRWMP was developed incrementally by Section and was provided to all interested stakeholders periodically for review. During development, there were multiple opportunities for stakeholders to provide input. Sections were finalized only after the stakeholders reached a majority consensus on the material. Early on in the process, stakeholders submitted many plans, reports, and studies to the region's IRWMP resource library to ensure that the IRWMP accurately reflects each stakeholder's individual perspectives, while fostering recognition of opportunities for partnering to resolve common issues.
- Project Website: A project website was developed (www.kernirwmp.com) to facilitate the distribution of project information to stakeholders and interested members of the public. The website contains background information about IRWMP development, a schedule of meetings and meeting information, and contact information. The website also includes a database tool through which stakeholders can submit or review projects or project concepts.
- Electronic and Written and Communications: Electronic mail was the main tool used to maintain a high level of stakeholder communication and engagement. All meetings and public hearing announcements were sent as far in advance as possible to stakeholders. Various stakeholder groups also forward these messages to their constituencies, thereby reaching additional stakeholders. In addition, written communications in the form of letters to cities and press releases to the media were utilized to expand awareness of, and participation in, this IRWMP development.

Newspaper coverage was a public access point identified for further outreach and development, whether it be through increased attendance at stakeholder meetings by the local press or regularly scheduled postings or announcements.

1.4.1 Disadvantaged Community Outreach

Initially, the process used for including DACs was not disaggregated from the outreach to the rest of the region's stakeholders, which was invitation of representatives from the region's local water agencies, special districts and municipalities to participate in the IRWMP development process. These were the "inaugural" pre-IRWMP stakeholder meetings, prior to the formation of a RWMG, whereby proactive stakeholders (including agencies with an interest in water and other resource management) in the Kern Region began meeting in March 2008 to improve communication and explore opportunities to leverage their collective staff and financial resources. After these initial meetings, an extensive list of as many potentially interested parties as possible was developed and subjected to multiple revisions and additions. This list was then utilized to invite potential stakeholders to the first "official" stakeholder meeting.

The first "official" stakeholder meeting was held in October 2008. The goal of this first meeting was to provide an orientation to the IRWMP process, to introduce goals and objectives for the IRWMP, and to identify opportunities for public involvement. Stakeholders were encouraged to attend stakeholder meetings, to participate in Plan development efforts, and to disseminate information to their constituents and communities. Identification and participation by DACs was discussed, as outreach is a critical element to the IRWMP process. As a result, the following

additional stakeholders, including DACs, were suggested for invitation to the Kern IRWMP process:

- Small water and system operators
- Kern Council of Governments
- Kern Water Bank Authority
- Oil companies
- Land use planners
- Green energy firms/environmental organizations
- City and County parks departments
- Tulare Basin Wildlife Partners
- DAC communities of Frazier Park, Mettler, Lost Hills, and those within the proposed Poso Creek IRWMP boundary but that are not participants in that planning effort.

Through this invitation and outreach effort, the Kern RWMG was officially established by Participation Agreement, with a diversified stakeholder group including a range of close to 100 participants that includes the agencies that comprise the RWMG, as well as state and federal agencies, recreational and environmental entities, community representatives and social justice organizations, DACs including those mentioned above, private interests and educational institutions, and agricultural interests.

Community outreach was targeted not just for DACs, but also underserved communities, traditionally isolated communities or rural communities, severely disadvantaged communities, and Native American tribes. Most of the outreach to these communities to date has all been through meeting invitations via mail, electronic mail and telephone. The most effective process or structure to promote access to and collaboration with people or agencies with diverse views within the Kern Region has so far been effective communication by direct mailings, emails and the IRWMP website, plus simple word of mouth. Telephone and word of mouth communication was especially critical in isolated and rural communities, as well as severely disadvantaged communities, which often lack the staff and/or financial resources, and even a formal organizational structure. Planned outreach activities in the future also include distribution of materials in Spanish. Many of the DACs that have been contacted have had continuous representation at the stakeholder meetings. The on-going outreach strategy will be to encourage the involvement of communities that had previously chosen, for whatever reason, not to participate or did not have the resources to participate in an effort like the IRWMP planning process. It will be part of the outreach strategy to effectually relate the benefits of the IRWMP to DACs, which include a reliable water supply, meeting water quality standards and protect existing supplies from contamination, managing flood waters and providing adequate flood control, and protecting and preserving open space, habitat, recreational uses, and agricultural lands within the entire region.

Because many severely disadvantaged communities do not have the staff to be able to regularly participate directly in meetings, the IRWMP relies on in-kind support from local technical assistance and other non-profit organizations, like Self Help Enterprises and Community Water Center to help support integration of these communities into the process. Additionally, representatives from the Kern region have participated in the Tulare Lake Basin Disadvantaged Community Water Study to help develop regional solutions to disadvantaged community water and wastewater challenges.

1.4.2 Environmental Justice Outreach

The United States Environmental Protection Agency (EPA) defines “environmental justice” as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Simply stated, this means that that no group of people should bear a disproportionate share of negative environmental consequences resulting from industrial, governmental, and commercial operations or policies.

To begin identifying potential environmental justice issues facing the Kern Region, EPA’s EnviroMapper database and maps were researched to locate any hazardous waste sites within the Kern Region. EPA’s EnviroMapper showed multiple hazardous waste sites, water discharge sites, and air emission release sites within the Region, the majority of which appeared to be concentrated in and around the cities/communities of Bakersfield, Oildale, Rosedale, Shafter, McFarland, Arvin and Delano. Oil fields and refineries are a part of the historic industrial development within Kern County, and many large facilities are located near or in these cities. Additionally, chemical production and/or processing facilities have historically operated at various locations in the Kern Region. Impacts from these and other facilities have created environmental justice concerns, which center on water quality. In particularly, localized elevated concentrations of arsenic and nitrates have been detected during routine regulatory water quality monitoring performed by water suppliers within the Kern Region. While there is no complete listing of affected communities, communities throughout the Kern Region have been faced with drinking and agricultural water well closures due to contamination. Drinking water well closures have resulted in increased costs to consumers, localized restrictions on growth, and water supply system limitations. Therefore, addressing soil and groundwater contaminants that are either currently impacting or have the potential to impact DACs in the future need to be addressed.

In addition to remediating current water quality concerns, great emphasis has been placed on preventing future impacts. As the Kern Region continues to grow, care will need to be taken to prevent creating environmental justice issues that unfairly affect certain communities. The Kern IRWMP objectives of ensuring water supply, water quality, flood protection, wise land use management, and environmental protection must be consistently applied to future projects and development to benefit all residents equally. Land use planning must designate enough open space to meet the recreational needs of all communities and include habitat preservation and restoration throughout the Region.

1.4.3 Media Coverage of Plan Preparation

During development of the Kern IRWMP, public notices were submitted to a number of regional newspapers and online news television stations announcing public meetings and/or regular stakeholder meetings for the IRWMP. Newspapers and online media included: the Bakersfield Californian, Arvin Tiller & Lamont Reporter, www.kget.com, www.kernlife.com, www.bakersfield.com, and the Kern County Community and Government Services Calendar.

1.5 IRWMP Development

The Kern IRWMP was created using the advice, feedback, and assistance of multiple Stakeholders. In order to guarantee a fruitful process, Stakeholder meetings were facilitated by a facilitation consultant team. The Stakeholder process was also governed by a set of "ground rules" and "operating procedures" developed by the facilitation consultant team as listed below.

1.5.1 Ground Rules for Participation

1. Cooperate with the process, including the scope and intent of our planning effort together and specific agenda topics.
2. Work toward shared goals, proposing strategies that relate to the goals and that may be acceptable to all stakeholders.
3. Base your opinions, ideas and comments on facts and experience rather than on perception.
4. Wait to be recognized by the facilitator before you speak.
5. Participate fully in the group discussion.
6. Keep your comments brief and constructive.
7. Focus on issues instead of people or personalities.
8. Reference the past if needed, but look to the future.
9. Be respectful of differing perspectives and opinions.
10. Stay with the topic at hand or hold your comment and yield to someone who has a comment on the topic at hand.
11. Be open to new ideas and be expansive in your thinking.

1.5.2 Operating Procedures

1. Stakeholders will abide by the agreed upon participation ground rules and operating procedures during this process.
2. We will strive for mutual agreement but note when we have a minority opinion.
3. Stakeholders are encouraged to participate consistently and attend all meetings. If unable to attend, a Stakeholder may send an alternate to ensure the organization's consistent participation.
4. Stakeholders who are participating based on their organizational affiliation represent the organization; their opinions should be consistent with and as authorized by the organization.
5. Meeting summaries will be prepared by the facilitators, and will include major points of discussion, agreements, and areas of disagreement.
6. Stakeholders will receive meeting materials ten days before the meeting to allow for advance review.
7. Stakeholders will provide review and comment during the timeframes requested.

As described in the following sections, through the facilitated Stakeholder process, participants in the Kern IRWMP have been able to address, discuss, and recommend regional objectives and strategies, and propose projects to meet those objectives.

1.6 Program Preferences

1.6.1 Include Regional Projects or Programs

Development of the Kern IRWMP provided an ongoing forum in which the Participants could collaborate and develop regional partnerships and programs. The IRWMP also provides a forum to facilitate regional partnerships and regional solutions for regional issues.

1.6.2 Integrate Water Management Programs and Projects

As part of the Kern IRWMP, Participants are asked to identify and consider a broad range of resource management strategies so as to ensure a wide range of strategies are brought to the table.

1.6.3 Resolve Significant Water-Related Conflicts

One of the primary benefits of an IRWM plan is that it creates the institutional framework through which water related conflicts can be discussed and even resolved.

1.7 Bay-Delta Program Goals

The four Bay-Delta Program objectives can be summarized as follows:

1. Water Quality
2. Water Supply
3. Ecosystem Restoration
4. Levee Integrity

The Kern IRWMP region receives SWP and CVP water delivered through the Delta. Friant Division CVP contractors are provided water from Millerton Lake by way of a series of exchanges with the “four exchange contractors” situated in western Fresno and Merced County, who then receive water from the Delta. Actions within the Region could contribute to the success of Bay-Delta Program objectives or those of similar programs. Any reduction in water demand would reduce demand on imported water and contribute to the attainment of Bay-Delta Program objectives. Senate Bill 7 of Extended Session 7 (SBX7-7) has been enacted mandating that urban water suppliers reduce statewide water use (in gallons per capita per day) by 20 percent by 2020. The IRWMP provides the opportunity for the Kern Region as a whole to tackle enhanced water use efficiency.

1.7.1 Address Water Supply and Water Quality Needs of DACs

The Kern IRWMP provides an opportunity to focus on the water quality and water supply needs of DACs in order to provide “a safe, clean, affordable, and sufficient water supply to meet the needs of California residents, farms, and businesses”.

1.7.2 Effectively Integrate Water Management with Land Use Planning

The Kern IRWMP has the benefit of participation from the City of Bakersfield planning entity and Kern County within the Region. Information in the IRWMP, including the demographic data and the resultant water demand relies on planning documents that include General Plans and recently updated Urban Water Management Plans (UWMPs). Information from the Tulare Basin Conservation Plan Water Supply Strategies Report (2010) can also serve to effectively integrate water management with land use planning.

1.7.3 Drought Preparedness

This Plan is focused on drought preparedness and takes a major step forward by incorporation of region-specific climate change data. The Plan not only evaluates the Region's vulnerability to climate change but develops adaptive strategies.

1.7.4 Use and Reuse Water More Efficiently

Methods of complying with SBX7-7, the legislation mandating a 20 percent reduction in urban per capita water use by 2020, include enhanced water conservation, water use efficiency, and recycled water. The Kern IRWMP provides a forum for the Region as a whole to address water use efficiency.

1.7.5 Climate Change Response Actions

The Kern IRWMP identifies strategies to address adapting and mitigating the general effects of climate change. These "no regrets" strategies recognize the current water management context of the region and are a part of the region's overall objectives.

1.7.6 Expand Environmental Stewardship

As part of the IRWMP process, participants are asked to identify new strategies to achieve all the Plan objectives, including resource stewardship. Information in the IRWMP related to resource stewardship relies on planning documents that include General Plans, Specific Plans, Tulare Basin Wildlife Partners Conservation Plans, local habitat conservations plans, and numerous state and federal documents. Resource stewardship throughout the Kern Region is also intrinsically linked to land use planning.

1.7.7 Practice Integrated Flood Management

The IRWMP is intended to identify both existing and future issues related to water resources and greatly informs the description of future flood management conditions and needs. Climate Change will provide a means to consider uncertainty and risk not only for water management but specifically for flood management. Existing research on climate change suggests that one of the primary outcomes will be a shift in snowfall to rainfall and an increase in peak flood flows. Climate Change will identify flood vulnerabilities as well as adaptation strategies, including the potential for integrated flood management.

1.7.8 Protect Surface Water and Groundwater Quality

The Kern Region will need to balance the sometimes competing objectives of developing new, local water supplies, with protection of surface water and groundwater quality. Nowhere is this truer than when an area is contemplating the production and use of recycled water.

1.7.9 Improve Tribal Water and Natural Resources

The Kern Region is within the historic range of the Tubatulabals of Kern Valley. The Tubatulabals are Participants in the Kern IRWMP and they provided helpful, direct feedback during development of the Plan.

1.7.10 Ensure Equitable Distribution of Benefits

The Kern IRWMP includes processes to maximize access and participation by a broad range of Participants. Input and participation is sought through email, a publicly accessible website, water agency mailers, and notices in local newspapers. Meetings and workshops were, and will continue to be, held at a time to allow maximum Stakeholder and public involvement. Participation of the Stakeholders ensures that all the various water users (DACs, tribes, municipal, agricultural, environmental) are represented. All participants are able to submit projects for consideration and integration. This will also ensure that benefits are shared and potential impacts do not unduly fall on one particular group.

1.8 IRWMP Updates

Kennedy/Jenks Consultants (KJ) was retained the Kern Regional Water Management Group Participants to prepare the Kern IRWM Plan. The Plan was adopted by the participants at the November 14, 2011 meeting.

The participants executed an agreement with KJ and Provost & Pritchard for on-going management of the Kern IRWMP Plan, which included assistance with quarterly participant meetings and project prioritization for the pursuit of grant funding. The consultants assisted with preparing implementation grant applications for the Round 2 (2012) and the Drought Grant (2014) that were both funded through Proposition 84. For the Drought Grant round, the grant applicants were required to have an IRWM Plan that met the 2012 DWR Guidelines. KJ prepared a Climate Change and Vulnerability Assessment memorandum that brought the Kern IRWM Plan into compliance with these 2012 Guidelines. After these tasks were completed, the on-going contract expired.

In 2019, the participants executed an agreement with Provost & Pritchard to update the Kern IRWM Plan to meet the 2016 Guidelines so that implementation grant funding under Proposition 1 could be pursued by participants. The Draft Plan Update was submitted to the participants for their review in August 2019. After Provost & Pritchard addressed the participant comments, the Final Draft Plan Update was submitted to DWR on September 4, 2019. DWR performed a consistency check on the plan and determined that it was consistent with the 2016 Guidelines. A thirty (30) day public review period was completed on January 9, 2020 and no public comments were submitted. The participants met on March 11, 2020 and voted to approve the adoption of the Kern IRWMP Plan Update.

1.9 IRWMP Organization

This IRWMP complies with the 2016 Guidelines for integrated water management planning. The IRWMP provides the following chapters:

- Section 1 – Introduction: Provides the purpose of this IRWMP, identifies the RWMG, Executive Committee, and Stakeholders, and overall organization of the document.
- Section 2 – Tulare Lake Basin Portion of Kern County Region: This Section provides a description of the larger geographic boundary of the Region and includes an explanation of why it is an appropriate area for this IRWMP. A description of the social and cultural makeup, cultural and social values, and economic conditions and trends of the Region is provided. The potential impact of these issues on water supply planning, flood management planning and other technical components is discussed.
- Sections 3 to 9 – Subregion Descriptions: Sections 3 to 9 provides characterizations of the regions for each of the individual Region Groupings: Greater Bakersfield, Kern Fan, Mountains/Foothills, Kern River Valley, North County, South County, and West Side. Within each Section, the water and environmental issues and needs are identified specific to that localized region.
- Section 10 – Plan Objectives: Documents the development of the objectives and planning targets for the IRWMP. Objectives refer to the general intent for planning within the Kern Region.
- Section 11 – Resource Management Strategies Used to Meet Plan Objectives: Introduces the diverse menu of resource management strategies that are available to meet the objectives for the Kern Region.
- Section 12 – Project Priorities and Implementation: Presents the criteria that were identified and agreed upon by the Participants and Stakeholders for setting priorities and how they were applied to prioritize projects.
- Section 13 – Finance Plan: Identifies potential funding sources to implement the IRWMP, discusses ongoing support and financing for operation and maintenance of implemented projects, and presents the grant funding package.
- Section 14 –Technical Analyses, Data Management, and Plan Performance: Provides a discussion of the data, technical methods, and analyses used in plan development. Data gaps are identified; measures and monitoring systems used to evaluate project/plan performance and opportunities to adapt project operations based on monitoring of performance are discussed; and the economic and technical feasibility of projects are demonstrated. This chapter also includes a discussion of how data is managed and disseminated to stakeholders and the public, as well as how data collection will support statewide data needs.
- Section 15 – Coordination and Outreach: Documents the extensive public outreach activities that occurred prior to and during IRWMP development and discusses the mechanisms and processes that facilitated stakeholder and public involvement and communication.
- Section 16 – Climate Change: Provides a review of climate change effects in the Region and analyzes specific vulnerabilities that are of priority to the Kern Region.
- Section 17 – References: Documents used in the development of this IRWMP.

Section 2: Tulare Lake Basin Portion of Kern County Region

2.1 Introduction and Overview

This section presents a regional description for the Kern Region, including the physical and environmental characteristics of the Region, the social and demographic characteristics of the Region, hydrologic features, discussion of water reliability, and regional growth projections.

As described in Section 1, the Kern Region, as defined for this IRWMP, covers approximately 5,690 square miles (3,641,600 acres) of southwest Kern County, or approximately 70 percent of Kern County and a small portion (37,600 acres) of Kings County. The Kern Region includes the southern half of the San Joaquin Valley, part of the Temblor Range to the west, the Tehachapi Mountains to the south, and part of the southern Sierra Nevada to the east. Elevations range from about 400 feet on the valley floor in the Bakersfield area to about 8,800 feet in the Frazier Park area. The headwaters of the Kern River are at an elevation of about 13,000 feet at the divide in the southern Sierra Nevada separating the Region. As discussed in Section 1.1.1, this IRWMP Region encompasses the Poso Creek IRWMP planning region and overlaps a part of the Southern Sierra IRWMP planning region.

The major water body in the Region is the Kern River and its tributaries. Major State, Federal and local water conveyance meet in the Region: the California Aqueduct, Friant-Kern Canal, Kern River and Cross Valley Canal (CVC), respectively. Minor streams include, but are not limited to, Poso Creek, Caliente Creek, and El Paso Creek. **Figure 2-1** provides a map of the Region and these features.

2.2 Climate

Climate in the Kern Region is characterized as an “inland Mediterranean climate” with hot and dry summers and cool winters. The climate around the Valley floor is prone to large diurnal fluxes due to its inland location, and is dominated by dry, hot weather throughout the summer months.

In the winter, the Kern Region experiences a phenomenon known in the southern San Joaquin Valley as “Tule Fog.” Tule Fog forms as a result of radiation inversions when air closer to the ground is cooled faster than the air above. The result is an inversion layer where warmer air sits at the top of the air column, trapping the cooler and denser air below. Low wind speeds, combined with low inversion layers in the winter, create a climate conducive to high concentrations of fog. Visibility in Tule Fog can be less than an eighth of a mile (about 600 feet) down to at times less than 10 feet, often causing dangerous driving conditions on regional Interstate 5 and other arterial highways. While Tule Fog can contain significant moisture, it does not qualify as “precipitation,” as it does not typically soak into soils.

The Valley floor receives average precipitation of less than 6 inches per year, most of which falls between November and April, whereas the various mountain ranges can receive up to 20 inches per year (Western Regional Climate Center, Precipitation data for Bakersfield, CA and

Glennville, CA). **Table 2-1**, Climate on the San Joaquin Valley Floor in the Kern Region, summarizes the historical range in temperatures and precipitation on the Valley floor, **Table 2-2** summarizes the historical range in temperatures and precipitation in the foothill areas. **Figure 2-2** shows how these variables, along with evapotranspiration (ET) can differ between the Valley floor and higher mountain/foothill areas.

Table 2-1: Climate on the San Joaquin Valley Floor in the Kern Region

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
Monthly Avg. ET (inches)[(a)]	2.21	2.15	3.90	5.65	7.62	9.31	9.89	9.10	6.78	4.70	2.57	1.51	5.45
Avg. Rainfall (inches)[(b)]	1.04	1.16	1.12	0.67	0.21	0.07	0.01	0.04	0.10	0.30	0.59	0.85	6.17
Avg. Max Temp (ºF)[(b)]	57.4	63.6	69.0	75.7	84.2	92.1	98.6	96.7	91.0	80.5	67.3	57.8	77.8
Avg. Min Temp (ºF)[(b)]	38.5	42.1	45.4	49.7	56.6	63.3	69.2	67.7	63.1	54.0	44.1	38.5	52.7

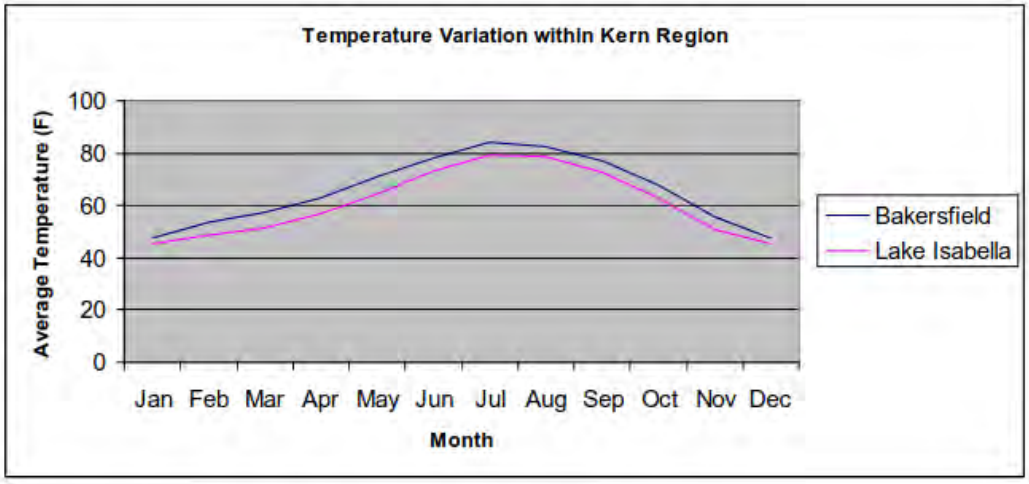
Notes:
(a) CIMIS Data for Arvin-Edison Station 125 (2018).
(b) Western Regional Climate Center, Bakersfield Airport (040442) for the years 1937-2016

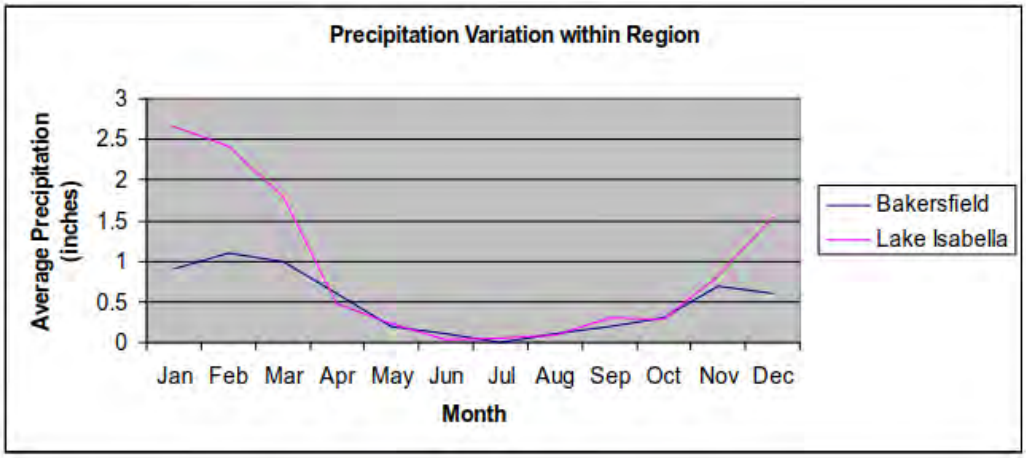
Table 2-2: Climate in the Kern Foothill Areas

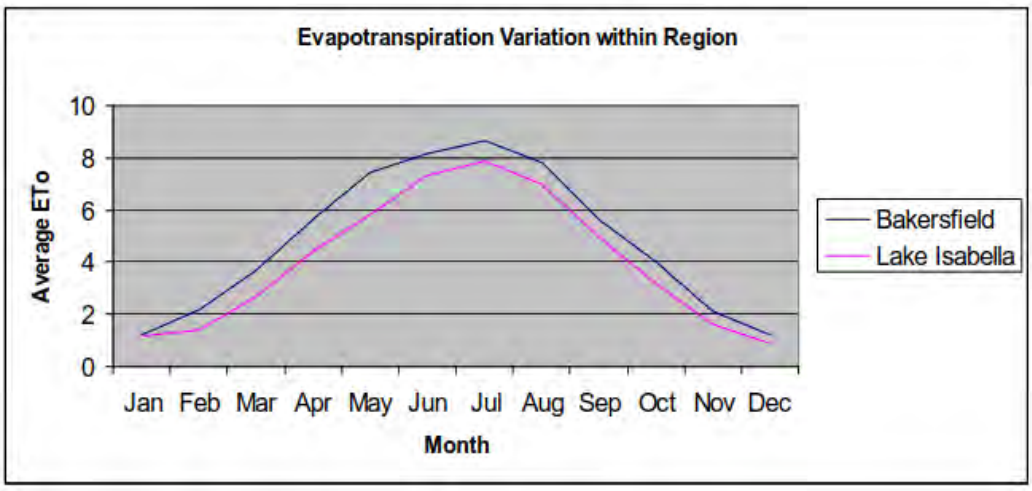
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
Monthly Avg. ET (inches)[(a)]	1.2	1.4	2.7	4.4	5.8	7.3	7.9	7.0	5.0	3.2	1.6	0.9	4.03
Avg. Rainfall (inches)[(b)]	2.62	2.64	2.08	0.73	0.34	0.1	0.17	0.18	0.23	0.51	1.53	1.97	13.1
Avg. Max Temp (ºF)[(b)]	60.1	62.6	66.7	72.2	80.9	90.1	97.5	97.3	90.8	80.0	67.7	60.0	77.2
Avg. Min Temp (ºF)[(b)]	31.1	33.3	36.7	41.5	48.8	56.3	62.5	61.5	55.1	46.2	36.2	30.8	45.0

Notes:
(a) University of California Cooperative Extension. 1989. Irrigation Scheduling: A Guide for Efficient On-Farm Water Management) National Weather Service.
(b) National Weather Service Monthly Climate Normals (1981-2010), Kern River PH3 Weather Station.

Figure 2-2 - Climatic Variation Within Kern Region







2.3 Land Use

Land use in the Kern Region is divided among urban and rural areas, predominately agricultural areas. **Figure 2-3** provides a map of the cities and communities within the Region. Most of the Region's population lives within or near the incorporated areas. The largest city in the Region is Bakersfield (with a population of over 380,000), followed by the City of Delano (with a population of over 53,000); then Shafter and Wasco (populations over 20,000); all other cities and communities in the Region have populations of less than 20,000 persons. **Figure 2-4** provides a map showing the different water agencies and special districts within the Region.

Land uses within the unincorporated areas are governed by the County of Kern, and the Kern County General Plan lays out the policies and regulations governing the physical development of the lands under County jurisdiction, as does the Kings County General Plan for the affected portion of Kings County. Agriculture is an important land use in Kern and Kings Counties and is vital to the local economy. Kern County is the third largest agricultural county in the state in economic value, and produces over 250 different crops, including over 30 types of fruits and nuts, over 40 types of vegetables, over 20 field crops, lumber, nursery stock, livestock, poultry and dairy products. The total value of these agricultural products annually exceeds $7.2 billion (2018). The average size of farms in Kern County is 1,272 acres.

In addition to agriculture, mineral and petroleum resources are fundamental parts of Kern County's economy. Because of the importance of agriculture, mineral resources and petroleum production to the Kern Region, the Kern County General Plan emphasizes policies for protecting agricultural lands and directing urbanization to areas without important mineral and petroleum resources.

Within the incorporated, generally urban areas, land use is guided by the following land use plans (see **Table 2-3**). Additionally, CDFW Conceptual Area Protection Plans provide important guidance on land use within the Kern IRWMP area. Region-specific plans include the Goose Lake Conservation Plan, Buena Vista Lake- Kern Lake Conservation Plan, Tulare Basin Riparian and Wildlife Corridors Conservation Plan.

Table 2-3: Local Land Use Policy Documents

Jurisdiction Planning Document	Land Use Element Last Adoption Date
Kern County Joint Metropolitan Bakersfield General Plan with City of Bakersfield	2007
Kings County General Plan	2009
City of Arvin General Plan	2012
City of Bakersfield Joint Metropolitan Bakersfield General Plan with Kern County	2009
City of Delano General Plan 2-3	2005
City of Maricopa General Plan	2016
City of McFarland General Plan	2011
City of Shafter General Plan	2005, currently under revision
City of Taft General Plan	2009
City of Tehachapi General Plan	2012
City of Wasco General Plan	2016

The Kern Region, like the rest of the Central Valley, is facing increasing population pressures. The County has been ranked among California's leading counties in total urbanization and loss of farmland. From 1990 to 2006, the amount of "important" farmland in Kern County decreased by 88,338 acres. Approximately one-third (approximately 29,000 acres) of this decrease was due to urban-related changes (County of Kern 2009). Increasing population raises many land use issues, including urban-rural conflicts and increased competition for resources such as water. Long-term water supply planning is important to ensuring that rural and urban economic growth can be accommodated.

2.4 Ecological Processes and Environmental Resources

Geologically, the Kern Region is located in four of the twelve traditionally recognized geomorphic provinces in California, including the Coast Ranges, the Great Valley, the Transverse Range, and the Sierra Nevada Range province. These geologic attributes influence the climate, wildlife, vegetation, hydrology, and other environmental factors in the Region.

The Coast Range borders the Region to the west. The San Andreas Fault is the most notable structural feature of this province and has a very well-defined fault zone in part of the Region as it trends approximately northwest-southeast in the Carrizo Plain. Only a small portion of the Transverse Range Province is in Kern County. It includes lands along the southern County line near Frazier Park and a small portion of western Tejon Ranch. In the Sierra Nevada Range, which includes the Tehachapi Mountains, are located the White Wolf fault, the Sierra Nevada fault, and the Kern Canyon-Breckenridge fault at the southeastern edge of the Region.

The Tulare Lake Basin, the southern portion of the San Joaquin Valley, which covers the Kern Region, has no natural outlet for surface waters. Streams from the Sierra Nevada, Coast Ranges and Tehachapi Mountains have eroded and deposited materials in the Tulare Lake Basin, forming alluvial fans at the surface. Most notable in the Region is the Kern River fan, sourced from the Sierra, and the largest of these formations, covering about 300 square miles of the Valley.

Environmental resources of the Region include the Kern River, Sequoia National Forest, several wildlife refuges, and the unique flora and fauna of the Tejon Pass area and Transverse Ranges. The riparian forest along the South Fork Kern River in the vicinity of Onyx and Weldon is one of the highest quality and most extensive stands of that vegetation type in California. This section of the river has the largest populations of Southwestern willow flycatchers and yellow-billed cuckoos in California. Much of this forest is conserved in the USFS South Fork Wildlife Area, Audubon California's Kern River Preserve, and CDFW's Canebrake Ecological Reserve.

The Kern River is a magnificent resource in the generally arid Valley, and originates on the western slopes of Mount Whitney; thus the upper reaches of the Kern River are within national forest lands and are not located within the Region. Once the two forks of the River pass the Sierra Nevada drainage divide and enter the Region near Weldon and Kernville, the Kern River pools as Isabella Reservoir behind Isabella Dam, which is a U.S. Army Corps of Engineers flood control facility protecting the City of Bakersfield and other downstream areas. After leaving Isabella Reservoir the River travels generally southwest through the Sierra foothills and the City of Bakersfield. North, south, and west of Bakersfield much of the River is diverted for agricultural use and the River becomes dry or nearly dry for most of the year below Calloway Weir.

The Kern River supports many vegetation types and both common and sensitive species are found along the River corridor. Vegetation types include riparian woodland, riparian scrub, riparian savannah, freshwater marsh, quail bush scrub, alluvial scrub, and grassland/scrub. Bakersfield cactus, Hoover's eriastrum, San Joaquin blue curls, and cottony (Kern) buckwheat are some of the sensitive plants found in the River corridor. The San Joaquin kit fox, blunt-nosed leopard lizard, Buena Vista Lake shrew Tipton kangaroo rat, giant kangaroo rat, San Joaquin antelope squirrel, Swainson's hawk, bald eagle, willow flycatcher, least Bell's vireo, and California condor are considered sensitive wildlife species within the Kern River (County of Kern 2003). The Kern River is the home of three California native trout: the California golden trout, the Kern River rainbow trout, and the Little Kern golden trout. Additionally, the Kern River is a resource for birds migrating along the Pacific Flyway (US Forest Service 2009a).

The Sequoia National Forest sits along the northeastern edge of the Region and extends into Tulare County. The forest draws visitors from around the world, primarily attracted by the giant sequoia trees, but also to visit the forest's other features, including the Kern River, glacier-carved U-shaped valleys, rock monoliths, limestone caverns, and wildlife habitats. Giant sequoia trees grow only on the western slopes of the Sierra Nevada and are considered to be the largest tree species in the world in terms of volume. In addition to the giant sequoia, the forest is home to 339 species of vertebrates, 60 of which are game species. Several rare and endangered species including the California condor, California spotted owl, Pacific fisher, American marten, and goshawk are known to occur in the Sequoia National Forest (US Forest Service 2009b).

The KNWR is located 18 miles west of the city of Delano in the northern part of the Region. The 11,249-acre Kern refuge contains remnant habitats of the original Tulare Lake region and consists of freshwater marshes, valley grasslands, and a relict cottonwood-willow riparian corridor. The refuge provides habitat for wintering and migrating waterfowl, shorebirds, and marsh birds and also provides habitat for upland and riparian bird species. The endangered Buena Vista Lake shrew, San Joaquin kit fox and blunt-nosed leopard lizard occur within the refuge (US Fish and Wildlife Service 2009a).

The Bitter Creek National Wildlife Refuge is located in the southwest corner of the Region. This refuge is intended to protect dwindling California condor foraging and roosting habitat; the 14,097-acre refuge is the site where the last wild female condor was trapped in 1986. The refuge is bisected by the San Andreas Fault and Bitter Creek Canyon. In addition to the California condor, the refuge provides habitat for San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, western spadefoot, coast horned lizard, and tricolored blackbird. Coyote, bobcat, mountain lion, mule deer, pronghorn, tule elk, and western rattlesnake are also found in the refuge (US Fish and Wildlife Service 2009b).

The southeastern portion of the Region, surrounding the Tejon Pass area, is located at the intersection of five geomorphic provinces: Sierra Nevada, Great Central Valley, Coast Ranges, Transverse Ranges, and Mojave Desert. These geomorphic areas each have a distinct ecology, and the intermixing of these geomorphic provinces creates a unique and diverse landscape in a relatively small area. Here the oak-dominated habitat of the Sierra Nevada intermixes with the conifer forests of the Tehachapi Mountains and the desert species of the adjacent Antelope Valley. Because of its unique biogeography and location between major urban centers in Los Angeles and Kern counties, the Tejon Pass area also supports many threatened and endangered species and other species considered rare or sensitive because of their restricted distributions and substantial loss of habitat. At least 20 species listed as Threatened or

Endangered under the Federal and California Endangered Species Acts and an additional 61 species otherwise designated as sensitive are known to occur or have the potential to occur in the vicinity of Tejon Pass. Species that are known or have the potential to occur in this area include:

- American peregrine falcon
- Bakersfield cactus
- Bald eagle
- Blunt-nosed leopard lizard
- Burrowing owl
- California condor
- California jewelflower
- California red-legged frog
- California spotted owl
- Fort Tejon woolly sunflower
- Golden eagle
- Least Bell's vireo
- Little willow flycatcher
- Ringtail
- San Joaquin antelope squirrel
- San Joaquin kit fox
- Southwestern willow flycatcher
- Striped adobe lily
- Tehachapi pocket mouse
- Tehachapi slender salamander
- Tejon poppy
- Western yellow-billed cuckoo

(US Fish and Wildlife Service 2009c)

In 2008, five environmental organizations and the Tejon Ranch Company entered into an agreement to permanently protect 240,000 acres of Tejon Ranch in the southern area of the Region, near the community of Lebec. The Tejon Ranch Conservancy, an independent nonprofit conservation organization monitors and enforces a conservation easement on the conserved lands while implementing a long-term stewardship plan to protect and restore habitat. The majority of the preserve is in Kern County with a portion in Los Angeles County (Tejon Ranch Conservancy 2009).

Since 1998, The Wildlands Conservancy has owned and managed Wind Wolves Preserve, an ecologically unique region where the Transverse Ranges, Coast Ranges, and San Joaquin Valley converge. Due to elevation ranging from 640 to 6,005 feet, the preserve has an impressive array of landforms and habitats that serve as a critical landscape linkage and wildlife corridor between the Coast Ranges and Sierra Nevada. At 95,000 acres, Wind Wolves, the west coast's largest non-profit preserve, extends from rolling grasslands on the valley floor and extends uphill through blue oak and valley oak savanna and extensive riparian woodlands to juniper and pinyon forests that ascend into stands of ponderosa pine and big cone spruce. Tule elk were reintroduced to the Wind Wolves Preserve, the southernmost extension of their historic range. The elk herd has grown to more than 300 elk and the CDFW estimates the preserve can support up to 2,500 elk. The USFWS places stillborn elk calves on the preserve as a food source for California condor, which can be seen regularly. On the San Joaquin Valley floor, the preserve contains 30 square miles of annual grasslands with remnant stands of saltbush. These grasslands are home to the endangered San Joaquin kit fox and blunt-nosed leopard lizard, and one of the largest stands of the endangered Bakersfield cactus.

Other environmental resources in the Region include the Center for Natural Land Management's Lokern Preserve and Semitropic Preserve, and the CDFW Semitropic Ecological Reserve.

2.5 Social and Cultural Characteristics

2.5.1 Demographics and Population

Table 2-4 provides a summary of the demographics for the Kern Region as determined by 2010 U.S. Census Bureau and 2017 American Community Survey data. Where possible, data was estimated from census tracts within the Region boundaries. For some subjects, it was necessary to assume the Region had characteristics similar to Kern County as a whole.

Based on census data for Kern County, it is estimated that within the Region the population is largely White and Latino. Approximately 34 percent of the population identifies as being white and approximately 54 percent of the population reports being Hispanic (US Census Bureau 2005). Persons identifying as African American, Asian, American Indian, and Native Hawaiian make up less than 12 percent of the population. English is the primary language, but a significant portion of the population speaks Spanish.

2.5.1.1 Population Projections

The Region is nearing 840,000 persons and is in one of the fastest growing counties in California. Generally, all the areas are experiencing growth within the IRWMP Region. Prison construction and corresponding job openings have increased growth rates in the communities of Delano, McFarland, Taft, and Wasco. The historic and projected populations for the Kern Region are shown in **Table 2-5**. Historical population data is based on 1980 to 2010 Census Bureau records while projected population data is derived from the Kern Council of Governments 2018 Regional Transportation Plan. Projections indicate that over one million people will reside in the Region by the year 2030. See **Figure 2-5** for a graph of these population projections.

Table 2-4: Demographics Summary for the Kern Region

Area:	Bakersfield	Wasco	Arvin	Delano	Maricopa	Shafter	Taft	Tehachapi	Overall Kern County
Age Structure (by %)[1]									
under 5	9.0	8.6	11.5	8.0	7.1	10.2	5.8	5.2	8.7
5-9	8.5	7.9	10.5	8.0	6.3	10.0	4.9	4.7	8.2
10-14	8.6	7.5	10.5	7.7	6.8	9.6	5.4	5.1	8.2
15-19	8.7	8.5	10.3	8.5	10.4	10.2	6.9	5.4	8.6
20-24	7.4	10.4	9.0	11.0	5.5	8.5	7.9	8.4	7.8
25-34	14.7	20.4	15.2	18.0	9.6	14.8	19.3	22.5	14.6
35-44	13.3	19.0	12.7	14.6	12.2	12.5	18.5	18.3	12.9
45-54	12.4	9.5	10.7	11.5	15.9	10.7	14.0	14.6	13.0
55-59	5.0	2.4	3.2	3.7	6.8	4.0	4.9	4.1	5.1
60-64	3.9	1.9	2.4	2.9	7.5	2.7	4.1	2.9	4.1
65-74	4.7	3.2	2.9	3.5	7.5	3.8	4.9	4.8	5.2
75-85	2.7	1.7	1.7	1.9	2.8	2.1	2.4	3.0	2.8
85 and over	1.1	0.5	0.5	0.7	1.5	0.7	1.0	1.1	1.0
Median Household Income[1]	60,058	36,681	36,789	38,708	29,773	40,493	51,370	44,470	50,826
Income Levels by (%)[2]									
< $10,000	5.8	8.5	6.5	5.2	11.8	5.2	6.9	8.9	6.7
$10k to $14.9k	5.4	6.4	6.4	5.0	11.3	5.0	10.5	7.2	6.0
$15k to $24.9k	9.1	16.9	16.5	17.9	15.6	17.9	14.9	9.1	11.9
$25k to $34.9k	9.3	15.6	14.5	18.1	17.8	18.1	6.0	10.3	10.9
$35k to $49.9k	12.6	15.0	21.3	14.7	15.3	14.7	10.2	18.7	13.8
$50k to $74.9k	18.2	21.0	19.4	17.3	13.8	17.3	17.2	16.4	17.6
$75k to $99.9k	13.0	8.9	7.4	9.8	6.3	9.8	9.3	6.4	11.4
$100k to $149k	15.3	5.0	6.1	8.7	5.0	8.7	16.1	16.3	12.9
$150k to $199k	6.2	2.4	1.2	2.6	0.3	2.6	5.8	4.9	5.1
$200k or more	5.1	0.3	0.6	0.7	2.8	0.7	3.2	1.7	3.7
Population Density (persons per	3,328	3,458	4,283	5,210	786	977	588	1,382	108 [4]

Sources:

[1] 2010 U.S. Census Bureau

[2] U.S. Census Bureau, 2013-2017 American Community Survey 5-year Estimates, total households

[3] Data taken from City-data.com, 2019.

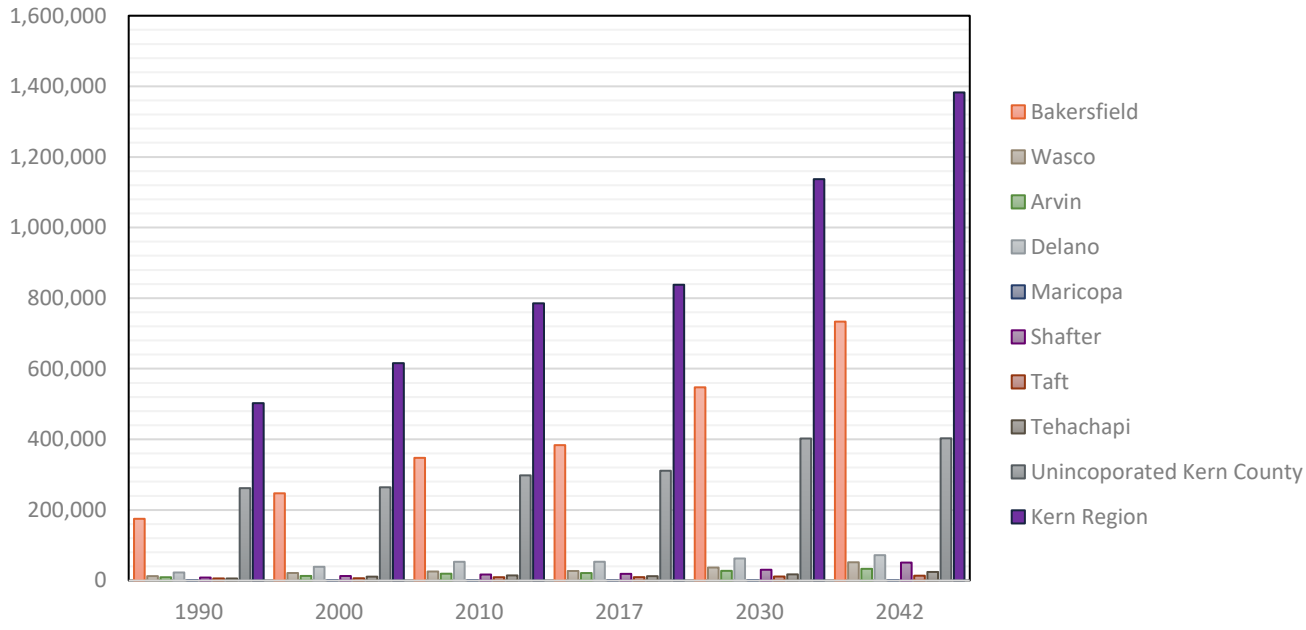
Table 2-5: Population Projections

	Population						
	1980	**1990**	**2000**	**2010**	**2017**	**2030**	**2042**
Bakersfield	105,611	174,820	247,057	347,483	383,512	547,300	733,400
Wasco	9,613	12,412	21,263	25,545	26,980	36,800	51,640
Arvin	6,863	9,286	12,956	19,304	21,157	27,400	33,100
Delano	16,491	22,762	38,824	53,041	53,152	62,400	71,800
Maricopa	946	1,193	1,111	1,154	1,140	1,160	1,190
Shafter	7,010	8,409	12,731	16,988	18,868	30,500	50,810
Taft	5,316	5,902	6,400	9,327	9,492	11,300	13,680
Tehachapi	4,126	5,791	10,957	14,414	12,280	17,400	24,240
Unincoporated Kern County	223,290	261,647	264,111	297,901	311,015	402,340	402,850
Kern Region	379,266	502,222	615,410	785,157	837,596	1,136,600	1,382,710

Source: Kern Council of Governments 2018 Regional Transportation Plan Destination 2042 (Table 3-5)

Notes: Projections assume future growth in the unincorporated portions of the Kern Region would have a lower annual growth rate (1.0%) than Metropolitan Bakersfield (2.5%). Estimates for past populations rely on US Census data (1980-2010).

FIGURE 2-5 Population Projections



2.5.2 Economic Factors

The Region's economy is based on the diverse assets of agriculture, oil, and warehousing services. Transportation, logistics and warehousing, are emerging and growing industries in the Region. Biomass is a growing form of locally-generated renewable energy while solar remains a relatively untapped potential. Lower business costs, the availability of land, and relatively lower costs of living also add to Kern's attractiveness and competitive advantage.

Despite this seeming economic diversification, the overall performance of the Region has been mixed in recent years when compared to the State and other areas, although noticeable progress has been made overall. The agricultural sector consists mostly of low paying and often seasonal employment which limits the positive multipliers within the economy. In May 2019, Kern County's estimated unemployment rate was 7.2 percent (California Employment Development Department 2019).

2.5.3 Disadvantaged Communities

DACs, as defined by 2016 Guidelines, are communities whose average MHI is less than 80 percent of the statewide annual MHI. In 2016, 80 percent of the state of California's MHI was $51,026. A number of communities within the Kern Region have been identified as DACs. These are listed in **Table 2-6** and shown on **Figure 2-6**. It should also be noted that many of these communities listed below are severely disadvantaged communities, whose average MHI is less than 60 percent of the statewide annual MHI.

Table 2-6: Disadvantaged Communities in the Kern Region

	Median Household Income	Percentage State Median Income
California	63,783	N/A
Arvin City	36,524	57.26%
Bodfish	26,004	40.77%
Buttonwillow	34,352	53.86%
Delano City	36,265	56.86%
Frazier Park	31,171	48.87%
Ford City	32,441	50.86%
Fuller Acres	32,763	51.37%
Greenfield	46,206	72.44%
Lake of the Woods	45,333	71.07%
Lake Isabella	26,369	41.34%
Lamont	34,421	53.97%
Lebec	27,000	42.33%
Lost Hills	30,583	47.95%
Maricopa City	33,295	52.20%
McFarland City	33,687	52.82%
McKittrick	43,125	67.61%
Mettler	38,036	59.63%
Mountain Mesa	29,223	45.82%
Oildale	36,866	57.80%
Onyx	28,438	44.59%
Shafter City	41,085	64.41%
South Taft	40,625	63.69%
Taft City	49,844	78.15%
Taft Heights	43,945	68.90%
Tehachapi City	42,961	67.35%
Tupman	35,833	56.18%
Wasco City	39,559	62.02%
Weedpatch	28,451	44.61%
Weldon	33,333	52.26%
Wofford Heights	34,167	53.57%

Source: American Community Survey Estimates 2012-2016

2.5.4 Social and Cultural Values

The earliest recorded history of the Region begins with Native Americans. The Region was at one time home to at least three Indian groups, the Yokuts, Shoshonean (sometime also referred to as Piutes), Tubatulabals, and coastal Chumash (Brewer 2001). Yokuts had major village sites throughout the valley and foothill area, including the western edge of Buena Vista Lake, Poso

Creek, and Bakersfield (Brewer 2001). At the southern end of the Central Valley were a group called the Tejon Indians, a part of the coastal Chumash. Tubatulabals and later Shoshone (Paiutes) Tribes lived in the Green Horn and Johnsondale Area Mountains, Kern River Canyon, and the Kern River Valley to the Tehachapi Pass (Brewer 2001).

Tubatulabals refer to the current day Bakersfield area as the following: “Palatalap” – Bakersfield “the place where the sun and water sets” (Gomez 2009).

Many of the Native American Tribes in Kern Region continue to speak their native language, hold their traditional and sacred ceremonies, live on lands in trusts (i.e., allotments), and continue to petition for federal recognition status. Existing Native American Tribes in Kern Region are sovereign Tribes with their own governance, Tribal Council, and Tribal members. Protection of sacred lands, waters, and natural resources (i.e., native plants, birds, animals, medicines of the land) continue to be a priority for these Tribes. Water is viewed as sacred and goes beyond just quantification. Water is seen as a cycle of life, from the ocean to the top of the mountain snows, and natural filtration of streams and rivers. Water stewardship is important in managing headwaters, mountain meadows, watersheds, and major rivers. Manmade lakes have only existed in the Kern area since the 1940s. Isabella Dam had flooded the convergence of the North and South Forks of the Kern River.

In May 2009, DWR, Tubatulabals of Kern Valley and North Fork Mono Tribe hosted a 1 day Tribal Water Regional Planning day which was attended by representatives from U.S. Forestry – Sequoia Rangers, Kern River Audubon, California Governor’s Office of Emergency Planning, KCWA, several local Tribes (Tubatulabals, Paiutes, Chumash, Yokuts), and other local interested residents. Protection and continued access to quality drinking water was identified as a high priority for these Tribes. Due to non-federally recognized status for many of the local Tribes, federal and state funding is very limited, if at all available for these Tribes. In addition, the protection of cultural and sacred Tribal sites has also been placed as a high priority. Participation in the planning process has also allowed the Tubatulabal Tribe to emphasize the importance of protecting the headwaters coming from USFS lands in this IRWMP.

Native Americans first arrived in Southern Sierra mountains more than 13,000 years ago (Johnson et al. 2002), in the Paleo-Indian period. Their presence may be an indication that warm and dry climate conditions allowed the piñon-juniper ecosystem to spread down slope between 3,000 and 1,500 B.C. Several sites in the Kennedy Meadows region, near Kernville, have been dated to this phase (Moratto 1984:333). Sawtooth phase (AD 600-1300), as indicated by greater numbers of temporary use sites and “piñon camps,” as well as increasing quantities of obsidian artifacts (Moratto 1984:333). Increasing site and artifact numbers suggest even more intensive occupation of the southern Sierra during the Chimney phase (AD 1300 – historic) (Moratto 1984:333-334). Prior to European contact, Native Americans had lived very close to rivers, streams, and springs. Seasonal living in the flood plains occurred for source of food and natural resources (i.e., basket making and housing materials, collection of tule, and net fishing).

Spanish explorers entered the Kern area as early as 1772 and the area became territory of Mexico in 1822, but widespread European settlement in the area was not common until the 1840’s when the Mexican government began awarding large ranchos. In 1843 the American government commissioned John C. Fremont to explore the West. In 1844, while returning from mapping the Oregon territory, Fremont entered the Kern Region. Fremont is responsible for naming Kern County (Brewer 2001).

By 1848 California was an American possession. Following the gold rush, former miners moved throughout California, including Kern County. These miners started several gold mining operations in the Region, including several mining camps near where is now Lake Isabella. Other businesses, particularly agriculture and ranching, grew in support of the gold mining operations. Large irrigation systems were developed to deliver water from local rivers in dry years and to take away water in wet years. By the 1860's large portions of former swamp land in the San Joaquin Valley were being drained for agriculture and ranching. Under the Montgomery Act, any person reclaiming swamp land belonging to the state would be deeded a percentage of the recovered land.

From 1851 to 1852, there were 18 treaties (one signed by Tribes in Camp Burton – Tule Reservation and one signed by Tribes in Texon/Tejon area), these treaties were never ratified by the U.S. government. The treaties would have assigned additional lands, resources, and on-going access to traditional territories (California State Library, April, 2006 – Resource Center, Senator Burton requested a study of these 18 unratified treaties). In these treaties, many of the Tribal Territories were outlined by existing rivers and streams.

The growing ranching industry attracted large numbers of French and Spanish Basque settlers. Chinese laborers and later African Americans were in demand as field laborers (Brewer 2001). Grapes, cotton, citrus and almonds were all grown by the mid-1800's and these continue to be important crops today. The mining and agricultural industries benefited from stagecoach and wagon routes that connected Los Angeles and San Francisco via Tejon Pass. By the turn of the century, the Kern Region was served by two major railroads, the Southern Pacific and Santa Fe (Brewer 2001).

In the mid-1860's a local entrepreneur began to market unrefined oil found in the region for use as farm machinery lubrication. Until this point, petroleum in Kern County had received little interest. It is known that local Yokut Indians used asphaltum for waterproofing, roofing, baskets, and pots. Despite some false starts, by the turn of the century several large oil fields were in operation in the Region, including the McKittrick Field and Kern River Oil Field. In 1910, drillers working in what is now known as the Midway-Sunset Oil Field tapped the Lakeview Gusher. The initial flow of the Lakeview Gusher is estimated at 125,000 barrels a day. The gusher flowed uncontrolled for over 18 months and is considered the largest recorded oil gusher in US history. Today Kern produces almost half of all the oil from California.

Kern County is characterized by its traditional industries, agriculture, oil and gas production, as well as increasing urbanization and population growth. Kern has a large immigrant population and is culturally diverse. A survey by the Public Policy Institute of California (PPIC), in Collaboration with the Great Valley Center, identified the strains growth is placing on the Kern Region. Over 50 percent of respondents to the survey stated that "growth in the wrong places" and "lack of effective regional planning" as major causes of problems in the Southern San Joaquin Valley. In this survey, more than 40 percent of respondents identified affordable housing, and job opportunities as "big problems" in the Central Valley; and more than 60 percent identified air quality as a big problem in the Southern San Joaquin Valley.

The PPIC survey showed a strong concern for the environment. More than 60 percent of respondents in the Southern San Joaquin Valley favored the following statements:

"Protecting the wetlands and rivers, and other environmentally-sensitive areas, even if this means there will be less commercial and recreational development"

"Restricting the development of housing on land that has a significant risk of flooding, even if this means there will be less housing available"

"Restricting urban development on farms and agricultural lands, even if this means there will be less housing available"

Decisions regarding future land use and the dedication of water resources will need to weigh varying agricultural, municipal, and industrial needs as they continue to develop and as the balance between these interests continues to change.

2.6 Water Supply

The following section describes the sources of water supply for the Region including imported surface water, local surface water, and local groundwater. Water related infrastructure in the Region is shown in **Figure 2-1**.

Water supplies utilized in the Region are the SWP and CVP via the California Aqueduct, the CVP via the Friant-Kern Canal, and local surface supplies from the Kern River and other local streams, as well as the largest common groundwater basin, the San Joaquin Valley groundwater basin. Other groundwater basins in the Region include the Kern River Valley groundwater basin to the east; Walker Valley Creek Basin to the southeast; Cummings Valley and Tehachapi Valley West on the eastern side of the Region, and Cuddy Canyon Valley, Cuddy Ranch Area, Cuddy Valley, and Mil Poterero Area basins to the south.

2.6.1 Imported Water Supply from the State Water Project

The SWP is the largest state-built, multi-purpose water project in the country. It was authorized by the California State Legislature in 1959, with the construction of most initial facilities completed by 1973. Today, the SWP includes 28 dams and reservoirs, 26 pumping and generating plants, and approximately 660 miles of aqueducts and is managed by DWR. The primary water source for the SWP is the Feather River, a tributary of the Sacramento River. Storage released from Oroville Dam on the Feather River flows down natural river channels to the Sacramento-San Joaquin River Delta (Delta). While some SWP supplies are pumped from the northern Delta into the North Bay Aqueduct, the vast majority of SWP supplies are pumped from the southern Delta into the 444-mile-long California Aqueduct. Many of the agencies participating in the Kern IRWMP receive SWP water from turnouts located on the California Aqueduct, and few also receive SWP water from the Coastal Branch of the California Aqueduct. Several centrally located water districts in the Region lie to the east of the Aqueduct and receive shares of SWP water through the CVC, which is also used for many operational exchanges and groundwater banking. For example, AEWSD has a bidirectional intertie to the California Aqueduct at the end of its canal system to facilitate various water management programs. CVC conveyance capacity is approximately 1,400 cfs at the upstream end. SWP facilities in the Region are shown in **Figure 2-1**.

In the early 1960s, DWR began entering into individual SWP Water Supply Contracts with urban and agricultural water supply agencies located throughout northern, central, and southern California for SWP water supplies. KCWA and Dudley Ridge Water District (DRWD) are two of

29 water agencies (commonly referred to as "contractors") that have a SWP Water Supply Contract with DWR. Each SWP contractor's SWP Water Supply Contract contains a "Table A," which lists the maximum amount of water an agency may request each year throughout the life of the contract. Table A is used in determining each contractor's proportionate share, or "allocation," of the total SWP water supply DWR determines to be available each year. The total planned annual delivery capability of the SWP and the sum of all contractors' maximum Table A amounts was originally 4.23 million acre-feet (MAF). The initial SWP facilities were designed to meet contractors' water demands in the early years of the SWP. With the construction of additional diversions of coastal rivers, a Peripheral Canal and storage facilities were planned as demands increased. However, the Wild and Scenic Rivers Act blocked diversions from coastal rivers, the Peripheral Canal was not authorized by voters, and essentially no additional SWP storage facilities have been constructed since the early 1970s. SWP conveyance facilities were generally designed and have been constructed to deliver maximum Table A amounts to all contractors. After the permanent retirement of some Table A amount by two agricultural contractors, the maximum Table A amounts of all SWP contractors now total about 4.17 MAF. Currently, KCWA's annual Table A amount is 982,730 acre-feet (AF) and DRWD's current Table A amount is 45,350 AF.

Consistent with other SWP contractors, historically, SWP deliveries to KCWA and DRWD have increased as its requests for SWP water have increased. **Table 2-7** presents historical total SWP deliveries to KCWA municipal and agricultural purveyors and to DRWD agricultural purveyors.

While Table A identifies the maximum annual amount of water an SWP contractor may request, the amount of SWP water actually available and allocated to SWP contractors each year is dependent on a number of factors and can vary significantly from year to year. The primary factors affecting SWP supply availability include hydrology, the amount of water in SWP storage at the beginning of the year, regulatory/biological and operational constraints, and the total amount of water requested by SWP contractors. Urban SWP contractors' requests for SWP water, which were low in the early years of the SWP, have been steadily increasing over time, which increases the competition for limited SWP dry-year supplies.

In an effort to assess the impacts of these varying conditions on SWP supply reliability, DWR issued its "State Water Project Delivery Reliability Report" in May 2003. The report assists SWP contractors in assessing the reliability of the SWP component of their overall supplies. DWR updates this report every two years with the most recent update in 2017 (DWR 2009). The report was renamed to the "SWP Delivery Capability Report" in 2015. In these updates, DWR provides a recommended set of analyses for SWP contractors to use in water supply planning. The 2017 analysis indicates that the SWP, using existing facilities operated under current regulatory and operational constraints, and with all contractors requesting delivery of their full Table A Amounts in most years, could deliver 62 percent of total Table A Amounts on a long-term average basis. The 2017 analyses also projected that SWP deliveries during multiple-year dry periods could average about 29 to 34 percent of total Table A amounts and could possibly be as low as 8 percent during an unusually dry single year.

Table 2-7: Historical Total SWP Deliveries to KCWA M&I Purveyors and Agricultural Member Units

Year	KCWA Deliveries (AF)	DRWD Deliveries (AF)	Year	KCWA Deliveries (AF)	DRWD Deliveries (AF)
1968	127,384	26,360	1994	700,996	28,793
1969	141,265	31,375	1995	1,119,343	60,686
1970	204,634	40,407	1996	1,139,656	56,948
1971	360,151	41,053	1997	1,062,287	71,308
1972	490,781	42,443	1998	825,155	55,650
1973	505,243	22,057	1999	1,136,962	59,697
1974	646,433	33,390	2000	1,115,661	60,539
1975	821,640	40,555	2001	505,994	41,902
1976	881,400	41,421	2002	692,921	48,915
1977	432,837	11,153	2003	908,680	46,082
1978	675,970	51,747	2004	763,285	49,080
1979	1,290,293	38,544	2005	1,398,797	79,005
1980	964,933	41,000	2006	1,248,604	72,080
1981	1,340,581	41,000	2007	670,545	45,135
1982	895,193	41,000	2008	263,032	22,174
1983	595,112	42,900	2009	320,410	21,237
1984	1,099,391	45,100	2010	536,343	27,967
1985	1,083,749	46,251	2011	1,149,316	60,560
1986	929,278	50,249	2012	617,957	30,450
1987	1,028,124	46,288	2013	441,121	27,046
1988	1,009,520	47,994	2014	100,383	40,535
1989	1,146,062	57,049	2015	354,098	41,733
1990	712,448	36,296	2016	714,424	20,908
1991	91,918	927	2017	1,050,374	59,313
1992	487,328	23,770			
1993	1,209,653	50,618			

Sources: KCWA Zones of Benefit for FY 2019-20 and DWR Bulletin 132-17.

However, recent regulatory and judicial decisions related to endangered species in the Delta have further impacted the reliability of the SWP, due to increased restrictions on pumping from the south Delta.

The SWP supplies projected to be available for delivery to the Region were determined based on the total SWP delivery percentages identified by DWR in its 2017 analyses. **Table 2-8** shows SWP supplies projected to be available to the Region in average/normal years (based on the average delivery over the study's historic hydrologic period from 1921-2003). **Table 2-8** also summarizes estimated SWP supply availability in a single dry year (based on a repeat of the worst-case historic hydrologic conditions of 1977) and over a multiple dry year period (based on a repeat of the worst-case historic four-year drought of 1931-1934).

Table 2-8: KCWA Wholesaler Supply Reliability (AF)

Wholesaler (Supply Source)		2020	2025	2030	2035	2040
Average Water Year						
DWR (SWP)						
	KCWA Table A Supply	611,258	611,258	611,258	611,258	611,258
	% of Table A Amount	62.2%	62.2%	62.2%	62.2%	62.2%
Single Dry Year						
DWR (SWP)						
	KCWA Table A Supply	78,618	78,618	78,618	78,618	78,618
	% of Table A Amount	8%	8%	8%	8%	8%
Multiple Dry Year[1]						
DWR (SWP)						
	KCWA Table A Supply	334,128	334,128	334,128	334,128	334,128
	% of Table A Amount	34%	34%	34%	34%	34%

Source: The Final State Water Project Delivery Capability Report 2017.
Note: Assumes Table A contract amount of 982,730 AFY.

While the primary supply of water available from the SWP is allocated Table A supply, SWP supplies in addition to Table A water have, until recently, been periodically available, including "Article 21" water, Turnback Pool water, and DWR dry-year purchases. Article 21 water (which refers to the SWP contract provision defining this supply) is water that may be made available by DWR when excess flows are available in the Delta (i.e., when Delta outflow requirements have been met, SWP storage south of the Delta is full, and conveyance capacity is available beyond that being used for SWP operations and delivery of allocated and scheduled Table A supplies). Article 21 water is made available on an unscheduled and interruptible basis and is typically available only in average to wet years, generally only for a limited time in the late winter. However, the past regulatory decisions mentioned above have significant impacts on the future availability of Article 21 water, since excess flows that normally make up the bulk of this supply will now be used to meet new flow requirements for Delta fish species.

The Turnback Pool is a program where contractors with allocated Table A supplies in excess of their service area needs in a given year may turn back that excess supply for purchase by other contractors who need additional supplies that year. The Turnback Pool can make water available in all types of hydrologic years, although generally less excess water is turned back in dry years. As urban contractor demands have increased through time, the amount of water turned back and available for purchase has diminished.

In critical dry years, DWR has formed Dry Year Water Purchase Programs for contractors needing additional supplies. Through these programs, water is purchased by DWR from willing sellers in areas that have available supplies and is then sold by DWR to contractors willing to purchase those supplies. Because the availability of these supplies is somewhat uncertain, they are not included as supplies in this IRWMP. However, KCWA's access to these supplies when

they are available may enable it to augment its SWP supplies beyond the values used throughout this report.

2.6.2 Imported Water Supply from the Central Valley Project

The CVP is a set of federal facilities that extend generally from north of Redding to areas near Bakersfield, as well as the South Bay Area. The CVP encompasses two of California's largest river systems, the Sacramento River, which flows southward toward the Delta and the San Joaquin River, which flows north into the Delta. Friant Dam stores San Joaquin River flows in Millerton Lake and diverts this water southward through the Friant-Kern Canal (and north in the Madera Canal, though that facility is not located in the Kern Region). The Friant-Kern Canal is 151.8 miles long and carries water south from Millerton Lake just northeast of Fresno and terminates into the Kern River.

Through various agreements, the California Aqueduct can deliver west side CVP contractor supplies from the Delta, which are typically sold to west side districts with California Aqueduct access or exchanged with Friant districts such as AEWSD. For example, AEWSD's Friant water can be delivered to upstream Friant reaches while AEWSD takes delivery of SWP supplies delivered via the California Aqueduct.

The Friant-Kern Canal has a maximum capacity of 5,000 cfs, which decreases to 2,000 cfs at its terminus into the Kern River. Deliveries are dependent upon Class 1 (firm) and Class 2 (non-firm, hydrology dependent) contract percent allocations determined by the Bureau of Reclamation, however the Bureau of Reclamation may also provide surplus water (Section 215 contracts to non-long term contractors), of which the Kern Region has utilized in the past. In addition, and similar to the SWP Article 21, the Westside CVP contracts from the Delta also have Section 215 contracts. An average of 313,000 AF of CVP water is delivered through the Friant-Kern Canal annually to the Kern Region for agricultural and municipal and irrigation uses. **Table 2-9** provides a summary of the historical deliveries to Kern County. Future deliveries are anticipated to be below the average historic delivery, at approximately 244,000 AFY (see **Table 2-10**). Due to the San Joaquin River Restoration Program, Friant Division contractors as well as Section 215 contracts to Kern Region are expected to experience a reduction in water deliveries.

Table 2-9: Central Valley Project Deliveries to Kern Region

Year	Kern Region Deliveries (AF)	DRWD Deliveries (AF)	Year	Kern Region Deliveries (AF)	DRWD Deliveries (AF)
1950	762		1985	337,514	
1951	27,005		1986	589,262	
1952	49,500		1987	291,981	
1953	83,558		1988	292,828	
1954	112,093		1989	293,865	
1955	126,238		1990	200,141	
1956	279,134		1991	204,396	
1957	141,684		1992	208,021	
1958	223,830		1993	489,783	
1959	166,099		1994	186,303	
1960	156,987		1995	647,077	1,587
1961	126,412		1996	611,262	7,498
1962	231,045		1997	630,026	2,804
1963	234,283		1998	466,490	2,246
1964	189,330		1999	350,526	
1965	245,482		2000	494,023	
1966	232,084		2001	331,416	
1967	319,706		2002	250,598	
1968	206,499		2003	363,108	
1969	372,826		2004	241,290	
1970	351,392		2005	702,465	4,881
1971	348,865		2006	582,490	3,509
1972	238,475		2007	197,894	
1973	412,178		2008	259,998	
1974	480,575		2009	453,803	
1975	442,130		2010	621,962	
1976	226,512		2011	664,321	1,259
1977	121,469		2012	169,990	
1978	357,847		2013	131,051	
1979	462,526		2014	36,865	
1980	462,772		2015	11,232	
1981	469,966		2016	198,736	
1982	656,608		2017	399,986	
1983	550,874				
1984	425,371		**Mean**	**315,336**	

Source: KCWA Water Supply Report: 2011 and USBR Central Valley Operations Office

Table 2-10: Projected Central Valley Project Deliveries to Kern Region (Including Deliveries To DRWD)

Year	Delivery (AF)	Year	Delivery (AF)
2015	243,887	2035	243,887
2020	243,887	2040	243,887
2025	243,887	2045	243,887
2030	243,887	2050	243,887
		Mean	243,887

Source: Unpublished data, KCWA

The San Joaquin River is currently subject to a restoration effort that is a direct result of a Settlement reached in September 2006 on an 18-year lawsuit to provide sufficient fish habitat in the San Joaquin River below Friant Dam by the U.S. Departments of the Interior and Commerce, the Natural Resources Defense Council, and the Friant Water Users Authority (now Friant Water Authority). The Settlement received Federal court approval in October 2006 and required specific legislation which passed in 2009.

The two mains goals of the restoration effort are 1) the Restoration Goal, which is to restore and maintain fish populations, specifically self-sustaining populations of salmon and other fish, and 2) the Water Management Goal, which is to reduce or avoid adverse water supply impacts to all of the Friant Division long-term contractors that may result from the Interim Flows and Restoration Flows provided in the Settlement. The restoration effort spans the middle 150 miles of the 350-mile River, from Friant Dam to the confluence of Merced River. Interim Flows were experimental or test flows, scheduled to be released prior to the introduction of salmon into the river, and were limited by downstream channel capacity.

Full Restoration Flows began January 1, 2014. Flows generally range from 350 cfs to over 4,000 cfs, depending on hydrology and time of year, with reduced flows in critically dry years. Total Restoration Flow releases in excess of current water rights requirements as defined in the Settlement will range from approximately 71,000 AF in critical dry years (except a repeat of 1977 when there would be no Restoration Flow releases) to approximately 556,000 AF (San Joaquin River Restoration Program 2009). The Restoration flows have a priority over existing contracts and as such the largest make-up of these supplies result in water losses to Class 2 districts. During drier years, the water losses will be from Class 1 districts.

Restoration flows result in reductions to water supply deliveries to CVP Friant Division contractors. Depending on which assumptions are used regarding use of buffer flows and reductions in Section 215 water (surplus flows), modeling results based on historical hydrology indicate that total annual deliveries to the Friant Division water service area during the Interim Flow period would be reduced by approximately 175 to over 200 thousand AF on average, corresponding to an approximate 13 to 15 percent reduction in average annual deliveries from Friant. These flows, however, could potentially be recaptured and recirculated by CVP Friant Division contractors downstream from Friant Dam, such as at existing CVP and SWP export facilities, subject to environmental and other regulations.

These flows could affect the future flows to the Kern Region provided in **Table 2-10**. AEWSD, the largest Class 2 district, has estimated that impacts to its CVP supplies will average 30,000 to 40,000 AFY. Additionally, it has been estimated that CVP supplies to Kern County will be

further reduced by an average of 30,000 to 40,000 AFY due to reductions in Section 215 water. These averages assume full Restoration flows, which have been temporarily reduced due to capacity restraints and seepage impacts. In the future, this impact will then be reduced by the various mitigation tools, assuming they are effective.

2.6.3 Local Surface Water

The most important source of naturally occurring surface water in the Region is the Kern River, which is regulated by the Isabella Dam and Reservoir, operated by the U.S. Army Corps of Engineers and the Kern River Watermaster. Approximately 1,300 acres at the eastern end of the reservoir is managed by the USFS for wildlife stewardship. Local minor streams, many of which are ephemeral, provide additional local surface water. A very small percentage of minor stream runoff is collected and used as irrigation for agriculture; the majority of these irregularly-occurring flows serve to recharge local groundwater basins. It is estimated that roughly 95 percent of local runoff percolates into the underlying aquifers and contributes to groundwater levels near the Kern Lake Bed, AEWSD/KDWD boundaries, and the KNWR.

2.6.3.1 Kern River

The Kern River is approximately 164 miles long and is fed by annual snowmelt from the Southern Sierra Nevada, including Mount Whitney. **Figure 2-1** depicts the Kern River, Isabella Reservoir, as well as the downstream canals that divert water from the River. **Table 2-11** provides a summary of the natural flows and flows measured at the First Point of Measurement for the Kern River. The “First Point of Measurement is located upstream of the Beardsley Weir (near Hart Park).

The Kern River originates high in the Sierra Nevada and drains approximately 2,100 square miles of watershed area above Isabella Reservoir, another 300 square miles of the foothills below Isabella Reservoir, and about 600 square miles of alluvial fan in the Kern River Canyon (County of Kern 1985). The main branch of the River (also called the North Fork Kern) joins the South Fork Kern River just upstream of Isabella Reservoir. Minor tributaries are Erksine, Bodfish, Clear, and Cottonwood creeks, which join the River downstream of Isabella Reservoir. With the exception of the small valley in which Isabella Reservoir is located, the Kern River and its principal tributaries flow in steep, narrow canyons from their headwaters to the mouth of Kern Canyon, where it debuts onto the Valley floor. Beyond the mouth of the Canyon, the River channel is deeply entrenched in an alluvial fan that extends westward to the main valley trough where the channel is controlled by levees to prevent flood flows from spreading to adjacent lands (City of Bakersfield and County of Kern 2007).

The Kern River had an unregulated flow until 1954, when the Isabella Dam and Reservoir were constructed by the US Army Corps of Engineers. The primary purpose of the dam is flood control. Isabella Reservoir was designed to store approximately 570,000 AF of water; however, since 2006 due to seepage, earthquake concerns, and overtopping, water storage in the Lake has been limited to approximately 60 percent of capacity, 20 feet below the spillway, and 340,860 total AF. The US Army Corps of Engineers has completed the design of the Isabella Dam facilities with the intent of restoring reservoir capacity by 2022 (US Army Corps of Engineers 2019). The work consists of excavation of a new emergency spillway, raising the main dam, and improvements to the auxiliary dam.

Table 2-11: Historic Kern River Flows (AF)

Year	Natural Flow (AF)	Flow Measured at First Point (AF)	Year	Natural Flow (AF)	Flow Measured at First Point (AF)
1980	1,639,957	1,560,652	2000	476,819	472,536
1981	449,263	460,469	2001	391,451	375,769
1982	1,271,139	1,121,088	2002	424,696	357,160
1983	2,489,128	2,381,575	2003	519,724	460,406
1984	821,797	834,036	2004	407,305	407,272
1985	672431	668,971	2005	1,156,109	935,439
1986	1,444,939	1,331,561	2006	1,071,841	1,027,688
1987	375,935	432,309	2007	252,692	318,050
1988	294,685	335,473	2008	517,997	455,874
1989	397,038	348,773	2009	470,166	442,268
1990	203,571	219,501	2010	910,878	752,302
1991	406,289	333,494	2011	1,374,894	1,404,645
1992	296,829	272,822	2012	327,988	369,185
1993	853,760	642,339	2013	206,218	196,751
1994	336,456	422,361	2014	175,409	164,105
1995	1,385,160	1,197,100	2015	138,740	129,678
1996	1,038,261	968,036	2016	364,207	264,745
1997	1,181,969	1,133,463	2017	2,000,790	1,871,716
1998	1,717,967	1,662,556	2018	393,166	445,805
1999	433,971	461,621			

Source: KCWA Water Supply Report: 2011 and City of Bakersfield (data for 2012-18)

The Kern River Watermaster represents entities with water rights downstream of Isabella Reservoir. The Watermaster identifies the daily water releases to be made from the reservoir by the Army Corps of Engineers. The Watermaster also keeps records of Kern River flow. Except for very wet years, there is no river flow downstream of Bakersfield due to upstream canal diversions (see **Figure 2-1**). The River encounters its first diversion into a canal when it first exits the Kern River Canyon and encounters another diversion when it reaches the east side of Bakersfield, near Hart Park. The Beardsley and Rocky Point weirs are the first two of seven diversion weirs in Bakersfield. From there, canal water travels north and south to irrigate farmlands. In total, the River is diverted into seven canals that pass through the City. During very wet years, water flows in the River southwest to the Buena Vista Lake Bed and then north to Tulare Lake or into the California Aqueduct near Tupman.

2.6.3.2 Minor Streams

Local minor streams are the second-largest source of local surface water after the Kern River. Streams with measurable runoff are grouped into four separate watershed areas: Poso, Caliente, El Paso, and San Emigdio. Streams with the largest historical flows, including Poso and Tehachapi Creeks, are equipped with flow meters to record actual data while flow rates of smaller streams are estimated by statistical methods based on historical watershed, precipitation, and runoff data. The mean stream flow of these minor streams is 103,000 AF and

is assumed for future stream flow projections. Historic minor stream runoff is summarized in **Table 2-12**. Data for years beyond 2012 have not been published.

Small creeks and streams drain local mountain ranges. The majority are ephemeral and quickly infiltrate once reaching the valley floor. However, under certain hydrologic conditions, some of these streams carry very large flows that can be quite damaging. Examples include flooding in the Kelso Creek area, and in the area around the cities of Arvin and Lamont. Regional efforts to address flooding and to better manage such flow events have been initiated among various parties in the Region, including the County of Kern, KCWA and the affected areas.

A very small percentage of runoff from local minor streams is collected and used as irrigation for agriculture located in the NKWSD and the SWSD. It is estimated that on average, roughly 37,600 AF or 95 percent of the runoff percolates into the underlying aquifers and contributes to the shallow groundwater near the Kern Lake Bed and KNWR areas (KCWA).

Table 2-12: Historic Minor Stream Runoff (AF)

Year	Annual Stream Flow (AF)	Year	Annual Stream Flow (AF)
1980	70,300	1997	103,000
1981	45,100	1998	709,500
1982	93,600	1999	40,100
1983	503,300	2000	27,700
1984	46,500	2001	37,200
1985	37,800	2002	22,800
1986	52,400	2003	55,900
1987	70,900	2004	30,700
1988	29,900	2005	89,900
1989	27,800	2006	54,100
1990	17,500	2007	20,500
1991	41,900	2008	60,300
1992	87,300	2009	40,870
1993	110,900	2010	72,525
1994	37,400	2011	149,722
1995	426,400		
1996	79,500		

Source: KCWA Water Supply Report: 2011

2.6.4 Groundwater

With only six (6) inches per year of average rainfall, groundwater is necessary to maintain a sufficient water supply in the semi-desert climate of the Region. It is estimated that on average groundwater accounts for 39 percent of total water supply to the Region; however, it is estimated to be as much as 60 percent during dry years.

The main sources of groundwater recharge in the Region are deep percolation of applied irrigation water, surplus SWP/CVP water (Article 21 and Section 215 type as well as large declarations of Table A and Class 2) and the Kern River. In the riverbed are 500 to 2,000 foot thick poorly sorted deposits of silt, sand, rock, and clay that originated from the Sierra Nevada, and that provide moderate to high permeability through the riverbed. This phenomenon is also seen in some of the unlined canals which branch off from the river and creeks such as the Kelso, Canebrake, and Brite. Major water banking and conjunctive use projects also contribute large amounts of recharge to the Region. Secondary sources of groundwater are infiltration of water used for irrigation in agricultural applications, as well as urban runoff.

The main basin is the San Joaquin Valley groundwater basin (DWR Groundwater Basin 5-22.14), which covers the majority of the managed resources in the Region. Other groundwater basins in the Region include the Kern River Valley groundwater basin (DWR Groundwater Basin 5-25) to the east; Walker Basin Creek Valley (DWR Groundwater Basin 5-26) to the east; Cummings Valley (Basin 5-27), Tehachapi Valley West (Basin 5-28), and Brite Valley (Basin 5-80) to the southeast; and Cuddy Ranch Area (Basin 5-83), Cuddy Valley (Basin 5-84), and Mil Potrero Area (Basin 5-85) basins to the south (DWR 2003). All of these groundwater basins boundaries are within the watershed boundary of the Kern Region. Groundwater basins in the Region are depicted in **Figure 2-7**.

It should be noted that DRWD is within the Tulare Lake groundwater basin. It is categorized in DWR Bulletin 118 as having “groundwater unavailable and/or unusable”. Because of this factor, DRWD has participated in out-of-district conjunctive use projects, including groundwater banking and water exchange projects in the Kern Region and elsewhere.

2.6.4.1 Groundwater Extractions

Agriculture, M&I users, and groundwater banking operations all draw upon local groundwater resources. Agriculture is estimated to be the largest user of groundwater. The majority of groundwater extractions in the Region are not recorded; thus obtaining an accurate assessment of groundwater extractions in the Region is difficult. In the past, agricultural and urban power records were matched with calculations for groundwater production. However, because the accuracy of such power record calculations was unsatisfactory, since the year 2001 groundwater extractions have been estimated based on trends in groundwater storage (see Table 2-13) and/or assessment of crop water requirements. Data for years beyond 2012 have not been published.

Table 2-13: Historical Total Groundwater Extractions by Purveyors

Year	Groundwater Pumped	Year	Groundwater Pumped
1980	977,000	1997	1,091,400
1981	1,161,000	1998	1,290,200
1982	802,200	1999	1,471,500
1983	762,700	2000	1,360,100
1984	1,252,200	2001	1,953,900
1985	1,293,800	2002	1,575,000
1986	947,600	2003	1,203,900
1987	1,208,700	2004	1,842,300
1988	1,540,200	2005	599,800
1989	1,588,500	2006	717,500
1990	1,796,500	2007	2,212,300
1991	2,002,400	2008	2,306,500
1992	1,673,600	2009	1,212,400
1993	987,700	2010	230,400
1994	1,897,700	2011	419,000
1995	1,242,800		
1996	1,609,600		

Source: KCWA Water Supply Report: 2011

2.6.4.2 Groundwater Banking and Recharge

Groundwater banking programs are widely used in the Kern Region; conjunctive use programs have been utilized in the region since the early 1900s. Many notable groundwater storage programs exist in the Kern Region, including those operated by AEWSD, Semitropic WSD, North Kern WSD, the City of Bakersfield, Rosedale-Rio Bravo Water Storage District (RRWSD), and various other districts in the Region. The Kern Water Bank Authority (KWBA) is responsible for the largest water banking program in the world and has contributed over 2 MAF of water into storage since the program began operations in 1995.

Groundwater banking is the storage/recharge of excess water supplies into aquifers during wet periods for later withdrawal/recovery for use during dry periods, usually within a mile or two of where the recharge took place. Sometimes, however, recovery can occur up to a few miles from where the recharge took place. Historically, during wet periods, surface water imports have been substantial enough to satisfy irrigation and urban water needs and thus, excess water has been recharged to groundwater aquifers. The groundwater is then pumped/extracted out through the many private and publicly owned wells located throughout the Region during dry periods when local or imported surface water supplies are insufficient. It is estimated that there are over 30,000 acres of groundwater recharge ponds alone in the Region. During wet periods,

these basins provide excellent habitat for bird species including great blue herons, bald eagles, mallards, white pelicans, and others. Banking programs include the following:

- City of Bakersfield 2800 Acres
- Berrenda Mesa Banking
- Pioneer Banking
- Kern Water Bank
- Semitropic Water Storage District Banking
- Arvin-Edison Water Storage District Banking
- Kern Tulare and Rag Gulch Water Districts Banking
- Buena Vista Water Storage District Banking
- Rosedale-Rio Bravo Water Storage District Banking
- Kern Delta Water District Banking
- Cawelo Water District Banking

In total, maximum annual recharge capacity in the Region is estimated over 1.5 MAFY with maximum annual recovery estimated approximately 900,000 AF. The estimated total storage capacity for the Region is approximately 50 MAF. Currently, approximately 10 MAF of that storage has been dewatered and, therefore, is available for conjunctive use and groundwater banking operations. There is approximately 5.4 MAF in managed groundwater storage in the Region.

2.6.5 Recycled Water

Recycled water programs are important in the Kern Region due to the fact that the Tulare Lake hydrologic region mainly consists of a “closed basin,” that is, supplies entering the basin have no natural outlet. Because there is no natural outflow all effluent must be treated and disposed of within the basin. Agriculture, which accounts for the majority of total water use in Kern County, does not require water treated to potable water standards. The large amount of agriculture in the Region has meant that nearly all wastewater effluent produced by the various treatment facilities in the County can be applied to salt tolerant non-human consumption crop irrigation and environmental habitat restoration. Recycled water is also used to irrigate and flood certain areas of the KNWR.

Currently, in the Region there are 17 wastewater treatment plants (WWTPs) that provide secondary and tertiary treated effluent. In 2015, approximately 57,000 AF of effluent was recycled. In addition to treatment plant effluent, agricultural tailwater return systems are also used to recover and reuse water. These return systems collect runoff and transport it to the main irrigation system.

Increased use of recycled water for irrigated agriculture as well as landscape irrigation in the M&I sector could help lower dependence on high quality SWP and CVP water and will provide an additional water source during drought or periods of regulatory restrictions when imported potable water quantities are reduced. In addition, waste discharges will be greatly reduced and the high quality imported water can be applied towards best use. Recycled water is regulated by the California Code of Federal Regulations (CFR) as well as DDW. Municipal treatment

facilities producing effluent for introduction into irrigation canals must disinfect to a minimum of 23 most probable number (MPN) of coliform per 100 ml of discharge.

2.6.6 Other Water Supply Opportunities

2.6.6.1 Kern River Oil Field

The Kern River Oil Field located just north of the City of Bakersfield is the third largest oil field in the State and the fifth largest field in the Country. Water trapped within oil deposits is released as part of the oil extraction and refining process. In the past, the water released during oil extraction was deposited into the Kern River, but following implementation of more stringent environmental protection measures, Shell Oil Company began reusing the water in the form of steam to accelerate oil extraction. Beginning in 1980, the NKWSD and Cawelo Water District located in northern Kern County began receiving oil field produced water for recharge and irrigation purposes.

Edison oilfield produced water has potential for southern districts like AEWSD, KDWD and/or Wheeler-Ridge Water Storage District; however, water quality and M&I concerns, given banking programs with urban agencies, need to be addressed and mitigated.

2.6.6.2 Agriculture Processing Wastewater

In addition to treated wastewater effluent, effluent from plants processing crops harvested from the field and those preparing processed food potentially provide a source of additional water supply opportunities. Currently, effluent from agricultural processing facilities is being recycled for irrigation use and is being evaluated for use in groundwater recharge programs.

2.7 Transfers and Exchanges

As described above, the Region has multiple water sources including the Kern River, SWP, CVP, groundwater, and minor local streams. In response the Region has developed a complex and interconnected water distribution system (see **Figure 2-1**). This network of canals and pipelines makes it possible to “wheel” or convey water from one area to another, both regional and statewide. Local agencies have agreements in place that allow agencies to call on available supplies when another supply source is experiencing shortage, and for other reasons to reduce costs, conserve energy, and/or improve water quality. For example, the KCWA Improvement District Number 4 (ID4) has transfer and exchange agreements in place with NKWSD, Buena Vista Water Storage District and KDWD that allow ID4 to increase its use of Kern River water in years when SWP supplies are limited. AEWSD also has assisted districts with transfers and exchanges given its CVP contract and facility infrastructure interconnections with all major conveyance systems (Kern River, CVP/Friant-Kern Canal, SWP/California Aqueduct, CVC, and interconnections with Kern Delta WD).

This distribution network makes it possible to store excess water in a given year or period and then recover and deliver that water in another year or later in a year. In fact, several water banks have agreements to store surface water from agencies outside the Region. These agreements allow imported supplies that belong to the out-of-Region banking participants to be delivered to banking programs within the Region, usually via the California Aqueduct or Friant-Kern Canal. The water is either percolated into the groundwater basin and stored, or local agencies use the water in-lieu of groundwater pumping, thus allowing water levels in the

groundwater basin to be maintained or improved. During water-short periods, the stored water can either be pumped and delivered directly (if the banking participant is physically located south of the Region), or arrangements can be made to use out-of-Region banked water locally, in exchange for the use of KCWA's Table A or Arvin-Edison WSD contract amount (if the banking participant is physically located north of the Region).

2.8 Water Quality

There are many tools, whether regulatory, voluntary, or incentive based, currently available for preventing pollution. The US EPA, SWRCB, and Regional Water Quality Control Boards (RWQCBs) have permitting, enforcement, remediation, monitoring, and watershed-based programs to prevent pollution. Pollution can enter a water body from point sources like WWTPs and other industries that directly discharge to the river/stream and from nonpoint sources over a broad area, such as runoff from a city and/or agricultural farmland or grazing areas located adjacent to stretches of the river reach. Some nonpoint source (NPS) contaminants are naturally occurring in local rocks and soil, such as heavy metals, (arsenic, chromium, selenium). Preventing pollution from most point sources relies on a combination of source control and treatment, while preventing NPS pollution generally involves the use of best management practices (BMPs), efficient water management practices, and source control. NPS pollution is not typically associated with discrete conveyances.

The Safe Drinking Water Act (SDWA) was originally passed by Congress in 1974 to protect public health by regulating the nation's public drinking water supply. SDWA applies to every public water system in the United States. SDWA authorizes the US EPA to set national health-based standards for drinking water to protect against both naturally-occurring and man-made contaminants that may be found in drinking water. Originally, SDWA focused primarily on treatment as the means of providing safe drinking water at the tap. Amendments in 1996 greatly enhanced the existing law by recognizing source water protection, operator training, funding for water system improvements, and public information as important components of safe drinking water. Under the SDWA, technical and financial aid is available for certain source water protection activities.

The Federal Clean Water Act (CWA) contains two strategies for managing water quality including: (1) a technology-based approach that envisions requirements to maintain a minimum level of pollutant management using the best available technology; and (2) a water quality-based approach that relies on evaluating the condition of surface waters and setting limitations on the amount of pollution that the water can be exposed to without adversely affecting the beneficial uses of those waters. Section 303(d) of the CWA bridges these two strategies. Section 303(d) requires that the States make a list of waters that are not attaining standards after the technology-based limits are put into place. For waters on this list (and where the US EPA administrator deem them appropriate) the States are required to determine all the sources of the pollutants that caused the water to be listed including, contributions from point sources and non-point sources. Impaired water bodies within Kern County are listed in Table 2-17.

The federal CWA, as well as the State Porter-Cologne Water Quality Control Act, requires water quality control plans to establish water quality standards which address beneficial uses of water sources. The CVRWQCB has established and adopted the Water Quality Control Plan for the Tulare Lake Basin (Basin Plan). The Basin Plan describes designated beneficial uses to be protected, water quality objectives to protect those uses, and a program of implementation needed for achieving the objectives. Beneficial uses, together with their corresponding water

quality objectives, meet federal regulatory criteria for water quality standards. Hence, the Basin Plan serves as regulatory references for meeting both State and federal requirements for surface and groundwater water quality control in the Tulare Lake Basin.

2.8.1 Surface Water Quality

The Kern River, the primary native surface supply in Region, is generally considered a high quality supply. Portions of the River, though, have water quality issues but are not listed on the 303 (D). However, Isabella Lake which serves as the source for the lower Kern River has three constituents listed on the 303(D) list including dissolved oxygen, mercury, and pH.

Water agencies, the City of Bakersfield, Kern County Department of Parks, the US Bureau of Land Management (USBLM), and USFS, in coordination with the California Department of Public Health perform regular surveys of the Kern River watershed. These surveys focus on identifying any activities that could affect water quality and water quantity.

2.8.2 Imported Water Quality

DWR regulates the water quality of the SWP through the Department of Water Resources Water Quality Policy and Implementation Process for Acceptance of Non-Project Water into the State Water Project (October 2012). The current water quality criteria for the SWP are compared to current water quality conditions in the California Aqueduct and to the current federal primary and secondary drinking water standards, provided in **Table 2-14**. The table reports water quality in the California Aqueduct from a point just upstream of Kern County (data taken from Station KA017226, Check 21 near Kettleman City). It is important to note that not all constituents currently in the Water Supply Contract between DWR and the KCWA are sampled for by DWR. It is also important to note that while some constituents do not have SWP pumpback criteria and/or a maximum contaminant level (MCL) standard (bromide, total organic carbon, total dissolved solids (TDS), and chloride) high levels of these constituents can be of concern, especially with regard to potential treatment costs to downstream users. SWP water meets or exceeds applicable standards (see **Appendix D** for data).

Table 2-14: Comparison of SWP Water Quality Criteria

Constituent	SWP Contract Criteria ppm	CA Drinking Water Standards ppm
Arsenic	0.05	0.010
Hexavalent Chromium	0.05	-
Copper	3.0	1 (b)
Fluoride	1.5	2 (b)
Boron	0.6(a)	-
Sodium Percentage	50%(a)	-
Iron and Manganese, together	0.3	0.3 and 0.05(b)
Magnesium	125	-
Lead	0.1	0.015
Phenol	0.001	-
Selenium	0.05	0.05
Zinc	15	5(b)
Sulfate	110(a)	250(b)
Total Hardness	180(a)	No standard
TDS	440(a)	500(b)
Chloride	110(a)	250(b)

Notes:
(a) Monthly Average
(b) Denotes secondary standard.

US Bureau of Reclamation regulates water quality of the Friant Division CVP through the "Baseline Water Quality Report for CVP" as well as other programs such as "Policy for Accepting Non-Project Water into the Friant-Kern and Madera Canals".

SWRCB regulates water quality within the State including but not limited to the "Anti-degradation Policy", which has been in effect and administered since 1968 (Resolution 68-11).

> *"Whenever the existing quality of water is better than the quality established in policies as of the date on which such policies became effective, such existing high quality will be maintained, until it has been demonstrated to the state that any change will be consistent with maximum benefit to the people of the State, will not unreasonably affect present and anticipated beneficial uses of such water and will not result in water quality less than prescribed in the policies."*

Due to the drastically varying water qualities of the various local water supplies (SWP, CVC, FKC, Kern River, groundwater), conveyance agreements, such as the CVC Operating Agreement, provide certain protections. Total dissolved solids (TDS) or Electric Conductivity (EC), both being "salt" constituent indicators, exhibit on average a 10 times differential between the California Aqueduct (200 and 300, respectively) and the Friant-Kern Canal (20 and 30, respectively) water supplies. As an example of water quality protections, the following is an excerpt from the CVC Operating Agreement:

> *"Use of the Intertie for delivery of water from the CVC to the Friant-Kern Canal may result in adverse water quality impacts to Arvin-Edison. Due consideration for such impacts shall be negotiated between those Participants desiring to introduce water into the Friant-Kern Canal and Arvin-Edison; provided, however, no such consideration shall*

be due with respect to any water provided under existing contracts and renewals thereof between Rag Gulch, Kern-Tulare and the Fresno- Tulare Group and United States providing for deliveries from the California Delta or Rag Gulch or Kern-Tulare supplies delivered pursuant to Federal approval. " ...

2.8.3 Groundwater Quality

Groundwater quality throughout the region is typically suitable for most urban and agricultural uses with only localized impairments including high TDS (salts), sodium chloride, sulfate, nitrate, organic compounds, boron, arsenic and 1,2,3,-Trichloropropane (1,2,3-TCP). High TDS, arsenic, 1,2,3-TCP, and nitrates are the primary groundwater quality issues.

The CVRWQCB has stated, “The greatest long-term problem facing the entire Tulare Lake Basin is the increase of salinity in ground water” (2004). Salt in imported water supplies such as the SWP and CVP is the major source of salt which circulates throughout the groundwater in Kern County. An estimated 1,206 tons of salt is annually imported to the region and because the Tulare Lake Hydraulic Region does not have any natural outlets, the salt builds up and remains in the underlying aquifers. Agricultural practices can exacerbate the problem, irrigation water applied to the land can be high in salts, then evaporation and crop transpiration remove water from soils and salts accumulate in the root zone. It is then necessary to apply additional water to flush the salts from the root zone and the salts eventually end up in groundwater or surface waters. High salt concentrations (e.g., greater than the primary drinking water standard) are a particular problem in the western portion of the Region. DWR and other federal, state and local agencies continue to study alternative approaches for salt management. The CVRWQCB has stated that evaporation basins are an acceptable interim means for dealing with salts in agricultural drainage, but only when precautions are taken to limit wildlife exposure. The RWQCB’s preferred method for salt management is the construction of a valleywide drain to carry salts outside of the Central Valley. Planning for regional drainage facilities began as early as 1950. Planning has focused on the western side of the San Joaquin Valley, generally north of the Region.

Nitrates are usually derived from irrigated agriculture, dairies, disposal of sewage from community waste systems and septic tanks, as well as discharges of wastewater to land. Man-made pesticides used in agriculture and naturally occurring arsenic have occasionally contaminated domestic groundwater supplies in the area. The MCL for Nitrate (as N) is set at 10 mg/L.

Arsenic is both a groundwater and surface water quality issue. Arsenic is ubiquitous in the environment and is naturally present in soil, water, air, plants and animals. Weathering of arsenic-containing rocks is considered to be the primary natural source of arsenic in the environment. Arsenic is found in groundwater throughout the state, resulting from its natural occurrence. It may also be present in localized environments in high concentrations as a result of specific releases, such as from mine tailings and chemical spills. Arsenic treatment tends to be expensive, not just because of the more exotic treatment technologies required, but because of the large volumes of groundwater that typically must be treated when the source of the arsenic is naturally occurring. As described earlier if the SWP acceptance standard for arsenic is lowered it could limit the ability to introduce groundwater recovered from water banking operations into SWP facilities.

1,2,3-TCP is a manmade chemical used in industrial and agricultural applications. In agricultural applications it was a chemical used in fumigants until the 1990s. The chemical percolated into the groundwater aquifer and is present in multiple locations in the Valley. The ingestion of 1,2,3-TCP is of concern as it is a probable carcinogen. In 2017, DDW has set the MCL for 1,2,3-TCP at 0.005 µg/L (5 parts per trillion).

2.9 Water Demand

Water demands within the Kern Region are serviced by a variety of water purveyors, including the large wholesale agency, KCWA, its member districts, irrigation or water storage districts, investor-owned water companies, mutual water companies, municipalities and private well owners. Water demands are presented for urban and agricultural demand sectors.

2.9.1 Urban Demand

Urban water demands were developed from information provided by the various water agencies participating in this IRWMP. Generally historic and projected urban water demands were taken from UWMPs developed by the agencies. Specifics on how these demands were developed are provided in the subregion specific sections of this report. Urban water demands include residential, commercial/industrial/institutional, landscape, and other water use types (including water losses). **Table 2-15** provides a summary of historic and projected urban water demands.

Table 2-15 Summary of Urban Water Demand (AFY)

Subregion	Purveyor	2015	2020	2025	2030	2035	2040	Note
Greater Bakersfield	California Water Service*	55,033	77,781	81,878	86,191	90,019	94,088	(a)
	City of Bakersfield*	35,954	47,629	51,865	56,495	58,556	67,091	(b)
	East Niles CSD*	7,502	14,381	15,744	17,126	18,542		(c)
	Oildale MWC*	7,915	9,639	10,436	11,297	12,231		(d)
	Casa Loma Water Company							
	Greenfield CWD							
	Subtotal	**106,404**	**149,430**	**159,923**	**171,109**	**179,348**		
Kern Fan	Buttonwillow CWD	298	250	255	259	264		(e)(1)
	Vaughn WC	9,847	11,186	12,708	14,436	16,399		(f)
	West Kern WD	21,003	20,418	20,508	20,600	20,693	20,788	(g)
	Subtotal	**31,148**	**31,854**	**33,470**	**35,295**	**37,356**		
	City of Tehachapi	1,755	1,867	1,972	2,083	2,200		(h)
	Golden Hills CSD	1,032	1,256	1,320	1,387	1,458		(h)
	Stallion Springs CSD	421	528	554	581	610		(h)
	Bear Valley CSD	919	1,097	1,145	1,195	1,249		(h)
	Lake of the Woods MWC	117	119	0	0	0		(i)(1)
	Frazier Park PUD	360	366	494	503	512		(j)(1)
	Lebec CWD	193	196	200	204	207		(k)(1)
	Tejon-Castaic WD	164	167	170	173	176		(l)(1)
	Subtotal							
Kern River Valley	California Water Service- KRVD	688	950	942	940	942	947	(m)
	Mt. Mesa WC							
	Long Canyon WC							
	Rainbird Valley MUC							
	Valley Estates Property Owners							
	Talbatulabals of Kern County							
	Subtotal	**688**	**950**	**942**	**940**	**942**		
North County	City of Delano	13,375	13,931	15,728	17,273	18,929	21,000	(n)
	City of Shafter	1,388	1,532	1,692	1,868	2,062		(o)
	City of Wasco	6,661	8,925	11,469	14,293	17,397		(p)
	City of McFarland	1,569	2,027	2,485	2,944	3,402	3860	(q)
	Subtotal	**22,993**	**26,415**	**31,374**	**36,378**	**41,790**		
South County	Arvin CSD	3,768	4,085	4,712	5,752			(r)
	Lamont PUD	3,808	3,977	4,310	4,648			(s)
	Mettler CWD							
	Subtotal	**7,576**	**8,062**	**9,022**	**10,400**			
West Side	Lost Hills PUD							
	Subtotal							
	Grand Total	**169,497**	**217,661**	**235,674**	**255,062**			

Sources:

* KCWA Improvement District No. 4 (ID4) member agency; ID4 has no direct demand; wholesale water to member agencies ranges from 44,909 AFY in actual deliveries in 2015 to 65,600 AFY in projected deliveries in 2040

(1) Projections unavailable. Assumed 1.8% increase per year based on County growth rate.

(a) CWS-BAK 2015 UWMP- Table 4-3

(b) COB 2015 UWMP- Table 4-3

(c) ENCSD 2015 UWMP- Table 4-3

(d) OMWC 2015 UWMP- Table 8C (Standard Table 4-3)

(e) BCWD 2018 Rate Study

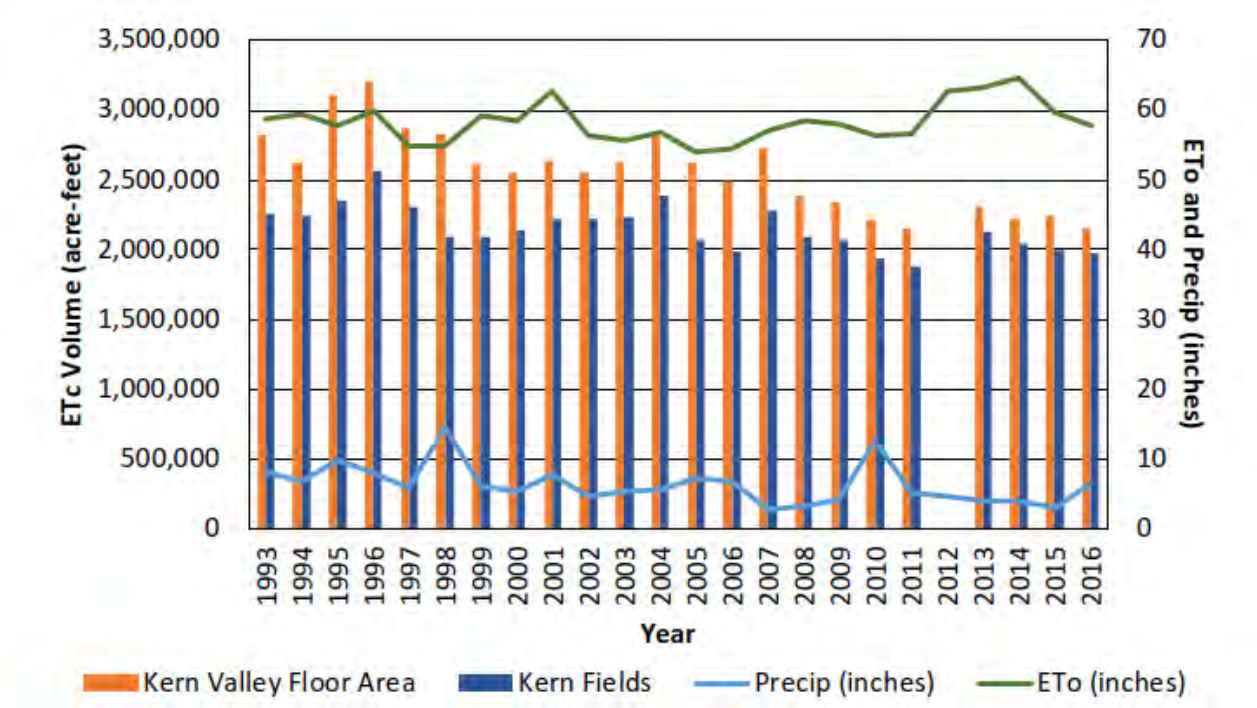
(f) 2015 Actual Water Use from SWRCB; 2020-2030 Vaughn Water 2010 WMP Table 16
(g) West Kern Water District 2015 UWMP Table 4-2
(h) 2015 Greater Tehachapi Regional UWMP Table 2:4-1, 3:4-3, 4:4-3, 5:4-3, 6:4-3
(i) Lake of the Woods MWC Water Demands, consolidation expected by 2025
(j) Frazier Park PUD Est. of Water Demands for the Study Area - Final Report
(k) Lebec County Water District 2019 Preliminary Design Report
(l) Tejon-Castaic Water District Water Rate Study
(m) 2015 Cal Water KRVD WMP Table 4-2
(n) City of Delano 2015 Urban Water Management Plan Table 4.2.3
(o) City of Shafter 2015 Urban Water Management Plan Table 24
(p) City of Wasco 2040 General Plan
(q) City of McFarland 2017 Analysis of Available Water Supply
(r) Arvin CSD Final 2010 UWMP Table 11
(s) Lamont PUD 2014 UWMP Table 11

2.9.2 Agricultural Demand

Agricultural demands in the Kern County valley floor were analyzed by the Irrigation Training & Research Center (ITRC) for the period of 1993 to 2016 (ITRC 2018). Specifically, ITRC used a modified Mapping of EvapoTranspiration with Internal Calibration (METRIC) procedure to compute actual evapotranspiration using LandSAT Thematic Mapper data. The results of this study showed that agricultural water demands have decreased over time, with approximately 2 MAF of water used in recent years (see **Figure 2-8**).

Table 2-16 lists the irrigated acreages and crop water use from available AWMPs for each district by subregion.

Figure 2-8: Annual volume of ETc for the Kern County Valley floor and within fields in Kern County



Note: Kern Fields volume is specific agricultural demand. The remaining Kern Valley floor volume is primarily landscape areas from urban areas.

Table 2-16 Summary of Agricultural Water Demand (AFY)

Subregion / Water District	Data Source	Irrigated Acres	Crop Water Demand	Projected Water Demand
Kern Fan Subregion				
Buena Vista Water Storage District	2015 AWMP (2015 Data)	32,437	96,886	96,886
Henry Miller Water District	Kern IRWMP (2005 Data)	18,876	47,000	47,000
Rosedale Rio Bravo Water Storage District	2014 Operations Report (2014 Data)	29,000	87,465	87,465
	Subtotal	**80,313**	**231,351**	**231,351**
Mountains and Foothills Subregion				
Tehachapi-Cummings County Water District	Kern IRWMP (2005 Data)	3,393	8,449	7,059
	Subtotal	**3,393**	**8,449**	**7,059**
North County Subregion				
Cawelo Water District	2016 AWMP (2015 Data)	33,630	114,816	114,816
Delano- Earlimart Irrigation District	2012 WMP (2008 Data)	49,149	158,320	158,320
Kern Tulare Water District	2016 AWMP (2015 Data)	18,157	61,514	61,514
North Kern Water Storage District	2015 AWMP (2014 Data)	57,393	185,603	185,603
Semitropic Water Storage District	2015 AWMP (2015 Data)	135,996	388,120	388,120
Shafter-Wasco Irrigation District	2011 WMP (2011 Data)	30,127	101,026	101,026
	Subtotal	**324,452**	**1,009,399**	**1,009,399**
South County Subregion				
Arvin-Edison Water Storage District	2011 WMP (2011 Data)	112,617	325,024	325,024
Kern Delta Water District	2015 AWMP (2013 Data)	91,530	297,260	297,260
Wheeler Ridge Maricopa Water Storage District	2015 AWMP (2015 Data)	85,973	219,595	219,595
	Subtotal	**290,120**	**841,879**	**841,879**
West Side Subregion				
Belridge Water Storage District	2015 AWMP (2014 Data)	36,885	138,757	138,757
Berrenda Mesa Water District	2015 AWMP (2014 Data)	24,204	85,003	85,003
Dudley Ridge Water District	2015 AWMP (2015 Data)	16,622	62,527	62,527
Lost Hills Water District	2015 AWMP (2014 Data)	27,900	112,048	112,048
	Subtotal	**105,611**	**398,335**	**398,335**
	Grand Total	**803,889**	**2,489,413**	**2,488,023**

Total urban and agricultural demand for the Kern Region is estimated at around 2.66 MAF/year (2.49 + 0.17 MAF/year). Assuming water use for agriculture demands remains constant, the projected 2035 total demand is estimated to be 2.75 MAF/year.

2.10 Water Related Infrastructure

The following sections include a discussion of the major water-related infrastructure within the Kern Region. In general, many Kern County communities are older and the physical components of their water systems are aging and outdated. Aging infrastructure is a particular

issue for rural communities and DACs. In recent years rapid development in some areas has provided new infrastructure, but this new infrastructure is limited to those areas receiving new development.

Water treatment improvements have been completed by KCWA, the City of Bakersfield, California Water Service Company (CWS), and North of the River Municipal Water District (NORMWD). Surface water improvements by agricultural districts have also been undertaken by AEWSD, KDWD, WKWD, and RRBWSD.

KCWA and other CVC Participants also expanded the CVC and constructed a 500 cfs intertie with the Friant-Kern Canal. Other communities are planning upgrades to their water treatment infrastructure. Part of the impetus for joining and participating in the Kern IRWMP is to identify infrastructure issues and potential collaborative projects to address infrastructure needs.

2.10.1 Imported Water Infrastructure

Imported water from the SWP or Westside CVP enters the Region through the California Aqueduct. The CVP also uses the Friant-Kern Canal to transport supplies into the Region. The Friant-Kern Canal and California Aqueduct are linked by KCWA's CVC and AEWSD's Intertie Pipeline (IPL), which allows water to be transported and exchanged between the facilities of the SWP and the CVP, as well as local surface water facilities (see **Figure 2-1**).

- The Friant-Kern Canal is 151.8 miles long and carries CVP water south from Millerton Lake just north of Fresno to the Kern River. The Canal has a maximum capacity of 5,000 cfs which decreases to 2,000 cfs at its discharge point into the Kern River. The Canal's capacity has been reduced due to subsidence; long term repairs are currently being pursued.
- The CVC is a local facility that is used to move water 22 miles from the California Aqueduct to Henry C. Garnett Water Purification Plant near Highway 204. With the exception of the last mile of the CVC, the canal is concrete-lined to minimize seepage losses. The CVC delivers water to a combination of participant water districts and water banking projects for agricultural, municipal and water recharge purposes. CVC conveyance capacity was expanded from 922 to 1,422 cfs. The expansion project was completed in 2012.
- The AEWSD bidirectional IPL conveys water from/to AEWSD's South Canal (and other areas of the district) to/from the California Aqueduct through a 4.5 mile 78" diameter pipeline. The IPL pumps water to the Aqueduct at approximately 175 cfs and can gravity back from the Aqueduct into its canal system at approximately 125 cfs. AEWSD completed the South Canal Improvement Project (SCIP) in 2009, which allows the district to reverse flow 9 miles of the South Canal so as to deliver Aqueduct water to its Tejon Spreading Works for banking as well as grower demands along the 9 mile stretch. The SCIP also increased the forward flow canal capacity among other things.

2.10.2 Surface Water Infrastructure

Isabella Dam and Reservoir, constructed in 1954 by the Army Corps of Engineers, operates primarily as a flood control reservoir and provides storage capacity for Kern River water. The Reservoir regulates stream flows for delivery to irrigation and groundwater recharge basins providing for water conservation and recreation benefits. Isabella Reservoir was designed to

store approximately 570,000 AF of water; however due to the aforementioned seepage, overtopping, and earthquake concerns, water storage in the Lake has been limited to approximately 60 percent of capacity. The US Army Corps of Engineers has completed the design of the Isabella Dam facilities with the intent of restoring reservoir capacity by 2022 (US Army Corps of Engineers 2019).

There are also multiple diversion and conveyance facilities used to carry Kern River, as well as Poso Creek water, to multiple users on the Valley floor. Some of the more significant canals include:

- AEWSD Intake Canal;
- AEWSD California Aqueduct Turn-out/Turn-in and South Canal;
- Beardsley Canal;
- Lerdo Canal;
- Calloway Canal;
- East Side Canal;
- Kern Island Canal;
- Stine/Farmers Canals; and
- Buena Vista Canal.

2.10.3 Groundwater Infrastructure

Groundwater recharge and recovery requires extraction wells, recharge basins and canals/pipelines to move water to recharge areas and recovered groundwater to areas where it will ultimately be used. It is estimated that nearly 30,000 acres are used for groundwater recharge operations in the Region. The Region has many operational wells for various purposes.

As described in Section 2.6.4.2, there are many large groundwater banking programs in the Region. Banking uses previously existing facilities, and facilities constructed specifically for banking programs. Typical groundwater infrastructure such as conveyance canals/pipelines, recharge basins, extraction wells, and motors including electrical requirements (distribution lines, transformers, starters, etc.), but also depends on connections to regional conveyance facilities. Banking activities (whether recharge or recovery) also require extensive management including but not limited to on-going maintenance of ponds or wells, power management, labor intensive (man power to safely operate ponds), water quality monitoring and watching groundwater levels. Groundwater banking programs have developed various interties to the regional conveyance systems including:

- Arvin-Edison Water Storage District's Intake Canal and South Canal/Aqueduct Intertie
- The Semitropical Intake Canal; and
- Kern Water Bank Canal.

2.10.4 Water Treatment Infrastructure

Multiple water districts, large and small, public and private exist in the Region. Water treatment for these various districts varies depending on the uses for the water. State law does not require

that water used for agricultural purposes be treated, though farmers and agricultural water districts may treat raw water to remove certain constituents and to add nutrients prior to using it for irrigation, particularly in high-efficiency drip or microsprinkler irrigation systems.

The State does have strict guidelines about the treatment and disinfection of surface water and groundwater used for domestic and drinking water. Drinking water infrastructure is subject to permitting and inspection by Kern County Environmental Health Services and the DDW. Large surface water treatment facilities in the Region include:

- Henry C. Garnett Water Purification Plant - facility is owned and operated by ID4. The plant treats Kern River, SWP and CVP water and has been expanded to 72 mgd. Treated water from this facility is distributed to CWS, City of Bakersfield, East Niles Community Services District, NORMWD, and the Oildale Mutual Water Company (OMWC).
- Northeast Bakersfield Water Treatment Plant (NEBTP) - 20 mgd facility owned and operated by the CWS that treats Kern River water provided to the northeastern area of the Greater Bakersfield area.
- North Garden Water Treatment Plant (NGWTP) – 8 mgd facility that is owned and operated by the CWS that serves northwest Bakersfield.
- Kernville – 1 mgd facility that treats Kern River water for Kernville and Wofford Heights and other small communities.

There are also multiple smaller treatment works in the Region, including activated carbon and ozone facilities that treat groundwater. Most of the purveyors providing groundwater for domestic use add small doses of chlorine to their distribution systems as a preventative measure against microbial contamination.

2.10.5 Wastewater and Recycled Water Infrastructure

As described in Section 2.6.5, there are 17 WWTPs in the Region. These WWTPs, produced volume, treatment levels, and resultant reclaimed water use are described in **Table 2-16**.

Table 2-17: Wastewater Treatment and Recycled Water in Region

Facility	Average Flow (mgd)	Average Flow (AFY)	Design Flow (mgd)	Treatment System	Effluent Use
City of Arvin	1.2	1,344	2	Secondary	Agriculture/ Percolation
City of Bakersfield					
WWTP #2	13.7	15,348	25	Secondary	Agriculture
WWTP #3	17.9	20,054	32	Secondary	Irrigation/Agriculture
Kern County Waste Management Department					
Kern Sanitation Authority	3.35	3,753	4	Secondary	Agriculture
Sheriff's Lerdo Facility	0.4	448	0.68	Secondary	Percolation
Reeder Tract	0.03	34	0.04	Secondary	Percolation
NOR Sanitary District No. 1	4.4	4,929	5	Secondary	Agriculture/ Percolation
City of Delano	4.4	4,929	7.2	Secondary	Agriculture
Lamont Public Utilities District	1.2	1,344	3.25	Secondary	Agriculture
City of McFarland	1	1,120	1.55	Secondary	Percolation
City of Shafter	1.2	1,344	2.5	Secondary	Agriculture/ Percolation
City of Wasco	1.4	1,568	3	Secondary	Agriculture
CCI WWTP	0.14	157	1.1	Tertiary	Irrigation
City of Tehachapi WWTP	0.8	896	1.25	Secondary	Percolation/Land Application
Golden Hills Sanitation Company	0.03	34	0.1	Tertiary	Surface Water Discharge
Bear Valley WWTP	0.05	56	0.25	Tertiary	Landscape/Surface Water Discharge
Stallion Springs WWTP	0.02	22	0.1	Secondary	Surface Water Discharge
Total	**51.22**	**57,383**			

As shown in the table, most WWTPs in the Region are treating water to secondary standards. Water treated to secondary standards can be used for:

- Orchards with no contact between edible portion and recycled water
- Vineyards with no contact between edible portion and recycled water
- Nonfood-bearing trees, including Christmas trees
- Fodder crops (e.g., alfalfa) and fiber crops (e.g., cotton)
- Seed crops not eaten by humans
- Ornamental nursery stock, sod farms

With additional treatment, it is possible to put recycled water to more extensive use. Under California law, tertiary treated water can be used for all of the above uses as well as:

- Food crops
- Parks and playgrounds, including school yards
- Landscaping

- Golf courses
- Pasture for milk animals
- Decorative fountains
- Fish hatcheries
- Groundwater recharge
- Commercial laundry
- Dust control
- Industrial process water (where there is no contact with workers)

2.11 Regional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for the Kern Region with respect to water resource management include the following, which are discussed in greater detail below:

- Aging and/or duplicative infrastructure
- Urban growth and water demand
- Urban growth encroachment on key recharge areas
- Decreased imported water supply
- Flood management
- Groundwater overdraft
- Legislative water use efficiency requirements
- Water quality/groundwater contamination
- Water rights
- Watershed protection
- Climate Change
- Protection of cultural resources
- Education, expertise, and new management to support infrastructure and regional planning efforts (i.e., public awareness, staffing/employment, governance)

2.11.1 Aging and/or Duplicative Infrastructure

The Region is home to some of the oldest settled areas in California, as well as to several DACs. Aging and/or substandard infrastructure is a particular issue for rural and disadvantaged communities in the Region. Due to the age of some of these communities, many of these water systems are quite old and in need of repair and replacement. However, these same small communities are least able to pay for system upgrades due to the high capital costs involved. In recent years rapid urban development in some areas has provided new infrastructure, but this new infrastructure is limited to those areas receiving new development.

Examples include substandard drinking water wells, master connected drinking water systems (where several individual households all rely on only one master connection to a water source), complete lack of treatment or low treatment contact times, pipeline leaks or breaks, inefficient pumps, inefficient and/or out-of-date electrical systems, corrosion (cathodic protection) problems, and other problems. Duplicative infrastructure is also found in some rural parts of the Region, where numerous small systems have been established that are wholly separate from

nearby systems. In these cases, no economies of scale have been realized for water distribution nor joint treatment systems constructed, either which can be due to physical (geographic or topographic) separation or perceived local political differences.

Part of the impetus for the Kern IRWMP is to identify infrastructure issues and potential collaborative projects to address infrastructure needs for both urban and agricultural sectors.

2.11.2 Urban Growth and Water Demand

One of the most pressing issues in California water is population growth and how urban water suppliers will meet increasing demands for potable supplies as well as commercial, institutional and industrial sector needs. The California Department of Finance forecast that by 2030, the state will have a population of over 44 million, compared to 39 million persons in year 2015.

In 2001, two water supply planning bills, Senate Bill 610 (SB 610) and Senate Bill 221 (SB 221), were enacted that require greater coordination and more extensive data to be shared between water suppliers and local land use agencies for large development projects and plans. SB 610, codified as Water Code Sections 10910 and 10911, requires the public water system that may supply water to a proposed residential development project of more than 500 dwelling units (or a development project with similar water use), to prepare a water supply assessment for use by the lead planning agency in its compliance with the California Environmental Quality Act (CEQA). Such a water supply assessment (WSA) is performed in conjunction with the land use approval process associated with the project and must include an evaluation of the sufficiency of the water supplies available to the water supplier to meet existing and anticipated future demands. SB 221 codified as Government Code section 66473, requires projects which include tentative tract maps for over 500 dwelling units to obtain verification from the water system operator that will supply the project with water, that it has a sufficient water supply to serve the proposed project and all other existing and planned future uses, including agricultural and industrial uses, in its area over a 20-year period, even in multiple dry years. SB 221 is intended as a “fail safe” mechanism to ensure that collaboration on finding the needed water supplies to serve a new large subdivision occurs before construction begins.

As growth in the Kern Region increases, and larger development projects are being proposed, the preparation of WSAs or written verifications pursuant to these bills is becoming increasingly more common, forcing some urban water purveyors in the area to question their ability to provide service to these developments. If water supplies were to be deemed unavailable, developers in the Region would be required to find water outside the Region in sufficient quantities to serve their projects.

Additionally, water agencies must coordinate with land use planning agencies in the development of their UWMPs, which include projections of future water demand and water supply availability during normal and dry periods. Water agencies and land use planning agencies within the Region are working together to ensure adequate management and planning for water supplies to meet the needs of growing communities.

2.11.3 Urban Growth Encroachment on Key Recharge Areas

As growth in the Kern Region increases and larger development projects are being proposed, the municipalities within the Region have been expanding their borders. This has resulted in

urbanization of lands that were formerly native and/or in agricultural use. Results of this urbanization include the paving of permeable recharge areas and encroachment of urban development on areas used for conjunctive use and/or recharge purposes. Loss of permeable areas and incompatible urban development near recharge areas could degrade the overall absorptive capacity of the groundwater basins of the Region. Several objectives developed by Region stakeholders relate to this issue, and are mainly focused on identifying, protecting and increasing prime recharge areas and the vital storage capacity they provide. When incorporated into project design, these areas may also provide multiple benefits to include wildlife habitat, as well as open space for recreation and education.

As a means of achieving these objectives, water agencies and land use planning agencies will attempt to coordinate in the development of general plans and other land use planning documents to ensure that recharge areas are protected and to ensure adequate management and planning for water supplies to meet the needs of growing communities.

2.11.4 Decreased Imported Water Supply

Since 1994, the two large projects that import water into the Kern Region, the CVP and the SWP, have been incrementally impacted by environmental and regulatory requirements that have served to diminish the ability of the projects to reliably deliver water supplies. A large proportion of recent imported water cutbacks has stemmed from the following: (1) fishery issues in the Sacramento-San Joaquin Delta, where the pumping plants for the CVP and SWP are located, (2) the San Joaquin River Settlement or Public Law 111-111 where water previously supplied to the CVP Friant Division for M&I and agricultural irrigation is being diverted into the San Joaquin River for in-stream flows (see section 2.6.1 for more details on the settlement).

In May 2007 the US District Court ruled that the existing 2005 biological opinion for Delta smelt, a small fish found in the Delta, issued by the USFWS, did not comply with the Endangered Species Act. The biological opinion had guided pumping operations for the CVP and SWP to ensure no long-term jeopardy to the health and habitat of Delta smelt. Until a revised biological opinion is prepared by the federal agencies, the Court ordered certain “remedies” or actions to protect the endangered fish species. Those remedies, imposed in the decision, collectively amounted to a cut in statewide water supply of as much as 30 percent in certain hydrologic year types, or nearly 2 MAF. The remedies were finalized in December 2008. On-going court battles continue to change CVP and SWP operations at the time of the IRWMP.

In June 2009, additional restrictions on the water projects were announced, further reducing the amount of water available. These additional cutbacks were outlined in a biological opinion for Chinook salmon, steelhead and green sturgeon, issued by the National Marine Fisheries Service. The new biological opinion increases restrictions on water project operations even though the projects are currently limited by existing restrictions to taking no more than two percent (2%) of the listed salmon populations in the Delta. DWR has forecasted that these restrictions would cut an additional 10 percent from statewide water deliveries (300,000 to 500,000 AF) on average, expected to begin in 2010. Public water agencies throughout the state have filed lawsuits challenging the opinion. Recently, a federal court ruled in favor of water agencies, ordering the federal fish agencies to comply with environmental laws and take into account the harm that the water cutbacks have on people due to economic impacts.

Public water agencies filed for an injunction early in 2011 to prevent regulatory agencies from implementing Fall X2, which is one of the more restrictive elements of the previously-overturned

biological opinion (X2 is the location where freshwater from the Sierra watershed and saltwater from San Francisco Bay meet in the Sacramento-San Joaquin Delta). The U.S. Fish and Wildlife Service had proposed a measure to release much larger than usual amounts of freshwater from the state's reservoirs during 2011 to move the X2 location westward. The proposal was based on a highly disputed hypothesis that moving this intersection of salt and fresh waters would lead to increased delta smelt populations.

Under the federal proposal, the SWP would have faced losses from 300,000 AF up to 670,000 AF of water. The judge ordered a modified proposal that greatly minimizes these water supply impacts.

Late in 2011, a court decision threw out parts of a management plan to protect endangered salmon, steelhead and other species in the Sacramento-San Joaquin Delta. The court invalidated parts of the U.S. National Marine Fisheries Service's biological opinion, calling the plan "arbitrary, capricious, and unlawful." The previous salmon and steelhead management plan was thrown out by the same judge in 2008, which led the government to release the new proposal a year later. The court held that pumping operations negatively impact the fish and adversely modify their critical habitat, but this latest decision means the agency must rewrite the biological opinion again.

The most immediate impacts of the cutbacks have occurred in agricultural communities in the Kern Region and the Tulare Lake Hydrologic Region as a whole, as farmers have been forced to abandon and/or alter crop planting plans and districts have been forced to increase groundwater extractions and limit recharge. This has caused severe economic impacts in the Region, to its DACs in particular. It is estimated that due to drought and decreases in imported water supply, about 45,000 acres of farmland in the Region will be idled and an additional 100,000 acres will be under-irrigated. In late 2008, the U.S. Department of Agriculture designated Kern County as a primary natural disaster area because of losses caused by drought that has occurred since October 2007, and during the preparation of this Plan. Long-term there is a concern that cutbacks and pumping restrictions will limit the ability of the Region to acquire surplus water in wet and very wet hydrologic year types. This surplus water is vital to the conjunctive use and banking programs pioneered and relied upon by both agricultural and urban water districts throughout the Region.

The Region stakeholders determined that the issue of decreased water supply is the most pressing issue for the Region, and as a result IRWMP Stakeholders have made "Increase Water Supply" a primary Regional objective.

2.11.4.1 Dependence on Delta Supply

As discussed above, the Kern Region has a strong dependence on the Sacramento-San Joaquin Delta water supply. Through the implementation of the Kern IRWMP, including implementation of local water supply projects, collaboration and coordination of water agencies, and water efficiency and conservation projects, the Region will be able to reduce its dependence on Delta water supplies.

2.11.5 Flood Management

Floods occur when runoff exceeds the capacity of a river or stream channel, overflowing into adjacent low-lying lands called floodplains. Human activities in floodplain areas often contribute to flood damage.

Physical damage from floods includes the following:

- Inundation of structures, causing water damage to structural elements and contents.
- Erosion or scouring of stream banks, roadway embankments, foundations, footings for bridge piers, and other features.
- Impact damage to structures, roads, bridges, culverts, and other features from high-
- velocity flow and from debris carried by floodwaters. Such debris may also accumulate on bridge piers and in culverts, increasing loads on these features or causing overtopping or backwater effects.
- Destruction of crops, erosion of topsoil, and deposition of debris and sediment on croplands.
- Release of sewage and hazardous or toxic materials as WWTPs are inundated, storage tanks are damaged, and pipelines are severed.

Floods also cause economic losses through closure of businesses and government facilities, disruption of communications and the provision of utilities such as water and sewer, result in excessive expenditures for emergency response, and generally disturb the normal functions of a community. Flood management strategies recommended in this document will serve as guidelines to address concerns and prevent some of the damage listed above.

The key issues, needs, challenges, and priorities for the Kern County portion of the Tulare Lake Basin with respect to flood management include the following, which are discussed in greater detail below:

- *Lack of coordination throughout the Region;*
- *Poor water quality of runoff;*
- *Nuisance water and dry weather runoff; and*
- *Difficulty providing flood control without interfering with groundwater recharge.*

As described earlier, the primary flood control facility in the Region is Isabella Dam on the Kern River. The dam protects the urban Bakersfield area and about 350,000 acres of agricultural land and oilfields. Kern River had an unregulated flow until 1954 when the Isabella Dam and Reservoir were constructed by the Army Corps of Engineers. Unfortunately, due to seepage, overtopping, and earthquake concerns, the flood control capacity of the reservoir has recently been limited.

Other flood management efforts in the Region are currently performed by local jurisdictions within their particular areas, but there is not a regional entity that coordinates flood control for the entire Kern County Region. For example, KCWA has limited flood control responsibilities throughout Improvement Districts Nos. 1 and 3 which lie in the Rosedale area of Bakersfield and east of Isabella Reservoir, respectively. KCWA also sponsored the Kern River – California Aqueduct intertie which was constructed by the Army Corps of Engineers in 1977 as a measure to channel Kern River flood water into the Aqueduct to prevent erosion damages downstream of the intertie.

Several local land use entities, including the County of Kern, participate in the National Flood Insurance Program (NFIP) as administered by the Federal Emergency Management Agency (FEMA). By adopting flood damage prevention ordinances to regulate development in special flood hazard areas, private property owners in participating communities are allowed to

purchase affordable flood insurance through NFIP, while the community retains its eligibility to receive certain federally backed monies, and disaster relief funds. In addition, both the City of Bakersfield and the County of Kern participate in the state-mandated Kern River Designated Floodway Program, which is administered by the DWR Reclamation Board. The Kern River Designated Floodway Program provides development criteria and issues permits for development within the limits of the Kern River Designated Floodway.

The FEMA Flood Insurance Rate Map for the Kern Region designates multiple areas as "High Risk", areas with a 1 percent or greater risk of flooding in any year and a 26 percent chance of flooding over the life of a 30-year mortgage. The area at greatest flood risk is the area surrounding the communities of Lamont, Weedpatch, and the City of Arvin. Other large flood area includes the Buena Vista lakebed as well as areas in the historic Tulare lakebed and nearby drainage areas. Areas along the Kern River and other local streams are also considered to have a high flood risk. These areas are depicted in **Figure 2-8**.

Flood management is generally guided by local, State, and Federal entities but relies upon the local communities for implementation. Local communities like cities, through the adoption of ordinances and the formation of special districts, manage development in floodplains and implement flood mitigation projects that prevent flood damages.

2.11.6 Groundwater Overdraft and SGMA

2.11.6.1 Groundwater Overdraft

One of the longest-standing issues in the Kern Region is groundwater overdraft. Groundwater pumping in the Region has been high since the area was settled in the late 1800s, and today groundwater provides approximately 39 percent of local water needs. Certain portions of the groundwater basin underlying the Region have experienced overdraft conditions. According to DWR Bulletin 118, the basin generally underlying the Region experiences a net loss to storage of approximately 325,000 AFY.

2.11.6.2 Sustainable Groundwater Management Act (SGMA)

In response to California's recent drought (2012-2017), the state legislature passed the Sustainable Groundwater Management Act (SGMA) that became law in November 2014. SGMA, collectively contained in Senate Bill (SB) 1168, SB 1319, and Assembly Bill (AB) 1739, mandates that groundwater basins determined by DWR to be high or medium priority to have Groundwater Sustainability Plans (GSPs) developed and implemented to have the groundwater basin become sustainable. Within the Kern Region, the San Joaquin Valley – Kern County groundwater basin (DWR Groundwater Basin 5-22.14) is designated as a high priority basin that is critically overdrafted, and the San Joaquin Valley – White Wolf groundwater basin (DWR Groundwater Basin 5-22.18) is designated as a medium priority basin.

SGMA empowers local agencies to form Groundwater Sustainability Agencies (GSAs) to prepare GSPs and manage basins sustainably. The GSAs that have been formed in the region are shown in **Figure 2-9**. The GSAs are required to prepare GSPs by 2020 and the basins are to reach sustainability within 20 years (2040). The GSP must include monitoring and management over a 50-year planning horizon.

GSPs must include measurable objectives to achieve the goal of basin sustainability within 20 years of implementation. SGMA defines the sustainability goal as the implementation of one or

more GSPs that achieve sustainable groundwater management by ensuring the basin is operated within the sustainable yield. Sustainable yield is the maximum quantity of water that can be withdrawn from the basin over a period of years without causing an undesirable result. Undesirable results include effects caused by the following:

- Chronic lowering of groundwater levels;
- Significant and unreasonable reduction of groundwater storage;
- Significant and unreasonable seawater intrusion;
- Significant and unreasonable degraded water quality;
- Significant and unreasonable land subsidence that substantially interferes with surface land uses; and
- Depletions of interconnected surface water that have significant and unreasonable adverse impacts on beneficial uses of surface water.

2.11.7 Legislative Water Use Efficiency Requirements

As water shortages and increasing demands upon infrastructure occur throughout the country, water conservation planning, technologies and practices are evolving today at an unprecedented rate. Legislation has been enacted to reduce various sectors' dependence on potable water will be impacted.

2.11.7.1 Federal Legislation

Executive Order (EO) 13123, Greening the Government through Efficient Energy Management (1999), is a federal directive to government agencies for the implementation of measures to reduce water use. This order directs federal government agencies to reduce potable water use and incorporate cost-effective water conservation measures in their facilities by 2010. Another aspect of the order is Federal agencies must report baseline water usage and report on water usage every two years.

2.11.7.2 State Legislation

The state of California has been progressive in legislating water conservation policies and measures. Described below are existing State laws relevant to water conservation.

2.11.7.2.1 Urban Water Management Planning Act

The Urban Water Management Planning Act was enacted in 1983 and has been amended many times since then. The Act states that every urban water supplier that provides water to 3,000 or more customers, or that provides over 3,000 AF of water annually, should make every effort to ensure the appropriate level of reliability in its water service sufficient to meet the needs of its various categories of customers during normal, dry, and multiple dry years. The Act describes the contents of the UWMPs as well as how urban water suppliers should adopt and implement the plans. The intent of the Act is to encourage water management planning commensurate with the numbers of customers served and the volume of water supplied.

2.11.7.2.2 Assembly Bill 1881

Assembly Bill 1881 built upon many past legislative acts related to landscape water use efficiency. AB 1881, the Water Conservation in Landscaping Act of 2006, enacted many landscape efficiency recommendations of the California Urban Water Conservation Council (CUWCC) for improving the efficiency of water use in new and existing urban irrigated

landscapes in California. AB 1881 required DWR, not later than January 1, 2009 to update the existing Model Local Water Efficient Landscape Ordinance and local agencies to adopt the updated model ordinance or an equivalent no later than January 1, 2010. DWR has completed the update of the Model Local Water Efficiency Landscape Ordinance. The law also requires the Energy Commission to adopt performance standards and labeling requirements for landscape irrigation equipment, including irrigation controllers, moisture sensors, emission devices, and valves to reduce the wasteful, uneconomic, inefficient, or unnecessary consumption of energy or water.

The Model Local Water Efficient Landscape limits the water budget for new landscapes (or rehabilitated landscapes), greater than 2,500 square feet, to 70 percent of the local reference ET. The model ordinance lays out the procedures for evaluating potential landscape water use during the land development process. In addition, the ordinance contains requirements for planting as well as the design and maintenance of irrigation systems, all with the intent of limiting outdoor water use and avoiding irrigation runoff.

2.11.7.2.3 Assembly Bill 1420

AB 1420, passed in 2007 and in effect as of January 2009, changes the funding eligibility requirements of Section 10631 of the Water Code (Urban Water Management Planning Act). For any urban water supplier to be eligible for grant or loan funding administered by DWR, the SWRCB, or the Bay-Delta Authority (such as Propositions 50 and 84), the supplier must show implementation the 14 water use efficiency demand management measures/best management practices (DMMS/BMPs) listed and described in the UWMP Act and the CUWCC MOU, or show the schedule by which the supplier will begin implementing the DMMs/BMPs. Any supplier not implementing the measures based on cost-effectiveness must submit proof showing why the measures are not cost-effective.

2.11.7.2.4 AB 2882

This bill was passed in 2008 and encourages public water agencies throughout California to adopt conservation rate structures that reward consumers who conserve water. Prior to AB 2882 state law authorized water agencies to promote conservation using rate structures; however, some agencies were concerned that such rate structures may be inconsistent with other parts of state law. AB 2882 clarifies the allocation-based rate structures and establishes standards that protect consumers by ensuring a lower base rate for those who conserve water.

2.11.7.2.5 SBX7-7

Senate Bill 7 of Special Extended Session 7 (SBX7-7) was signed into law in November 2009, which calls for progress towards a 20 percent reduction in per capita water use statewide by 2020. As a result, the legislation now mandates each urban retail supplier to develop and report a water use target in the retailer's 2010 UWMP. The legislation further requires that retailers report an interim 2015 water use target, their baseline daily per capita use and 2020 compliance daily per capita use, along with the basis for determining those estimates. SBX7-7 provides four possible methods for an urban retail water supplier to use to calculate its water use target. DWR has also developed methodologies for calculating base daily per capita water use, baseline commercial, industrial and institutional water use, compliance daily per capita water use, gross water use, service area population, indoor residential water use and landscape area water use. Agencies not in compliance with SBX7-7 will be ineligible for state loan and grant funding.

2.11.7.2.6 SB 606 and AB 1668

SB 606 and AB 1668 establish guidelines for efficient water use and a framework for the implementation and oversight of new standards, which must be in place by 2022. The guidelines include the following provisions:

- Establishing water use objectives for efficient water use that apply to water purveyors for indoor and outdoor residential water use, commercial, industrial, and institution irrigation.
- Providing incentives for water suppliers to recycle water.
- Providing recommendations for small water systems that may be in risk of drought and water shortage vulnerability.
- Requiring both urban and agricultural water suppliers to set annual water budgets and prepare for drought.

2.11.7.3 Agricultural Conservation-Related Legislation

Legislation has been enacted and is currently being considered to encourage reduced dependence on imported water and groundwater for agricultural uses.

2.11.7.3.1 Assembly Bill 3616

This bill was enacted in 1990 and authorized the development of Agricultural Water Management Plans (AWMP) and the formation of the Agricultural Water Management Council (AWMC). Entities join the AWMC by signing the Agricultural MOU Regarding Efficient Water Management Practices (EWMPs) by Agricultural Water Suppliers in California. Entities signing the MOU voluntarily pledge to undertake the following activities:

- Prepare a water management plan and identify efficient water management practices that will be implemented;
- Perform a comprehensive Net Benefit Analysis on EWMPs to establish cost-
- effectiveness of each EWMP for implementation.
- Net Benefit Analysis takes into consideration the technical, environmental, socioeconomic, financial and third party factors, thus helping to determine whether and in what manner implementation may be appropriate.
- Implement, in a timely manner, those EWMPs found to provide benefit in a cost effective manner.
- Prepare progress reports on implementation of EWMPs and results on a biannual basis.

2.11.7.3.2 SBX7-7

SBX7-7, as discussed above, also contains requirements for agricultural water suppliers. All agricultural water suppliers, either publicly or privately owned which irrigate 10,000 or more acres are required by SBX7-7 to implement critical Efficient Water Management Practices (EWMPs) and additional EWMPs if locally cost effective and technically feasible. Affected agricultural water suppliers must implement EWMP's by July 31, 2012. Critical EWMPs include:

- Each agricultural water supplier is to measure the volume of water delivered to customers with sufficient accuracy to comply with standards set by DWR.
- Each agricultural water supplier is to develop a pricing structure for water customers, based at least in part on the volume of water delivered.

SBX7-7 also created the Agricultural Water Management Planning Act, which requires affected agricultural water suppliers to adopt AWMPs. These plans facilitate management and conservation of water suppliers, and also guide and document the implementation of EWMPs. The plans are mandatory for many suppliers and are required to be completed and adopted for affected agricultural water suppliers by December 31, 2012. AWMPs are to be updated every 5 years.

2.11.8 Water Quality/Groundwater Contamination

2.11.8.1 Groundwater Quality

Quality of local groundwater supplies in general are good throughout the Region, is useable for agricultural purposes, and meets drinking water standards. Exceptions are areas that have exceeded MCLs for a variety of compounds. Some of these are due to the long history of oil and gas drilling in the Region (sulfate, 1,2-dibromo-3-chloropropane [DBCP], Ethylene Dibromide [EDB], organics, inorganics), and others are due to long term agricultural activities (nitrate, pesticides, 1,2,3-TCP, volatile organic compounds [VOCs]). Some contaminants, such as arsenic and radiologic compounds, are naturally occurring in certain areas of the Region. Problems associated with shallow groundwater include TDS, sodium chloride and sulfate, which can be problematic for agriculture. The water supplies of some DACs in the Kern Region have been impacted by one or more contaminants. As a result, many areas are required to abandon wells, blend water from multiple wells, and/or install water treatment facilities.

The Tulare/Kern Funding Area Preliminary Needs Assessment (January 2019) was prepared under the Disadvantaged Community Involvement Program to provide a better understanding of the water management needs of the DACs. The Assessment identified the DACs that are out of compliance with water quality standards; many of these communities are shown in **Figure 2-10**.

2.11.8.2 AB1249 – Inorganic Constituents

In 2014, AB 1249 was enacted into law which requires IRWMPs to discuss nitrate, arsenic, perchlorate, and hexavalent chromium (Cr6) that occur within the IRWM boundary. Specifically, the IRWMP must identify the location and extent of the contamination, the impact on communities, existing efforts the region is taking to address the impacts, and any additional efforts that are needed to address the impacts.

2.11.8.2.1 Location and Extent of Contamination

Three of the contaminants have been found to be present in the region. The State Water Board Groundwater Ambient Monitoring and Assessment (GAMA) Program was used to obtain sampling data for these four constituents. Sampling results for these contaminants are shown in **Figure 2-11**. The following are the 2018 sampling results for each contaminant:

- Nitrate: The dataset resulted in 211 samples that exceeded the MCL for Nitrate as Nitrogen (10 mg/L). These high nitrates occur throughout the region as shown in the figure. Based on the Preliminary Needs Assessment, approximately 8 DAC water systems are not in compliance with the arsenic water standard.
- Arsenic: The dataset resulted in 718 samples that exceeded the MCL for arsenic (0.010 mg/L). These arsenic exceedances occur throughout the region as shown in the figure.

Based on the Preliminary Needs Assessment, approximately 9 DAC water systems are not in compliance with the arsenic water standard.

- Perchlorate: The dataset resulted in 68 samples that exceeded the MCL for perchlorate (0.006 mg/L). These perchlorate exceedances occur in the Cummings Groundwater Basin; however, no water systems are out of compliance due to this contaminant.
- Hexavalent Chromium: Hexavalent Chromium has not been found to occur in the region above the 0.010 mg/L limit. Prior samples collected with this constituent have been below the MCL.

2.11.8.2.2 Impacts Caused by Contamination

The following are potential impacts that are caused by the different contaminants:

- Nitrate: Ingestion of nitrate can lead to the inability of red blood cells to carry oxygen to the tissues of the body, producing a condition called methemoglobinemia, which can particularly affect babies (aka "blue baby syndrome"). These impacts are most often observed in the very young or elderly segments of the population. None of these symptoms have been reported within the Region in the information consulted for this study.
- Arsenic: The potential impacts caused by exposure to arsenic include acute and chronic toxicity. Acute toxicity is not commonly an impact from drinking water ingestion. Long-term exposure could have cancerous effects and other effects such as cardiovascular, pulmonary, immunological, or other diseases. It is difficult to determine the impacts of this constituent on the communities that have this contaminant in their drinking water.
- Perchlorate: The potential impacts of perchlorate in drinking water include disruption of the thyroid gland, which can cause irregular heart rate, blood pressure, temperature, and metabolism. For fetuses and infants, the thyroid hormone is critical for development. Other impacts can be eye and skin irritation, coughing, nausea, vomiting and diarrhea. None of these impacts have been reported in the Region.
- Hexavalent Chromium: No impacts have occurred since this contaminant has not been above the MCL.

2.11.8.2.3 Existing Efforts to Address Contamination

The water purveyors in the region have been proactive in treating for contaminants in their water supply. Treatment systems, blending operations, consolidation with other water systems, and well abandonment have been implemented for many communities to address nitrate and arsenic contamination (perchlorate and Cr6 have not required treatment as they have not impacted the water systems). The larger water purveyors have been able to implement treatment systems as needed to maintain compliance with drinking water standards. Smaller water systems, especially DACs, are slower to implement treatment due to funding constraints and longer time periods required to obtain grant/loan funding.

Table 2-18 is a list of communities in the Region that have a contaminant compliance issue along with the current remediation that is planned for that community. Note that the four communities at the bottom of the list have been returned to compliance.

2.11.8.2.4 Additional Efforts Needed to Address the Contamination

Based on the list in **Table 2-18,** there are approximately 9 communities that need to address an AB 1249 listed contaminant. In order to accomplish this effort, additional funding will be needed

to implement water treatment systems, consolidation projects, and replacement groundwater wells.

Other remediation efforts can also help address these contaminants through the following projects:

- Construction of regional surface water treatment plants.
- Construction of groundwater recharge basins to displace or dilute contaminants below the MCL.
- Reduce nitrogen applications from fertilizers.
- Reduced groundwater pumping where the aquifer level affects arsenic concentrations.
- Replacement of septic systems with sewers to regional wastewater treatment plants thereby reducing nitrate contamination.

TABLE 2-18: Status of Communities With AB 1249 Contaminants

COMMUNITY NAME	COMPLIANCE STATUS	COMPLIANCE ISSUE	REMEDIATION
ARVIN	Out-Of-Compliance	Arsenic MCL	$14M Grant Requested for treatment
LAMONT	Out-Of-Compliance	1,2,3-TCP, Arsenic MCL	$457K Grant Requested for Treatment
R.S. MUTUAL WATER COMPANY	Out-Of-Compliance	Arsenic, Combined Uranium, Nitrate MCL	$538K Grant Requested for Consolidation
EL ADOBE POA, INC	Out-Of-Compliance	Arsenic MCL	$5M Grant Requested for Consolidation
LAKE OF THE WOODS	Out-Of-Compliance	Nitrate, Fluoride MCL	Frazier Park PUD - Planning Phase of Consolidation
RAINBIRD VALLEY	Out-Of-Compliance	Combined Uranium, Nitrate MCL	Planning Phase of Consolidation
EAST WILSON ROAD	Out-Of-Compliance	1,2,3-TCP, Nitrate-Nitrite, E. Coli, Nitrate MCL	
GREENFIELD COUNTY WD	Out-Of-Compliance	Arsenic MCL	
HUNGRY GULCH	Out-Of-Compliance	Arsenic, Total Coliform MCL	
LAKEVIEW RANCHOS	Out-Of-Compliance	Arsenic, Combined Uranium MCL	
METTLER	Out-Of-Compliance	1,2,3-TCP, Nitrate MCL	
OASIS PROPERTY OWNERS ASSOCIATION	Out-Of-Compliance	Arsenic MCL	
SAN JOAQUIN ESTATES	Out-Of-Compliance	1,2,3-TCP, Nitrate-Nitrite, Nitrate MCL	
WILSON ROAD	Out-Of-Compliance	1,2,3-TCP, Nitrate-Nitrite, Nitrate MCL	
WINI MUTUAL WATER COMPANY	Out-Of-Compliance	1,2,3-TCP MCL, Nitrate MCL	
FOURTH STREET	Returned to Compliance	Arsenic MCL	
KERNVALE	Returned to Compliance	Arsenic, Nitrate MCL	
PINON HILL WATER COMPANY	Returned to Compliance	Arsenic MCL	
VALLEY VIEW ESTATES	Returned to Compliance	Nitrate MCL	

Source: Preliminary Needs Assessment (2019)

2.11.8.3 Surface Water Quality

Since SWP water originates in rivers and streams in central and northern California and travels through the peat soils of the Sacramento-San Joaquin Delta to the Region, it is generally high in TDS, organics and bromide, although levels of these constituents can vary with hydrology given year. If imported SWP water is treated for drinking water purposes, the organics and bromide can form disinfection by-products, which at certain levels may raise health concerns. Water entering the Region via the Friant-Kern Canal of the CVP originates in the central Sierra Nevada as snowpack runoff stored in Millerton Lake. Therefore, it is generally of good quality.

2.11.8.4 Irrigated Lands Regulatory Program

Due to pollutants (i.e. pesticides, fertilizers, salts, pathogens, and sediment) found in runoff from irrigated lands that impact surface water and groundwater, the Irrigated Lands Regulatory Program was initiated in 2003 to prevent agricultural runoff from impairing waters. In 2013, the CVRWQCB adopted General Order (Order R5-2013-0120) that requires any commercial irrigated land having the potential to discharge to surface water or groundwater to comply with requirements set forth by the CVRWQCB.

Much of the lands within the Kern Region have obtained regulatory coverage under a coalition that assists with compliance with the General Order. There are multiple coalitions that have been established within the region including the Kern River Watershed Coalition Authority, Buena Vista Coalition, Cawelo Water District Coalition, and the Westside Water Quality Coalition. The coalition works directly with its members to assist with compliance, monitoring, and reporting.

2.11.9 Water Rights

At the local Region level, the Kern River has had its share of historical controversy, with Kern River water rights disputes often settled by negotiated agreement. Numerous participants rely on the Kern River and for some IRWMP stakeholders it represents their entire water supply. As such, the Kern RWMG recognizes the importance of the Kern River and role of the Kern IRWMP in the protection, restoration and long-term management of the Kern River watershed in order to improve the health of the watershed and protect this water supply for its users.

The Kern IRWMP water supply analysis is based on assumptions made regarding availability and reliability of the Kern River supply and was used to identify specific planning objectives for the IRWMP. Thus, it is possible that the outcome of water rights hearings may require a change in these assumptions as well as the Regional objectives, and may delay implementation of the IRWMP. Additionally, water rights hearings could have outcomes that may place limitations not considered on various groundwater banking and recharge projects included for implementation.

2.11.10 Watershed Protection

Increased flooding, aftereffects of forest and brush fires, diminishing water availability and quality, and the loss of critical habitat for fish and wildlife are key issues facing the Kern Region. The entire Region depends on river, stream and creek production of reliable supplies of clean water to support human communities and natural habitats, restore resources and provide for agricultural production. Historic land-use practices have placed many downstream property owners at risk and created a tension between public safety and resource protection needs. In order to move forward on increasingly critical water issues, citizens, interest groups, and government agencies must develop more comprehensive, collaborative, and coordinated ways of solving problems, and this is an objective of the Kern Region stakeholders.

There are a variety of constraints and challenges to the effective implementation of watershed planning. Development of comprehensive watershed management plans, including recommendations for action and specific projects, could be time consuming and expensive. Depending upon the recommendations that result from the stakeholder and consensus driven planning process, the constraints and challenges can be minimized. Another constraint involves

the consensus process itself. It is not always possible to reach consensus among diverse members or reconcile conflicting interests or needs.

2.11.11 Climate Change

Climate change refers to significant changes in temperature, precipitation, wind patterns and other weather that occur over several decades and beyond. Climatic changes observed in recent decades are occurring due to rising average global temperatures that are the result of elevated levels of gases released primarily by human activities, which trap heat in the atmosphere in a process known as the greenhouse effect. These so-called greenhouse gases (GHGs) include, among others, water vapor, carbon dioxide (CO2) and methane (CH4).

Climate change is expected to have various impacts on the Kern Region including:

1. fluctuations in temperature resulting in longer and drier conditions over the year, and associated impacts on water quality and flooding;
2. changing hydrology, and the resultant impacts to conjunctive use operations, due to a shift from snow to rain precipitation;
3. higher wildfire risk due to warmer, drier conditions over the year, and associated impacts on water quality and flooding;
4. longer and more severe multi-year droughts;
5. greater summer water demand from all categories of users; and
6. impacts to habitats and species.

The historical average annual temperature in the Kern Region is 61.4°F; different climate scenarios project increases of 3.5°F and 6.3°F by the end of the 21st century. The months of February, March, and May are shown to have the largest temperature response. The net result is milder winter temperatures, an earlier arrival of spring, and increased summer temperatures. Under this model, snow accumulation is significantly decreased in all months, with snow accumulation still beginning in November but with lower monthly accumulations and ending about a month earlier (large decreases in April I snowpack.) The impact would be much less in the higher elevation of southern Sierra. For example, in the San Joaquin River and Tulare Lake hydrologic regions, about 70 percent of the snow zone would remain. It is anticipated that the overall ET will increase while soil moisture will generally decline except in areas where precipitation will significantly increase. The higher water consumption with warmer temperatures will likely only be partially offset by the carbon dioxide-based reductions. Thus, the net result could be slightly higher agricultural water requirements. Warmer winter temperatures between storms would be expected to increase ET, thereby drying out the soil between storms. Changes in recharge will result from changes in effective rainfall as well as a change in the timing of the recharge season.

Potential impacts of climate change are projected for the SWP and for the Delta, which are both related to the Kern Region's imported water supplies. Since the Region is reliant on imported SWP supplies as part of its overall supply mix, any reduction or change in the timing of availability of those supplies could have negative impacts on the water supply of the Region. It is possible that local surface flows could also be reduced by changes in snowpack altitude levels and/or quantity of snowpack in the Sierra Nevada and other regional mountain ranges, which would reduce natural recharge, thus exacerbating groundwater availability problems.

The California Climate Change Center evaluated impacts to the Delta, the SWP, and the CVP. The California Climate Change Center projects that warmer air temperatures will cause sea level rise. Projections anticipate a sea level rise between 0.4 feet and 1.2 feet by mid-century to as much as 3.9 feet by the end of the century. Rising sea levels will bring saline ocean water further into the Delta and will require that additional fresh water be released from reservoirs to maintain water quality (California Climate Change Center 2009). By mid-century, Delta exports could decrease by 7 to 10 percent and by as much as 25 percent by the end of the century. Carryover storage (water held in storage from one water year to the next) in the SWP and CVP systems would decrease by up to 19 percent by mid century and by up to 38 percent by the turn of the century.

The California Natural Resources Agency released the 2009 Climate Adaptation Strategy. This report analyzes potential climate change impacts and risks for various sectors including public health, forestry, transportation, agriculture and water management. This report predicts the following agricultural impacts related to climate change:

- Crop yield changes
- Changes in crop type
- New weed invasions
- New disease and pest invasions
- Flooding and crop pollination changes
- Heat waves and crop stress leading to lower crop yield, vulnerability to pests
- Heat waves leading to animal stress, vulnerability to disease, and lower meat/milk/egg production Lack of water available for agriculture and livestock
- Increased fire risk to rangeland

In theory, Central Valley agriculture could be helped by higher levels of atmospheric carbon dioxide, which acts as a fertilizer as well as a longer growing season and fewer freezing temperatures. However, these changes are accompanied by other factors that harm agriculture, including weed and pest migration and crop pollinator timing changes. Several valuable crops require a certain amount of chill hours in the winter. The number of winter chill hours has statistically declined since 1950, with the greatest decline in the northern portion of the Central Valley. Grapes, almonds, and cherries are some of the crops that would be affected by reduced chill hours. Specific crop models predict that the yield of Kern County grapes will decline as much as 5 percent by year 2030 and that the yield of cherries will decrease by as much as 15 percent.

In 2006, California passed AB 32, the Global Warming Solutions Act, which has committed California to reducing the state's greenhouse gas emissions to 2000 levels by 2010 (approximately 11 percent below business as usual), to 1990 levels by 2020 (approximately 25 percent below business as usual), and to 80 percent below 1990 levels by 2050. The California Air Resources Board (CARB) is charged with developing the appropriate regulations and reporting system to effectively implement the caps on emissions. AB 32 requires that CARB use the following principles to implement the caps: distribute benefits and costs equitably; ensure that there are no direct, indirect, or cumulative increases in air pollution in local communities; protect entities that have reduced their emissions through actions prior to this mandate; and allow for coordination with other states and countries to reduce emissions. Consistent with AB 32, actions ranging from assessments of one's carbon footprint and carbon trading, to use of

alternative energies, to reduction of emissions through direct conservation of both water and energy, for example, will likely be expected of many organizations and even individuals dealing directly and indirectly with water throughout the state. Counties, cities, water agencies, water purveyors, and water consumers can all expect to be affected by this legislation.

2.11.11.1 Potential Adaptation Strategies

The California Natural Resources Agency has identified several climate change adaptation strategies for water management systems. One of the primary strategies is the preparation of IRWMPs. Integrated regional water management planning can be used to improve the coordination of local resources, including groundwater storage and banking, conjunctive use with surface runoff, and utilization of flood flows. Other adaptation strategies identified by the California Natural Resources Agency include:

- Aggressive water use efficiency in urban and agricultural sectors
- Use of recycled water (where energy efficient)
- Integrated flood management (projects to reduce flood peaks while increasing aquifer recharge and environmental water flows)
- Development of a Central Valley Flood Protection Plan
- Local emergency flood preparedness
- Land use policies to decrease flood risk
- Establishment of flood plain corridors
- Expand water storage
- Protection of recharge areas

Many of these strategies are currently in use in the Region or are planned to be implemented, and are identified within the Objectives of this IRWMP, as described below.

- Water Use Efficiency. Stakeholders of this IRWMP have identified water use efficiency as an important component of water supply planning. One of the stated objectives of this IRWMP is to “Pursue and implement cost effective water use efficiency programs.” In addition to direct water use efficiency, stakeholders have expressed a desire to improve system operation, reduce system water loss, and decrease energy use related to water infrastructure. Another objective of this IRWMP is to “Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions.”
- Recycled Water. Nearly all wastewater effluent produced by the various treatment facilities in the County can be applied to non-food crop irrigation and environmental habitat restoration. Increased use of recycled water for irrigated agriculture as well as landscape irrigation in the M&I sector could help lower dependence on high quality SWP and CVP water and will provide an additional water source during drought or periods of regulatory restrictions when imported potable water quantities are reduced. Stakeholders of this IRWMP have identified “Increase the use of recycled water for beneficial uses within the Kern Region” as an objective of their planning efforts.
- Flood Management. Stakeholders of this IRWMP have identified flood management as an important component of water planning. One of the stated objectives of this IRWMP

is to “Create tools to re-regulate water supplies within the Region, including storage, storm flows, and operational flows.”

- Flood Preparedness. Stakeholders of this IRWMP have identified flood preparedness, flood response and post flood actions as important objectives of the IRWMP regional planning process.
- Expand Water Storage. Kern County is a leader in groundwater banking and storage. Stakeholders have expressed a desire to increase groundwater recharge as well as groundwater banking in the Region. One of the objectives of this IRWMP planning effort is to “Increase water storage capacity in the Region by increasing recharge acreage and expanding groundwater storage programs.”
- Protection of Recharge Areas. In the past the Kern Region has emphasized groundwater and groundwater recharge as priorities. “Identify and preserve prime recharge areas in the Kern fan area and other areas” is a stated objective of this IRWMP.

In the future, the Kern Region RWMG may consider supplementing these strategies with those adopted by CARB in its AB 32 Scoping Plan. Agencies in the RWMG may also consider joining the California Climate Action Registry, a non-profit organization that serves as a voluntary greenhouse gas registry to promote early actions to reduce greenhouse gas emissions.

Further discussion of the Kern Region’s strategies for adaptation and mitigation of the effects of climate change are further described in Sections 10 and 11.

Section 3: Greater Bakersfield Subregion

3.1 Subregion Introduction

This section presents a regional description for the Greater Bakersfield subregion of the Kern IRWMP Region, including a summary of the subregion's IRWMP participants, as well as a description of the physical, environmental, social and demographic characteristics of the subregion, the hydrologic features and overall water reliability, major water related infrastructure, and the identified subregional issues, needs, challenges and priorities. The Greater Bakersfield subregion is centrally located within the Kern Region. It encompasses major north-south highways (Interstate Route 5, State Highway 99) and water infrastructure connecting the growing cities and unincorporated communities in this subregion to the greater Kern County area. Eight public agencies comprise the Greater Bakersfield subregion, as described in greater detail below.

3.2 Subregion IRWMP Participants

The Greater Bakersfield subregion consists of:

1. The City of Bakersfield (City or Bakersfield)
2. California Water Service Company Bakersfield District (CWS-BAK)
3. Casa Loma Water Company (CLWC)
4. East Niles Community Services District (ENCSD)
5. Greenfield County Water District (GCWD)
6. Kern County Water Agency Improvement District No. 4 (ID4)
7. North of the River Municipal Water District (NORMWD)
8. Oildale Mutual Water Company (OMWC)

These participants' roles and responsibilities for managing water, natural resources, and land use within this subregion are discussed below.

3.2.1 City of Bakersfield

The City of Bakersfield (Bakersfield or City) is located within the southern San Joaquin Valley in Kern County; approximately 100 miles north of the Los Angeles metropolitan area.

Bakersfield is the largest metropolitan city of Kern County, operating under a council-manager form of government, with the Water Board of the city recommending, administering and implementing domestic water policies set by the City Council. Bakersfield's water system is a municipally-owned system, acquired by the City in 1976. The City purchased Kern River water rights, land and the physical water distribution systems for the Ashe Service Area from Tenneco West. The City subsequently added service areas in the Fairhaven and River Lakes areas. These service areas are the only portions of the City that directly receive water service from the City Water System.

The City contracts with CWSC-BAK to serve retail customers within its service area. ENCSD, NORMWD and Vaughn Mutual Water Company, while not contracted by the City, also serve drinking water within City limits and in the unincorporated urban area. The City provides water primarily for residential uses and also for business, commercial, industrial, and public customers in and adjacent to the westerly portion of Bakersfield.

The City of Bakersfield provides water to a population of approximately 147,000 through 41,100 residential service connections through a combination of local groundwater produced by 65 wells, treated Kern River water from CWSC-BAK's North Garden Water Treatment Plant, and treated Kern River or imported State Water from four turnouts off of ID4's Northwest Feeder (City of Bakersfield, 2015 UWMP). Approximately 14 of the groundwater wells are equipped with wellhead treatment for removal of constituents such as hydrogen sulfide, VOCs, SOCs, and Arsenic. In 2019, the City completed a project to install GAC wellhead treatment for the removal of 1,2,3-TCP at 35 of their wells. Twelve of the 65 wells are currently inactive or on standby due to elevated levels of Arsenic, 1,2,3-TCP or other water quality problems. The City's Domestic Water System has 6 water reservoirs (above ground storage tanks) with a combined storage capacity of 18 million gallons. At each of these reservoirs is a booster pumping station that pumps water from the reservoir out into the distribution system, which consists of approximately 570 miles of pipe ranging in size from 2 to 42-inches in diameter (City of Bakersfield, 2017 Water System Analysis Report).

The City of Bakersfield also operates the river channel and owns and operates canals that run through Bakersfield as well as 1,470 acres of recharge ponds along the Kern River (referred to as the City's 2,800 Acre Recharge Facility). Several agricultural districts have contracts with the City of Bakersfield. Through these contracts, the agricultural water districts receive about 135,000 AF annually of Kern River water for irrigation purposes. The majority of the water provided to the agricultural districts is transported through a series of canals throughout the subregion.

Groundwater replenishment is accomplished by the City through a variety of means including: captured precipitation in over 330 storm water basins; percolation in the Kern River Channel and the unlined Carrier Canal; recharge ponds in the 2,800 Acres Recharge Facility; percolation of treated wastewater from the City's Wastewater Treatment Plant No. 3; recharge from urban irrigation and City water amenities such as parks and man-made lakes (City of Bakersfield, 2015 UWMP).

The City owns and operates two wastewater treatment plants, one of which (WWTP No. 2) is located outside of the City's Domestic Water System in southeast Bakersfield. Secondary treated, undisinfected water from WWTP No. 3, located in southwest Bakersfield, is sent to percolation ponds for groundwater replenishment and to a farm owned by the City of Los Angeles for irrigation of non-human consumption crops. Tertiary treated water from WWTP No. 3 is used for irrigation of the adjacent Sports Facility (City of Bakersfield, 2015 UWMP).

3.2.2 California Water Service Company Bakersfield District

CWS is the largest investor-owned water utility in the western United States and one of the largest in the country. It serves 1.7 M people in 63 California communities with 24 operating districts stretching from Chico in the north to Palos Verdes in the south. Rates and operations are regulated by the California Public Utilities Commission.

CWS has provided water utility services in the Bakersfield area since 1926 when it purchased Bakersfield Water Works, then later the incorporated the communities of Olcese and North Garden. CWS-BAK encompasses approximately 51 square miles of service area and serves eastern portions of the City of Bakersfield and segments of unincorporated Kern County lands adjacent to the City of Bakersfield. CWS-BAK provides water to a population of approximately 279,000 through 70,000 service connections. The dominant land use is for residential and commercial purposes. Residential services account for 90 percent of all services and 67 percent of water uses in the District.

CWS-BAK provides a combination of local groundwater produced by approximately 80 wells, Kern River water purchased from the City of Bakersfield and treated by CWS-BAK's Northeast Bakersfield and North Garden Treatment Plants, and treated Kern River or State Water Project water purchased from ID4 through five turnouts off of the Northwest Feeder. Approximately 42 of the groundwater wells are treated for removal of constituents (CWS-BAK, 2015 UWMP). In 2018, CWS-BAK completed a project to install GAC wellhead treatment for the removal of 1,2,3-TCP at 25 of their wells.

CWS-BAK is also contracted to operate and maintain the City of Bakersfield's Domestic Water System that covers the western portion of the City of Bakersfield as is described in the previous subsection.

3.2.3 Casa Loma Water Company

Formed in 1976, CLWC is a small urban water purveyor located in Southeast Bakersfield that serves approximately 900 residential customers through 248 non-metered connections. The water company meets their customers' demands with groundwater from 2 active wells and purchased treated water from an interconnection with CWS-BAK's distribution system. The groundwater is untreated as there are no current elevated levels of constituents (SDWIS).

3.2.4 East Niles Community Services District

ENCSD has provided high-quality water utility services in the east Bakersfield area since 1956 when it acquired the properties and rights of the East Bakersfield Water Company and the Pacific Water Company. ENCSD provides drinking water to a population of approximately 35,000 through 7,800 service connections. To meet their customers' needs, the District uses a combination of local groundwater produced by 7 wells and purchased imported surface water from ID4 All of the wells pump directly into the Kern Citrus Tank Facility then pumped to higher elevation storage reservoirs and distributed to the system through 121 miles of pipelines. Three of the wells are treated for arsenic removal and one is blended for treatment of nitrates and some wells have elevated levels of 1,2,3-TCP (ENCSD, 2015 UWMP).

ENCSD also owns and operates a sanitary sewer collection system and holds a joint agreement with the City of Bakersfield for wastewater treatment at their WWTP No. 2 and agreements with the City of Bakersfield and Kern County for joint use of sewer trunk lines. WWTP No. 2 provides secondary treatment and then sends the treated water to adjacent agricultural lands for irrigation of non-human consumption crops. ENCSD does not have a dedicated recycled water system.

3.2.5 Greenfield County Water District

GCWD is located south of the Arvin-Edison Intake Canal and east of Highway 99. GCWD supplies drinking water from groundwater to a population of approximately 10,000 through 3,000 connections from its five (5) wells. The groundwater is untreated and there are elevated levels of Arsenic (SDWIS).

3.2.6 Kern County Water Agency Improvement District No. 4

KCWA was formed by Chapter 1003 of the Statutes of 1961 for the primary purpose of establishment of a single entity in Kern County to negotiate and administer a water supply contract with the SWP water. KCWA contracted the DWR in 1963 for a water supply for member units within Kern County, which included 77,000 AF annually for ID4. ID4 was formed to provide a supplemental water supply to the metropolitan Bakersfield area.

Subsequent amendments to the KCWA Act added provisions for the formation of improvement districts as needed to expedite solutions to specific problems relating to flood control, drainage or water supply. Activities leading to the creation of ID4, embracing the urban Bakersfield area, were initiated by the KCWA Board of Directors by adoption of Resolution 25-70 on 10 December 1970, which outlines the need for such an improvement district. ID4 was formed by a resolution adopted by the KCWA Board of Directors on 21 December 1971, for the purpose of financing the construction of the Henry C. Garnett Water Purification Plant, related water conveyance facilities, and a portion of the cost of the CVC. Resolutions Nos. 16-71 and 17-71 were adopted by the KCWA Board of Directors on 21 December 1971. These resolutions finalized formation activity and established the boundaries of ID4 as they exist today.

The ID4 service area includes a number of retail water agencies servicing a population of approximately 387,000. Of these agencies, ID4 wholesales to four, which include: (1) CWS-BAK, (2) the City of Bakersfield Domestic Water System, (3) ENCSD, and (4) NORMWD. Within ID4, there are other, smaller retail water agencies that rely on groundwater pumping and have no contract with ID4 for treated water. These include Vaughn Mutual Water Company, Casa Loma Water Company, Stockdale Annex Mutual Water Company, and Stockdale Mutual Water Company. (ID4, 2015 UWMP).

ID4 participates in several groundwater recharge and recovery programs including 2800 Acre Recharge Facility, Kern Water Bank, Pioneer Project, Allen Road Complex Well Field, and ID4/Rosedale Joint Use Recovery Project. ID4 occasionally pumps groundwater to supplement its water supply when a limited amount of SWP water is available.

3.2.7 North of the River Municipal Water District and Oildale Mutual Water Company

NORMWD was formed in 1969 to serve wholesale delivery of State Water Project water to the unincorporated community of Oildale located north of the City of Bakersfield. From 1980 to 2014, NORMWD supplied groundwater and purchased treated surface water to a small retail area serving a population of approximately 6,000 through 2,000 service connections. They were also the wholesale water supplier of treated surface water purchased from ID4 to the OMWC, a retail water purveyor that falls within the NORMWD boundary. In 2014, NORMWD's retail customers were integrated into OMWC's service area. District facilities include two 4.5 million gallon of reservoir storage, booster pump stations, pressure reducing stations and relief

valves, and 30 miles of asbestos-cement and PVC distribution pipe (NORMWD, 2015 UWMP & ID4, 2015 UWMP).

OMWC, incorporated in 1919, provides municipal, industrial and domestic water service to its service area. OMWC currently serves a population of approximately 34,000 persons via 10,300 active service connections. The current service areas "Oildale Service Area" and “Southeast Shafter Service Area” encompass approximately 18 square miles. Oildale distributes water from two sources: groundwater from 8 active wells and treated water from ID4 through NORMWD. OMWC has relied on imported treated water to supply over 95 percent of its total supply. South Shafter Service Area is served by groundwater only (OMWC, 2015 UWMP).

Wastewater collection and treatment is carried out by North of River Sanitary District. OMWC purchases treated wastewater from NORSD which is used for groundwater replenishment by application to agricultural lands in-lieu of groundwater pumping. OMWC also implements a dual-use water system for new developments in Southeast Shafter using “blue pipe” for domestic service and “purple pipe” for landscape and fire suppression service. The “purple pipe” system is supplied by untreated shallow groundwater that is high in nitrates and not fit for human consumption without treatment (OMWC, 2015 UWMP).

3.3 Subregion Description

3.3.1 Land Use

The Land Use, Open Space, and Conservation Element of the Kern County General Plan, and the Land Use element of the City of Bakersfield General Plan provide the policies protecting the land uses within the Greater Bakersfield subregion. The Greater Bakersfield subregion can be generally characterized as containing land uses of 84% M&I, 9% agricultural and 6% undeveloped. The undeveloped rural uses are generally located at the periphery of the subregion while urban uses are located at its core, mainly within the City of Bakersfield. The largest city in the subregion is Bakersfield with a population of over 380,000. This subregion is the most urban as compared to the other subregions. The City’s General Plan defines the urban areas as areas in which a minimum of 50 percent of all parcels within one-half mile radius are developed for residential uses in excess of three units per net acre and/or commercial uses with a floor area ratio of 0.2 (RBF Consulting, 2002). However, the overwhelming majority (approximately 80 percent) of the General Plan area consists of open space uses, where open space includes parks and recreational facilities, agriculture and mineral petroleum land uses. Residential is the second greatest land use at 11 percent, with commercial, industrial, and public services following each around 2 to 3 percent of land use by area. As discussed in Section 2.3, this subregion has been greatly affected by recent population increases and resulting land use issues.

3.3.2 Ecological Processes and Environmental Resources

Ecological processes and environmental resources for the Kern Region as a whole are described in Section 2.4. With regard to the Greater Bakersfield subregion, these resources have been impacted more than other regions due to agriculture, urban development and oil/gas extraction, which have resulted in many changes in the natural environment. These impacts have resulted in drained and diverted lakes and wetlands, the loss of native plants and animal species, and a decrease in native lands. This has also resulted in the introduction of invasive

species and spread of exotics leading to the decline of native plant communities. The City and County of Kern have determined that the appropriate approach to conservation of protected Biological Resources in the Metropolitan Bakersfield area is through the Habitat Conservation Planning process which mitigates for urban development. In 1994, the City and County received permits under Section 10(a)(1)(B) of the Federal Endangered Species Act and Section 2081 of the California Endangered Species Act for incidental take of protected species in connection with development projects. Both permits expired in 2014 but were extended or granted an interim permit until 2019.

The Metropolitan Bakersfield Habitat Conservation Plan (MBHCP) and implementing agreements and ordinances provide a method of collecting funds for the acquisition and enhancement of Habitat Land for purposes of creating preserves.[2] Development projects within the Metropolitan Bakersfield area pay mitigation fees which are used to buy habitat lands. These lands are managed by wildlife agencies or entities they approve. “Take” avoidance measures are also listed in the MBHCP.

The City and the County are currently drafting a new plan known as the Bakersfield Habitat Conservation Plan, which will build on the original goals and objectives under the MBHCP and comply with new standards and requirements under the jurisdictions of the USFWS and CDFW.

The MBHCP addresses urban development activities for incorporated and unincorporated areas of the Metropolitan Bakersfield General Plan area. For oil and gas production activities, the Metropolitan Bakersfield General Plan area is included in the draft Kern County Valley Floor Habitat Conservation Plan (VFHCP) Program. Those activities are not included in the MBHCP.

The VFHCP Program represents a comprehensive strategy that provides a means of addressing compliance with the California and Federal Endangered Species Acts for Kern County’s oil and gas production industry, urban development, water district development and maintenance, public infrastructure activities, and other activities for the signatory districts. The term of the Program is 30 years. The Program was undertaken by local industry and interest groups and local, State, and federal government agencies to translate federal and State laws into a locally acceptable program that provides an alternative to negotiating each development project or activity directly with the CDFW and USFWS. The Endangered Species Element provides broad policy language relative to the conservation of threatened and endangered species in accordance with State and federal laws. The VFHCP represents a specific program to implement the proposed Endangered Species Element (Garcia and Associates 2006).

3.3.3 Social and Cultural Characteristics

The social and cultural characteristics of the Greater Bakersfield subregion are as diverse as the range in employment seen within the City and across the subregion. The City is home to many of the County’s governmental facilities, while agriculture, petroleum, and the service sector also provide significant employment in the area.

[2] The MBHCP and associated implementing ordinances and agreements are available through the Kern County Planning Department. The Plan provides descriptions of species of concern and habitat areas within the General Plan area.

3.3.3.1 Economic Conditions and Trends

The Greater Bakersfield subregion is in a period of transition. Over the past 50 years the major land uses have been agriculture, oil, and residential development to support these major industries. Recent growth has resulted in a transformation of land uses to more residential, retail, commercial, industrial, institutional and recreational. Rapid residential growth has occurred over the last few decades, as seen by Bakersfield expanding from an early 1990s population of 175,000 to a current population of over 380,000. The City is projected to continue to grow over the next 10 years to an estimated 547,000 residents. The community has a strong interest in preserving its "feel" and historical past while managing its future growth to produce quality neighborhoods that translate to a healthy economy. The demographics of this subregion are shown in **Table 2-4**. English is the primary language, but a significant portion of the population speaks Spanish. Although future ethnic demographics are projected to transition to a greater mix of Hispanic and non-Hispanic residents, there will be a substantial Hispanic or Latino population in Bakersfield in the future. A high priority for the City will be to continue to address the specific needs and cultural desires of the Hispanic community.

3.3.3.2 Disadvantaged Communities

The community of Oildale, located just north of Bakersfield, has been identified as a DAC within the Greater Bakersfield subregion (refer to Section 2.5.3). An Environmental Justice issue that could potentially impact this DAC is that Oildale is adjacent to three large oil fields, including two of the largest in California. The Kern River Oil Field to the east and northeast has more active oil wells than any other field in California except for the Midway-Sunset Oil Field in southwestern Kern County. Also adjacent is the large Kern Front Oil Field, north of Oildale, and the smaller Fruitvale Oil Field, to the southwest.

3.3.4 Water Supply

3.3.4.1 Imported Water Supplies

Water supplies imported to the Greater Bakersfield subregion come from the SWP or CVP via the California Aqueduct and the CVP via the Friant-Kern Canal. These supplies are discussed in detail in Section 2.6.1. The subregion is very dependent on these imported supplies, for direct delivery to customers after treatment as well as to recharge groundwater resources.

3.3.4.2 Surface Water

The two primary sources of local surface water in the Greater Bakersfield subregion are the Kern River and the streams from the Caliente Creek watershed. These sources are described in detail in Section 2.6.2. With the exception of very wet periods, there is no flow in the Kern River past Bakersfield due to upstream canal diversions. During very wet periods, water flows in the river southwest to the Buena Vista Lake Bed and then north in the Kern River Floodway or into the California Aqueduct through an intertie near Tupman.

3.3.4.3 Groundwater

The Greater Bakersfield subregion overlies the primary aquifer in the Kern Region, the large Southern San Joaquin Groundwater Basin. This Basin is described in Section 2.6.3. Groundwater is the primary source of supply within the subregion. Surface or imported water supplement groundwater resources.

Groundwater recharge in the Basin is obtained through natural recharge by precipitation runoff; river and canal seepage; reclaimed water; and spreading and banking. These four sources, as they are described in the Draft Metropolitan Bakersfield General Plan Update Environmental Impact Report (RBF Consulting, 2002) are reiterated below:

1. Natural Recharge. Natural recharge is provided by precipitation runoff, which is defined as the amount of melted snow and rainwater measured after evaporation, ET, and percolation. Precipitation runoff falling within the Plan area is collected as runoff in a series of drainage basins or "sumps" operated by the City. The runoff collected in these basins percolates to the groundwater thereby recharging the groundwater basin.
2. River and Canal Seepage. Canal seepage is defined as the amount of water that percolates into the ground from unlined earthen canals. When added with seepage from the Kern River channel, it contributes more than half the City's water supply. Canal and river seepage also enhance unincorporated water supplies. It should be noted that lined canals, which also seep, albeit at a much lower percentage, can also contribute to aquifer recharge.
3. Recycled Water. Recycled wastewater, or reclaimed water, produced from the City's two WWTPs is used in land application. Recycled water applied to non-edible crops for irrigation also percolates into the ground recharging the groundwater basin.
4. Spreading and Banking. Percolation of water spread in open basins has been historically used in Kern County as a means of recharging and banking groundwater. The City owns and operates the 2,800-acre recharge facility located in and along the Kern River Channel (approximately 8 miles west of Highway 99) which is used to replenish water to the groundwater aquifers.

The 2,800-acre recharge facility is a 6-mile long site consisting of old river channels, overflow lands, and constructed spreading basins. Groundwater is recharged in this facility by spreading water onto these spreading basins, which look like small lakes surrounded by levees, and allowing it to percolate. Additionally, the facility receives surface water supplies from the Kern River, the CVP, and the SWP during years when surpluses exist. The 2,800-acre recharge area improves groundwater quality by recharging low salinity Kern River water into the aquifers. This dilutes the more saline irrigation water that percolates underground from adjacent farming operations. The underground reservoir can be pumped in dry years for agricultural and domestic use and in wet years, the reservoir can be built up. This allows water to be used without causing a groundwater overdraft problem.

Other banking programs within the subregion include the Kern Water Bank, Pioneer Project, Allen Road Complex Well Field and Berrenda Mesa. ID4 participates in groundwater banking projects that were developed to capture and store high-flow waters, such as Article 21 water from the SWP, Section 215 and flood water from the CVP and flood waters from the Kern River. These groundwater banking projects provide both recharge and recovery facilities dedicated for the storage and recovery of water.

- **Kern Water Bank:** ID4 has a 9.62 percent interest in the recharge and recovery facilities of the Kern Water Bank as a result of the 1996 agreement between Project Participants, the Agency and DWR. As payment for its share of the project, ID4 returned 4,330 AF of its SWP firm agricultural entitlement to DWR. This reduction is reflected in current SWP allocations. The number of recovery wells currently available is about 91, yielding a total annual recovery capacity of approximately 230,000 AF, of which ID4 has

a first priority right to 22,100 AF of recovery capacity. The maximum annual recharge capacity of the project is about 450,000 AF, of which ID4 has a first priority right to 43,300 AF of recharge capacity.

- **Pioneer Project:** ID4 has a 10 percent interest in the recharge and recovery facilities as a result of the 1998 Pioneer Participation Agreement. The total number of completed wells on the project is 38, which yields a total maximum annual recovery of approximately 100,000 AF, of which ID4 has a first priority right to 10,000 AF of recovery capacity. ID4's share of the maximum annual recharge capacity of the project is 14,600 AF.
- **Allen Road Complex Well Field:** ID4 owns and operates seven wells located along the north side of the Kern River between Allen Road and Coffee Road. These wells may be used as part of joint program with the City of Bakersfield to recover groundwater for discharge into the river channel during dry years for recreational purposes and for potential exchanges with other districts to enhance the quality of water delivered to the Henry C. Garnett Water Purification Plant. These wells are owned and operated by ID4 and are available to ID4 for supply augmentation, using previously banked water within ID4. The total recovery capacity is 36,000 AF.
- **ID4/Rosedale Joint Use Recovery Project:** The Rosedale and ID4 Joint Use Groundwater Recovery Project (JURP) includes seven recovery wells with a total capacity of 45 cfs. ID4 operates this well field to recover banked water for two of Rosedale's partners, Kern-Tulare Water District and Arvin-Edison Water Storage District. The JURP Agreement also provides ID4 with the ability to exchange surface water for an equal amount of banked water in the Joint Use Groundwater Recovery Project area (ID4 RWC, 2018).

In an effort to eliminate the potential for overdraft conditions in the Greater Bakersfield subregion, surface water was made available to former groundwater users via the Friant-Kern Canal and the SWP. As is evidenced by the discussion above, recharge of groundwater supplies is very dependent on surface water. The sources of surface water available to the City are the Kern River, the SWP and the CVP. Also, the wet period/dry period cycle can have a significant impact on recharge, with groundwater banking being the most noticeably impacted source of recharge.

3.3.4.4 Recycled Water

As mentioned in the discussion above and as described in Section 2, recycled water produced from the City of Bakersfield's two WWTPs is used to irrigate non-edible crops such as cotton and alfalfa and is also a source of recharge to the underlying groundwater basin. The City's WWTP No. 3 produces tertiary treated water that is used to irrigate the State Farm Sports Village, a local soccer and football complex. The City of Bakersfield's 2015 UWMP reported that approximately 733 AF of tertiary water was used in 2015 for this purpose.

3.3.5 Water Quality

Imported water supplies within the Greater Bakersfield subregion (the SWP and CVP), are generally of good quality, and are discussed in detail in Section 2.7.2.

Surface water quality in the Greater Bakersfield subregion, referring to the Kern River and streams from the Caliente Creek watershed, is generally good, with excellent quality exhibited

by most streams on the east side of the Region (CVRWQCB, 2018). Generally, the quality of the groundwater within the Greater Bakersfield subregion has remained relatively stable. However, the closed nature of the Tulare Lake Basin, which results in little subsurface outflow, is the greatest long-term problem facing the Region. The closed nature of the Basin results in an accumulation of salts within the Basin over time due to importation and evaporative use of the water. This problem is compounded by overdraft of groundwater for municipal, agricultural, and industrial purposes, and the use of water from deeper formations, which further concentrates salts within remaining groundwater.

Other water quality concerns within the Greater Bakersfield subregion include storm water runoff from residential and industrial areas that can contribute to water quality degradation since it contains organics, pesticides, oil, grease, and heavy metals. Also of concern is naturally occurring erosion, which can cause discoloration of streams, and suspended matter settling to form a smothering blanket on the streambed. Erosion is accelerated by poor drainage and soil stabilization associated with road building, clearing and leveling land, construction, brush clearing, off-road vehicle use, agriculture, overgrazing, and fires.

The City of Bakersfield and the County of Kern adopted a 2014 Storm Water Management Plan (SWMP) in 2015, which provides a framework for management of storm water discharges under its NPDES Permit. The SWMP includes program elements and control measures to reduce the discharge of pollutants in storm water to the maximum extent practicable, and to prohibit non-stormwater discharges into MS4s and watercourses within the jurisdiction. (City of Bakersfield and County of Kern, 2015)

3.3.6 Water Demand

Water demands for urban water use and agricultural water use within this subregion are provided in Section 2.9.

3.3.7 Watershed Flood Management

Flooding within the Greater Bakersfield subregion originates from the Kern River watershed, which lies in Kern and Tulare Counties at the southern end of the Sierras, and from the Caliente Creek stream group which drains the west slopes of the Tehachapi Mountains. Also, some smaller areas are subject to flooding from local watersheds.

The most severe flooding problems on the Kern River near the City have resulted from high-intensity winter rainstorms over a large portion of the basin, which generally occur from November through April. Floods caused by snow melt, which usually occur in the late spring and early summer, generally have a longer period of runoff and also a lower peak than rain floods. As a result, spring storms have rarely caused significant damage (RBF Consulting, 2002).
The City entered the Regular Phase of the NFIP as administered by the FEMA on May 1, 1985. The County of Kern followed on September 29, 1986. By adopting flood damage prevention ordinances to regulate development in special flood hazard areas, private property owners in participating communities are allowed to purchase affordable flood insurance through the NFIP, while the community retains its eligibility to receive certain federally backed monies, and disaster relief funds.

Both the City and the County of Kern participate in the state-mandated Kern River Designated Floodway Program, which is administered by the DWR Reclamation Board. The Kern River

Designated Floodway Program provides development criteria and issues permits for development within the limits of the Kern River Designated Floodway.

Floodplain mapping has been performed under the NFIP to delineate special flood hazard areas. The City of Bakersfield Public Works Department and the Kern County Department of Engineering and Survey Services have the official Flood Insurance Rate Maps (FIRMS) and Flood Boundary Floodway Maps (FBFM) which show the extent of the floodplains. In addition, the communities are empowered to develop and use improved floodplain information.

Both the City and County have adopted general plan designations which identify allowable uses in the floodplain. Local zoning ordinances more closely define known areas to have potential for flooding.

In July 1985, both the City and County adopted the Kern River Plan Element (KRPE) as a part of their general plans. The KRPE establishes provisions for development along the Kern River, and specific policies for floodplain management.

The Flood Damage Prevention Ordinance provides criteria for development within all floodplains, including prohibiting encroachments into a floodway, and requiring protection and/or elevation of construction within a floodway fringe. The City has merged the Kern River Levee System into its Water Resources Department operation. The established levee system is maintained to United States Army Corps of Engineers (USACE) standards. The USACE provides an annual inspection and maintenance report in the evaluation of the Kern River levees.

3.3.8 Water-Related Infrastructure

Water-related infrastructure such as surface water impoundments, water collection systems, distribution systems, wastewater systems, and recharge systems, are described generally for the Greater Bakersfield subregion participants in their general descriptions above, and in greater detail for the entire Kern Region in Section 2.9.

In general, many Kern Region communities are older and the physical components of their water systems are aging and outdated. Aging infrastructure is a particular issue for rural communities and DACs. In recent years rapid urban development in some areas has provided new infrastructure, but this new infrastructure is limited to those areas receiving new development. Water treatment improvements have recently been undertaken by the City of Bakersfield, CWS, and others. With the new water quality standard for 1,2,3-TCP, many of the agencies have implemented new wellhead treatment systems at well sites or are planning implementation.

The Kern River encounters its first diversion into a canal when it first exits the Kern River Canyon and encounters another diversion when it reaches the east side of Bakersfield, near Hart Park. The Beardsley and Rocky Point weirs are the first two of seven diversion weirs in Bakersfield. From there, canal water travels north and south to irrigate farmlands. In total, the Kern River is diverted into seven canals that pass-through Bakersfield.

ID4 operates the Henry C. Garnett Water Purification Plant which was constructed and put into service in January 1977. This conventional water purification plant, designed to purify surface water for human consumption, has a permitted maximum flow of 103 MGD. The Henry C.

Garnett Water Purification Plant, provides water to retail purveyors which include CWS-BAK, City, ENCSD and NORMWD, which wholesales to OMWC.

The NEBTP was constructed in 2001. The construction of the NEBTP allowed tremendous growth to take place in relatively undeveloped lands from Northeast Bakersfield to the mouth of the Kern River Canyon, which is entirely in CWS-BAK service area. NEBTP utilizes membrane technology to treat Kern River water. Current capacity of the NEBTP is 23 MGD with an ultimate build out capacity of 60 MGD (CWS-BAK, 2015).

The NGWTP is a micro-filtration treatment facility that began operation in 2007. The plant is operated by CWS-BAK and services northwest Bakersfield with treated Kern River water supply. The plant has a base load capacity of 8 MGD with a 10.4 MGD peaking capacity. Half of the base load capacity is supplied to the City of Bakersfield.

3.4 Subregional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for this subregion with respect to water resource management are discussed in detail in Section 2 as follows:

- Decreased Imported Water Supply (see Section 2.11.4)
- Groundwater Overdraft and SGMA (see Section 2.11.6)
- Urban Growth and Water Demand (see Section 2.11.2)
- Legislated Water Use Efficiency Requirements (see Section 2.11.7)
- Urban Growth Encroachment on Key Recharge Areas (see Section 2.11.3)
- Water Quality/Groundwater Contamination (see Section 2.11.8)
- Water Rights (see Section 2.11.9)
- Climate Change (see Section 2.11.11)

Section 4: Kern Fan Subregion

4.1 Subregion Introduction

This section presents a description for the Kern Fan subregion of the Kern Region. The Kern Fan subregion encompasses the southwestern portion of the Kern Region extending from the extreme westerly edge of the City of Bakersfield to the western County line. The subregion is bounded by Highway 46 to the north and extends slightly beyond Highway 166 to the south. Descriptions of the Kern Fan subregion's participants, as well as the physical and environmental characteristics, hydrologic features, and issues and needs of the subregion are provided.

4.2 Subregion IRWMP Participants

The Kern Fan subregion consists of ten participants and includes:

1. Buena Vista Water Storage District (BVWSD)
2. Buttonwillow County Water District (BCWD)
3. City of Taft (Taft)
4. City of Maricopa (Maricopa)
5. Henry Miller Water District (HMWD)
6. Kern Water Bank Authority (KWBA)
7. Olcese Water District (OWD)
8. Rosedale-Rio Bravo Water Storage District (RRBWSD)
9. Vaughn Water Company (VWC)
10. West Kern Water District (WKWD)

These participants' roles and responsibilities for managing water, natural resources, and land use within the Kern Fan are discussed below.

4.2.1 Buena Vista Water Storage District

BVWSD is an agricultural water district organized in 1924 to manage the irrigation and tail water recovery systems and water rights originally held to Kern River water. The District is located approximately 16 miles west of the City of Bakersfield near the town of Buttonwillow and has a gross area of approximately 49,000 acres between the townsites of Tupman and Lost Hills. It does not include the Buena Vista Lakes, which are owned by the County of Kern. The goal of BVWSD is to provide its landowners and water users with a reliable, affordable, and usable surface and groundwater supply. BVWSD provides agricultural water to its customers and is engaged in groundwater recharge, banking, and recovery programs. BVWSD's water sources include Kern River water, SWP, CVP, and groundwater.

The Miller-Haggin Agreement of July 28, 1888 is the basis of distribution of Kern River flows between the upstream "First Point" interests and the downstream "Second Point" interests. The Miller-Haggin Agreement, as amended, allocates all of the waters of the Kern River on a daily basis. Under the Agreement, BVWSD as the successor-in-interest to the Second Point interests, is apportioned approximately one third of the Kern River flows from March to August. A subsequent amendment also apportioned some river flows from winter runoff. The average entitlement is approximately 158,000 AFY of surface water from the Kern River.

In 1973, BVWSD contracted with KCWA for additional surface water supply from the SWP. The contract provided for an annual firm entitlement of 21,300 AF and surplus entitlement (Article 21) of 3,750 AF. BVWSD currently has access to five turnouts from the California Aqueduct. Its geographic location, with respect to the California Aqueduct and other KCWA member units, provides the opportunity for exchanges of BVWSD's Kern River water for east-side member units' SWP water. BVWSD has also been a historic user of surplus Friant-Kern Canal flows to serve irrigation demands and for groundwater recharge programs.

The average supply from the Kern River and SWP provides approximately two-thirds of the BVWSD landowner irrigation needs. The remaining irrigation demands are filled by landowner wells.

4.2.2 Buttonwillow County Water District

BCWD is a California Special District, governed by an elected board, serving a population of approximately 1,500 persons. BCWD was established in 1956 to provide sanitary sewer facilities to the unincorporated area of Buttonwillow and did so through the sale of General Obligation Bonds. In 1971, the BCWD formed Improvement District No. 1 containing the water system previously owned and operated by the East Buttonwillow Water Company. In 1974, by Board resolution, the merger of Kern Mutual Water Company, a private water company with the BCWD was approved. BCWD provides domestic water to the townsite of Buttonwillow, located in Kern County, approximately 3 miles west of Interstate 5 on Highway 58. The service area is approximately 1 mile long and 0.5 mile wide. Services include 440 total connections.

The existing infrastructure consists of three wells, one 500,000-gallon storage reservoir, a booster pump station and approximately eight miles of distribution lines. In general, the water system is aging and outdated. Approximately four miles of 2 to 4 inch diameter distribution lines made of asbestos cement were installed in the 1940's. Two miles of 4 and 6 inch distribution pipeline was added in the late 1950's. In 2018, BCWD completed a project to install meters at all service connections and replace approximately 2.5 miles of pipe. BCWD also recently drilled a new well and will begin equipping it in early 2020.

BCWD also operates a wastewater collection and treatment system for the community of Buttonwillow. The wastewater consists primarily of residential waste, a small amount of commercial waste, and no industrial waste. The treatment plant's membrane bioreactors are inadequate for the wastewater flows; this condition requires BCWD to bypass the majority of the flow to the plant's original Imhoff Tank which provides only primary treatment. Effluent from the wastewater plant is distributed to recycled water ponds where it percolates or evaporates. Excess effluent can also be applied to pasture lands adjacent to the plant. BCWD is currently planning to replace the cost membrane bioreactor WWTP with a conventional aerated pond treatment system.

4.2.3 City of Maricopa

Maricopa is an incorporated city with a population of 1,140 located in southern most part of the Kern Fan subregion at the junction of California State Highways 166 and 33. It is located seven miles south of the Taft, covers 1.5 square miles and is approximately 900 feet above sea level. The Carrizo Plain, a major feature of the San Andreas Fault Zone is northwest of the town, and the Midway-Sunset Oilfield (the third largest oilfield in the United States) is adjacent to the town

on the north and east. Incorporated July 25, 1911, this “mother city” of the prolific Midway-Sunset Oilfields is the gateway to the Cerro Noreste/Mt. Pinos recreation area. Maricopa is south of the site of the Lakeview Gusher, the greatest oil gusher in world history, producing 9 M barrels of oil in 18 months. Water is supplied and distributed by WKWD. The City provides sewer to about half of the properties and treats and disposes of the wastewater in two ponds about a mile east of the City. Maricopa used grant funding for the replacement of portions of the sewer collection system.

4.2.4 City of Taft

City of Taft (Taft) is an incorporated city located in southwestern Kern County at the junction of California State Highways 119 and 33. It is located 37 miles southwest of Bakersfield in the Buena Vista Hills and is approximately 955 feet above sea level. Taft encompasses 15 square miles. The Taft Sphere of Influence (planning area) includes Taft and the unincorporated adjacent communities of Ford City, South Taft, and Taft Heights. Included in the Greater Taft Area are several small rural residential/industrial communities. The communities of Tupman, Dustin Acres, and Valley Acres are located along Highway 119 between Bakersfield and Taft. The communities of Fellows, Derby Acres and McKittrick are located northwest of Taft along State Highway 33.

Taft is situated in a major petroleum and natural gas production region of California. The town is built between two major California oilfields, the Midway-Sunset and the Buena Vista Hills fields. The Occidental Petroleum-operated Elk Hills field is north of Taft. The majority of Taft’s economic base is directly related to the petroleum industry.

Water is supplied and distributed to Taft by WKWD. The description of WKWD is included in Section 4.2.10.

Taft has two WWTPs, the City of Taft and Ford City-Taft Heights Sanitation District Wastewater Treatment Plant and the Federal Taft Correctional Institution wastewater treatment facility. The Taft Municipal Wastewater Treatment Plant is a Grade I system with a capacity to treat 1.5 MGD of waste per day. It is operated by the Kern Sanitation Authority and treats flows from City of Taft, Taft Heights, and Ford City. Annual wastewater treatment is about 1,460 AF and flows are primarily domestic and commercial. The Federal Correctional Facility wastewater treatment facility has a capacity of 0.5 MGD. Currently the municipal plant treats approximately 1.3 MGD. The current treatment plants can handle present inflow without capacity being attained. However, commercial and industrial ventures in and around Taft proper will need to be served by adding capacity to the current plants. The wastewater effluent is used for irrigation of feed and fodder crops adjacent to the facility.

4.2.5 Henry Miller Water District

HMWD is an agricultural water district formed in 1964 for the purpose of obtaining a water supply from the SWP. HMWD is located approximately 30 miles southwest of Bakersfield and consists of 26,400 acres of lands in the now dry Buena Vista Lake area. In 1967, HMWD contracted with KCWA for SWP water. HMWD relies on groundwater, Kern River water and SWP water supplies, with SWP water being the primary source. HMWD supplies approximately 50,000 AF on average 20,000 acres annually. The HMWD distribution system consists of approximately 83 miles of earthen canals, 28 wells that discharge directly into the system and a

recovery system that reclaims all drain water for reuse. There are three SWP turnouts and one turnout from the Kern River.

4.2.6 Kern Water Bank Authority

KWBA is a Joint Powers Authority (JPA), formed in 1995 for the purpose of recharging, storing, and recovering water to improve the water supply during periods of water shortages. The JPA participants include DRWD, ID4, SWSD, Tejon-Castac Water District (TCWD), Westside Mutual Water Company (WMWC), and Wheeler Ridge-Maricopa Water Storage District (WRMWSD). The KWBA owns 20,000 acres known as the Kern Water Bank in Kern County.

The Kern Water Bank can receive water from three geographically diverse sources, the Kern River, the California Aqueduct (collecting water from the northern Sierra Nevada) and the Friant-Kern Canal (collecting water from the central and southern Sierra Nevada). Hydrogeologic studies show that the Kern Water Bank has the capability of storing over 1,500,000 AF on a long-term basis, and in fact, the KWBA has stored over 1,300,000 AF since its inception. The program also has the capability of extracting approximately 240,000 AFY. According to KWBA, these factors make it the largest direct-recharge water-banking project in the world (Website, KWBA).

4.2.7 Olcese Water District

OWD is an irrigation water district formed in 1968. OWD is located on the northeastern edge of the Bakersfield area and has a service area of approximately 5,100 acres. OWD water sources are from groundwater, Kern River surface water and Kern River riparian water. OWD provides approximately 3,700 AF and 850 AF annually to Rio Bravo Ranch and the Rio Bravo Golf Course, respectively. OWD sold its water rights of approximately 50,000 AF of stored water on 2,800 acres owned by the City of Bakersfield along with their domestic water system to CWS-BAK. OWD also sold its Hacienda Water Rights which are Kern River flows during peak years, to KCWA. The OWD consist of six pump stations, five earth-lined reservoirs, two wells and mainlines to reservoirs (Nickel, OWD, personal communication).

4.2.8 Rosedale-Rio Bravo Water Storage District

The RRBWSD is located on the extreme western edge of the City of Bakersfield and has a service area of approximately 43,000 acres of predominantly agricultural land. The RRBWSD was formed in 1959 for the purpose of constructing and operating a groundwater recharge project to offset declining groundwater levels. RRBWSD provides agricultural, municipal, and industrial water to customers within its service area, and in engaged in groundwater recharge, banking, and recovery programs. RRBWSD acquires water for recharge purposes from the Kern River through a water service agreement with the City of Bakersfield, from the Friant-Kern Canal of the CVP as available, and from the SWP through a water supply contract with KCWA.

RRBWSD groundwater recharge project facilities generally follow the alignment of the Goose Lake Slough, utilizing the natural recharge capabilities of those soils. Water supply contracts provide for delivery of water to the project from the adjacent Kern River and nearby state and federal water facilities. The water supply available to the RRBWSD varies greatly, both seasonally and from year to year, depending on runoff conditions. The groundwater aquifer functions as a storage reservoir that provides both seasonal and long-term regulation of variable

water deliveries to meet demands. Urban encroachment has resulted in the conversion of over 6,000 acres to residential, commercial and industrial use.

The RRBWSD's recharge and channels cover approximately 1,200 acres and result in an estimated average recharge rate of 350 cfs. Water for agricultural and urban uses is supplied by privately owned wells located throughout the District. The District also has the right to use groundwater recharge facilities in groundwater banking projects as part of agreements with the City of Bakersfield, Kern Water Bank, KCWA, and Irvine Ranch Water District.

The RRBWSD makes surface deliveries to agricultural landowners located adjacent to its groundwater project facilities when water is available. These deliveries in-lieu of groundwater pumping are an additional form of groundwater recharge. From 1962 through 2011, the District has taken delivery of approximately 3.4 MAF of imported water supplies (RRBWSD GWMP, 2013).

4.2.9 Vaughn Water Company

The VWC was incorporated in 1928 and serves the residential customers of the Rosedale area of the City of Bakersfield and adjacent areas in the County of Kern. The VWC operates under a water supply permit issued by the DDW. The VWC service area covers approximately 27 square miles of Kern County and currently serves property in 15 sections of the County. The area is located north of the Kern River channel and overlays portions of ID4 and the RRBWSD. VWC provides water to a population just under 32,000 through 10,700 service connections. The customer base consists of 97 percent residential and 3 percent commercial and industrial. Most of the services are in the County. The water system consists of 12 active groundwater wells, 12 booster pumping stations, 8 activated carbon treatment plants, 4 ozone treatment facilities, 4 million gallons of above ground water storage capacity, and 4 water interties with other systems. In 2018, four wellhead treatment plants were upgraded, and 4 wellhead treatment plants were constructed to remove 1,2,3-TCP from 8 groundwater wells (2019 Annual Drinking Water Quality Report).

Most of the residential and commercial developments are on land that overlies ID4. VWC pays a "pump tax" for groundwater extracted within ID4 to help pay for the operation of the ID4 project. The majority of future development overlies RRBWSD. The VWC has entered into a MOU with the RRBWSD in a cooperative effort to allow development of certain lands within the RRBWSD. These lands are being converted from agricultural use to residential use. Lands within the RRBWSD pay water tolls based on the benefit the lands receive from the RRBWSD's groundwater recharge programs. Lands that are converted to urban use continue to pay these groundwater benefit charges. The RRBWSD has endeavored to create a groundwater balance through importation of water for recharge and in-lieu water supply programs, and through cooperative programs with other water agencies. Studies by the RRBWSD indicate that a groundwater balance is being achieved. The conversion of agricultural lands to residential and commercial use decreases the groundwater demand by about 50 percent, thus reducing the pressure on the groundwater basin (VWC, 2010 WMP).

VWC benefits from transfers, exchanges, and groundwater replenishment projects through ID4's and RRBWSD's involvement in these programs

North of River Sanitary District and Kern County CSA-71 both operate wastewater collection and treatment facilities within VWC's boundary. City areas are on sewer and county areas are

on septic systems. Storm water is collected in both city and county sumps where it percolates and evaporates. VWC does not operate a recycled water program (VWC, 2010 WMP).

4.2.10 West Kern Water District

The WKWD was formed in 1959 and has a service area of approximately 300 miles that includes the incorporated cities of Taft and Maricopa, together with the Westside communities of Taft Heights, South Taft, Ford City, Tupman, Dustin Acres, Valley Acres, Fellows and McKittrick. WKWD is located approximately 30 miles west of Bakersfield. WKWD provides water supply for domestic, industrial and for recreation/landscaping. WKWD serves water to a population of approximately 23,000 through 7,500 service connections. Water conveyance facilities include 13 active groundwater wells, 26 above ground storage tanks, 15 booster pump stations, 306 miles of distribution pipelines, and 415 acres of recharge basins.

Approximately 80 percent of WKWD's annual water sales are served to the oil and electrical power generating industry in western Kern County. Domestic water sales account for the remaining 20 percent of WKWD's annual sales. WKWD contracts with KCWA to deliver SWP water, with a current entitlement of 31,500 AFY. WKWD delivers up to 6,500 AF of SWP water entitlement from the California Aqueduct for industrial usage. WKWD's local water supply is obtained from thirteen groundwater wells located approximately 17 miles north east of Taft in the underflow area of the Kern River Basin. The North and South well fields are adjacent to the Kern Water Bank recharge area.

WKWD receives the majority of its SWP water by exchange with BVWSD as an in-lieu groundwater pumping/groundwater banking exchange program. BVWSD, a portion of which is located south and northwest of WKWD's well field, typically obtains water from the Kern River, the SWP, and from local groundwater pumping. In the exchange, BVWSD takes WKWD SWP water from the California Aqueduct for its needs instead of pumping local groundwater. WKWD, in turn, can then pump or bank a volume of water equivalent to that which BVWSD would otherwise have pumped. As part of the exchange agreement, BVWSD can turn back SWP water in extremely wet years, when it can meet its needs through Kern River supplies. In these years, WKWD will exchange or take delivery of the SWP water through conveyances provided by the KWBA or the CVC. This SWP water will be delivered to the WKWD groundwater spreading vicinity and credited to WKWD's banking program.

WKWD also has two turnouts along the California Aqueduct, which have been used to deliver untreated water diverted from the California Aqueduct directly to industrial customers. Currently only one of the turnouts is operated, which supplies untreated water to La Paloma Power Co. LLC (La Paloma). An agreement was established in 2001 for a maximum of 6,000 AF between WKWD and La Paloma. Historically La Paloma has taken less than 6,000 AFY and WKWD utilizes the balance of the water for recharge to its water banking program or exchanges with other entities. Delivery of WKWD's SWP entitlement is dependent on the availability of SWP supplies. Since the early 1970's, WKWD's water requirements have generally been less than SWP supplies delivered via the exchange with BVWSD. WKWD can accumulate this banked water from year-to-year. The average volume of water banked by WKWD since 1979 is 24,500 AFY. The total water currently banked, as of the end of the 2015, is estimated at 200,000 AF.

The WKWD well field and recharge ponds are located adjacent to the KWBA. WKWD and KWBA maintain an operating agreement relative to pumping and recharge activities. Within this agreement, WKWD has the opportunity to connect to three KWBA production wells. WKWD

participates in exchanges and transfers of SWP water with Kern Tulare Water District, RRBWSD, TCCWD and BVWSD.

Wastewater collection and treatment in the incorporated areas within WKWD's service area are handled by the City of Taft as described in a previous subsection. Many of the small unincorporated communities within WKWD's service area are on septic systems.

4.3 Subregion Description

4.3.1 Land Use

As discussed in Section 2.3, the Land Use, Open Space, and Conservation Element of the Kern County General Plan provide the policies protecting the Kern County unincorporated areas, including the communities comprising the Kern Fan Subregion. Because of the close interrelationship between land use, conservation, and open space issues, Kern County's Land Use, Conservation, and Open Space Element provides for a variety of land uses for future economic growth while also assuring the conservation of Kern County's predominant agricultural, natural, and resource attributes.

The Kern Fan can be generally characterized as containing a predominance of rural uses including agriculture/open space and mineral/petroleum uses. The majority of the western portion of the Kern Fan, south of McKittrick and Tupman and north of the City of Maricopa, consists of mineral/petroleum uses. The northern and eastern portions of the subregion consist mostly of agricultural uses. There are some isolated areas within the subregion that are designated in the Kern County General Plan as "State/Federal Land." Agriculture and petroleum resources are important land uses in Kern Fan subregion and are vital to the local economy. The Midway-Sunset Oilfield, the third largest oilfield in the United States, is located in the Kern Fan subregion. Because of the importance of agriculture and petroleum production to the Kern Fan subregion, the Kern County General Plan emphasizes policies for protecting agricultural lands and directing urbanization to areas without important mineral and petroleum resources.

The largest City in the subregion is Taft with a population of 9,500. The land use element of Taft's General Plan, Buttonwillow Community Development Plan, Derby Acres Rural Community Plan, Dustin Acres Rural Community Plan and Valley Acres Rural Community Plan also provide policies protecting the uses within the Kern Fan.

4.3.2 Ecological Processes and Environmental Resources

Ecological processes and environmental resources for the Kern Region as a whole are described in Section 2.4. With regard to the Kern Fan subregion, agriculture, urban development and oil/gas extraction have resulted in many changes in the natural environment. These impacts have resulted in drained and diverted lakes and wetlands, the loss of native plants and animal species, and a decrease in native lands. This has also resulted in the introduction of invasive species and spread of exotics leading to the decline of native plant communities.

The CDFW and the USFWS have listed some species as threatened or endangered, requiring species recovery by establishing a network of conservation areas and reserves that include terrestrial and riparian natural areas in the San Joaquin Valley and thus Kern Region. As part of

their conservation efforts in the San Joaquin Valley, MBHCP and the draft VFHCP have been established to implement endangered species recovery programs within the Kern Region to promote species recovery and protect ecological processes and environmental resources. The Kern Fan subregion is within the boundaries of the Endangered Species Recovery Program for the San Joaquin Valley. There are some areas planned for habitat acquisition within easterly edge of the subregion identified in the Metropolitan HCP. Much of the subregion is under the conserved jurisdiction, for those signatories, of the draft VFHCP.

The Kern Fan subregion is further distinct because it contains the Kern River, the Kern Water Bank, the Tule Elk State Natural Reserve and the Coles Levee Ecosystem Preserve. West of Bakersfield much of the Kern River is diverted for agricultural use and the river becomes dry or nearly dry for most of the year. During wet years the Kern River continues through the Kern Fan and terminates at Buena Vista Lake bed. The Kern River supports many vegetation types, both common as well as sensitive species are found along the river corridor.

The Kern Water Bank consists of about 20,000 acres of land bisected by the Kern River southwest of Bakersfield. The bank, which operates under its own HCP/NCCP, has restored over 17,000 acres of farmland to upland and intermittent wetland habitat. These habitats are home to over 34 at-risk species, including the Tipton kangaroo rat, San Joaquin kit fox, burrowing owl, loggerhead shrike, osprey, and tricolored blackbird. The bank is also home to rare and endangered plants, including the San Joaquin woolly thread and Hoover's wooly star. A portion of the bank is also a conservation bank, where third-parties can mitigate impacts to species and habitat in other parts of the San Joaquin Valley.

The Coles Levee Ecosystem Preserve consists of about 6,060 acres of threatened and endangered species habitat which also encompasses the last two miles of riparian habitat along the Kern River before it enters the Buena Vista Lake. It was established in 1992 by Arco and the CDFW, the Preserve was acquired in 1998 by Aera Energy LLC. More than a dozen rare, threatened, and endangered birds, animals, and plant life can be found in the Preserve. The Preserve represents a unique public-private partnership dedicated to conserving entire ecosystems rather single species on scattered, smaller preserves.

The Tule Elk State Natural Reserve is approximately 953 acres located near the town of Tupman, and protects a herd of Tule elk, once in danger of extinction. In the 1880s, vast herds of Tule elk were greatly reduced in number by hunting and loss of habitat. Cattleman Henry Miller began a 50-year effort to save them in 1874. At that time, few elk remained. In 1932, the herd was given permanent protection on the park property, now known as Tule Elk State Natural Reserve. Elk from the reserve have been successfully transplanted to other areas in California where free-roaming herds of Tule elk can be found today (Brochure, California State Parks).

4.3.3 Social and Cultural Characteristics

The social and cultural characteristics of the Kern Fan are not different from that as described for the Kern Region as a whole, as provided in Section 2.5. The Kern Fan is characterized by its traditional industries, agriculture, oil and gas production, and a local prison, as well as increasing urbanization and population growth.

4.3.3.1 Economic Conditions and Trends

The Kern Fan subregion makes up approximately 6 percent of the total population within the Kern Region. The cities and communities of Buttonwillow, Derby Acres, Dustin Acres, Fellows, Ford City, Maricopa, McKittrick, South Taft, Taft City, Taft Heights, Tupman, and Valley Acres are within the Kern Fan. The majority of the population lives in or around Taft.

The Kern Fan subregion economy is agriculture and resource based. Agriculture makes up a large segment of the land use in the eastern portion of the subregion. Oil exploration and production provide a large segment of the employment base in the western portion of the sub-region, with clay mineral extraction also occurring in the area. The majority of the economic base in Taft and Maricopa is directly related to the petroleum industry. The Midway-Sunset Oilfield, the third largest oilfield in the United States, has produced over 3 billion gallons of crude oil. A prison in Taft also provides an additional source of employment in this area.

This subregion has a low growth rate than other areas of the Region. For example, Taft's population has remained mostly stagnant for the last decade. The low population growth within Taft is highly influenced by the lack of available property. Oil companies and government agencies control the majority of the land surrounding Taft, and until recently, land for development has not been for sale. Some small scale residential developments are anticipated within the next 5 years.

4.3.3.2 Disadvantaged Communities

A number of municipalities within the Kern Region have been identified in **Table 2-5** in Section 2.5.3 which meets the definition of a DAC. Of those identified as a DAC, Buttonwillow, Ford City, Maricopa, South Taft, Taft, Taft Heights, and Tupman are located in the Kern Fan subregion.

4.3.4 Water Supply

The following section describes the sources of water supply for the Kern Fan subregion including imported surface water, local surface water, and local groundwater.

4.3.4.1 Imported Water

Imported water supplies into the Kern Fan subregion are SWP and CVP via the California Aqueduct and CVP via the Friant-Kern Canal. Turnouts on the California Aqueduct deliver water to KCWA, who then delivers it to its 13 member units for distribution. Imported SWP water is discussed in detail in Section 2.6.1. The subregion is very dependent on this supply to recharge groundwater.

4.3.4.2 Surface Water

The primary source of surface water in the Kern Fan subregion is the Kern River. This source is described in detail in Section 2.6.2.

Except for very wet periods, there is no flow in the Kern River past Bakersfield due to upstream canal diversions. During very wet years, water flows in the river southwest to the Buena Vista Lake bed and then north to Tulare Lake or into the California Aqueduct near Tupman.

Buena Vista Lake (Lake Evans/Lake Webb) is located approximately 23 miles southwest of Bakersfield at the terminus of the Kern River. This recreation area occupies a portion of the old Buena Vista Lakebed. Technically, the recreation area is an Agricultural Water Conveyance

Facility that connects the Alejandro Canal with the Kern River Channel and the California Aqueduct for the purpose of facilitating more efficient storage and distribution of water. The resultant lake developments provide almost 960 acres of water surface for boating, skiing, sailing, and fishing. The two separate lakes (Lake Evans and Lake Webb) provide the primary attraction for the park with adjacent camping and picnic areas ancillary to this feature (Draft Recirculated Program EIR, Kern County Revised General Plan Update, January 2004). The aquatic lakes “Lake Webb” and “Lake Evans” are part of the Buena Vista Aquatic Recreation Area. These are owned and operated by the County of Kern. BVWSD is the water master that keeps the records of water into and out of the Lake. A portion of this area is within the boundary of HMWD, which operates and maintains four wells. HMWD has rights to move its water through the lakes.

4.3.4.3 Groundwater

Groundwater is an important water supply to the Kern Fan subregion. The San Joaquin Valley groundwater basin underlies the majority of the Kern Fan. Major water banking and conjunctive use projects contribute large amounts of recharge to the Kern Fan. Secondary sources of groundwater are infiltration of water used for irrigation in agricultural applications. During wet years, Kern River water is also a source of groundwater recharge. Groundwater banking programs are widely used in the Kern Fan subregion. Many notable storage programs in the Kern Fan include those operated by BVWSD, KWBA, RRBWSD, and WKWD. It is estimated that approximately two-thirds of water banking storage in Kern County is in the Kern Fan.

The Kern Fan Monitoring Committee was established to monitor the impacts of banking programs located on the Kern Fan. The purpose of this committee is to ensure that the banking and recovery projects do not result in significant impacts to water levels, groundwater quality, or land subsidence. Annual groundwater level and quality maps are prepared by the committee.

4.3.4.4 Recycled Water

As discussed in Section 2, wastewater effluent produced by treatment facilities can be applied to non-food crop irrigation and environmental habitat restoration. Taft currently has two WWTPs, the Taft Municipal Wastewater Treatment Plant and the State Prison Wastewater Plant. The Taft Municipal Wastewater Treatment Plant serves the Taft Sphere of influence and has a capacity to treat 1.5 MGD. State Prison Wastewater Plant has a capacity of 0.5 MGD. Taft plans to eventually double the capacity of both plants to accommodate future development.

4.3.5 Water Quality

Imported water supplies in the Kern Fan subregion regard SWP water and generally are of good quality. This supply is discussed in detail in Section 2, Section 2.7.2.

The quality of groundwater in the Kern Fan subregion is excellent. The concentration of TDS averages about 220 mg/L, far below the MCL for drinking water of 500 mg/L. The TDS in the California Aqueduct averages 240 mg/L and can range up to about 400 mg/L. The subregion participants regularly monitor groundwater conditions using dedicated monitoring wells. The water quality is tested in accordance with protocols developed by the DDW for drinking water. Water levels are measured at least semiannually, and the water is tested for the presence of several constituents annually. With the exception of a few localized oilfield operations, there are no potential pollution sources (KWBA Website).

Other water quality concerns within the Kern Fan subregion include the storm water runoff from residential and industrial areas that can contribute to water quality degradation since it contains organics, pesticides, oil, grease, and heavy metals. Also of concern is naturally occurring erosion, which can cause discoloration of streams, and suspended matter settling to form a smothering blanket on the streambed. Erosion is accelerated by poor drainage and soil stabilization associated with the following activities: road building, clearing and leveling land, construction, brush clearing, off-road vehicle use, agriculture, overgrazing, and fires.

Some participants, primarily domestic water purveyors, rely solely on the groundwater source for their supply of water. Water quality deterioration would greatly impact the ability of some of the participants to supply a reliable source of water to their customers. The areas supplied by the WKWD for example need imported water from outside their region because the local groundwater is of poor quality due to high TDS and not suitable for domestic or agricultural purposes.

4.3.6 Water Demand

Water demands for urban water use and agricultural water use within this subregion are provided in Section 2.9.

4.3.7 Water-Related Infrastructure

Water related infrastructure such as surface water impoundments, water collection systems, distribution systems, wastewater systems, and recharge systems, are described generally for the Kern Fan subregion participants in their general descriptions above, and in greater detail for the entire Kern Region in Section 2.9.

In general, many Kern Region communities are older, and the physical components of their water systems are aging and outdated. Aging infrastructure is a particular issue for rural communities and DACs.

4.4 Subregional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for this subregion with respect to water resource management are discussed in detail in Section 2 as follows:

- Aging and/or Duplicative Infrastructure (see Section 2.11.1)
- Decreased Imported Water Supply (see Section 2.11.4)
- Groundwater Overdraft and SGMA (see Section 2.11.6)
- Urban Growth Encroachment on Key Recharge Areas (see Section 2.11.3)
- Water Quality/groundwater contamination (see Section 2.11.8)
- Water Rights (see Section 2.11.9)
- Climate Change (see Section 2.11.11)

Section 5: Mountains/Foothills Subregion

5.1 Subregion Introduction

This section presents a description for the Mountains/Foothills portion of the Kern Region. The section includes a summary of the subregion's participants, as well as a description of the physical, environmental, social and demographic characteristics of the subregion, the hydrologic features and overall water reliability, and major water related infrastructure. The Mountains/ Foothills subregion is located at the southeast quadrant of the Kern Region primarily amongst the Tehachapi Mountains which are bounded by the Mojave Desert/Great Basin to the east, the Caliente Creek to the north and the San Joaquin Valley to the west. Highway 58 runs southeast through this subregion from Bakersfield over the Tehachapi Mountains to the City of Tehachapi and provides a connection from the San Joaquin Valley to the Great Basin/Mojave Desert.

5.2 Subregion IRWMP Participants

The Mountains/Foothills subregion is comprised of ten participants and includes:

1. Tehachapi-Cummings County Water District (TCCWD)
2. City of Tehachapi
3. Golden Hills Community Services District (GHCSD)
4. Bear Valley Community Services District (BVCSD)
5. Stallion Springs Community Services District (SSCSD)
6. Tehachapi Resource Conservation District (TRCD)
7. Frazier Park Public Utility District (FPPUD)
8. Lebec County Water District (LCWD)
9. Tejon-Castac Water District (TCWD)

These participants' roles and responsibilities for managing water, natural resources, and land use within the Mountains/Foothills subregion are discussed below.

5.2.1 Tehachapi-Cummings County Water District

TCCWD is a member of KCWA with a SWP Table "A", firm contract entitlement of 19,300 AFY. The District is located in the Tehachapi Mountains with a service area that encompasses roughly 266,000 acres. TCCWD's connection to the California Aqueduct is just upstream of the Edmonston Pumping Plant near Tejon Ranch; a pipeline 31 miles in length which ranges from 27- to 39-inches in diameter delivers water to the District's turnouts located in the Cummings, Brite and Tehachapi Groundwater Basins.

TCCWD serves as the court-appointed Watermaster for three adjudicated groundwater basins (Cummings Valley, Brite Valley, and Tehachapi Valley groundwater basins). In its role as watermaster, TCCWD has implemented a regional water conservation program that received grant funding through a Proposition 84 Implementation Grant. TCCWD is currently pursuing grant funding to increase groundwater recharge capacity.

TCCWD provides water to agricultural customers and also wholesales surface water to other water agencies such as BVCSD, City of Tehachapi, GHCSD, SSCSD, and the California Department of Corrections and Rehabilitation. Many of these agencies including TCCWD will recharge some or all of their SWP supplies into their local groundwater basins to create a more reliable potable water source (conjunctive water use). One of the goals of the Board of Directors of the TCCWD is to direct the use of imported SWP water to agricultural and industrial uses and reserve the high-quality groundwater for domestic demand. At times, the District has sold portions of its contract entitlement to KCWA member units when practical; the district also reserves a portion of its allotment for carry over into the following year.

5.2.2 City of Tehachapi

The City of Tehachapi, a disadvantaged community, provides groundwater to more than 12,000 residents which is pumped from the Tehachapi Groundwater Basin. The City purchases imported SWP water from TCCWD to meet demands in excess of its groundwater allocation. This water is recharged into the City's groundwater allocation; at the end of 2015, the City has 1,295 AF of groundwater banked. The City maintains six groundwater wells, storage tanks, and 37 miles of transmission lines that provide potable water to residences, schools, and businesses. The distribution system includes 5 pressure zones, four of which are used and regularly tested (TCCWD 2015 UWMP, 2016).

The City received Proposition 84 funding through the IRWM Implementation Grant Program to construct a pipeline from a groundwater well with high nitrates to the TCCWD irrigation system. Through this pipeline system, the nearby school athletic fields can be irrigated with these water supplies, and the goal is to pump out the high nitrate water to bring the well back into compliance for drinking water.

The City also provides sewer service to its customers and treats the wastewater at its WWTP. The treated effluent is used for irrigating alfalfa and pasture from April through September. Potable water that was used for process water at the WWTP has been replaced with recycled water in 2016. The City is investigating options for other uses of recycled water including indirect potable reuse (IPR) and landscape irrigation.

5.2.3 Golden Hills Community Services District

GHCSD serves a 5,980 acre community in the Tehachapi Mountains, one-half mile west of the City of Tehachapi, bounded by State Highway 202 (Cummings Valley Boulevard) to the south, Reeves Street and the western border of the Southern Pacific Railroad right-of-way to the east, and a line parallel with Valley View Road to the north. GHCSD provides potable water service to approximately 8,800 customers through over 2,800 service connections. GHCSD's water source is derived from groundwater pumped by 16 wells. The District also purchases surface water from the Tehachapi-Cummings CWD, which is ultimately recharged back into the underlying aquifer.

GHCSD also received Proposition 84 funding through the IRWM Implementation Grant Program to construct a new production well and connection pipeline. The project continued the District's goal of recharging surface water for later access by the District's wells (conjunctive water use).

5.2.4 Bear Valley Community Services District

BVCSD serves as the local government for the community of Bear Valley Springs. It is similar to a city government, supplying such services as police protection, fresh water, road maintenance, wastewater treatment, and solid waste disposal. The BVCSD exists under California law governing special districts (Government Code, Sec 61000 et seq). It was established by resolution of Kern County Board of Supervisors on May 4, 1970 for the purpose of providing infrastructure services for the newly developing community of Bear Valley Springs.

BVCSD's services are funded by property taxes, special assessments and standby charges collected by Kern County on the regular property tax bill. Some funds are collected through user fees such as water, sewer and refuse charges and capacity fees for new water connections.

The BVCSD's freshwater system is comprised of nearly 18 potable wells (13 located in the Bear Valley Groundwater Basin and 5 located in the Cummings Groundwater Basin), 5 non-potable wells that fill a lake, 40 storage tanks, and 110 miles of delivery pipe, which is monitored and maintained by the Water Department. The system provides fresh water for all residents as well as for all amenities. BVCSD provides water to a population of approximately 5,300 through approximately 2,950 service connections (TCCWD 2015 UWMP, 2016). Each lot is metered, and monthly billings are made according to water usage.

Wastewater treatment is provided at its facility located on Lower Valley Road. All residents and amenities inside the Lower Valley Road loop (golf course area) are hooked into this sewer system, and treated effluent is used for irrigation purposes on a local golf course or is discharged into Sycamore Creek.

5.2.5 Stallion Springs Community Services District

SSCSD encompasses 23,000 acres of mostly undeveloped land, containing roughly 2,300 parcels. SSCSD provides potable water to over 2,800 customers throughout their service area, which lies 10 miles west of the City of Tehachapi. Currently the company has over 1,300 connections and eight active wells which lie outside its service area. Similar to the other districts, SSCSD purchases water from the TCCWD for local groundwater recharge purposes.

SSCSD also collects and treats wastewater from a portion of its service area. Its WWTP treats to a disinfected secondary standard and discharges the effluent to Chanac Creek that is regulated under an NPDES permit. SSCSD is also evaluating options for upgrading its WWTP to a tertiary treatment level for irrigation use.

5.2.6 Tehachapi Resource Conservation District

The TRCD manages resource conservation projects within an area of approximately 400 square miles of public and private lands. Projects planned for or already implemented include: prevention and control of soil erosion and stormwater runoff; reducing the impact, and eventual eradication of noxious weed species; reducing the impact of non-point sources of pollution; water quality and water conservation activities; improving farmland irrigation methods; preserving prime and unique farmlands and ranchlands; and preserving and improving oak woodlands and wildlife habitats.

5.2.7 Frazier Park Public Utility District

FPPUD was formed on February 20, 1939 as the successor to the Frazier Mountain Water Company. FPPUD primarily serves the Frazier Park community, located 2 miles west of the project sites. Frazier Park has a population of approximately 2,690, and services 1,303 connections to these residents. Four groundwater wells (three active and one standby) are maintained by the FPPUD. These wells pump water from the middle subbasin of the Cuddy Canyon Valley Groundwater Basin. Thirteen water tanks are scattered throughout the service area. These have a combined storage capacity of 2 MG.

Since 2014, FPPUD has participated in a consolidation planning project to annex Lake of the Woods Mutual Water Company into its district. Both communities have agreed to the annexation and the pre-planning phase has been completed. State Water Resources Control Board Planning funds were obtained in August 2019 and test well development has started. Consolidation is contingent on locating adequate, clean water supplies for the District and the consolidating systems."

5.2.8 Lebec County Water District

LCWD services the entire community of Lebec located east of Frazier Park just off the Interstate 5 Freeway on the southern border of Kern County. The District was formed in 1967 and provides groundwater from three existing wells to over 350 customers. The District has seven pressure zones with approximately 500,000 gallons of water storage.

One of the District's wells on the westside of the District has fluoride and uranium just over the MCL. The District has completed a planning grant through the SDWSRF program, which included the design of a new groundwater well and water system improvements to address this water quality issue and system deficiencies. The District is currently awaiting funding for the construction of the project.

5.2.9 Tejon-Castac Water District

TCWD is a member of the KCWA and has contractual rights to the SWP water in the California Aqueduct. In addition, the agency has rights to store and retrieve water in both the Kern Water Bank and the Pioneer Project Water Bank. TCWD provides potable water, reclaimed water, sewer and storm drainage services to the Tejon Ranch Commerce Center (TRCC), which is located adjacent to Interstate 5 at the base of the Grapevine (located in the South County Subregion). The 1,500-acre TRCC is a commercial and industrial park focusing on the needs of trucking, warehousing and distribution industries as well as highway commercial services for the general public.

TCWD is also the proposed water district to serve the Tejon Mountain Village development that includes 3,450 residences, 160,000 square feet of commercial space, up to 750 hotel rooms, and two 18-hole championship golf courses. The district will supply approximately 2,100 AFY of SWP water through a nearby turnout and would construct additional wastewater recycling and water treatment facilities to serve the Tejon Mountain Village proposed development.

TCWD will also serve the proposed Grapevine Master Planned Community, which will serve 12,000 residences and 5.1 million square feet of commercial development. This development

will be located at the base of the Grapevine and is adjacent to the TRCC (located in the South County Subregion).

5.3 Subregion Description

5.3.1 Land Use

The unincorporated areas within the Mountains/Foothills subregion are governed by the land use policies of the Kern County General Plan, and for the Tehachapi Area, the Greater Tehachapi Area Specific Plan adopted in 2010. Because of the close interrelationship between land use, conservation, and open space issues, the Land Use, Conservation, and Open Space Element of these plans provide for a variety of land uses for future economic growth while also assuring the conservation of the County of Kern's predominant agricultural, natural, and resource attributes.

5.3.1.1 Ecological Processes and Environmental Resources

Ecological processes and environmental resources for the Kern Region are described in Section 2.4. With respect to the Mountains/Foothills subregion, the area is dominated by the geologic features of the Southern Sierra Nevada Mountains which are divided into four smaller ranges: The Greenhorn Mountains to the northwest, the Scodie Mountains to the northeast, the centrally located Piute Mountains, and the Tehachapi Mountain Range to the south. Due to the small amount of developed area in comparison to the other subregions, the Mountains/Foothills region boasts some of the most diverse flora and fauna in the Kern Region, due to the ecological extremes of the mountains and the Kern River system.

The mountainous provinces of this subregion are lined primarily with conifers including incense cedars, white firs, and small groupings of aspens while the low-lying foothills or savannahs grow a variety of oak species as well as sycamore, cottonwood, and willow trees. The composition of fauna within this area is analogous to most California mountain ranges and consists of mule deer, mountain lion, wild boar, coyote, fox, black bear, bobcats, and raccoons. Over 68 species of birds reside in the Tehachapi Mountains alone and provide for excellent bird watching opportunities for enthusiasts such as members of the Tehachapi Mountains Birding Club and the Audubon Society.

The Tehachapi Mountains also form an important wildlife corridor because of the biogeographically unique linkage they provide between the Sierra Madre, Castaic, and Sierra Nevada Ranges (SWCA 2008). This area forms a linkage from the foothills and grasslands of the San Joaquin Valley, to the high-elevation hardwood and coniferous forests, to the foothill transition into the Mojave Desert along the base of the southern Tehachapi Mountains (SWCA 2008).

5.3.2 Social and Cultural Characteristics

The cities and communities of Bear Valley Springs, Frazier Park, Golden Hills, Keene, Lake of the Woods, Lebec, Stallion Hills, and Tehachapi are within the Mountains/Foothills subregion. The majority of the subregion's population lives in or around Tehachapi.

The Mountains/ Foothills subregion is known for diverse social and cultural characteristics due to its vast array of landscapes and environments. The greater Tehachapi area, which falls under

the 'foothills' classification, is known for its four seasons, electricity-generating wind turbines, rural communities, and the Tehachapi Loop, a historically-significant railroad feature. Cultural resources in the subregion include archaeological, historical, and man-made resources such as buildings, structures, towns, and objects. The Native American Heritage Commission has completed a Sacred Lands file search which has indicated the presence of numerous historic Native American burial grounds in the region. There are also California-Registered historical landmarks in the foothills region including number 643, Old-Town Tehachapi which commemorates the oldest settlement in the Tehachapi Valley. Landmark number 508 is the famous Tehachapi Railroad Loop in which a 4,000 foot long train crosses 77 feet above its rear cars in a tunnel below as the train gains elevation around a central hill. The National Cesar Chavez Center is located in Keene, also the location of the National Farm Workers Association, which later became the United Farm Workers of America.

The mountainous communities within this subregion are essentially broken up into two areas: the Tehachapi area and the southern mountains including the Frazier Park-Lebec Specific Plan Area. The southern mountains, which include the Mount Pinos Recreational area, Hungry Valley State Recreational Vehicle Area, Fort Tejon, and picturesque terrain, attract over 500,000 visitors per year. Recreational activities include mountain biking, camping, fishing, boating, swimming, backpacking, hiking, hunting, horseback riding, and cross country skiing, sledding, and snowmobiling in the winter months.

Section 2.5.1 provides a summary of the human demographics for the Kern Region. The population is largely White and Latino. Approximately 75 percent of the population identifies as being white and approximately 16 percent of the population reports being Hispanic (US Census Bureau 2005). Persons identifying as African American, Asian, American Indian, and Native Hawaiian make up 9 percent of the population. English is the primary language.

5.3.2.1 Economic Conditions and Trends

Tehachapi has seen a huge increase in businesses in the last 7 years, including its first big-box store, Home Depot, and a Wal-Mart Supercenter. One of the largest employers in Tehachapi is the California Correctional Institution (CCI), which is a high-security prison.

The Tejon Mountain Village may bring new economic development to this subregion. Tejon Mountain Village proposed development includes 3,450 residences; up to 160,000 square feet of commercial development; hotel, spa, and resort facilities, which include up to 750 lodging units; and up to 350,000 square feet of facilities in support of two 18-hole golf courses, riding and hiking trails, equestrian facilities, two helipads, fire stations, private community centers, electrical sub-station facilities, permanent and interim water treatment and wastewater treatment facilities and access and utilities to serve the project, and ranchland and other undeveloped open space. The proposed development would occur within an approximately 7,867-acre development envelope of which an approximately 5,082-acre building area would ultimately be developed. Approximately 21,335 acres (80 percent) of the site would be permanently preserved as ranchland and other undeveloped open space (Tejon Village EIR, 2009).

5.3.2.2 Disadvantaged Communities

A number of municipalities within the Mountains/Foothills subregion have been identified in **Table 2-5** of Section 2.2.5.3 which meets the definition of a DAC.

5.3.3 Water Supply

5.3.3.1 Imported Water Supplies

While most of the water purveyors within the region primarily provide groundwater to their customers, imported water supplies via the SWP California Aqueduct are also available. These imported water supplies are discussed in more detail in Section 2.6.1.

5.3.3.2 Surface Water

Many small local surface water sources are very seldom utilized by communities and local water purveyors in the Mountains/Foothills subregion as a direct source of domestic or agricultural and industrial water due to poor infrastructure connections and low flows. Thousands of acres of land are used for ranching throughout the foothill and mountain areas on both private and public lands. Irrigated agriculture in the region includes orchard crops (e.g. apples), vegetables, and other crops with some farmed in large nursery facilities. Tributaries within the region such as Caliente Creek and Tehachapi Creek provide small sources of water, typically used in agricultural irrigation applications in the portions of the County of Kern at lower elevations. Refer to Section 2.6.3 for more information regarding natural surface waters in the Kern Region.

5.3.3.3 Groundwater

Groundwater is the primary source of domestic water for the residents of this subregion. In the Tehachapi Area, high quality water is present in basins such as the Tehachapi Groundwater Basin, Brite Groundwater Basin, and Cummings Groundwater Basin .

In 1972, the Superior Court of California issued a ruling in the “Tehachapi Basin Case” that provided for a water exchange pool, which allowed the City of Tehachapi, Golden Hills, and various others with shortfalls in supply to pump groundwater in excess of their pumping rights. In response, agricultural parties who owned groundwater pumping rights gave up their right to pump in lieu of additional surface water imports for irrigation uses. Over the last few years, land use and water rights changes have rendered the water exchange pool unnecessary and although the pool is still intact, it is currently not in use. The Tehachapi Groundwater Basin has an annual safe yield of 5,500 AF which was established in the Tehachapi Basin Case.

The Cummings Basin has a conjunctive use plan including return flows and aquifer recharge that produces an annual safe yield of 4,090 AF, with approximately 2,989 AF used for agricultural use and 911 AF used for M&I purposes.

Brite Groundwater Basin has a much smaller adjudicated annual safe yield of 500 AF in which 229 AF are extracted for agricultural use and 99 AF are extracted for municipal and domestic purposes (Integrated Resource Management, LLC. 2009).

The Cuddy Groundwater Basin (divided into 3 basins in Bulletin 118) and the Castac Lake Valley Basin are not adjudicated basins and has not been identified by the DWR as an over drafted basin. However, due to insufficient snowfall and rainfall in the recent drought, portions of the Cuddy Groundwater Basin were dewatered to levels that primarily impacted Lake of the Woods.

5.3.3.4 Recycled Water

Currently, the City of Tehachapi, SSCSD, Golden Hills Sanitation Company, TCWD, and the California Department of Corrections and Rehabilitation existing treatment systems provide recycled water. Title 22 from the California Code of Regulations sets limitations on water discharges including potential for reuse in applications such as irrigation and groundwater recharge. Secondary treated wastewater may only be surface applied to forage crops on non-consumptive grasses without any percolation to groundwater.

TCCWD entered in an agreement with the California Department of Corrections and Rehabilitation to purchase up to 1,200 AF annually of the treated effluent from their wastewater treatment facility (WWTF). TCCWD can supply this recycled water for landscape irrigation at the local golf course or to nearby farmers.

The TCWD operates two separate, tertiary WWTFs located in the District's TRCC in the southern portion of the Mountains/Foothills subregion. These WWTFs are permitted by the CVRWQCB to treat water to meet Title 22 standards for non-potable use on landscape throughout the TRCC.

BVCSD and Golden Hills Sanitation Company operate a sewer plants with tertiary treatment.

5.3.4 Water Quality

Groundwater quality within the Mountains/Foothills subregion is variable seeing small localized areas with contaminants above the CCR Title 22 screening limits. Many community and noncommunity water systems have contaminated water sources from nitrates, bacteria, fluoride, uranium, arsenic, and gross alpha radiation. The most common contaminant found at higher than desirable concentrations within the Tehachapi Basin, Cummings Basin, and the Cuddy Valley Basin is nitrate. High levels of nitrate within these areas is a result of more than 60 years of use of nitrate and ammonium fertilizers as well as secondary treated effluent from small wastewater treatment facilities and septic systems.

SWP water quality is discussed in Section 2.7.2.

Almost all of the water systems in this subregion have implemented chlorination systems at the wellhead to protect against bacteria contamination. Water treatment systems for nitrates or other contaminants have not been necessary as purveyors pursue other locations for wells or flushing/blending operations are conducted.

5.3.5 Water Demand

Water demands for urban water use and agricultural water use within this subregion are provided in Section 2.9.

5.3.6 Water-Related Infrastructure

Water related infrastructure such as surface water impoundments, water collection systems, distribution systems, wastewater systems, and recharge systems, are described generally for the Mountains/Foothills subregion participants in their general descriptions above, and in general for the entire Kern Region in Section 2.9. Many Kern Region communities are older

and the physical components of their water systems are aging and outdated. Aging infrastructure is a particular issue for the Mountains/Foothills subregion, its rural communities and DACs.

5.4 Subregional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for this subregion with respect to water resource management are discussed in detail in Section 2 as follows:

- Groundwater Overdraft (see Section 2.11.6)
- Watershed Protection (see Section 2.11.10)
- Aging and/or Duplicative Infrastructure (see Section 2.11.1)
- Urban Growth and Water Demand (South Mountains) (see Section 2.11.2)
- Climate Change (see Section 2.11.11)
- Water Quality/Groundwater Contamination (see Section 2.11.8)

Section 6: Kern River Valley Subregion

6.1 Subregion Introduction

This section presents a description for the Kern River Valley portion of the Kern Region. The section includes a summary of the subregion's participants, as well as a description of the physical, environmental, social and demographic characteristics of the subregion, the hydrologic features and overall water reliability, and major water related infrastructure.

The Kern River Valley subregion is located in the northeast quadrant of the Kern Region. It is bounded by the Mojave Desert/Great Basin to the east, the northernmost segment of the Mountains and Foothills region to the south by the Caliente Creek divide, and the San Joaquin Valley to the west. Highway 178 runs northeast through the subregion along the channel of the Kern River, from where the river debuts into the San Joaquin Valley, through the axis of the Kern River Valley and out to the Great Basin/Mojave Desert.

6.2 Subregion IRWMP Participants

The Kern River Valley subregion is comprised of six participants and includes:

1. California Water Service – Kern River Valley District (CWS-KRVD)
2. Long Canyon Water Company (LCWC)
3. Desert Mountain Resource Conservation and Development Council (DMRCDC)
4. Mountain Mesa Water Company (MMWC)
5. Rainbird Valley Mutual Water Company (RVMWC)
6. Valley Estates Property Owners Association (VEPOA)
7. Tubatulabals of Kern Valley Tribe

These participants' roles and responsibilities for managing water, natural resources, and land use within the Kern River Valley subregion are discussed below.

6.2.1 California Water Service, Kern River Valley District

CWS-KRVD provides water to the Kern River Valley Area. CWS-KRVD was formed in 2000 with the purchase of the Kern River Valley Water Company and currently serves over 5,600 customers throughout the valley through 4,056 service connections. About half of the water delivered by CWS in this area is pumped from rock fissures in granitic rocks beneath the ground and the other half is derived from the Kern River. The CWS-KRVD operates over 50 wells, 30 storage tanks, 75 miles of distribution mains and 8 treatment plants, including a 1.01 MGD surface water plant.

Water quality concerns are an issue for groundwater in the District's service area. Iron, manganese, uranium, and arsenic are the water constituents of concern. In the Southlake area, nitrates are a concern. In the Kernville, Wofford Heights and Lakeland systems, fluoride is a concern. In Wofford Heights a treatment plant removes iron and manganese and blends to reduce arsenic and fluoride concentrations. Kernville is served by the surface water plant.

6.2.2 Long Canyon Water Company

LCWC serves 64 customers at flat rate billing in the town of Weldon on the edge of Lake Isabella. The company operates two wells. Gross alpha particle activity and uranium are high in concentration but lower than the MCL.

LCWC, Bella Vista Mutual Water Company, Tradewind Water Association, KOA Campground, Rainbird Valley Mutual Water Company are currently working on an interconnection between the communities to address uranium and nitrate contaminated wells in the communities. Two new well sites have been selected and a transmission pipeline system has been designed. A new district replacing these individual agencies is being formed through LAFCo. The project is being funded through the SWRCB and USDA. Construction is anticipated to start in 2020.

6.2.3 Desert Mountain Resource Conservation and Development Council

The mission statement of the DMRC&DC is to create partnerships that will enhance the quality of life and promote economic growth while protecting the environment. The DMRC&DC worked with East Kern County Resource Conservation District to control the spread of purple loosestrife in the South Fork Kern River Wildlife Area. The DMRC&DC established a watershed coordinator position in the Kern River Valley to address water quality, quantity, erosion, and wildlife habitat issues in the Upper Kern and South Fork Kern River Watersheds. This project was funded through a grant from the California Department of Conservation.

6.2.4 Rainbird Valley Mutual Water Company

RVMWC is located in the town of Weldon, south of State Highway 178, in the Kelso Canyon area near the South Fork of the Kern River, east of Lake Isabella. This mutual water company has 238 customers with 85 individual metered connections. The company operates two wells; the main well has shown high levels of uranium concentrations and the back-up or stand-by well has shown high nitrate concentrations. Both wells fail to meet the State and Federal safe drinking water standards for these contaminants. Refer to Section 6.2.2 regarding the planned consolidation project.

6.2.5 Valley Estates Property Owners Association

The VEPOA is located in Weldon approximately 16 miles east of the town of Lake Isabella and was formed in 1983 as a successor to Paradise Cove Development Association. The association has a retail population of 386 and maintains 113 connections on 5/8 acre lots. The Valley Estates development was built in 1972 and receives water from two wells and nearly 3 miles of original asbestos concrete piping. Water quality for the wells is generally good.

6.2.6 Tubatulabals of Kern Valley Tribe

The Tubatulabals of Kern Valley Tribe work in conjunction with U.S. Department of Indian Health Services (USIHS), Kern Council of Governments, KCWA, and U.S. Bureau of Indian Affairs to provide safe drinking water to the Tribal residents of the public domain lands located in the Kern River Valley subregion. In addition, the Tribe has partnerships and memorandum of agreements with USFS, USBLM, CDFW, and Tule River Indian Reservation to help protect cultural resources near and around Lake Isabella, the Kern River (canyon, north and south forks) and Kern Valley. The Tubatulabals of Kern Valley has over 260 Tribal Members; 35 Tribal

families live on public domain allotment lands (total of 1,600 acres). The Tubatulabals of Kern Valley also operate a 501(c)(3) non-profit organization that provides services to their Tribal members.

6.3 Subregion Description

6.3.1 Land Use

The unincorporated areas within the Kern River Valley subregion are governed by the land use policies of the Kern County General Plan and the Kern River Valley Specific Plan (2011). Because of the close interrelationship between land use, conservation, and open space issues, the Land Use, Conservation, and Open Space Element of the General Plan and Specific Plan provide for a variety of land uses for future economic growth while also assuring the conservation of the County of Kern's natural and resource attributes. Land use designations include: non-jurisdictional land, physical constraints overlay, public facilities and services, special treatment areas, residential, commercial, industrial, resource, and protection of cultural resources.

6.3.1.1 Ecological Processes and Environmental Resources

Ecological processes and environmental resources for the Kern Region as a whole are described in Section 2, Section 2.4. With respect to the Kern River Valley subregion, the area is dominated by the geologic features of the southern Sierra Nevada Mountains, which are divided into four smaller ranges: the Greenhorn Mountains to the northwest, the Scodie Mountains to the northeast, the centrally located Piute Mountains, and the Tehachapi Mountain Range to the south. Due to the small amount of developed area in comparison to the other subregions, the Kern River Valley region boasts some of the most diverse flora and fauna in the Kern Region, due to the ecological extremes of the mountains and the Kern River system.

The mountainous provinces of this subregion are lined primarily with conifers including incense cedars, white firs, and small groupings of aspens, while the low-lying foothills or savannahs grow a variety of oak species as well as sycamore, cottonwood, and willow trees. The composition of fauna within this area is analogous to most California mountain ranges and consists of mule deer, mountain lion, wild boar, coyote, fox, black bear, bobcats, and raccoons.

The Kern River, discussed in detail in Section 2.6.3.1, is one of the most outstanding environmental resources in this subregion. The Kern River supports many types of habitat, vegetation and animal species. Vegetation found along the river corridor include riparian woodland, riparian scrub, riparian savannah, freshwater marsh, quail bush scrub, alluvial scrub, and grasslands. As described in Section 2.4, the riparian forest along the South Fork Kern River in the vicinity of Onyx and Weldon constitutes another exceptional natural resource in this subregion. This riparian forest is one of the highest quality and most extensive stands of that vegetation type in California, supporting the largest populations of Southwestern willow flycatchers and yellow-billed cuckoos in California. Much of this forest is conserved in the US USFS South Fork Wildlife Area, Audubon California's Kern River Preserve, and CDFW's Canebrake Ecological Reserve.

The CDFW and the USFWS have listed some species as threatened or endangered, requiring species recovery by establishing a network of conservation areas and reserves that include terrestrial and riparian natural areas in the San Joaquin Valley and thus Kern Region. As part of

their conservation efforts in the Region, MBHCP and the draft VFHCP have been established to implement endangered species recovery programs within the Kern Region to promote species recovery and protect ecological processes and environmental resources. The Kern River Valley subregion's westerly edge is within the Metropolitan HCP and under the jurisdiction of the draft VFHCP.

Some areas in the subregion are subject to periodic flooding, including the South Fork of the Kern River, Kelso Creek, and Erskine Creek. Areas prone to flooding are predominantly south of Isabella Reservoir and Highway 178. The area is also prone to wildfires, which impact water quality when rain washes fire debris into waterways. In July 2008, the Piute Fire burned a significant area in the region. It was soon followed by a summer thunderstorm, which washed fire debris into the South Fork and ultimately down the Kern River.

6.3.2 Social and Cultural Characteristics

The cities and communities of Bodfish, Kernville, Lake Isabella, Mountain Mesa, Onyx, Squirrel Mountain Valley, Weldon, and Wofford Heights are within the Kern River Valley subregion. The majority of the subregion's population lives in or around Lake Isabella.

The Kern River Valley subregion is known for diverse social and cultural characteristics due to its vast array of landscapes and environments. Cultural resources in the subregion include archaeological, historical, and other resources such as buildings, structures, towns, and objects. The Native American Heritage Commission has completed a Sacred Lands file search which has indicated the presence of numerous historic Native American burial grounds in the region. Tubatulabals of Kern Valley have registered with the National Trust for Historic Preservation to assist with protection of sacred sites and notification of repatriation reburials.

Recreational activities include mountain biking, camping, fishing, boating, swimming, backpacking, hiking, hunting, horseback riding, and cross country skiing, sledding, and snowmobiling in the winter months.

Section 2.5.1 provides a summary of the human demographics for the region

6.3.2.1 Economic Conditions and Trends

According to the Kern River Valley Specific Plan 2006, much of the Kern River Valley's economy depends on tourism and recreation. A large share of the region's population is employed in the services (primarily tourism related), retail, construction, and government sectors. The Kern River Valley is characterized by the presence of many hotels, lodges, and recreational activity areas. The Kern River and Isabella Reservoir are major tourist attractions, as are the nearby Sequoia National Forest and Sequoia National Park. This tourism-driven economic activity fluctuates seasonally and creates an unreliable source of income as well as lower-paying employment opportunities for those who depend on it. Economic activity tends to be highest in the spring and summer as recreational use peaks.

6.3.2.2 Disadvantaged Communities

A number of municipalities within the subregion have been identified in **Table 2-5** of Section 2.2.5.3 which meets the definition of a DAC.

Many of these DACs are located in very rural environments and do not gain economic benefits from certain types of infrastructure including public transportation, new roadways, and state of the art water treatment facilities. It is also common for communities located at higher elevations to pay higher prices for potable water due to the expenses involved with transporting the water through pumping, which requires water to be moved uphill from lower elevations. In addition, these rural communities do not boast a wide variety of businesses or jobs that generate significant amounts of revenue and thus some people will find themselves facing lengthy commutes to developed areas such as Bakersfield. In addition to rural environments, Tribal allotment lands are also located within the DACs. These allotment lands lack infrastructure and due to the current status of the non-federally recognized Tribe, there are limited federal or state services provided to these Tribal communities.

6.3.3 Water Supply

6.3.3.1 Imported Water Supplies

This subregion receives no direct imported water from either the SWP or the CVP.

6.3.3.2 Surface Water

The most important source of naturally occurring surface water in the Region is the Kern River. Due to poor infrastructure connections and low flows, the many small local surface water sources present are very seldom utilized by communities and local water purveyors as a direct source of domestic or agricultural and industrial water. However, the North and South Forks of the Kern River have dedicated riparian rights that are extensively used for pasture and hay irrigation, stock watering and agriculture. South Fork water is treated and used for community water supply by CWS in the Kernville and Wofford Heights areas. Much of the water used for agriculture recharges the local aquifer. Refer to Section 2.6.3 for more information regarding natural surface waters in the Kern Region.

6.3.3.3 Groundwater

Similar to the Mountains/Foothills subregion, groundwater is the primary source of domestic water for the residents of this subregion. The Kern River Valley Specific Plan 2006 has identified shallow groundwater as an issue in several Kern River Valley communities. Shallow groundwater presents development constraints and creates occasional problems for existing homes. It can cause deterioration of roads and buildings, increased soil instability, and septic system failure. Shallow groundwater levels generally coincide with periods of high precipitation. Significant portion of the shallow groundwater area is located under commercially zoned property.

6.3.4 Water Quality

Groundwater quality within the Kern River Valley subregion is similar to that of the Mountains/Foothills subregion; with contaminants above the CCR Title 22 screening limits in small localized areas. Many community and non-community water systems have contaminated water sources from nitrates, bacteria, fluoride, uranium, arsenic, and gross alpha radiation. Infrastructure can be a huge barrier to having quality water in these rural and remote areas as the local residents may not be able to support the rate increases necessary for water purveyors to attain water quality standards. In addition, the continued use of septic systems in the area may contribute to degradation of the groundwater quality.

6.3.5 Water Demand

Water demands for urban water use and agricultural water use within this subregion are provided in Section 2.9.

6.3.6 Water-Related Infrastructure

As of 2004, 49 water purveyors served customers throughout the Kern River Valley. CWS-KRVD serves the majority of the population. Several other private companies regulated by the PUC also provide water service. The remaining companies that are not regulated by the PUC typically serve fewer than 100 customers or only provide water during the summer months for specific establishments such as campgrounds, hotels, motels, trailer parks, lodges, and schools. These systems are regulated by the Kern County Environmental Health Services Department. Most of the water supply is provided through small water purveyors that rely on groundwater, and through community wells. The lack of central water treatment and distribution facilities creates vulnerabilities during drought situations because communities do not have alternative water sources if wells go dry. Additionally, residents may not have alternative sources of supply if wells exceed water quality standards.

The Isabella and Auxiliary Dams are located in the Kern River Valley. A discussion of the dams and the retrofit project is in Section 2.6.3.1.

6.4 Subregional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for the Kern River Valley subregion include the following:

- Some areas have natural water quality problems due to the geology of the area, particularly with arsenic, uranium and nitrates. The construction and operation of water treatment plants is a significant expense for small communities.
- Most areas are served by septic systems, which contribute to water quality issues.
- Most of the water supply is provided through small water purveyors and through community wells. The lack of central water treatment and distribution facilities creates vulnerabilities during drought situations because communities do not have alternate water sources if wells go dry.
- The subregion, consisting primarily of DACs, lacks local funding for new facilities.
- Some areas are subject to periodic flooding, including the South Fork of the Kern River, Kelso Creek, and Erskine Creek.
- The area is prone to wildfires, which impact water quality when rain washes fire debris into waterways.
- The Isabella Dam and the Auxiliary Dam are located in the Kern River Valley subregion. Concerns with the dams include: seepage, overtopping, and earthquake stability.

Section 7: North County Subregion

7.1 Subregion Introduction

This section presents a description of the North County subregion of the Kern Region. The North County subregion is located in the central-northern portion of the Kern Region, east of the West Side subregion. Descriptions of the subregion's participants, as well as the physical and environmental characteristics, hydrologic features, and issues and needs of the subregion are provided.

7.2 Subregion IRWMP Participants

Five participating entities within the North County subregion include:

8. The City of Delano
9. The City of McFarland
10. The City of Shafter
11. The City of Wasco
12. The North West Kern Resource Conservation District (NWKRCD)

The Poso Creek IRWMP Region also currently exists within the North County subregion, however, that is a separate IRWMP planning process from the Kern IRWMP, and is not included as part of this description. Refer to Section 1.1.1 in Section 1 for a more detailed discussion of how the Kern IRWMP RWMG and the Poso Creek RMG have coordinated and communicated to get to this point in the Kern IRWMP's development.

These participants' roles and responsibilities for managing water, natural resources, and land use within the North County subregion are discussed below.

7.2.1 City of Delano

The City of Delano is located within the northwestern portion of the County of Kern, 32 miles north of Bakersfield. Delano's nearest neighbor, McFarland, is approximately 6 miles south. State Highway 99 runs north and south through Delano. The natural resources and gentle topography of Delano has made it hospitable to agriculture. Delano is surrounded by productive farmland and is known for production of table grapes, almonds, and citrus.

Delano was founded in 1873 as a railroad town and was incorporated in 1915. Delano is a growing community with a population of approximately 53,000. As such, Delano is the second largest city in the Kern Region (the City of Bakersfield is the largest). Delano is currently in a transitional stage of growth from a small, semi-rural town to a medium-sized urbanized community. Over the next 20 years, the population is projected to grow to 70,000 by 2040.

Delano's water system serves 9,900 connections through 120 miles of distribution piping ranging in size from 4 to 16 inches in diameter. Its water supply consists solely of groundwater. It currently has fifteen active wells with a total supply capacity of 15,400 GPM. The City

maintains five storage reservoirs with a total capacity of 10.6 million gallons (Delano 2015 UWMP).

Delano is implementing treatment for multiple wells due to arsenic and 1,2,3-TCP. An Arsenic Mitigation Study was conducted by Carollo for the City in 2013. The study recommended wellhead treatment and drilling new wells to augment supply capacity in the system. The cost of the project is approximately $21 million. The State approved a no-interest loan to fund the project. In addition to working on the arsenic mitigation project, the City is also needing to treat wells for 1,2,3-TCP. The preliminary design of the GAC treatment systems is in process.

7.2.2 City of McFarland

The City of McFarland is a municipality located in northern Kern County on Highway 99. Incorporated July 15, 1957, the town was named for J. B. McFarland, who with W. F. Laird, established the townsite in 1908. It is community deeply rooted in agriculture with cotton, sugar beets, potatoes, and roses as some of the leading crops. A citrus processing plant, an almond hulling facility, and a winery further serve the area's agriculture and economic interests.

The City of McFarland provides domestic water service to a population of 15,000 persons through over 2,800 unmetered connections. The City's water system consists of four groundwater wells (1 that is inactive), one storage tank with booster pumps. Total pumping capacity of the 3 active wells is 3,600 GPM. Water quality is generally good for the City, but its water supply does exceed the MCL for 1,2,3-TCP since the new regulation came into effect (SDWIS).

The City also operates a wastewater treatment plant that has an average flow of 1.1 MGD. The capacity of the plant is 1.55 MGD. The plant consists of two complete-mix aerated lagoons operated in series. The effluent is stored in 3 storage reservoirs with a total capacity of 472 AF. The effluent is then applied to feed and fodder crops on City-owned farmland.

7.2.3 City of Shafter

The City of Shafter is located in the heart of the San Joaquin Valley, approximately fifteen miles northwest of metropolitan Bakersfield and one hundred miles north of downtown Los Angeles. The City of Shafter is named for General William Rufus "Pecos Bill" Shafter, general of American forces in Cuba during the Spanish-American War in 1898, the same year the railroad was completed in this area. In 1914, the Kern County Land Company sold lots for the town of Shafter and in 1938 the City of Shafter was incorporated. Shafter became a Charter City in 1995. Shafter covers nearly 30 square miles and has an estimated population of 19,000. Like many rural areas with opportunities for residential expansion, Shafter has exhibited relatively steady growth. The Southeast Shafter annexation of approximately 5,200 acres of planned residential property in the southeast portion of its service area is projected to add about 30,000 residential units over its build-out period. However, water service for the Southeast Shafter area will be provided by OMWC.

The City of Shafter owns, operates, and maintains the domestic and firefighting water system within the City of Shafter. The water system was first placed in operation in 1925 as the Shafter Public Utility District. The water system presently consists of seven water wells, approximately 87 miles of distribution lines, and five water storage tanks equipped with booster pumps. It

provides water service to about 4,600 connections, mostly residential, within Shafter city limits and some outlying, unincorporated communities.

Groundwater quality issues of concern for the wells include salt intrusion primarily from agricultural activities; nitrate contamination from natural and agricultural activities; organic chemical contamination primarily from DBCP and EDB; arsenic; and 1,2,3-TCP. Prior to the 1,2,3-TCP regulation coming into effect in 2018, treatment consisted of only disinfection. In 2009, the City started its first GAC treatment plant for 1,2,3-TCP to be proactive in treatment in advance of the new regulation. The City will be continuing to implement treatment systems at its other wells with the intent of fully removing TCP from its water supply by 2020 (Shafter 2015 UWMP).

The City of Shafter and NKWSD have established a retailer/wholesaler relationship wherein North Kern, as the underlying wholesaler, replenishes the groundwater basin through collection of tolls on lands within the NKWSD. These tolls have been established because the overlying lands have received a benefit from the NKWSD recharge program. These tolls will continue to be paid by the overlying landowners.

The SWID and NKWSD service area overlap Shafter's current service area and areas planned for development. Their supply and demand information are included within the Poso Creek IRWMP and not accounted for in this IRWMP.

7.2.4 City of Wasco

The City of Wasco, incorporated in 1945, is a municipality located in northern Kern County, approximately 25 miles from Bakersfield. Wasco provides water, sewer collection, wastewater treatment, storm drainage, road, and refuse service to the community.

The original water system was developed in the 1920's under the authority of the Wasco Public Utilities District. The system consisted of groundwater wells and tower reservoir. The Wasco Public Utility District operated and maintained the water and sewage collection and treatment systems within Wasco until 1989. At that time the district's assets were transferred to Wasco. The tower reservoir is no longer used; the water system has been improved and expanded since the original construction to meet current needs.

Wasco currently serves approximately 27,000 people with about 5,100 water service connections. Water service is provided to residential, commercial and industrial sites. Wasco's distribution system currently includes nine wells. Two wells are inactive due to high concentrations of nitrates and DBCP. One well was dedicated to supply irrigation water to the defunct Valley Rose Golf Course. The remaining six wells supply domestic service and fire flow and can produce up to 6,900 GPM of flow (Wasco 2015 UWMP).

The SWID service area overlaps Wasco's service area. Its supply and demand information are included within the Poso Creek IRWMP and is not accounted for in this IRWMP.

7.2.5 North West Kern Resource Conservation District

The NWKRCD encompasses an area of approximately 595,000 acres that is traversed in a northwesterly direction by Poso Creek which outlets into the KNWR. NWKRCD manages resource conservation projects on public and private lands within its boundaries, and assists

farmers, and ranchers make the best use of their natural resources to enable local programs that conserve soil and water, prevent soil erosion, and control floodwaters and sediment damage.

NWKRCD has delineated areas of toxic salt accumulation and areas in critical need of protection from water and wind erosion, and brackish agricultural drainage water. Other water management issues that need to be addressed are saltwater intrusion, the pollution of groundwater supplies, and areas in the NWKRCD with severe water penetration problems.

Water conservation in the NWKRCD is needed to address the excess use of groundwater and water penetration problems on the sandy loam and loam soils of the NWKRCD. The NWKRCD's Irrigation Water Management Program provides practical field testing of irrigation systems. The Mobile Lab, which is also utilized in the other subregions, can determine the distribution uniformity of applied irrigation water and the efficiency of an irrigation system.

There are also numerous techniques for implementing different elements of the NWKRCD program. For example, voluntary agreements between the NWKRCD and the individual landowners or users have been negotiated. The purpose is to supply certain services according to a farm or ranch conservation plan or engineering plans for a specific conservation practice.

7.2.6 Poso Creek IRWMP Region

The Poso Creek IRWMP Region was developed in 2005 and their IRWM Plan was adopted in July 2007. The Poso Creek IRWMP Region comprises the SWSD, Cawelo Water District, DEID, KTWD, NKWSD, Rag Gulch Water District (which as of January 2009 is part of KTWD), and SWID. Most of the Poso Creek IRWM Region is located within the Kern Region.

7.3 Subregion Description

7.3.1 Land Use

The Land Use Element of the Delano and Shafter General Plans, and Land Use, Open Space/Conservation, and Agricultural Elements of the Wasco General Plan provide the policies protecting the land uses within the North County subregion. The North County subregion can be generally characterized as containing a predominance of agricultural and rural uses. The agricultural communities in the North County subregion consist of both large and small farms. Crops typically grown in the area generally include grapes, plums, citrus, stone fruit, almonds, and alfalfa. The soils in the subregion are part of an extensive area of the San Joaquin Valley with "prime" agricultural (Class I and II) soils. Prime farmland is land best suited for producing seed, feed, forage, fiber, and oilseed crops and also available for these uses (the land could be cropland, pasture land, rangeland, forest land or other land but not urban built-up land or water). It has the soil quality, growing season and moisture supply needed to produce sustained high yields of crops economically when treated and managed, including water management, according to modern farming methods.

7.3.2 Ecological Processes and Environmental Resources

Ecological processes and environmental resources for the Kern Region as a whole are described in Section 2.4. Much like the Region as a whole, the natural vegetation of the North

County subregion area was historically characterized by vast stretches of savanna, Valley Needlegrass Grassland, Valley Sacaton Grassland, and Non-native Grassland natural vegetation communities. The range of these natural vegetation communities has been significantly reduced from historic levels as a result of conversion of these lands to urban and agricultural uses. The only remnants of these natural communities presently remain in the Central Valley.

The CDFW and the USFWS have listed some species as threatened or endangered, requiring species recovery by establishing a network of conservation areas and reserves that include terrestrial and riparian natural areas in the San Joaquin Valley and thus Kern Region. As part of their conservation efforts in the San Joaquin Valley, the Metropolitan Bakersfield HCP and the draft VFHCP have been established to implement endangered species recovery programs within the Kern Region to promote species recovery and protect ecological processes and environmental resources. The North County subregion is within the boundaries of the Endangered Species Recovery Program for the San Joaquin Valley. There are some areas planned for habitat acquisition within the subregion identified in the Metropolitan HCP. Much of the subregion is under the conserved jurisdiction of the draft VFHCP HCP.

The North County subregion is further distinct because it contains the KNWR. The KNWR, located approximately 20 miles west of the City of Delano, covers an area of approximately 11,000 acres, consisting of natural valley grasslands, a riparian corridor, and developed marsh. The KNWR is located just south of the historic Tulare Lake Bed, which once covered almost one-half million acres during flood years. As a remnant of this once expansive lake, the KNWR provides wintering habitat for migrating birds, shorebirds, marsh and waterfowl, as well as upland species. About 6,400 acres are specifically managed for wetland purposes. In general, refuge managers start wetting the areas sometime in August, and by February, they begin to draw the water down. During the drawdown, from 500 to 2,000 AF is recycled by releasing the water from the Refuge and allowing it to be used for irrigation of crops on nearby lands.

7.3.3 Social and Cultural Characteristics

The social and cultural characteristics of the North County subregion are not different from that as described for the Kern Region as a whole, as provided for in Section 2.5.4. The subregion is characterized by its traditional industries, agriculture, oil and gas production, and the local prisons, as well as increasing urbanization and population growth. There has been a continuing shift in the mix of businesses in the agricultural sector towards the production of more high value added goods and services, which has affected the growth potential for agribusinesses and industrial markets.

7.3.3.1 Economic Conditions and Trends

Delano, McFarland, Wasco, and Shafter are within the North County subregion. The population is largely White and Latino. Approximately 16 percent of the population identifies as being white and approximately 70 percent of the population reports being Hispanic (US Census Bureau 2005). Persons identifying as African American, Asian, American Indian, and Native Hawaiian make up 14 percent of the population. Spanish is the primary language, but a significant portion of the population speaks English.

The recent prison construction and corresponding job openings have increased growth rates in the communities of Delano, McFarland, and Wasco. The historical and projected population for communities in the subregion is shown in **Table 2-4**.

7.3.3.2 Disadvantaged Communities

All of the cities/communities within this subregion have been identified as DACs as shown in **Table 2-5** of Section 2.2.5.3.

7.3.4 Water Supply

7.3.4.1 Imported Water Supplies

Imported water supplies to the North County subregion are SWP and CVP via the California Aqueduct and CVP water via the Friant-Kern Canal. These supplies are discussed in detail in Section 2.6.1. The subregion is the crossroads of the SWP and the Friant-Kern Canal due to the Semitropic Intertie.

7.3.4.2 Surface Water

Surface water has historically been a significant part of the North County subregion water supply. The historical average use of local surface water supplies, primarily the Kern River and Poso Creek, has amounted to about one-third of the total surface water supplies of the subregion. Imported supplies from the SWP and CVP make up the remaining two-thirds.

The potential for increased conjunctive use of surface water and groundwater supplies is an asset to the Region.

Lake Woollomes, located southeasterly of the community, is a storage facility for the Friant-Kern Canal.

7.3.4.3 Groundwater

The primary source of domestic water for the communities within this subregion is groundwater pumped from the Kern County subbasin of the Tulare Lake Basin described in Section 2.6.3. As a generalization, all of the lands in the North County subregion are underlain by useable groundwater. Accordingly, to the extent that surface water supplies are inadequate to meet irrigation water requirements, groundwater is used to make up the shortfall. Groundwater is conjunctively used, via water spreading in constructed ponds or natural channels, and via surface water deliveries in lieu of pumping groundwater. Overdraft is a significant concern for the entire region and will be mitigated for through SGMA.

Prior to agricultural and urban development, groundwater moved from areas of recharge along the eastern rim of the Valley to areas of discharge along the Valley axis. Recharge was primarily by seepage from stream flows. Under present conditions, groundwater is recharged primarily from stream flow percolation, from percolation basins developed by agricultural irrigation districts, by percolation from treated wastewater disposal facilities and from percolation attributed to excess applied surface irrigation water.

7.3.4.4 Recycled Water

Within the North County subregion, treated effluent from WWTPs is discharged through pipelines and open ditches to city-owned lands for agricultural irrigation. Irrigation water helps replenish the groundwater through deep percolation. The following is a discussion of the wastewater systems for each of the communities.

City of Delano

Delano provides wastewater services to its residential, commercial, and industrial users within its limits and some unincorporated areas, including the North Kern State Prison. The Delano WWTF consists of flow metering, screening, aerated grit chamber, primary clarification, trickling clarification, biofiltration, secondary clarification, primary and secondary sludge pumping facilities, shops, effluent pumping facility, sludge digesters, and a sludge thickener.

With the City's recent WWTF upgrade project, the City expanded its reclaimed water effluent disposal facilities. The City added a new 480-acre site to its prior 932 acres of farmland. An additional effluent storage pond and improvements to percolation ponds were included in the project. The City currently has facilities to adequately dispose of the ultimate flow of 7.2 MGD (2015 UWMP).

City of Shafter/North of the River Sanitary District Plant

The North of the River Sanitary District (NORSD)/City of Shafter WWTF, which is located within Shafter City limits, but operated by NORSD, renders wastewater treatment services to approximately 5,000 customers in Shafter and 7,800 customers from unincorporated areas of the County of Kern including water customers of the OMWC currently outside Shafter's boundaries. Two (2) 30-inch trunk lines, which are owned and operated by Shafter, tie into a 42-inch regional NORSD main at Seventh Standard Road. The current sewage flow from Shafter averages between 1.1 and 1.3 MGD.

Shafter owns one-third (1/3) of the NORSD/Shafter plant's current 6.0 MGD of raw sewage capacity or 2.0 MGD. In addition, Shafter will purchase an additional one-third ownership of the plant's increased capacity upon the completion of an ongoing expansion project, leaving an expected total Shafter capacity of 2.5 MGD.

Effluent from primary clarifiers is pumped through a biofilter, which reduces organic matter. After this process, the effluent flows into a final clarifier. Through sedimentation, particulate matter settles to the bottom of the tank and is removed. The effluent from this treatment process is used by a neighboring farming operation for crop watering thus eliminating reliance on groundwater supplies.

City of Wasco Wastewater Treatment Plant

Wasco owns and operates a WWTF located west of the community. The present wastewater treatment facilities were originally constructed in 1937. The facilities have since been enlarged and/or modified on a number of occasions. The last major upgrades took place in 2010-11.

The current plant facilities consist of headworks with a Parshall flume, one mechanical bar screen, and flow meter, aerated grit chamber, two primary clarifiers, two plastic media trickling filters, two secondary clarifiers, two smaller bentonite-lined aerated ponds and one large (25 acre) unlined storage pond, three anaerobic sludge digesters, four unlined sludge drying beds, and three 15-acre effluent disposal ponds. The WWTP also has a septage receiving station and laboratory, which is only used for process sampling. The design capacity of the existing plant is 3.0 MGD. The average daily flow is 1.7 MGD.

Wasco is permitted to discharge its effluent to 700 acres of Wasco-owned land that surrounds the WWTP to the south and west. The irrigation practice helps to replenish the groundwater table through deep percolation and reduces groundwater overdraft (Wasco 2010 UWMP).

7.3.5 Water Quality

In general, the groundwater quality within the North County subregion is relatively high. Several domestic wells require treatment or are inactive due to concentrations of nitrates, DBCP, EDB, 1,2,3-TCP and hydrogen sulfides that exceed drinking water quality standards. Other than these contaminants, the groundwater supply is suitable for domestic purposes without treatment. Specific water quality issues for each community is discussed in their general descriptions above.

7.3.6 Water Demand

Water demands for urban water use and agricultural water use within this subregion are provided in Section 2.9.

7.3.7 Water-Related Infrastructure

Water related infrastructure such as surface water impoundments, water collection systems, distribution systems, wastewater systems, and recharge systems, are described generally for the North County subregion participants in their general descriptions above, and in greater detail for the entire Kern Region in Section 2.9.

In general, many Kern Region communities are older and the physical components of their water systems are aging and outdated. Aging infrastructure is a particular issue for rural communities and DACs. In recent years rapid urban development in some areas has provided new infrastructure, but this new infrastructure is limited to those areas receiving new development. Communities are planning and implementing upgrades to their water treatment infrastructure.

7.4 Subregional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for the North County subregion with respect to water resource management within the Kern Region include the following. These issue areas are discussed in greater detail in Section 2, in the following Sections:

- Water Quality/Groundwater Contamination (see Section 2.11.8)
- Urban Growth and Water Demand (see Section 2.11.2)
- Groundwater Overdraft (see Section 2.11.6)
- Legislated Water Use Efficiency Requirements (see Section 2.11.7)

Section 8: South County Subregion

8.1 Subregion Introduction

This section presents a description for the South County subregion of the Kern Region. The South County subregion is located at the extreme southern end of the San Joaquin Valley south of Bakersfield and the Kern River, and is generally bounded by the southern Sierra Nevada range to the east, the Tehachapi Mountain range and Tejon Pass to the south, and the San Emigdio Mountains to the west. It encompasses major highways (State Route 5, Highway 58, Highway 99, and Highway 166) and water infrastructure connecting the growing cities and unincorporated communities of the South County subregion to the greater Kern Region.

Descriptions of the subregion's participants, as well as the physical and environmental characteristics, hydrologic features, and issues and needs of the subregion are provided.

8.2 Subregion IRWMP Participants

The South County subregion is comprised of eight participants including:

1. Arvin Community Services District (ACSD)
2. City of Arvin
3. Arvin-Edison Water Storage District (AEWSD)
4. Kern Delta Water District (KDWD)
5. Lamont Public Utility District (LPUD)
6. Lamont Storm Water District (LSWD)
7. Mettler County Water District (MCWD)
8. Wheeler Ridge-Maricopa Water Storage District (WRMWSD)

These participants' roles and responsibilities for managing water, natural resources, and land use within the South County subregion are discussed below.

8.2.1 Arvin Community Services District

ACSD is a municipal water district that provides domestic/municipal water distribution and supply systems for the community of Arvin, south of Bakersfield. ACSD provides water to a population of over 22,000 through more than 4,000 service connections. ACSD's water system consists of six active water wells and a 500,000-gallon storage tank and booster pumping plant. Several of the District's wells are affected by arsenic and/or nitrates.

In 2019, ACSD is beginning construction of Phase 2 of its arsenic mitigation project. ACSD received a $14 million loan to construct 3 new wells, a 1-million-gallon storage tank and new water mains. The goal will be to construct new wells with arsenic levels below the MCL.

8.2.2 City of Arvin

The City of Arvin is located about 15 miles southeast of the city of Bakersfield, and approximately 90 miles northwest of the city of Los Angeles. Arvin was incorporated in 1914 and is part of the Bakersfield Metropolitan Statistical Area. Nestled against Bear Mountain, Arvin depicts a small town atmosphere that is driven by its agricultural community. Agriculture crops such as cotton, grain, carrots, potatoes, almonds, oranges, and grapes, surround the city as well as numerous private dairies and farmland.

The City's population is approximately 22,000 persons. The City provides community sewer and storm drainage services. ACSD supplies drinking water.

The City's WWTP is designed to accommodate 2.0 MGD of influent and current flows are at 1.1 MGD. It is estimated that the current WWTP could accommodate an increase in City population of 25 percent. The City's capital improvement plan includes improvements that would increase the capacity to 2.5 MGD with allowances for higher strength wastewater.

8.2.3 Arvin-Edison Water Storage District

AEWSD (or District in this section) is located in Kern County, California, and is situated at the extreme southern end of the San Joaquin Valley approximately 14 miles southeast of the City of Bakersfield. The City of Arvin is surrounded by District lands. District lands lie on the San Joaquin Valley floor. The Tehachapi Mountains bound the District to the East and South.

AEWSD was organized in 1942 under California Water Storage District law (Division 14 of the California Water Code) for the express purpose of, among other things, providing an agency to contract with the United States for water service from the Friant Division CVP as well as contracting for a Federal Power Contract and a Federal loan for construction of new facilities. The need for supplemental CVP supplies reflected the overdraft conditions occurring in the District at that time. The District is comprised of approximately 132,000 acres of land, 113,000 acres that are irrigated crops (vineyards, carrots, potatoes, cotton, citrus and orchards predominately) (AEWSD 2011 Water Management Plan, updated in 2015).

In 1962, the District entered into a water supply contract with the United States Bureau of Reclamation (USBR) to supply water for the District's project from the Friant Division of the Federal CVP. The permanent repayment water supply contract provides for the annual delivery of 40,000 AF of Class 1 (firm) water and up to 311,675 AF of Class 2 (non-firm) water, which is subject to water shortage provisions. However, the contract will not have to be renewed and is in perpetuity. However, with the recent San Joaquin River Restoration Program, the District is expected to lose up to 40,000 AFY to the San Joaquin River.

Because the imported Friant Class 2 water is highly erratic and variable, water management is key for the District to develop a means to regulate this variable supply to a fairly constant irrigation demand as well as mitigate overdraft conditions. The District has successfully regulated its imported water supplies historically through the use of groundwater banking facilities (i.e. recharge ponds and extraction wells) in combination with water management exchanges and transfers with other agencies.

The District delivers an average of approximately 157,000 AFY to customers in its surface water service area (approximately 52,000 acres), which rely almost entirely on District-provided water.

The District also recharges through both direct recharge in spreading basins and in-lieu deliveries during wet periods. It is important to note that landowners in both the surface water service area and groundwater service area, who rely almost entirely on water pumped from privately owned wells, benefit from the District's importation of surface water for direct delivery and spreading.

Groundwater is found underlying essentially the entire District. Groundwater management within the District is rooted in the conjunctive use of surface water and groundwater resources, since water supplies from these two sources are integrated to accomplish optimum utilization of each supply. District landowners have conjunctively used imported surface water supplies with groundwater since the completion of the District's irrigation distribution system facilities in the early 1960's. In 2003, the District adopted its AB3030 Groundwater Management Plan, which is SB1938 compliant.

As the District's Intake Canal weaves it way through Kern Delta WD, both districts have built interconnection facilities to assist each other in water management activities.

In 2004, AEWSD joined the Power and Water Resources Pooling Authority (PWRPA). PWRPA is authorized to, among other things, effectively study, promote, develop, conduct, design, finance, acquire, construct, and operate water and energy-related projects and programs. PWRPA member units utilize electric power to convey and treat water and recognize that water delivery and electric power consumption are directly related, and that exchange of water and electric power resources is a variable means of managing both electric power consumption and water supplies. PWRPA member units possess the right to receive capacity and energy from the Western Area Power Administration (WAPA), a federal agency engaged in the marketing and distribution of power generated by federally owned facilities, including the CVP.

AEWSD has a water banking program with Metropolitan Water District of Southern California (MWD). In order to facilitate this Program, AEWSD has constructed facilities worth nearly $42 million, including 500 acres of spreading works, 15 groundwater wells, a 4.5 mile bi-directional pipeline connecting the terminus of AEWSD's South Canal with the Aqueduct and reverse flow facilities in a 9-mile stretch of its South Canal to the Tejon Spreading Works site. These facilities can be used in conjunction with existing AEWSD facilities.

8.2.4 Kern Delta Water District

KDWD is located in the County of Kern, approximately 8 miles south of the City of Bakersfield. KDWD was formed in December 1965 under Division 13 of the State Water Code for the purposes of protecting the Kern River Water Rights serving certain lands within the District. Although the KDWD was formed in a relatively recent period of time, the systems of canals that provide services to customers have existed since the late 1800's.

Approximately 83 percent of the District's 129,000 acres are devoted to irrigated agriculture. KDWD has 500 agricultural connections. KDWD currently serves Kern River Water through four different water rights, via the Kern Island, Buena Vista, Stine, and Farmers Canals. The total length of these canals is approximately 126 miles. KDWD also contracts with the KCWA for a maximum entitlement of 25,500 AFY of SWP water and, as available, with USBR for surplus CVP water. In a normal year, KDWD would obtain over 8,000 AF of SWP water and 138,000 AF of Kern River water. Approximately 6,000 acres of lands in the District also receive treated

effluent from the City of Bakersfield WWTP and LPUD WWTP, resulting in 18,000 AFY of recycled water being used for irrigation. (KDWD 2015 AWMP)

Since 2003, the District has constructed over 800 acres of groundwater recharge basins with an annual recharge capacity of over 120,000 AF per year. KDWD has constructed or purchased 18 wells to recover banked groundwater and supplement surface water deliveries to landowners. The recovery capacity is estimated at 94,000 AF in a dry year. KDWD has groundwater banking program with exchange agreements with MWD and San Bernardino Valley Municipal Water District (SBVMWD) which allows the agencies to recharge up to 50,000 AFY, with a limit of 250,000 AF of total groundwater in storage. Stored water (less 11 percent losses) can be returned to these agencies via direct extraction or through water exchanges.

Certain lands within KDWD also have independent Kern River water rights (South Fork) or receive treated effluent from the City's WWTP Nos. 2 and 3. KDWD also makes arrangements to secure high flow water from the SWP, the CVP, and the Kern River on an as available basis.

8.2.5 Lamont Public Utility District

LPUD is a special-purpose district that provides the residents of Lamont, Weedpatch and other surrounding unincorporated areas and communities (Plainview, Sunset Farm Labor Camp, and local schools) with water, sewer, and street lighting services. The town of Lamont, settled in 1923, is an agricultural community located in the southern San Joaquin valley. LPUD serves a population of approximately 18,000 through 3,900 service connections.

The District operates seven water wells that have a production capacity of 4.9 MGD. Six well sites are equipped with booster pumps and hydropnuematic tanks. Three well sites have storage reservoirs of up to 450,000 gallons. The water distribution system consists of 38 miles of water mains ranging between 6 to 12 inches in diameters. Some of the District’s wells are affected by arsenic and the District is seeking affordable financing to correct these problems by either construction of new well(s) or water treatment plants.

Approximately 35 miles of sewer mains convey wastewater to the District’s WWTP located at the southern area of the District. The WWTP has a 3.25 MGD capacity that treats wastewater to a secondary level standard. The permitted capacity is 2.0 MGD with an average flow of about 1.4 MGD. The 640-acre site includes 80 acres for wastewater treatment and storage, 270 acres for green waste composting and 130 acres for farming fodder crops. (LPUD Website)

8.2.6 Lamont Storm Water District

LSWD was formed in 1984 by the Kern County Board of Supervisors, pursuant to the Storm Water District Act of 1909, after extensive flooding of the town of Lamont by the Caliente Creek outflow in 1983. LSWD provides and plans for storm water control and diversion projects within the Caliente Canyon watershed.

8.2.7 Mettler County Water District

MCWD provides water supply, from groundwater, to approximately 160 residents, highway service industries, packing sheds and other agricultural users located within the rural community of Mettler through 42 service connections. MCWD customers are also served by septic tanks, which have historically seen high rates of failure. The Director of the Kern County Environmental

Health Services Department declared a potential pollution problem in the area due to the septic tank failures and reports of nitrate levels above the MCL within the groundwater. The District received USDA funding and replaced one of two wells that were contaminated with high nitrates, installed waterlines and new storage and pumping facilities, and abandoned their nitrate contaminated wells.

The District obtained additional funding for a second well that was constructed in 2014. The well met drinking water standards, but with the 1,2,3-TCP contaminant MCL coming into effect, the well was shutoff in 2016. The District is currently planning a water treatment system for the well.

8.2.8 Wheeler Ridge-Maricopa Water Storage District

WRMWSD is a public agency whose jurisdiction encompasses about 148,000 acres of land in the South County. WRMWSD provides water supplies to about 90,000 acres of farmland within its boundaries. WRMWSD was formed on August 11, 1959 under California Water Storage District law for the purpose of securing a surface water supply for agricultural purposes from the SWP. The WRMWSD Project, including authority to execute a water supply contract for SWP supplies, and construct a water distribution system, was approved by the WRMWSD landowners at an election on November 14, 1967. WRMWSD provides water to agricultural customers through a combination of imported water from the SWP, imported water from several County of Kern banking projects including the Kern Water Bank, the Pioneer Recharge Project, the Berrenda Mesa Recharge Project, and from local groundwater. In addition, some agricultural water users in the WRMWSD provide their own irrigation water through groundwater pumping (WRMWSD GWMP, 2007).

The District has a SWP Table A allocation of 197,000 AF. SWP surface water deliveries began in 1970. From 1971 to 2013, the District has delivered on average 169,000 AFY to landowners. A small percentage of the water is supplied on a temporary basis for industrial, ground water recharge, and in-lieu of ground water pumping purposes. Except in drought years, the WRMWSD has negated the need for ground water pumping within its service area, and also allowed lands not previously irrigated to be productively farmed.

WRMWSD takes delivery of SWP water through 15 turnouts from the California Aqueduct. Water is then conveyed through 7 miles of lined canals and 294 miles of pipelines. The District has about 750 turnouts equipped with water meters. (WRMWSD 2015 AWMP)

8.3 Subregion Description

8.3.1 Land Use

The South County subregion can be generally characterized as containing a predominance of rural uses including agriculture/open space, mineral/petroleum, and public recreation uses.

As discussed in Section 2.3, the Land Use, Open Space, and Conservation Element of the Kern County General Plan provide the policies protecting the Kern County unincorporated areas, including the communities comprising the South County subregion. Because of the close interrelationship between land use, conservation, and open space issues, Kern County's Land

Use, Conservation, and Open Space Element provides for a variety of land uses for future economic growth while also assuring the conservation of the County of Kern's predominant agricultural, natural, and resource attributes.

The South County can be generally characterized as containing a predominance of agricultural and rural uses. The agricultural communities in the South County consist of both large and small farms. The soils of the subregion are highly conducive to agricultural uses with a majority classified as having wide crop adaptability with no limitations. Crops typically grown in the area generally include grapes, carrots, cotton, citrus, potatoes, wheat, plums, stone fruit, almonds, and alfalfa. Most farmland is irrigated. The soils in the subregion are part of an extensive area of the San Joaquin Valley with "prime" agricultural (Class I and II) soils.

Since the mid 1990's, agriculture within the South County has generally shifted from predominantly field crops, such as cotton, sugar beets and corn, to permanent crops, such as various tree (deciduous and subtropical) and vine crops. Acreage for field crops has declined from 1990 to 2001 and subsequently, vine and tree crops have increased over that same time period.

The land use element of the City of Arvin General Plan and the Mettler Community Plan also provide the policies protecting the uses within the South County.

8.3.2 Ecological Processes and Environmental Resources

Ecological processes and environmental resources for the Kern Region as a whole are described in Section 2.4. Regarding the South County subregion, slightly increased agriculture and urban development have resulted in many changes in the natural environment. These impacts have resulted in the loss of native plants and animal species, and a decrease in native lands. This has also resulted in the introduction of invasive species and spread of exotics leading to the decline of native plant communities. The southern portion of the San Joaquin Valley, which covers the South County subregion, has no natural outlet for surface waters. Streams from Coast Ranges and Tehachapi Mountains have eroded and deposited materials in the subregion, forming alluvial fans at the surface.

An environmental resource located in the subregion is Bitter Creek National Wildlife Refuge. The Bitter Creek National Wildlife Refuge is located in the southwestern corner of the subregion. This 14,097-acre refuge is intended to protect dwindling California condor foraging and roosting habitat. The refuge is bisected by the San Andreas Fault and Bitter Creek Canyon. In addition to the California condor, the refuge provides habitat other Federally-listed endangered species and species of Federal concern. Such as the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, the western spade foot toad, western horned lizard, and tricolored blackbird. Coyote, bobcat, mountain lion, mule deer, pronghorn antelope, tule elk, and western rattlesnake are also found in the refuge (USFWS 2009b).

The CDFW and the USFWS have listed some species as threatened or endangered, requiring species recovery by establishing a network of conservation areas and reserves that include terrestrial and riparian natural areas in the San Joaquin Valley and thus Kern Region. As part of their conservation efforts in the San Joaquin Valley, the Metropolitan Bakersfield HCP and the draft VFHCP have been established to implement endangered species recovery programs within the Kern Region to promote species recovery and protect ecological processes and environmental resources. The South County subregion is within the boundaries of the

Endangered Species Recovery Program for the San Joaquin Valley. There are some areas in the northerly part of the subregion planned for habitat acquisition within the subregion identified in the Metropolitan HCP. Much of the subregion is under the conserved jurisdiction of the draft VFHCP.

8.3.3 Social and Cultural Characteristics

The social and cultural characteristics of the South County subregion are not different from that as described for the Kern Region as a whole, as provided for in Section 2, Section 2.5. South County is generally characterized by its traditional industries in agriculture as well as increasing urbanization and population growth.

8.3.3.1 Economic Conditions and Trends

The City of Arvin and the communities of Lamont, Hilltop, Edmundson Acres, DiGiorgio, Mitchells Corner, Mettler, and Weedpatch are located within the South County. The majority of the South County's population lives in Arvin and Lamont.

The majority of the population in the South County is Latino. Approximately 84 percent of the population reports being Hispanic/Latino and approximately 13 percent of the population identifies as being white. Persons identifying as African American, Asian, American Indian, and Native Hawaiian make up less than 3 percent of the population. English is the primary language, but a significant portion of the population speaks Spanish.

The South County's economy is primarily agriculturally based but does have interest from the oil industry (i.e., Edison Oilfield). The agricultural sector consists mostly of low paying and often seasonal employment which limits the positive multipliers within the economy.

There are two active developments in the subregion. The Tejon Ranch Commerce Center (TRCC) consists of consists of over 1,100 acres of land located on the east side of Interstate-5 approximately at the Laval Road and Wheeler Ridge interchange 3 miles north of the Tejon Pass. The Interstate 5 freeway corridor links major metropolitan regions of the state and represents one of the primary commercial truck corridors for the movement of bulk material goods. This development consists of approximately 15 million square feet of industrial, commercial office, and highway commercial uses.

Tejon Ranch is also developing the 8,000-acre Grapevine Master Planned Community, which will serve 12,000 residences and 5.1 million square feet of commercial development. This development will be located at the base of the Grapevine and is adjacent to the TRCC. The project is currently in the planning stage.

8.3.3.2 Disadvantaged Communities

All of the cities/communities within this subregion have been identified as DACs as shown in **Table 2-5** of Section 2.2.5.3.

8.3.4 Water Supply

The following section describes the sources of water supply for the South County subregion including imported surface water, local surface water, and local groundwater.

8.3.4.1 Imported Water Supplies

The main sources of imported water to the region come from the CVP and the SWP, which transport their majority of their water through the Friant-Kern Canal and California Aqueduct, respectively. The subregion is very dependent on this supply to make deliveries to agricultural use as well as to recharge and bank groundwater. Importing affordable water supplies through the CVP or SWP, in quantities sufficient to achieve a long-term water balance within the region, is one of the long-term goals of these districts. Imported SWP and CVP water is discussed in detail in Sections 2.6.1 and 2.6.2, respectively.

8.3.4.2 Surface Water

Surface water is naturally available to the subregion from the Kern River and is regulated by the Isabella Dam and Reservoir which was constructed in 1954 by the Army Corps of Engineers. The Kern River is also a source of supply to various entities in the subregion, either through direct deliveries or through exchanges, transfers or surplus supplies.

Surface water drains toward the South via a number of ephemeral stream channels from the south, east, and west. The San Emigdio Mountains in the south are drained by the larger waterways of Santiago, San Emigdio, and Pleito creeks. The Tehachapi Mountains are drained by Tunis, El Paso, Pastoria and Grapevine creeks. The Southern Sierra Nevada are drained by the streams from the Caliente Creek watershed. These sources are described in detail in Section 2.6.2. Eastern drainage ways from the Temblor Range contribute very little runoff due to low elevation and low precipitation. Ephemeral creeks draining east toward the South County include Bitterwater and Bitter creeks.

8.3.4.3 Groundwater

The physical characteristics of the groundwater basin underlying the South County subregion, such as the permeability of the overlying and subsurface flows, greatly influence the manner in which groundwater is replenished. The subregion overlies areas of both unconfined and semi-confined aquifers. There are also areas of perched water and shallow groundwater tables.

Effective groundwater replenishment within the subregion involves the management of water supplies available to the purveyors with rights overlying the basin and extractions from the basin as well as minor surface streams (Caliente Creek, El Paso, etc.). Extractions occur by both district and private wells.

The replenishment of the underlying groundwater aquifer occurs naturally and through deliberate, controlled means. Direct recharge is achieved through the placement of surface water in channels or basins located on permeable soils for the express purpose of percolation to the underground aquifer. Indirect or in-lieu recharge is also conducted by delivering surface supplies to growers who would otherwise pump wells and thus extract groundwater. The canals that proceed from the Kern River throughout the subregion substantially consists of unlined canals. As a result, up to 30 percent of the surface water supplies diverted from the Kern River into local purveyor facilities percolates to the groundwater in the form of canal seepage losses. Delivery of surface water for irrigation purposes reduces the need for water users to draw on groundwater, thereby conserving the water available in the aquifer for later use. The use of surface water as in-lieu recharge is practiced extensively throughout the subregion. An additional benefit is derived when irrigation water applied beyond crop water needs results in deep percolation to the aquifer.

WRMWSD has been involved in the development of the Kern Water Bank, the Pioneer Project, and the Berrenda Mesa water-banking project on the Kern River Fan. These projects now enable WRMWSD to purchase surplus water and store it for dry-year use and store its own SWP entitlements for future use during years of higher than normal precipitation. KDWD is also a participant of the Pioneer Project and has its own Groundwater Banking Project. Another notable banking program in the subregion is AEWSD's groundwater banking program which it uses to regulate its Friant-Kern CVP and other supplies to provide banking services on behalf of its landowners and to others on a second priority.

8.3.4.4 Recycled Water

As discussed in Section 2.6.5, wastewater effluent produced by treatment facilities can be applied to non-human consumption crop irrigation and environmental habitat restoration. Certain lands within the South County subregion receive treated effluent from the City's WWTP Nos. 2 and 3. This water is also used for groundwater recharge programs. As noted in Section 2.6.6.2, in addition to treated wastewater effluent, effluent from agricultural processing facilities is also being recycled for irrigation use and is being evaluated for use in groundwater recharge programs.

8.3.5 Water Quality

Groundwater quality is generally suitable for irrigation use throughout the South County subregion. Groundwater throughout most of the WRMWSD meets Class I or Class II irrigation water quality standards for salinity (WRMWSD, 1981). Class I water is suitable for all crops grown in the WRMWSD with an EC value of less than 1,000 microsiemens per centimeter (uS/cm). Class II meets the water quality requirements of most crops with the exception of some salt sensitive vegetable crops and has typical EC values between 1,000 and 3,000 uS/cm (equivalent to TDS concentrations between about 700 and 2,000 mg/L).

AEWSD wells have an EC range from 250 to 750 uS/cm with a blending or melded supply to landowners in the 350 to 480 uS/cm range from the canal distribution system during strictly well operations (i.e., no mixing with surface water).

All of the communities in this subregion rely on groundwater for domestic use. Several of these communities are faced with high arsenic, nitrate, 1,2,3-TCP and DBCP contamination of local groundwater supplies.

8.3.6 Water Demand

Water demands for urban water use and agricultural water use within this subregion are provided in Section 2.9.

8.3.7 Water-Related Infrastructure

Water related infrastructure such as surface water impoundments, water collection systems, distribution systems, wastewater systems, and recharge systems, are described generally for the South County subregion participants in their general descriptions above, and in greater detail for the entire Kern Region in Section 2.9.

In general, many Kern Region communities are older and the physical components of their agricultural and drinking water supply systems are aging and outdated. Aging infrastructure is a particular issue for rural communities and DACs. In recent years rapid urban development in some areas has provided new infrastructure, but this new infrastructure is limited to those areas receiving new development. Communities are planning upgrades to their water treatment infrastructure. In addition to drinking water system upgrades, agricultural water supply infrastructure is also in need of upgrades. Aging canal and pumping facilities, as well as other related infrastructure, represent a threat to the reliability of water supplies and viability of agricultural operations. Part of the impetus for joining and participating in the Kern IRWMP is to identify infrastructure issues and potential collaborative projects to address infrastructure needs.

8.4 Subregional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for the South County subregion with respect to water resource management within the Kern Region include the following. These issue areas are discussed in greater detail in Section 2, in the following sections:

- Decreased Imported Water Supply (see Section 2.11.4)
- Water Quality/Groundwater Contamination (see Section 2.11.8)
- Urban Growth Encroachment on Key Recharge Areas (see Section 2.11.3)
- Water Rights (see Section 2.11.9)

Section 9: West Side Subregion

9.1 Subregion Introduction

This section presents a description for the West Side subregion of the Kern Region. The section includes a summary of the subregion's participants, as well as a description of the physical, environmental, social and demographic characteristics of the subregion, the hydrologic features and overall water reliability, and major water related infrastructure. The West Side subregion is located at the northwestern corner of Kern County west of Bakersfield and north of the Kern River, and is generally bound by the Kern-San Luis Obispo county line and Temblor Mountain Range to the west and south, the Kern-Kings county line to the north, and the North County subregion and the KNWR to the east. A small portion, representing DRWD, extends north into Kings County. The subregion is bisected diagonally by major north-south highway (State Route 5) and the California Aqueduct and horizontally by east-west highway (State Route 46).

9.2 Subregion IRWMP Participants

The West Side subregion consists of five participants:

1. Belridge Water Storage District (BWSD)
2. Berrenda Mesa Water District (BMWD)
3. Dudley Ridge Water District (DRWD)
4. Lost Hills Public Utility District (LHPUD), and
5. Lost Hills Water District (LHWD)

These participants' roles and responsibilities for managing water, natural resources, and land use within the West Side are discussed below.

9.2.1 Belridge Water Storage District

BWSD is located within the southern San Joaquin Valley about 40 miles northwest of the City of Bakersfield and encompasses approximately 97,000 acres. BWSD is located in the northwestern corner of the County of Kern on the eastern edge of the Temblor Range. State Highways 46 and 58 traverse the northern and southern District boundaries, respectively, with State Highway 33 traversing through the western portion of the District.

BWSD was formed in 1962 under California Water Storage District Law by interested landowners to provide a vehicle for construction, operation, and maintenance of an irrigation project. A five-person Board of Directors, elected by District landowners, governs the District. BWSD has the infrastructure to deliver water to approximately 46,000 acres of land. The net cropped acreage is about 39,000 acres (BWSD 2012 AWMP). BWSD's principal water supply is imported from the SWP, for which it contracts with KCWA. The District currently has a Table A contract water volume of 121,508 AF.

BWSD receives water by continuous gravity flow for delivery into three (3) turnouts. BWSD distributes SWP water, mainly by gravity, via a network of facilities; three main canals totaling 39 miles in length, 50 miles of pipelines, pump stations, and control structures. The District's two

main canals (415 Canal and 500 Canal) are located west of the California Aqueduct. Gravity pipeline laterals feed lands that are lower in elevation than the canals. Lands that are located higher in elevation than the canals are served by a mixture of landowner owned booster pumps and District owned lateral pipelines.

To supplement its surface water supply by transfer or exchange, BWSD participates in groundwater banking programs including: Pioneer Project and the Berrenda Mesa Project. In addition, the District's largest landowner, Wonderful Orchards, has the ability to deliver significant amounts of banked groundwater through its participation in the Kern Water Bank.

Approximately 9,200 acres within the District are used primarily for petroleum production related activities. The area is served by a separate system that is operated by the industrial water users. The industrial water supplied makes up less than one percent of the District's normal annual water deliveries.

9.2.2 Berrenda Mesa Water District

BMWD is located within the southern San Joaquin Valley about 50 miles northwest of the City of Bakersfield in the northwestern corner of the County of Kern on the eastern edge of the Temblor Range. State Highways 46 and 33 traverse the District boundaries.

BMWD is a California Water District formed under Division 13 of the CWC on September 3, 1963. A five-person Board of Directors, elected by District landowners, governs the District. The BMWD owns and operates an irrigation distribution system that encompasses 55,400 acres of agricultural lands in western Kern County. Approximately 27,000 acres are currently farmed. BMWD's principal water supply is imported from the SWP, for which it contracts with KCWA. The District currently has a Table A contract water volume of 92,800 AF (BMWD 2012 AWMP).

BMWD's main water supply is imported from the SWP via the California Aqueduct and the Coastal Branch Aqueduct. Before BMWD receives delivery of the water, it must be lifted through a series of pump stations: DWR's Las Perillas and Badger Hill Pumping Plants and BMWD's Pump Station A (and a lesser flow through BMWD's Coastal Pumping Plant).

BMWD's water conveyance and delivery system was designed mainly for gravity flow. Water is distributed through 15 miles of lined canal and 50 miles of pipelines. Once water is pumped uphill 225 feet by Pump Station A (located at the terminus of Coastal Aqueduct), the water flows by gravity through a concrete lined canal. Gravity pipeline laterals feed lands that are lower in elevation than the canal. Water is delivered to higher elevation land with pump stations and pipelines.

To supplement its surface water supply by transfer or exchange, BMWD participates in groundwater banking projects including: the Kern Water Bank, Pioneer Project and Berrenda Mesa Project. These water banking projects are located outside of the District's boundary just southwest of the City of Bakersfield and are operated and maintained by KCWA.

9.2.3 Dudley Ridge Water District

DRWD is located in southernmost Kings County on the western edge of the San Joaquin Valley. The District lies south of Kettleman City and is bounded on the northeast by the Tulare Lake

Basin Water Storage District, on the south by the Kings-Kern County Line, and on the west by the California Aqueduct. Interstate 5 traverses the District in a northwest-southeast direction.

The DRWD is a small agricultural water district that provides supply systems for irrigation interests located within its service area. The District's boundary encompasses approximately 37,600 acres. Approximately 25,700 acres have a water allocation and about 17,000 acres are currently cropped.

The District delivers SWP water from the California Aqueduct through five delivery structures (turnouts). From each turnout, water is delivered to landowners through 22 miles of District owned concrete-lined canals and/or underground pipelines to metered farm turnouts.

DRWD's principal water supply is imported from the SWP. The District currently has a Table A contract water volume of 50,343 AF. The surface water supply is comprised of SWP Table A, other SWP water (including Article 21 and Turnback Pool) as available, and non- project water obtained outside the District and delivered within the District for irrigation to banking/exchange programs outside of the District. In drier years, the supply is heavily supplemented by banked water retrieved from groundwater storage programs in which the District is participating; in average to wet years, the supply is mostly, or exclusively, from surface water sources (DRWD 2012 AWMP).

9.2.4 Lost Hills Water District

LHWD contains approximately 74,000 acres within its boundaries, beginning at the town of Lost Hills, California and extending north and west to the Kings-Kern County Line. The District lies in the northwest portion of the County of Kern just west of the KNWR. The California Aqueduct and Interstate 5 bisect the District diagonally. State Route 46 is located at the south end of the District. Of the 74,000 acres in the District, 70,314 acres are farmable, although not all this acreage is currently being farmed. The net cropped area is about 32,000 acres (LHWD 2012 AWMP).

LHWD was formed on February 8, 1963, pursuant to Division 13 of the CWC, for the purpose of providing irrigation water from the SWP to land within the District. LHWD is a "member unit" of the KCWA. The District currently owns and operates approximately 23 miles of concrete lined canals, 42 miles of pipeline and 27 miles of unlined canals (not in use).

LHWD primarily supplies agricultural water to growers within its boundaries with a small amount of industrial water delivered annually to oil production and commercial customers. The District supplies no municipal water. All of the water delivered by the District is SWP water and is delivered to the District through the California Aqueduct. The District currently has a Table A contract water volume of 119,110 AF. In some years, the District can purchase supplemental water supplies from the Agency. In many years, Article 21 water and Turnback water has been available for purchase that can be used to supplement the District's contract supply. In water short years, the District purchases supplemental water. Also, District landowners periodically transfer water into the District to help meet their crop water requirements.

To supplement its surface water supply by transfer or exchange, LHWD participates in groundwater banking programs including: Pioneer Project and the Berrenda Mesa Project. In addition, the District's largest landowner, Wonderful Orchard, has the ability to deliver significant amounts of banked groundwater through its participation in the Kern Water Bank.

9.2.5 Lost Hills Public Utility District

LHPUD is a small municipal and commercial water district that provides water distribution for the community of Lost Hills, Blackwells Corner, and the commercial businesses at the Interstate 5-Highway 46 Interchange. The LHPUD serves a population of 2,400 through 437 service connections.

LHPUD's potable water supply consists of groundwater stored in an aquifer that is pumped from two wells owned by an outlying district located 13 miles east of the community of Lost Hills. Prior to distribution to its service area, LHPUD treats the water for arsenic removal at a 625 gpm capacity water treatment plant installed near the wells in 2007.

It is also responsible for collection and treatment of wastewater for the community of Lost Hills. Interstate 5-Highway 46 Interchange owns and operates its own collection and treatment system. Effluent from both treatment plants is disposed of by evaporation and percolation.

9.3 Subregion Description

9.3.1 Land Use

The Land Use, Open Space, and Conservation Element of the Kern County General Plan provide the policies protecting the County of Kern unincorporated areas, including the communities comprising the West Side subregion. Because of the close interrelationship between land use, conservation, and open space issues, Kern County's Land Use, Conservation, and Open Space Element provides for a variety of land uses for future economic growth while also assuring the conservation of both the Counties of Kern and Kings' predominant agricultural, natural, and resource attributes.

The area within the subregion is almost entirely in existing or former agriculture on the western edge of the San Joaquin valley floor in or near northwestern Kern County, planted primarily with almonds, pistachios, pomegranates, vineyards and some row crops. Native valley floor habitat is lower Sonoran Grassland (BMWD 1996). The water supply is almost entirely SWP water. Local groundwater is considered to be unsuitable for agricultural irrigation because of high TDS, boron and sulfate concentrations (BMWD AWMP 2012). Farming declined in the 1980s and 1990s because farming had become less economical, and older, less productive trees and vineyards were being removed.

Prior to construction of the SWP, there was no land development in the subregion except for oil fields. Agricultural activities were limited to sheep grazing on non-irrigated pasture. When water was made available through construction of the SWP, land use in the subregion shifted toward agriculture. Currently, land use within the subregion is primarily for agriculture and petroleum production. Approximately 115,000 acres are in agricultural production with the most common crops being almonds, pistachios, cotton, citrus, grapes, grains, pomegranates, olives and alfalfa. Other crops include carrots, plums, persimmons, hay, melons, tomatoes, wheat, and a variety of vegetables. A significant area of non-irrigated land (approximately 15,000 acres) in the subregion is used to support petroleum production. The balance of acres is used for grazing or is not farmed. Rural communities within the subregion include Lost Hills, Blackwells' Corner, and the Interstate 5-Highway 46 Interchange.

9.3.2 Ecological Processes and Environmental Resources

Ecological processes and environmental resources for the Kern Region as a whole are described in Section 2.4. The West Side subregion is geologically located in the Great Valley geomorphic province. Much like the Kern Fan and North County subregion, environmental resources have been impacted due to agriculture, urban development and oil/gas extraction which have resulted in many changes in the natural environment. These impacts have resulted in drained and diverted lakes and wetlands, the loss of native plants and animal species, and a decrease in native lands. This has also resulted in the introduction of invasive species and spread of exotics leading to the decline of native plant communities.

The CDFW and the USFWS have listed some species as threatened or endangered, requiring species recovery by establishing a network of conservation areas and reserves that include terrestrial and riparian natural areas in the San Joaquin Valley and thus Kern Region. As part of their conservation efforts in the San Joaquin Valley, the Metropolitan Bakersfield HCP and the draft VFHCP have been established to implement endangered species recovery programs within the Kern Region to promote species recovery and protect ecological processes and environmental resources. The West Side subregion is within the boundaries of the Endangered Species Recovery Program for the San Joaquin Valley. There are some areas planned for habitat acquisition within the subregion identified in the Metropolitan HCP. Much of the subregion is under the conserved jurisdiction of the draft VFHCP.

9.3.3 Social and Cultural Characteristics

The social and cultural characteristics of the West Side subregion can be described as industries predominantly related to agriculture with a small portion of the subregion dedicated to oil and gas production. These industries are not different from those described for the Kern Region in Section 2.5.4.

Section 2.5 provides a summary of the human demographics for the Kern Region. Regional data was estimated from the data for the census tracts within the regional boundaries. The community of Lost Hills is located within the West Side subregion.

The population is largely Latino. Approximately 97 percent of the population identifies as being Hispanic or Latino and approximately 3 percent of the population reports being white. Spanish is the primary language.

9.3.3.1 Economic Conditions and Trends

The high cost SWP water in the subregion are impacted by the subregion's location and topography. About 70 percent of the lands currently taking delivery of SWP water in the subregion are located west of and at a higher elevation than the California Aqueduct. When reduced water supplies are received, the costs increase dramatically. This alone is incentive enough for most growers to efficiently manage their water allocation.

The primary products grown within the subregion are trees (mostly almonds and pistachios), cotton, carrots, citrus, and pasture crops. The evolution of irrigation and changing economic conditions has brought many crop changes to the subregion. Lands historically used for row crop production, mainly cotton, were converted to permanent plantings (almonds, pistachios and citrus). As lands are converted, pressurized irrigation systems such as drip and micro sprinkler

replace flood and sprinkler irrigation as the predominant method of irrigation. Similarly, the on-farm irrigation water efficiencies improve as the irrigation system conversions materialize.

In the early to mid-1990s, a portion of the previously irrigated land was dry-farmed or fallowed because landowners could not afford to operate farms due to increasing costs, including the cost of SWP water. At the time, with the burden of excess SWP Entitlement, participants began looking for options to allow for permanent water transfers AF of Annual Entitlement for use outside the subregion. However, with the recent reductions in supply from the SWP, westside districts have maintained their Table A supplies and are seeking additional water supplies.

9.3.3.2 Disadvantaged Communities

Both the communities of Lost Hills and Blackwells Corner have been identified as DACs as shown in **Table 2-5** of Section 2.2.5.3.

9.3.4 Water Supply

9.3.4.1 Imported Water Supplies

The main source of water to the subregion is imported from the SWP, which is transported through the California Aqueduct. This supply is discussed in detail in Section 2.6.1.

Importing affordable water supplies through the SWP, in quantities sufficient to achieve a long term water balance within the subregion, is a prerequisite for successful implementation of the various recharge programs underway or newly initiated.

Landowners in the subregion have higher costs for surface water given the subregion's location and topography. Water delivered to the subregion must be pumped to a higher elevation then gravity fed to the distribution system.

9.3.4.2 Surface Water

The primary source of surface water available to the West Side subregion is the SWP via the California Aqueduct.

Surface water flow into the subregion occurs in creeks (Bitterwater, Franciscan, Packwood, Salt, Chico Martinez, and Santos) that flow seasonally from the south and west. Surface water quality data from these creeks is limited. The surface waters have high concentrations of calcium sulfate due to leaching from surrounding soils. Due to the poor water quality, these creeks do not provide either irrigation water.

9.3.4.3 Groundwater

Groundwater in much of the subregion is not usable due to its low yields and poor quality. Some groundwater is imported to the subregion through programs where water is stored in off-site groundwater basins and from purchases and transfers from other water contractors. LHPUD pumps water from wells located 13 miles east of its service area.

Until recently, use of local groundwater as a supplemental water supply was thought to be uneconomical. However, with the reductions in the SWP supply and the recent drought, landowners have been blending surface water with groundwater from select wells with higher

concentrations of salts to irrigate pistachios and some cotton varieties that have a higher tolerance to salts.

9.3.4.4 Groundwater Banking

Some of the agencies in the subregion obtain non-project water outside of the West Side subregion by participating in banking/exchange programs, namely, Pioneer Banking, Berrenda Mesa Banking, the Kern Water Bank, and CWD/DRWD Banking. In drier years, their supply is heavily supplemented by banked water retrieved from groundwater storage programs in which they are participating. Section 2.6.4.2 provides a complete list of these programs and describes how they are used to benefit participants in the Region as a whole as well as those participating members from the West Side subregion.

9.3.4.5 Recycled Water

LHUD produces a small quantity of recycled water that is used for irrigation of feed and fodder crops.

9.3.5 Water Quality

Imported water supplies within the West Side subregion regard SWP water, are generally of good quality, and are discussed in detail in Section 2, Section 2.7.1.1.

As stated above, groundwater quality in this subregion is poor. When supplemental groundwater is needed to meet demands of the subregion, many districts participate in purchases and transfers from other water contractors outside of their boundary.

Elevated concentrations of arsenic beyond the MCL of 10 ppm can be found in some of the wells in the eastern portion of the subregion. The water from these wells is treated prior to distribution.

9.3.6 Water Demand

Water demands for urban water use and agricultural water use within this subregion are provided in Section 2.9.

9.3.7 Water-Related Infrastructure

The California Aqueduct diagonally bisects the subregion. Water related infrastructure such as surface water impoundments, water collection systems, distribution systems, wastewater systems, and recharge systems, are described generally for the West Side subregion participants in their general descriptions above, and in greater detail for the entire Kern Region in Section 2.9.

9.4 Subregional Issues, Needs, Challenges, and Priorities

The key issues, needs, challenges, and priorities for the Westside subregion with respect to water resource management within the Kern Region include the following. These issue areas are discussed in greater detail in Section 2, in the following sections:

- Decreased Imported Water Supply (see Section 2.11.4)

- Groundwater Overdraft (where there is groundwater) (see Section 2.11.6)

Section 10: Plan Objectives

This section presents the objectives for the Kern IRWMP. In this context, objectives refer to the general intent for planning within the Kern Region and they identify what the RWMG, Executive Committee, and Stakeholders have determined they would like this IRWMP to accomplish. The following pages describe how the objectives were developed utilizing the Stakeholder process and presents the objectives in issue-based categories. To the extent feasible, objectives have been quantified in order to provide a means by which the future success of the Kern IRWMP's implementation can be measured.

10.1 Objectives Development

Development of objectives for the Kern IRWMP was an iterative and consensus-based process. While technically their development took 3 stakeholder meetings to end up with those that are presented here, many meetings and discussions of the subregions, within and among each other, occurred to further the development of the objectives. Because the Kern Region is such a large and geographically diverse region, ranging from valley and desert landscapes to mountains and foothills, and from rural to urban, the bond that ties the region together is water, and its use. However, objectives that might be well suited for the Kern Fan subregion, such as "increased groundwater recharge" may not be as important of an objective to the Mountains/Foothills subregion. Thus, after the topic and concept of "objectives" was introduced to the group, and various goals and objectives from neighboring IRWMPs were presented and reviewed, and the Stakeholders held a brainstorming session on issues, goals, and objectives that would be appropriate for the entire Kern Region.

Once a final draft list of objectives was prepared and presented to the stakeholders at a subsequent Stakeholder meeting, they were sent to the Executive Committee for final refinement. The objectives were then evaluated against the California Water Plan Strategies, the IRWM Plan Preferences, and the California Statewide Preferences in order to identify any gaps or deficiencies in resource areas that the objectives may not be covering, but which they were intended to. The Executive Committee was tasked with preparing the draft of quantified objectives for Stakeholder review, and they were refined during subsequent meetings.

The resulting objectives generally apply to the Kern Region as a whole and are meant to focus attention on the primary needs of the Kern Region. The Stakeholders agreed that increasing water supply would be a priority objective for the region, and that other objectives would have lower priority. The objectives are shown in **Table 10-1** as agreed upon by the Stakeholders. In addition, the objectives address adapting to the effects of climate change, including changes in the amount, intensity, timing, quality and variability of runoff and recharge, as discussed in Section 2.10.11.

10.2 Regional Objectives

Objectives for the Kern Region are categorized into five resource categories: increase water supply, improve operational efficiency, improve water quality, promote land use planning and resource stewardship, and improve regional flood management. **Table 10-1** presents the objectives for the Kern Region, and where possible, the proposed means for measuring progress toward achieving each objective, depicted as 'planning targets' is presented.

Table 10-1: Kern IRWMP Objectives

Objectives	Planning Targets
Increase Water Supply (WS)	
Through cooperation and collaboration with other regions restore water supplies to levels that will mitigate for water lost from the region and eliminate overdraft	400,000 – 1 million acre-feet (MAF)
Pursue and implement cost effective water use efficiency programs	Conserve 30,000 acre-feet per year (AFY) by 2030
Increase water storage capacity in the region by increasing recharge acreage and expanding groundwater banking programs before all prime recharge land has been developed	8,000 recharge acres as soon a practicable
Integrate management of water banking facilities to maximize conjunctive use over the planning horizon	
Increase/augment water supplies to meet region demands (e.g., M&I, agricultural, environmental) by 2050.	
Improve Operational Efficiency (OE)	
Increase transfers and exchanges flexibility over the planning horizon	
Create tools to re-regulate water supplies within the region, including storage, storm flows, and operational flows over the planning horizon	
Increase distribution efficiencies and reduce energy usage over the planning horizon	
Increase the use of alternate energy sources (e.g. solar)	33% of energy provided by alternative sources to the region by 2020
Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions	Less than 10% losses in urban systems; replace 10% of all systems
Increase the use of recycled water for direct reuse within the Kern Region	20% of produced wastewater annually
Optimize local management of water resources to improve water supply reliability over the planning horizon	
Increase pool of qualified candidates to operate water and wastewater systems	20% increase in employees trained by 2020; reduction in water/wastewater job vacancies
Improve Water Quality (WQ)	
Monitor and/or manage headwaters/areas of origin, natural streams, and recharge areas to prevent or mitigate contamination	$10 million for planning and projects by 2020
Identify and preserve prime recharge areas in the Kern fan area and other areas	8,000 acres as soon as practicable
Improve water quality for DACs and the watershed over the planning horizon	
Continue to provide drinking water that meets or exceeds water quality standards; and support efforts to attain appropriate standards throughout the planning horizon	

Objectives	Planning Targets
Maximize the use of lesser quality water for appropriate uses (landscaping, certain ag crops, "aesthetic" projects) throughout the planning horizon	
Coordinate and enhance aquatic pest control efforts from this point forward	
Promote Land Use Planning and Resource Stewardship (LU)	
Promote stewardship of the local rivers and streams by applying appropriate measures in various reaches of the river from this point forward	
Encourage the removal of non-native invasive plant species that affect water quality, reliability, and operations	No more than 5% of plant matter in waterways will be non-native beginning in 2010
Identify and promote the regeneration and restoration of native riparian habitat	460 acres of restored/regenerated riparian habitat
Coordinate agricultural and urban water suppliers to more effectively address land use planning issues from this point forward	
Improve the linkage between land use planning and water supply in the region throughout the planning horizon	
Increase educational opportunities to improve public awareness of water supply, conservation, and water quality issues throughout the planning horizon	
Improve and coordinate integrated land use planning to support stewardship of environmental resources, such as local rivers and streams and the Kern Fan, and integrate with habitat conservation plans and other ongoing planning efforts from this point forward	
Preserve and improve ecosystem/watershed health throughout the planning horizon	
Improve Regional Flood Management (FM)	
Improve regional flood management by addressing preparedness, response, and post flood actions throughout the planning horizon	
Reduce the effects of poor quality runoff throughout the planning horizon	
Identify and promote innovative flood management projects to protect vulnerable areas	Reduce flood flows by an average of 2% per year through 2020
Plan new developments to minimize flood impacts from this point forward	

The following paragraphs provide additional detail about the regional objectives developed by the Stakeholders and the various means of measuring whether or not the objectives are being achieved.

10.2.1 Increase Water Supply

A reliable water supply is necessary to protect the economic vigor of the Region. Water supplies that are utilized in the Region; the SWP, CVP, and local surface supplies from Kern River and other local streams, as well as the largest common groundwater basin, the San Joaquin Valley groundwater basin, all are impacted by reliability issues.

Since 1994, the two large projects that import water into the Kern Region, the CVP and the SWP, have been incrementally impacted by environmental and regulatory requirements that have served to diminish the ability of the projects to reliably deliver water supplies. In June 2009, additional restrictions on the water projects were announced, further reducing the amount of water available. These cutbacks have occurred in agricultural communities in the Kern Region and have caused severe economic impacts to the Region and to its DACs in particular.

Groundwater has long been a variable resource as it has been pumped in the region since the 1800s when the area was settled. Today groundwater provides approximately 45 percent of local water needs; however, the resource is overdraft in many parts of the Region and thus is dependent on imported water to enhance reliability. With the significant overdraft problem exacerbated by the recent drought, the State enacted SGMA in 2014. It is anticipated that under SMGA, areas of the region will be impacted due to reductions in groundwater use required to bring the groundwater basins into sustainable management.

As water shortages and increasing demands upon infrastructure occur throughout the Kern Region, water conservation planning, technologies and practices are continuing to evolve today. Legislation has been enacted to reduce various sectors' dependence on potable water. Over the past decade multiple water conservation-related bills were enacted by the State as discussed in Section 2.10.7.

Thus, the Stakeholders have identified the following measurable objectives related to "Increasing Water Supply" within the Kern Region:

- *Through cooperation and collaboration with other regions restore water supplies to levels that will mitigate for water lost from the region and eliminate overdraft (400,000 – 1MAF)*

Stakeholders estimate that between 400,000 AF to 1 MAF have been lost to the Kern Region as a result of environmental regulations (e.g. reductions in SWP to the region), drought conditions, out of basin transfers, etc. Implementation of projects that would contribute to this target would help to meet the overall water supply needs for the Region.

- *Pursue and implement cost effective water use efficiency programs (conserve 30,000 AFY by 2030)*

In February 2008, Governor Schwarzenegger called for a 20 percent reduction in per capita water use statewide by 2020. The State Water Resources Control Board released a statewide implementation plan for achieving this goal (20x2020 Water Conservation Plan, February 2010) which establishes regional baseline and target per capita water use values by State hydrologic region. The 2020 targeted daily per capita water use value established for the Tulare Lake hydrologic region is 188 gallons per day per capita (gpcd).

The Kern Stakeholder have set a target conservation goal of 10% conservation savings from agriculture and 20 percent conservation savings from urban uses, the latter of which can be used to help meet the 20x2020 goal, where conservation measures have not already been implemented, for a total of approximately 30,000 AF by 2030.

It should be noted that under the CARB 2017 Climate Change Scoping Plan, it notes that conserving water results in reduced energy usage, which in turn results in reduction of GHG emissions.

- *Increase water storage capacity in the region by increasing recharge acreage and expanding groundwater banking programs before all prime recharge land has been developed (8,000 recharge acres as soon as practicable)*

Prime recharge land is important because of its watershed functions; filtration of surface water and stormwater detention. Within the Kern Region, these land use types have been decreasing as the urban landscape expands. According to Kern County planning staff, an estimated 8,000 acres of prime recharge land are not currently contained within existing specific plans or other planning documents. Therefore, the goal is to keep these acres undeveloped and retain their watershed function.

- *Integrate management of water banking facilities to maximize conjunctive use over the planning horizon*

Groundwater banking programs are widely used in the Kern Region; conjunctive use programs have been utilized in the region since the early 1900s. Many notable storage programs exist in the region, including those operated by AEWSD, SWSD, NKWSD, the City of Bakersfield, RRBWSD, and various other districts in the Region. Joint operation of some of these banking operations, if applicable, is desirable for efficient water management. However, duplicative infrastructure is also found in some rural parts of the Region, where numerous small systems have been established that are wholly separate from nearby systems. In these cases, no economies of scale have been realized for water distribution nor joint treatment systems constructed, either which can be due to physical (geographic or topographic) separation or perceived local political differences.

Part of the impetus for the Kern IRWMP is to identify infrastructure issues and potential collaborative projects to address infrastructure needs.

- *Increase/augment water supplies to meet region demands (e.g., municipal and industrial, agricultural, environmental) by 2040*

The Kern Region is highly dependent on imported water, as discussed above and in Sections 2.6 and 2.10.4. Given this dependence, all elements of its reliability should be considered. Fluctuations in delivery due to climatic changes have to be incorporated in supply and demand analyses in UWMPs. The planning horizon for these 2015 UWMP assessments is out to 2040. Therefore, this objective has a measurable planning target.

10.2.2 Improve Operational Efficiency

Improved operational efficiency would result in decreasing the amount of energy, labor, and other materials (e.g., water treatment chemical supplies) needed to move water from its source to the customer. For example, through proper sizing and placement of storage tanks it may be possible to fill and drain tanks during off-peak hours for electricity or use gravity-feed to fill tanks. Another example of operational efficiency is using the river channel itself as a groundwater recharge area, rather than purchasing land to create and operate recharge facilities or injection wells. An example of operational inefficiency is using resources to treat water to the drinking water standard if in fact that water is going to be used for non-potable uses (for example, landscape irrigation and industrial processes). In this example, there could be

greater operational efficiency if the recycled water distribution system were expanded to serve the non-potable uses currently receiving treated water.

Related to operational efficiency, the Stakeholders have identified the following objectives:

- *Increase transfers and exchanges flexibility over the planning horizon, including possibly consolidating the SWP and CVP place of use*
- *Create tools to re-regulate water supplies within the region, including storage, storm flows, and operational flows over the planning horizon*
- *Increase distribution efficiencies and reduce energy usage over the planning horizon*
- *Increase the use of alternate energy sources (e.g. solar) (33% of energy provided by alternative sources to the region by 2020)*

This measurable objective is based on Governor Arnold Schwarzenegger's EO directing CARB to adopt regulations increasing California's Renewable Portfolio Standard (RPS) to 33 percent by 2020, which was first established by the Governor's directive in 2008. The Governor's EO upholds California's leadership in environmental policies and builds on AB 32 goals by ensuring California will have the flexibility needed to use renewable energy sources for 33 percent of our state's energy consumption by 2020. With the State projecting to meet this goal, a new reduction target of 40 percent below 1990 by 2030 was established under SB 32. In addition, this objective addresses the region's need to mitigate climate change effects through the reduction of GHG emissions.

- *Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions (less than 10% losses in urban systems; replace 10% of all systems)*

This target stems from the regulatory requirement that calls for a 10% loss in urban systems and expanding that requirement system wide to produce a larger benefit.

- *Increase the use of recycled water for direct reuse within the Kern Region (20% of produced wastewater annually)*

This target was meant to focus recycled water on direct reuse, as all wastewater is put to beneficial use through crop irrigation and recharge. Direct reuse is considered to be application to crops and landscape irrigation. A target application of 20% of produced wastewater annually was chosen as it could be measured and incrementally increased throughout the planning horizon.

- *Optimize local management of water resources to improve water supply reliability over the planning horizon*
- *Increase pool of qualified candidates to operate water and wastewater systems (20% increase in employees trained by 2020; reduction in water/wastewater job vacancies)*

This target is an estimate from the County's Waste Management staff based on existing vacancies and growth projections/demands for the County. It translates into roughly 40 operators trained and certified by 2020.

- Establish a consolidated place of use for the CVP and SWP

Currently, the CVP and SWP places of use are inconsistent with one another in the Kern Region. This limits the operational flexibility of local water purveyors and the extensive groundwater banking projects throughout the Kern Region. Operational flexibility is a crucial component of water management in the Kern Region, where supplies are variable due to hydrology and regulatory impacts to the CVP and SWP. Establishing a consolidated place of use would improve operational efficiency by enhancing opportunities for operational exchanges and groundwater banking.

10.2.3 Improve Water Quality

Water quality is an important consideration not only for water delivered to the customer, but for ecosystems. The Kern River, the primary native surface supply in Region, is generally considered a high-quality supply. As discussed in detail in Section 2.7, groundwater quality throughout the region is typically suitable for most urban and agricultural uses with only localized impairments including high TDS (salts), sodium chloride, sulfate, nitrate, organic compounds, arsenic, and 1,2,3-TCP. High TDS, nitrates, arsenic and 1,2,3-TCP are the primary groundwater quality issues. The CVRWQCB has stated, “The greatest long-term problem facing the entire Tulare Lake Basin is the increase of salinity in ground water” (2018). Salt in imported water supplies such as the SWP and CVP is the major source of salt which circulates throughout the groundwater in Kern County.

Therefore, related to water quality, the Stakeholders have identified the following measurable objectives:

- *Monitor and/or manage headwaters/areas of origin, natural streams, and recharge areas to prevent or mitigate contamination ($10M for planning and projects by 2020)*

In order to project the quality of the underlying aquifer, it is also important to protect the surface waters entering the headwaters/areas of origin, natural streams, and recharge areas. Natural streams and surface waters feed the Kern River as well as recharge areas in the Kern Region. Thus, any degradation in water quality in the streams could result in the loss of this surface water supply as well as degradation in the recharge areas.

There has not been any comprehensive assessment of the headwaters, natural stream, and recharge areas with regard to contamination prevention in order to identify what is needed for future protection. The Executive Committee identified an initial estimate of $10M for planning/studies to determine what projects are needed and are feasible to implement, as well as for the actual implementation of initial projects (test or actual).

- *Identify and preserve prime recharge areas in the Kern Fan area and other areas (8,000 acres as soon as practicable)*

Identifying and preserving prime recharge areas and taking appropriate measures to reduce or eliminate the potential for contamination is crucial to ensuring a reliable water supply. Where the potential for contamination can occur, or where contamination has already occurred, programs and projects must be implemented to prevent its migration to other areas of the Region. In some cases, treatment or remediation may be required to prevent migration.

According to Kern County planning staff, an estimated 8,000 acres of prime recharge land are not currently contained within existing specific plans or other planning documents. Therefore, the goal is to keep these acres undeveloped and retain their watershed function.

- *Improve water quality for DACs and the watershed over the planning horizon*
- *Continue to provide drinking water that meets or exceeds water quality standards; and support efforts to attain appropriate standards throughout the planning horizon*

As discussed in Section 2.7, water quality is generally good Region-wide; the main concerns being high TDS, arsenic, nitrates, and 1,2,3-TCP in groundwater. In general, the water quality over time has remained relatively unchanged across the entire Region and generally meets MCLs. The exceptions to the good groundwater quality are high nitrates associated with fertilizer use, high arsenic levels, and 1,2,3-TCP due to the recent establishment of the MCL.

However, in addition to meeting the Federal and State standards for water quality, other secondary standards (such as taste, color, and odor) may also affect a customer's overall satisfaction with the water. Although these constituents do not result in any health effects to the customer, they do impact the customer's desire to drink and use the water.

- *Maximize the use of lesser quality water for appropriate uses (landscaping, certain ag crops, "aesthetic" projects) throughout the planning horizon*

As discussed in Section 2.6.5, approximately 57,000 AFY of recycled water, most treated to secondary standards, is available for use on non-edible crops and for landscaping needs. With further treatment upgrades, it will be possible to put more recycled water to more extensive uses.

- *Coordinate and enhance aquatic pest control efforts from this point forward*

Aquatic pests, including invasive plants (e.g., Tamaracks and animal species, have been fought on the Kern River for decades. Prevention and control of invasive species is an ongoing battle by many resource agencies such as the Kern River Preserve Audubon Society, and the Kern River Ranger District. Coordination of their control efforts would help to maximize efficiencies and enhance results.

10.2.4 Promote Land Use Planning and Practice Resource Stewardship

Water is intended for many beneficial uses including agricultural water supplies, groundwater recharge, water replenishment, recreation, wildlife habitat, rare and endangered species, and wetland ecosystems.

To this end, Stakeholders have investigated multiple objectives related to resource stewardship, including removal of invasive species, acquisition of floodplain areas for recreation and flood easements, and acquisition of habitat.

Stakeholders have identified the following measurable objectives related to resource stewardship:

- *Promote stewardship of the local rivers and streams by applying appropriate measures in various reaches of the river from this point forward*

This objective acknowledges the benefits of the Kern River that are worthy of protection; environmental, biological, economical, cultural, hydrological, agricultural, etc. By acknowledging that the Kern River is a resource to be protected, these beneficial uses can be contributed to by the projects implemented in this IRWMP.

- *Encourage the removal of non-native invasive plant species that affect water quality, reliability, and operations (no more than 5% of plant matter in waterways will be non-native beginning in 2010)*

This objective is to remove non-native plant species and promote revegetation by native plant species in the Kern River. The measurement is intended to prevent establishment of new species of invasive plants within the watershed, as it is the most cost effective way to control these plants and prevent further habitat degradation, and impacts to operations. This measurable objective takes into consideration current quantities and types of invasive species as well as what can realistically be reduced/removed from the watershed.

- *Identify and promote the regeneration and restoration of native riparian habitat (460 acres of restored/regenerated riparian habitat)*
- *Coordinate agricultural and urban water suppliers to more effectively address land use planning issues from this point forward*

As discussed in Section 2, there is over 800,000 acres of irrigated crop land in the Kern Region. Agriculture is an important industry for the Kern Region. In addition to direct production of food and fiber, secondary employment is created by the agricultural production, including transportation and food manufacturing. As mentioned, in Kern County it is estimated that one out of every five jobs are tied to the agricultural industry (Kern County Agricultural Commissioner 2017). In addition, agriculture plays an important role in community identity. The types of crops grown in an area may be unique to that place. Community festivals are often planned around the commodities unique to a place, or for which a community is known. The physical landscape of a place can be defined by its agriculture as the crops create a distinct color mosaic and pattern. Residents also can take advantage of the open space and views allowed by nearby agriculture. In addition, some agricultural crops may provide wildlife habitat (nesting, temporary foraging).

The demand for urban development is resulting in a conversion of agricultural land and is introducing conflicts between agricultural and residential development. As a result, agricultural land is increasingly found on the urban fringes. There is a desire to preserve agriculture as an industry and as a cultural asset. Kern County, Kings County and Los Angeles County have adopted policies intended to preserve agricultural resources. These policies include right-to-farm ordinances, reduced property tax programs for farm businesses, and policies discouraging provision of urban services in agricultural areas. To encourage the retention and expansion of agricultural use both within and outside a potential agricultural preserve, the policies promote compatible land use arrangements and offer technical assistance in support of farming interests. In addition, expansion of agricultural into underutilized lands, such as utility rights-of-way and flood prone areas is encouraged.

- *Improve the linkage between land use planning and water supply in the region throughout the planning horizon*

Coordination between land use planning agencies and water management agencies is crucial to implementation of a successful IRWMP. A regional land use management plan to guide the Kern Region's development would be a key step towards improving coordination and identifying future water needs throughout the Region. Growth management, the protection of various land uses and the efficient use of natural resources such as land, water and energy are three of the principal goals of regional land use planning. A regional land use management plan that directs the Kern Region's growth towards existing centers will not only encourage natural resource efficiency and the preservation of surrounding agricultural land uses and recreational open space, but it will also improve the efficient use of economic resources dedicated towards utilities infrastructure improvements and expansions.

- *Increase educational opportunities to improve public awareness of water supply, conservation, and water quality issues throughout the planning horizon*

The Kern IRWMP provides a positive model for the general public to reference as water districts and municipalities move forward in asking Stakeholders to become more efficient in their water usage. Increasing educational opportunities for local residents on the basics and importance of using appropriate amounts of water for irrigation, of awareness of water supply, conservation, and water quality will be important if the end result must be a significant reduction in overall water demand.

- *Improve and coordinate integrated land use planning to support stewardship of environmental resources, such as local rivers and streams and the Kern Fan, and integrate with habitat conservation plans and other ongoing planning efforts from this point forward*
- *Preserve and improve ecosystem/watershed health throughout the planning horizon*

The Kern Region is subject to increasing demand for community development, recreation, and resource utilization. Population in the Kern Region is expected to increase by about 35% between 2015 and year 2030. Some of this growth will result in the conversion of agricultural land, while some of this growth will occur in areas that are currently natural and undeveloped areas. Loss of both agricultural acreage and natural areas decreases the amount of open space in the Region. Open space can mean natural open space, passive and active recreation which may or may not be compatible with natural habitats or natural open space preservation.

As an example, open space can mean athletic fields and playgrounds and should not be considered as natural habitat. This growth and the associated loss of open space could adversely affect local water resources through the loss of wetland areas and the watershed functions these areas provide (filtration of surface water, stormwater detention).

Also, of concern is the negative effect of urban growth on the unique biological resources of the Region. Besides a direct loss of habitat, increasing proximity to urban development is harmful to the sensitive desert species, several of which are found only in the Kern Region. Thus, the RWMG found it important to make preserving and improving the ecosystem/watershed health throughout the planning horizon (2050) an objective of the Kern IRWMP.

10.2.5 Improve Flood Management

As described in Section 2.10.5, the key issues for the Kern Region with respect to flood management are: lack of coordination throughout the Region, poor water quality of runoff,

nuisance water and dry weather runoff, and difficulty providing flood control without interfering with groundwater recharge.

Floods also cause economic losses through closure of businesses and government facilities, disruption of communications and the provision of utilities such as water and sewer, result in excessive expenditures for emergency response, and generally disturb the normal functions of a community. Flood management strategies recommended in this document will serve as guidelines to address concerns and prevent some of the flood related damage.

Therefore, related to flood management, the Stakeholders have identified the following objectives:

- *Improve regional flood management by addressing preparedness, response, and post flood actions throughout the planning horizon*
- *Reduce the effects of poor-quality runoff throughout the planning horizon*
- *Identify and promote innovative flood management projects to protect vulnerable areas (reduce flood flows by an average of 2% per year through 2020)*
- *Plan new developments to minimize flood impacts from this point forward*

This planning target, held by the County of Kern, assumes the ability to continue to reduce flood flows by an average of 2% per year (based on the previous year's flood flows) through 2020. The target applies to currently uncontrolled, uncaptured or otherwise unmanaged flood flows. In 2020 the target will be evaluated to see whether the objective has been achieved or if it should be continued or modified.

Additionally, County of Kern, many of the Kern IRWMP participants, various regional public service providers, and land use planners have worked collaboratively to develop the Kern County Multi-Hazard Mitigation Plan (HMP). The HMP includes specific discussions of flood management throughout the County, as well as the identification of potential projects. The HMP was originally adopted in 2006 and was updated in 2012. The HMP is currently in the process of being updated. The County of Kern hired the consulting firm Dynamic Planning and Science in 2019 to begin the process and HMP update is expected to be completed in 2020.

10.3 Objectives Related to Climate Change and GHG Emissions

The objectives for the Kern Region address adapting and mitigating the general effects of climate change, including changes in the amount, intensity, timing, quality, and variability of runoff and recharge. These "no regrets" adaptations recognize the current water management context for the region. In addition, mitigation strategies addressed by the objectives for the Kern IRWMP include energy efficiency improvements, emissions reductions, and carbon sequestration through vegetation growth. The Climate Change Handbook (CDM, 2011) was used to help develop these adaptation and mitigation strategies, which are listed in **Table 10-2**. Further discussion of the climate change objectives and prioritization of the vulnerabilities is provided in Section 16.

The Kern Region will implement these strategies that adapt flood management, water supply, water quality, water dependent recreation, and habitat. Special consideration will be given to:

- Potential effects of climate change on the region and whether adaptations to the water management system are necessary.

- Potential contributions to adapting to climate change vulnerabilities.
- Change in amount, timing, intensity, quality and variability of runoff and recharge.
- Effects of sea level rise on water supply conditions.

Regarding GHG emissions, the Kern Region will prioritize development of water supplies with the lowest GHG emissions, implement use of renewable energy and conservation in water systems, reduce energy use from pumping. Decreasing the amount of energy required to produce water supply is the best way to reduce GHG to mitigate against further climate change impacts. The Region also must consider natural solutions such as carbon sequestration (e.g. wetland restoration). Further considerations of GHG emissions include:

- Quantification of GHG emissions
- Region-wide reduction in GHG emissions
- Reduction of energy consumption and renewable energy implementation

10.4 Strategies

After identification of objectives, the Stakeholders then moved to refining strategies appropriate to achieving the objectives. This process and its outcomes are described in Section 11.

Table 10-2: Kern IRWMP Objectives and Climate Change Adaptations

Objectives	Related CA Water Plan Resource Management Strategy	Climate Change Adaptation	Climate Change Mitigation
Increase Water Supply			
Through cooperation and collaboration with other regions restore water supplies to levels that will mitigate for water lost from the region and eliminate overdraft		Water Supply Reliability Additional Water Supply	
Pursue and implement cost effective water use efficiency programs	Urban/Agricultural Water Use Efficiency	Water Demand Reduction Water Quality Protection	Energy Efficiency Emissions Reduction
Increase water storage capacity in the region by increasing recharge acreage and expanding groundwater banking programs before all prime recharge land has been developed	Conjunctive Management & Groundwater	Flood Control Water Supply Reliability Additional Water Supply Water Quality Protection	
Integrate management of water banking facilities to maximize conjunctive use over the planning horizon	Conjunctive Management & Groundwater	Water Supply Reliability Additional Water Supply	
Increase/augment water supplies to meet region demands (e.g., M&I, agricultural, environmental) by 2050.			
Improve Operational Efficiency			
Increase transfers and exchanges flexibility over the planning horizon	Water Transfers	Water Supply Reliability Additional Water Supply Sea Level Rise	
Create tools to re-regulate water supplies within the region, including storage, storm flows, and operational flows over the planning horizon	System Reoperation	Flood Control Water Supply Reliability	
Increase distribution efficiencies and reduce energy usage over the planning horizon	System Reoperation	Water Supply Reliability	Energy Efficiency Emissions Reduction

Objectives	Related CA Water Plan Resource Management Strategy	Climate Change Adaptation	Climate Change Mitigation
Increase the use of alternate energy sources (e.g., solar)			Emissions Reduction
Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions			Energy Efficiency
Increase the use of recycled water for direct reuse within the Kern Region	Recycled Municipal Water	Water Supply Reliability Additional Water Supply	Energy Efficiency Emissions Reduction
Optimize local management of water resources to improve water supply reliability over the planning horizon		Water Supply Reliability Sea Level Rise	
Increase pool of qualified candidates to operate water and wastewater systems			
Improve Water Quality			
Monitor and/or manage headwaters/areas of origin, natural streams, and recharge areas to prevent or mitigate contamination	Pollution Prevention Urban Runoff Management	Habitat Protection Water Supply Reliability Water Quality Protection	
Identify and preserve prime recharge areas in the Kern fan area and other areas	Conjunctive Management & Groundwater	Water Quality Protection	
Improve water quality for DACs and the watershed over the planning horizon	Drinking Water Treatment and Distribution		
Continue to provide drinking water that meets or exceeds water quality standards; and support efforts to attain appropriate standards throughout the planning horizon	Drinking Water Treatment and Distribution	Water Quality Protection	
Maximize the use of lesser quality water for appropriate uses (landscaping, certain ag crops, "aesthetic" projects) throughout the planning horizon	Matching Water Quality to Use	Water Supply Reliability Additional Water Supply Water Quality Protection	
Coordinate and enhance aquatic pest control efforts from this point forward	Pollution Prevention Urban Runoff Management	Habitat Protection	

Objectives	Related CA Water Plan Resource Management Strategy	Climate Change Adaptation	Climate Change Mitigation
Promote Land Use Planning and Resource Stewardship			
Promote stewardship of the Kern River by applying appropriate measures in various reaches of the river from this point forward	Ecosystem Restoration Watershed Management	Habitat Protection Flood Control Water Supply Reliability Additional Water Supply Water Quality Protection	
Encourage the removal of non-native invasive plant species that affect water quality, reliability, and operations	Ecosystem Restoration	Habitat Protection Water Supply Reliability Water Quality Protection	Carbon Sequestration
Identify and promote the regeneration and restoration of native riparian habitat	Ecosystem Restoration	Habitat Protection Flood Control	Carbon Sequestration
Coordinate agricultural and urban water suppliers to more effectively address land use planning issues from this point forward	Land Use Planning and Management	Habitat Protection Flood Control Water Quality Protection	Energy Efficiency Emissions Reduction Carbon Sequestration
Improve the linkage between land use planning and water supply in the region throughout the planning horizon	Land Use Planning and Management	Water Supply Reliability	Carbon Sequestration
Increase educational opportunities to improve public awareness of water supply, conservation, and water quality issues throughout the planning horizon		Water Supply Reliability Water Quality Protection	
Improve and coordinate integrated land use planning to support stewardship of environmental resources, such as the Kern River and Kern Fan, and integrate with habitat conservation plans and other ongoing planning efforts from this point forward	Land Use Planning and Management Watershed Management	Habitat Protection	Carbon Sequestration
Preserve and improve ecosystem/watershed health throughout the planning horizon	Watershed Management	Habitat Protection	Carbon Sequestration

Objectives	Related CA Water Plan Resource Management Strategy	Climate Change Adaptation	Climate Change Mitigation
Improve Regional Flood Management			
Improve regional flood management by addressing preparedness, response, and post flood actions throughout the planning horizon	Flood Risk Management	Flood Control	
Reduce the effects of poor quality runoff throughout the planning horizon	Urban Runoff Management	Water Quality Protection	
Identify and promote innovative flood management projects to protect vulnerable areas	Flood Risk Management	Flood Control	Carbon Sequestration
Plan new developments to minimize flood impacts from this point forward	Flood Risk Management	Flood Control	Carbon Sequestration

Section 11: Resource Management Strategies Used to Meet Plan Objectives

This section introduces a diverse menu of resource management strategies available to meet the water management objectives within the Region. The State of California has identified 32 different resource management strategies that can be used to improve water resource management. Section 11.1 defines and discusses each of the 32 resource management strategies of the California Water Plan, in order to provide the reader with an understanding of the State's vision for possible ways to meet future water management challenges. This section also serves to provide background in common water management tools available. In this report, we have organized the 32 different management strategies into seven areas based on the objectives defined by the Stakeholders (reduce water demand, increase water supply, improve operational efficiency, improve water quality, promote land use planning and resource stewardship, increase regional flood management, and people and water).

Section 11.3 demonstrates how the Stakeholders have built upon the resource management strategies in the California Water Plan and resource management strategies already implemented in the area and have tailored these strategies to meet the water management objectives of the Region. Finally, Section 11.4 describes the "Call for Projects" process and gives an overview of projects submitted for inclusion in the IRWMP which will implement these strategies to meet the regional objectives.

11.1 California Water Plan Resource management strategies

This section describes the California Water Plan and each of the 32 resource management strategies. The California Water Plan, which is updated every five years as required by the CWC, is a resource for water planners, managers and policy-makers faced with the task of acting as stewards of this resource. More concisely, it is a strategic plan for all regions of the State that addresses the uncertainty of future water needs by recommending a diversified approach, consisting of multiple strategies and a range of short- and long-term actions. Given the many water challenges the State must actively respond to, the California Water Plan deems it imperative that planning take place on a regional scale and that planning constitute an inclusive process involving multiple players, particularly local agencies and governments and their citizens. The most current version of the California Water Plan was released in 2018.

Many of the resource management strategies described in the California Water Plan are currently being utilized in the management of water resources in the Kern Region. Strategies already practiced include drinking water treatment and distribution, groundwater/aquifer remediation, pollution prevention, conveyance, water transfers, conjunctive management/groundwater storage, floodplain management, urban runoff management, recharge areas protection, and agricultural lands stewardship, and land use planning and management.

The following resource management strategies are being implemented in the Kern Region, but their application may not be widespread, and opportunities exist to expand and better integrate these strategies: agricultural water use efficiency, urban water use efficiency, economic incentives, ecosystem restoration, water-dependent recreation, watershed management,

system re- operation, surface storage (regional/local), matching quality to use, recycled municipal water.

Some strategies are not used within the Kern Region at all such as desalination, precipitation enhancement, and surface storage (CALFED). This is because they are either infeasible, or underfunded. Desalination is generally not used because only relatively small amounts of brackish water exist locally. However, expanded utilization of some of these strategies could be implemented to enhance the implementation success of other currently used strategies.

11.2 Water Management Strategy Descriptions

11.2.1 Reduce Water Demand

11.2.1.1 Agricultural Water Use Efficiency

Agricultural water use efficiency involves improvements in technologies and management of agricultural water that result in water supply, water quality, and environmental benefits. Efficiency improvements can include on-farm irrigation equipment, crop and farm water management, and water supplier distribution systems.

11.2.1.2 Urban Water Use Efficiency

Urban water use efficiency involves technological or behavioral improvements in indoor and outdoor residential, commercial, industrial, and institutional water use that lower demand, lower per capita water use, and result in benefits to water supply, water quality, and the environment.

11.2.2 Improve Operational Efficiency and Transfers

11.2.2.1 Conveyance (Delta and Regional/Local)

Conveyance provides for the movement of water. Specific objectives of natural and managed water conveyance activities include flood management, consumptive and non-consumptive environmental uses, water quality improvement, recreation, operational flexibility, and urban and agricultural water deliveries. Infrastructure includes natural watercourses as well as constructed facilities like canals, pipelines and related structures including pumping plants, diversion structures, distribution systems, and fish screens. Groundwater aquifers are also used to convey water.

11.2.2.2 System Re-operation

System re-operation means changing existing operation and management procedures for such water facilities as dams and canals to meet multiple beneficial uses. System re-operation may improve the efficiency of existing uses, or it may increase the emphasis of one use over another. In some cases, physical modifications to the facilities may be needed to expand the re-operation capability.

11.2.2.3 Water Transfers

A water transfer is defined in the CWC as a temporary or long-term change in the point of diversion, place of use, or purpose of use due to a transfer or exchange of water or water rights. A more general definition is that water transfers are a voluntary change in the way water is

usually distributed among water users in response to water scarcity. Transfers can be from one party with extra water in one year to another who is water-short that year.

11.2.3 Increase Water Supply

11.2.3.1 Conjunctive Management and Groundwater Storage

Conjunctive use refers to the coordination of surface water and groundwater resources to maximize the utility of an area's collective water resources. Conjunctive use involves using surplus surface water when available (e.g., storm runoff, surplus surface water flows, or recycled water) to recharge the groundwater basin containing adequate storage capacity. Groundwater banking is a form of conjunctive use wherein surplus surface water or other available waters are injected or recharged for storage in the aquifer, and then extracted later when surface water supplies are limited.

11.2.3.2 Desalination – Brackish/Seawater

Desalination is a water treatment process for the removal of dissolved salts from water for beneficial use. Desalination is used on brackish (high salinity) water as well as seawater. Since groundwater within the Kern Region is not high in TDS, and that the basin is geographically distant from the ocean, desalination as a water management strategy is of low priority in the Region. However, it could become a source of future imported water supply through inter jurisdictional agreements.

11.2.3.3 Precipitation Enhancement

Precipitation enhancement, commonly called "cloud seeding," artificially stimulates clouds, in principle, to produce more rainfall or snowfall than they would naturally. Cloud seeding injects special substances into the clouds that enable snowflakes and raindrops to form more easily.

11.2.3.4 Recycled Municipal Water

Recycled water is defined in the CWC to mean "water which, as a result of treatment of waste, is suitable for a direct beneficial use or a controlled use that would not otherwise occur." Water recycling is a term which encompasses the process of treating wastewater, storing, distributing, and using the recycled water. The uses to which recycled water can be applied (e.g., landscape and agricultural irrigation, cooling, etc.) depend upon the quality of the treated water and the quality required for subsequent uses. Currently recycled water in the Kern Region that is treated to secondary quality levels is for irrigation of salt tolerant crops and for flood management within the KNWR. This IRWM Plan includes a number of current and planned management actions to increase recycled water use in the Kern Region.

11.2.3.5 Surface Storage – CALFED

The CALFED Bay-Delta Program was focused on interrelated water problems in the Sacramento-San Joaquin River Delta. In 2009, CALFED was replaced by the Delta Stewardship Council. The CALFED Record of Decision (2000) identified five potential surface storage reservoirs that are being investigated by DWR, the USBR, and local water interests. Building one or more of the reservoirs would be part of the long-term comprehensive plan to restore ecological health and improve water management of the Bay-Delta. The five (5) surface storage investigations are: Shasta Lake Water Resources Investigation, In-Delta Storage Project, Upper San Joaquin River Basin Storage Investigation, North-of-the-Delta Offstream Storage, and Los Vaqueros Reservoir Expansion.

11.2.3.6 Surface Storage – Regional/Local

Surface storage is the use of reservoirs to collect water for later release and use. Surface storage has played an important role in California where the pattern and timing of water use does not always match the natural runoff pattern. Most California water agencies rely on surface storage as a part of their water systems. Surface reservoirs can be formed by building dams across active streams or by building off-stream reservoirs where the majority of the water is diverted into storage from a nearby water source.

11.2.4 Improve Water Quality

11.2.4.1 Drinking Water Treatment and Distribution

Drinking water treatment includes physical, biological, and chemical processes to make water suitable for potable use. Distribution includes the storage, pumping, and pipe systems to protect and deliver the water to customers.

11.2.4.2 Groundwater/Aquifer Remediation

Groundwater remediation involves extracting contaminated groundwater from the aquifer, treating it, and discharging it to a water course or using it for some purpose. It is also possible to inject the treated water back into the aquifer. Contaminated groundwater can result from a multitude of sources, both naturally occurring and anthropogenic. Examples of naturally occurring contaminants include arsenic, high TDS, and high salinity from specific geologic formations or conditions. Groundwater can also be contaminated from anthropogenic sources with organic constituents, inorganic constituents, and radioactive constituents from many point and non-point sources. These anthropogenic sources include industrial sites, mining operations, leaking tanks and pipelines, landfills, impoundments, dairies, agricultural and storm runoff, and septic systems. Some groundwater concerns within the Region are dealt with via blending of supplies.

11.2.4.3 Matching Quality to Use

Matching water quality to water use is a management strategy that recognizes that not all water uses require the same quality water. One common measure of water quality is its suitability for an intended use, and a water quality constituent is often only considered a contaminant when that constituent adversely affects the intended use of the water. High quality water sources can be used for drinking and industrial purposes that benefit from higher quality water, and lesser quality water can be adequate for some uses, such as irrigation. Further, some new water supplies, such as recycled water, can be treated to a wide range of purities that can be matched to different uses.

11.2.4.4 Pollution Prevention

Pollution prevention can improve water quality for all beneficial uses by protecting water at its source, reducing the need and cost for other water management and treatment options. By preventing pollution throughout a watershed, water supplies can be used, and re-used, for a broader number and types of downstream water uses. Improving water quality by protecting source water is consistent with a watershed management approach to water resources problems.

11.2.4.5 Salt and Salinity Management

Salt and salinity management has been a long-term problem needing to be addressed as salts have been mismanaged where irrigation has been used. The CVRWQCB has stated, “The greatest long-term problem facing the entire Tulare Lake Basin is the increase of salinity in ground water” (2018). Salt in imported water supplies such as the SWP and CVP is the major source of salt which circulates throughout the groundwater in Kern County. An estimated 1,200 tons of salt is annually imported to the region and because the Tulare Lake Hydraulic Region does not have any natural outlets, the salt builds up and remains in the underlying aquifers. High salt concentrations (e.g., greater than the primary drinking water standard) are a particular problem in the western portion of the Region. DWR and other federal, state and local agencies continue to study alternative approaches for salt management.

11.2.4.6 Urban Runoff Management

Urban runoff management is a broad series of activities to manage both stormwater and dry weather runoff. Dry weather runoff occurs when, for example, excess landscape irrigation water flows to the storm drain. Urban runoff management is linked to several other resource strategies including pollution prevention, land use management, watershed management, water use efficiency, recycled water, protecting recharge areas, and conjunctive management (combined use of surface and ground water systems to optimize resource use and minimize adverse effects of using a single source).

11.2.5 Practice Resource Stewardship

11.2.5.1 Agricultural Lands Stewardship

Agricultural lands stewardship broadly means conserving natural resources and protecting the environment by land managers whose stewardship practices conserve and improve land for food, fiber, watershed functions, soil, air, energy, plant and animal and other conservation purposes. It also protects open space and the traditional characteristics of rural communities. Further, it helps landowners maintain their farms and ranches rather than being forced to sell their land because of pressure from urban development.

11.2.5.2 Ecosystem Restoration

The California Water Plan defines ecosystem restoration as “improving the condition of modified natural landscapes and biotic communities to provide for the sustainability and for the use and enjoyment of those ecosystems by current and future generations.” The benefits of ecosystem restoration in the Kern Region are numerous, and depending on the type of ecosystem restored, they can include: capturing and storing stormwater, groundwater recharge, flood protection, increasing water supply reliability, wildlife habitat creation, restoration and enhancement, water quality enhancement, flood management, and recreation.

11.2.5.3 Forest Management

Forests in California are used for sustainable production of resources such as water, timber, fish, wildlife, and livestock, as well as outdoor recreation, and almost all forest management activities can affect water quantity and quality. Forest management as a strategy focuses on those forest management activities that are designed to improve the availability and quality of water for downstream users, on both publicly and privately-owned forest lands.

11.2.5.4 Land Use Planning and Management

Land use planning as a strategy generally refers to actions that can be taken by agencies with land use decision-making authority (i.e., cities, counties) to further the objectives set out in this IRWMP to better manage and protect local water and related environmental resources. Land use strategies can include long-range planning goals, objectives, general plan policies, ordinances, regulations, education and outreach programs, etc. Opportunities exist in the Kern Region for increased land use planning efforts such as the enhancement of natural resource protection and efficiency ordinances. Other mechanisms for increased land use planning efforts can include the cities and county providing incentives for private development that promotes features to improve water quality, enhance groundwater recharge, and reduce water demand.

11.2.5.5 Recharge Areas Protection

Recharge area protection includes keeping groundwater recharge areas from being paved over or otherwise developed and guarding the recharge areas to prevent contamination. Protection of recharge areas, whether natural or man-made, is necessary if the quantity and quality of groundwater in the aquifer are to be maintained. Existing and potential recharge areas must be protected so that they remain functional and they are not contaminated with chemical or microbial constituents.

11.2.5.6 Watershed Management

The California Water Plan defines watershed management as "the process of evaluating, planning, managing, restoring and organizing land and other resource use within an area of land that has a single common drainage point." The Kern Region is a good example of a geographical watershed. Managing the water and environmental resources within the Kern Region, as is being investigated through this IRWMP, is a means of watershed management.

11.2.5.7 Sediment Management

Sediment is a valuable resource in the Region if properly managed. Proper management results in multiple water, environment, and economic benefits. Sediment is in limited supply and is a natural resource. Sediment is needed to renew stream habitat and maintain fisheries. Excessive sediment can also impact water supplies by degrading surface water, impact drinking water, impair fisheries, and physically alter a streambed or lakebed habitat, reduce hydraulic capacity of channels, decrease reservoir storage, and increase maintenance costs. Sediment management is closely tied to flood management. A significant benefit of sediment management planning is to reduce negative impacts to ecosystems.

11.2.6 Improve Flood Management

11.2.6.1 Flood Risk Management

Flood management includes minimizing impacts of floods on buildings and farmland, removing obstacles in the floodplain, voluntarily or with compensation, preventing interference with the safe operation of flood management systems, preserving or restoring natural floodplain processes, educating the public about avoiding flood risks and about planning for emergencies, and reducing flooding risks to humans. Opportunities exist in the Kern Region for minimizing flood risk and regional coordination of flood management activities.

11.2.7 People and Water

11.2.7.1 Economic Incentives (Loans, Grants, Water Pricing)

Economic incentives are financial assistance and pricing policies intended to influence water management. For example, economic incentives can influence the amount of use, time of use, wastewater volume, and source of supply. Economic incentives include low-interest loans, grants, and water pricing rates. Free services, rebates, and the use of tax revenues to partially fund water services also have a direct effect on the prices paid by the water users. Governmental financial assistance can provide incentives for resource plans by regional and local agencies. Also, government financial assistance can help water agencies make subsidies available to their water users for a specific purpose.

11.2.7.2 Water-Dependent Recreation

Water-dependent recreation includes a wide variety of outdoor activities that can be divided into two (2) categories. The first category includes fishing, boating, swimming, and rafting, which occur on lakes, reservoirs, and rivers. The second category includes recreation that is enhanced by water features but does not require actual use of the water, such as wildlife viewing, picnicking, camping, and hiking.

11.2.7.3 Outreach and Engagement

Outreach activities performed by water agencies and other organizations are needed in order for the public to engage with policymakers to help make good water management outcomes. Through this process the public contributes insight to decision-makers on the best approaches for water management; adopts water-wise practices; supports activities that result in beneficial water management outcomes; promoting collaboration and interdisciplinary approaches to solving problems; and ensuring access to water management information and decision-making. The overall goal of this outreach and engagement strategy is to develop knowledgeable citizens who participate in public discussion effectively and debate water issues. The Kern IRWMP has been an integral part of this effort.

11.2.7.4 Water and Culture

The Water and Culture resource management strategy recognizes how cultural values, uses, and practices are affected by water management. Expression of cultural connections to water and water-dependent resources can involve a wide range of activities such as subsistence (ex., fishing, hunting), recreation (ex., swimming), spiritual activities (ex., baptisms, medicinal uses, ceremonies), historic preservation and art. In California, there is a strong relationship between Native American Tribes and water. A failure to utilize cultural considerations can have significant cultural and political impacts, which may result in communities delaying projects and/or funding for essential projects. Likewise, cultural activities can help frame and promote needed management decisions. Protecting cultural resources is an integral part to the project planning process and a central requirement under CEQA.

11.2.8 Other Strategies

In addition to the 32 main resource management strategies that this IRWMP evaluates, the California Water Plan highlights other additional strategies that can potentially generate benefits to meet one or more water management objectives. However, these management strategies are currently limited in their capacity to strategically address long-term regional water planning

needs. In some cases, such as Dewvaporation, the strategy involves emerging technologies that will require more research and development. In other cases, such as Crop Idling and Irrigated Land Retirement, they involve voluntary and often temporary tradeoffs from one sector of use to another (i.e., agricultural to urban) that will likely be unpredictable and limited in scope over the time horizon of this California Water Plan Update. Finally, implementation of strategies such as Rainfed Agriculture will have limited applicability in California due to the variability and uncertainty of precipitation patterns within the state from year to year. The California Water Plan provides guidance on these strategies, and stakeholders can go to the DWR website for further information on these topics.

Additional resource management strategies:

- Crop idling for water transfers
- Dewvaporation or atmospheric pressure desalination
- Fog collection
- Irrigated land retirement
- Rainfed agriculture
- Snow fences
- Waterbag transport/storage technology

11.2.9 Strategies Related to Climate Change and GHG Emissions

"No-Regrets" adaptation and mitigation strategies to address the general effects of climate change have been identified for the Kern IRWMP in **Table 10-2**, along with the corresponding IRWMP objectives. Adaptation strategies are developed in conjunction with GHG mitigation strategies, which may overlap. For example, promoting water and energy efficiency are both GHG mitigation and climate change adaption strategies. These strategies fit into the current water management context for the region. Section 16 of the Kern IRWMP contains a detailed assessment of climate change and GHG emissions as it relates to modeled effects in the Region. This section also identifies the vulnerabilities, proposed mitigation and adaption measures, and in general how IRWMP objectives are impacted by climate change.

11.3 Adopted Resource Management Strategies (by Subregion)

The Kern Region is geographically diverse, and the reason why it was appropriate to identify nine (9) subregions within the overall Kern Region, that could focus on their smaller region's issues, needs, characteristics, goals, and IRWMP efforts. Each of the eight subregions were presented with a matrix that included the 26 resource management strategies, and were asked to identify which strategies were applicable and appropriate for their subregion, as well as to identify those top five strategies that were the strongest for their region. A Water Strategy Discussion Guide was also distributed to each subregion to help stimulate discussion of the resource management strategies and related projects. The results are summarized in **Table 11-1**. The table in **Appendix E** demonstrates the relationship of the Region's proposed projects with the California Water Plan strategies.

Table 11-1: Resource Management Strategies by Subregion

County of Kern	KCWA	Greater Bakersfield	Kern Fan	Mountains/ Foothills	North County	South County	West Side
All strategies	All strategies except for: -Desalination -Precipitation Enhancement -Groundwater aquifer remediation	-Agricultural water use efficiency -Urban water use efficiency -Conveyance -Surface Storage -Drinking water treatment & distribution -Recharge area protection -Sedimentation	All strategies	All strategies except for desalination.	-Water transfers -Conjunctive management & groundwater storage -Recycled municipal water -Matching water quality to use -Land use planning & management	All strategies	All strategies except for: -Precipitation enhancement -Matching water quality to use -Urban runoff management -Forest Management -Water-dependent recreation -Watershed management -Flood risk management

11.4 Call for Projects

The manner in which strategies are implemented and objectives are met via the IRWMP process is by project implementation. To identify the many potential projects in the Kern Region and to assess the potential contribution of these projects towards meeting the IRWMP objectives, a "Call for Projects" is performed on an annual or biennial basis. Projects could be submitted at any stage of development. The submittal of a project includes the submission of a project information form, either submitted via electronic mail or facsimile. All projects submitted are listed by subregion in **Appendix F** and the individual forms are provided in **Appendix G**. For certain IRWM grant funding rounds, DWR has required additional documentation be provided for grant eligibility; for these rounds the Kern Region requests this additional documentation from project sponsors interested in pursuing funding for that round.

While many of the projects lack detailed supporting information, the Call for Projects provides a mechanism to engage stakeholders in the process of sharing project information and discussing the issues related to the integration of projects. Stakeholders are made aware that detailed information will be required for each project should a funding opportunity arise that their project would be well suited for. Additionally, the Call for Projects is not a closed process; stakeholders can continually submit projects; there is a process to continually update the list of projects that have already been submitted.

Section 12: Project Priorities and Implementation

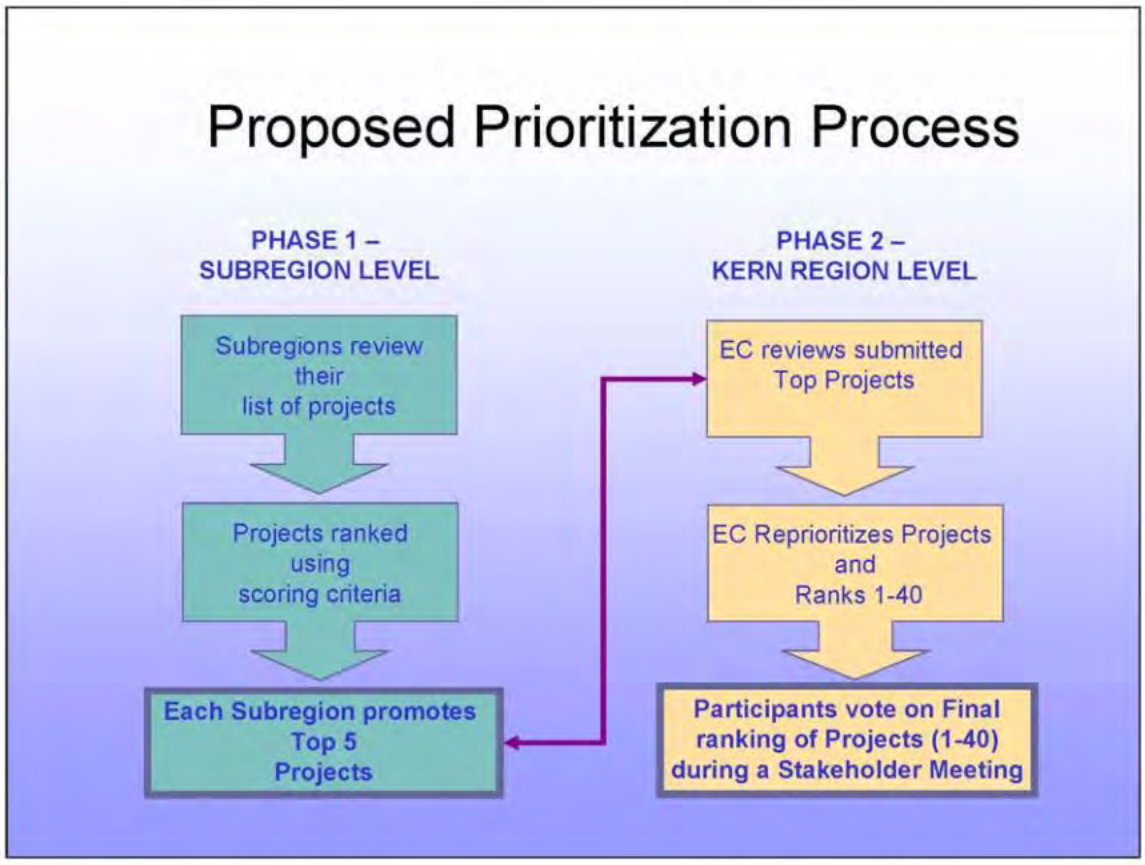
12.1 Project Prioritization Process

The Kern IRWMP will be implemented through the specific studies and actions, projects, and programs proposed by the Regions stakeholders and Participants. In order to identify potential projects that facilitate IRWMP implementation, and during the development of the IRWMP, the RWMG held an open "call for projects." Participants and others were encouraged to submit Project Submittal Forms during multiple Stakeholder meetings and in email correspondence solicitations, throughout IRWMP development. Subsequent to the initial development of the IRWMP, additional "calls for projects" have occurred on an annual or biennial basis. The current Project List is included in **Appendix E** and the Project Submittal Forms are contained in **Appendix F**.

The RWMG and Executive Committee developed a process to prioritize projects, in order to allow the subregions to identify their top ranked projects on a subregional level, with the intent that these projects would then be brought forth to represent the entire Kern Region as the best projects to be put forth in applications for funding. The formal project prioritization process and prioritization criteria are documented in this section and the scoring sheets in **Appendix G**. Any future changes to the project prioritization process will be reflected in amendments to **Appendix G**. The project prioritization process is described below.

Currently, the prioritization of projects is based upon a detailed screening process. The process is two-fold: Phase 1 - Subregion Level and Phase 2 - Kern Region Level (please see **Figure 12-1** for a graphical overview of the process). All projects submitted will remain on the Project list, and the list will be updated on a regular basis as new projects are submitted and as projects are developed through time and re-prioritized.

Figure 12-1: Prioritization Process



12.1.1 Introduction of Prioritization Concept

At the sixth stakeholder meeting in April 2009, the prioritization process was introduced to the RWMG and the larger Stakeholder group. The process was designed to meet two separate but related objectives: (1) to enhance and develop projects in order to meet regional objectives; and (2) to select the best suite of projects in order to maximize funding opportunities for the Region.

Examples of prioritization processes from other IRWMP Planning Regions were presented to the group for discussion in order to determine the important criteria by which the stakeholders wanted to have their projects evaluated. Due to the complexity of the issue, the discussion carried over to a second stakeholder meeting held in June 2009.

Some of the questions that were asked during these meetings included:

- Will it be possible to modify the ranking of projects, if those projects are later modified?
  Yes, as new elements are included in projects as a result of new partnerships or other factors, then re-evaluation of projects will definitely occur at the next round of the prioritization process.
- What does it mean, “How well does the project use sound scientific basis for data acquisition and project management?”

Do you have data to document the proposed benefits of your project, such as quantifiable baseline or historical data?

- Would it be possible to rank projects more in accordance with the regional objectives developed by the stakeholders, as those objectives are focused on the most critical problems in our region, rather than rely so heavily on the State objectives?

  The State objectives come from other planning documents and legislation, and so they must be taken into account in addition to the regional objectives. The idea is that regional objectives should help to address statewide problems.
- Do we know how similar projects from different IRWMPs will compete against each other, especially if one is ranked higher in one IRWMP than they are in another?

  DWR will be assessing the overall quality of each IRWMP, and not compare just the individual projects contained in each IRWMP.

In response to these and other questions and comments, an all-day project prioritization process workshop was proposed to handle all remaining questions and to finalize the prioritization criteria.

12.1.2 Project Scoring Criteria

The project prioritization criteria were initially developed at a focused workshop held in June 2009 and subsequent working sessions. They were finalized and adopted in September 2011. The proposed criteria are presented in the form of a two-tier, four-part matrix (provided in **Appendix G**):

- Tier 1 – Tier 1 criteria evaluate the projects' applicability to objectives as well as benefits. By evaluating projects based on these criteria, proposed projects will be consistent with the Statewide Priorities, as discussed in Section 1.6.
  - Part 1 – Kern IRWMP Objectives – these are the primary objectives developed by participants during the initial Stakeholder meetings and subsequently finalized by Executive Committee. These are the first and most important criteria that the proposed projects should address.
  - Part 2 - State IRWMP Program Preferences – These are criteria that DWR identifies in IRWMP funding rounds.
  - These criteria also consider whether the projects address Climate Change effects, AB 32 concerning GHG emissions, and water use efficiency legislative requirements.
  - Part 3 – Statewide Priorities – these are criteria that DWR identified in previous IRWMP Rounds and which may be used to evaluate funding applications.
- Tier 2 – Tier 2 criteria evaluate the projects' readiness for grant funding.
  - Part 4 – Criteria for Grant Applications – these are criteria that are derived from previous grant applications for IRWMP funding-related programs. Specifically, a project will be evaluated for the technical feasibility of a project, the analysis of project costs and financing, the economic feasibility, and how well developed the project is in relation to other high priority projects. Other considerations discussed in Section 12.1.3 below are also factored into the prioritization. Also, in recent funding rounds additional application documents have been required by

DWR; Project Sponsors have been required to submit applicable forms for consideration in these funding rounds.

A project would be scored depending on how well it contributed, or benefited, each criterion. The following simple system of points was used:

- 0 Points – Criteria does not apply
- 1 Point – Criteria may apply/need more information
- 2 Points – Criteria partially applies
- 3 Points – Criteria fully apply

12.1.3 Other Project Prioritization Considerations

In addition to the prioritization criteria discussed above, there are other special considerations that are made regarding how the Kern Region scores and ranks projects discussed below.

12.1.3.1 Critical DAC Water Issues

CWC 10540.(c)(7) states that identification and consideration of water-related needs of DACs in the Region must be addressed in the IRWMP. Regarding project prioritization, projects that address critical water needs of a DAC are to be promoted in the project selection process. Therefore, the Kern Region's Tier 2 selection process includes additional points for a project that meets critical DAC water issues. The higher-ranking DAC projects are considered by the Executive Committee in their prioritization process. In fact, the prior 3 implementation grant cycles included 1 to 3 projects that directly benefited a DAC.

12.1.3.2 Critical Water Issues for Native American Tribal Communities

Projects that benefit a critical water issue for a Native American Tribal community are also promoted in the prioritization process in a similar manner to the DAC discussion above.

12.1.3.3 Environmental Justice Considerations

Additional consideration in the project ranking is provided if a project addresses an environmental justice concern as discussed in Section 1.4.2. Should a project identify a potential concern that is being addressed, the prioritization process will review the project for consideration as a potential high priority project.

12.1.3.4 Adapting to the Effects of Climate Change

To ensure that climate change evaluation is part of the project review, the Project Submittal Form has been updated to include a discussion of how the project assists in adapting to the effects of climate change. Also, under the Tier 2 prioritization process, points are awarded for how well a project assists in adapting to the effects of climate change. Specifically, the prioritization will consider how well a project addresses the following:

- *Adaptation to the amount, intensity, timing, quality and variability of runoff and recharge that are caused by the effects of climate change;*
- *Adaptation to the effects of sea level rise that impacts water supplies;*
- *Adaptation of systems that are vulnerable to climate change effects in the region; and*
- *Overall adaptation of the water management system.*

12.1.3.5 GHG Reduction

The Project Submittal Form has also been updated to include a discussion of how a project reduces GHG emission. Under the Tier 2 prioritization process, points are awarded for how well a project addresses GHG reduction in comparison to other project alternatives. Specifically, points will be awarded based on the following items:

- *Project's estimation of GHG emission reduction in comparison to other project alternatives,*
- *Project's overall GHG emission reduction over a 20-year period,*
- *Project's estimation of energy use reduction.*

12.1.3.6 Reduce Reliance on the Delta

Lastly, projects will be evaluated based on how it helps reduce its dependence on the Sacramento-San Joaquin Delta water supply. An additional point is awarded for a project that meets this requirement under the Tier 2 Prioritization Process.

12.1.4 Project Lists

The projects will be grouped into the following four (4) project lists, based on the project scores.

1) Master Project List:
   a) The Master Project List includes all projects submitted to the Kern IRWMP.
   b) The Master Project List is a non-scored list of projects.
   c) Any member of the Kern IRWMP Stakeholder Group, as defined in the Kern IRWMP Governance Structure, may submit a project for inclusion on the Master Project List by completing a Project Submittal Form (presented in **Appendix G**).
   d) Projects may be added to or removed from the Master Project List at any time.
2) High Priority List:
   a) The High Priority List consists of the top 5 projects from each subregion, as determined by the Project Prioritization Process.
   b) The High Priority List is an unranked list.
   c) The High Priority List will be updated on an annual or biennial basis.
3) Moderate Priority List:
   a) The Moderate Priority List consists of all projects not included on the High Priority List, that receive more than 50 percent of the points available on the Tier 1 Scoring Matrix (presented in **Appendix G**), as determined by the Project Prioritization Process.
   b) The Moderate Priority List is an unranked list.
   c) The Moderate Priority List will be updated on an annual or biennial basis.
4) Low Priority List:
   a) The Low Priority List consists of all projects not included on the High Priority List, that receive less than 50 percent of the points available on the Tier 1 Scoring Matrix, as determined by the Project Prioritization Process.
   b) The Low Priority List is an unranked list.
   c) The Low Priority List will be updated on an annual or biennial basis.

These lists are combined into an overall table that is provided in **Appendix H**.

12.1.5 Project Prioritization Steps and Timeline

Project prioritization will occur on an annual or biennial basis (depending upon grant funding cycles) and will follow a two-tiered process, based on the above scoring criteria.

1. Project Prioritization Process:
    a. The Project Prioritization Process will be completed on an annual or biennial basis.
    b. All projects on the Master Project List at the time of the Project Prioritization Process will be prioritized.
        i. Projects submitted after the Project Prioritization Process will be eligible for prioritization during the subsequent year's Project Prioritization Process.
    c. Only prioritized projects, subject to the terms described in this section, will be eligible for IRWM program grant funding.
    d. Project prioritization will follow a two-tiered process.
    e. Tier 1 Prioritization:
        i. Each subregion, as defined in the Kern IRWMP Governance Structure, will score all projects physically located within the subregion. 1) Projects may only be scored in one subregion. Projects physically located in more than one subregion will be scored in the subregion in which a majority of the project lies.
        ii. All projects will be scored using the Tier 1 Scoring Matrix (presented in **Appendix G**). One Project Scoring Matrix will be completed for each project and submitted to the Executive Committee, or its designee, for record keeping purposes.
        iii. The top five (5) projects from each subregion will be placed on a High Priority List. The High Priority List is an unranked list and will not include the project scores.
        iv. Of the remaining projects, projects receiving more than 50 percent of the points available on the Tier 1 Scoring Matrix will be placed on the Moderate Priority List. Projects receiving less than 50 percent of the points available on the Tier 1 Scoring Matrix will be placed on the Low Priority List.
    f. Tier 2 Prioritization:
        i. Tier 2 Prioritization will be used to select project(s) for IRWM program grant funding.
        ii. Tier 2 Prioritization will be completed prior to the submission of each IRWM program grant application.
        iii. Only projects on the High Priority List that meet the grant requirements, as defined in the grant proposal solicitation package including required DWR application forms, will be eligible for Tier 2 Prioritization, unless the grant funds available exceed the funding requirements of the eligible projects on the High Priority List.

1. If the grant funds available exceed the funding requirements of eligible projects on the High Priority List, eligible projects on the Moderate Priority List will be eligible for Tier 2 Prioritization.
2. If the grant funds available exceed the funding requirements of eligible projects on the High and Moderate Priority Lists, eligible projects on the Low Priority List will be eligible for Tier 2 Prioritization.

iv. Tier 2 Prioritization will be completed by the Executive Committee using the following steps:

1. The project proponent of an eligible project must submit in writing to the Executive Committee, or its designee, documentation authorizing the project proponent to proceed with a grant application.
    a. The authorization must:
        i. Designate a point of contact; and
        ii. Document the availability of or ability to acquire matching funds, as defined by the grant proposal solicitation package.
    b. If completion of the project requires the contribution of goods, services and/or funding from a partnering entity, authorization to proceed from the partnering entity must also be submitted in writing to the Executive Committee or its designee.
2. Projects that are authorized to proceed will be scored by the Executive Committee using the Tier 2 Scoring Matrix (presented in **Appendix G**).
3. The top-ranking project(s) will be selected to proceed with an IRWM program grant application.
    a. The number of projects selected to proceed with an IRWM program grant application will be based on the grant proposal solicitation package and the total amount of grant funding available. The top-ranking DAC/tribal projects will be considered by the Executive Committee to proceed with an application if the grant proposal solicitation package has DAC preference scoring criteria.
4. If two or more projects receive the same score and either the grant proposal solicitation package or the amount of funding available does not allow all of the projects to apply for grant funding, the Executive Committee will break the tie by rescoring each project using the Tier 1 Scoring Matrix. The project(s) receiving the highest score(s) will be selected to proceed with an IRWM program grant application.

2. Removal of a Project:
    a. Projects may be removed from any of the four project lists at any time by request of the project proponent.
    b. Projects may be removed from Tier 2 Prioritization at any time by request of the project proponent.

c. To remove a project, the project proponent must submit a written request for removal to the Executive Committee or its designee. The request for removal must include: the project title, consent to remove the project from all project lists and/or the Tier 2 Prioritization and the reason for removal of the project.
d. It is the project proponent's sole responsibility to notify any and all partnering entities of the removal of the project from either the four project lists or the Tier 2 Prioritization.

12.1.6 Selected Plan Projects

The result of the prioritization process as described above, is the list of prioritized projects for the Kern IRWMP. This combined project list is provided in **Appendix H**. The list of prioritized projects will be updated through the project prioritization process on an on-going basis.

12.2 Integration of Resource Management Strategies

CWC § 79501 states the following:

> *The people of California find and declare that it is necessary and in the public interest to do all of the following…*
>
> *Establish and facilitate integrated regional water management systems and procedures to meet increasing water demands due to significant population growth that is straining local infrastructure and water supplies.*
>
> *Improve practices within watersheds to improve water quality, reduce pollution, capture additional storm water runoff, protect and manage groundwater better, and increase water use efficiency.*
>
> *Protect urban communities from drought, increase supplies of clean drinking water, reduce dependence on imported water, reduce pollution of rivers, lakes, streams, and coastal waters, and provide habitat for fish and wildlife.*

Integrated regional water management planning meets this intent by encouraging broad evaluation of watershed related issues as well as identification of projects to address these needs. Integrated regional water management planning solicits the input and expertise of various groups, including water agencies, flood control agencies, local planning entities, conservancies, sanitation districts, business organizations, tribes, open space and recreation interests, and habitat preservation interests. One of the benefits of this planning process is that it brings together this broad array of groups into a forum to discuss and better understand shared needs and opportunities. This format assures that a full range of issues and needs are considered. It also ensures that an extensive range of expertise is used to evaluate projects and identify means to improve and integrate projects.

Examples of integration took place in the Kern IRWMP process at the subregion level. The Phase I project prioritization process allowed for the opportunity to present support for projects, to discuss the merits of the projects with the subregion participants, and to discuss how projects could potentially be combined to create more regional, comprehensive, and logistically beneficial and efficient projects. Additionally, at the Phase I level, some subregions found that

their projects could be combined to provide greater benefit to the Region. They collectively modified versions of their projects that they felt better integrated with the goals and objectives of the Kern Region as well as other projects. The best example of this comes from the Kern Fan subregion where eight (8) individual projects were combined into one collective project, the Kern Fan Area Groundwater Recharge and Recovery Project.

12.3 Advantages and Benefits of Plan Implementation

There are many advantages to preparing a regional plan as opposed to implementing isolated local efforts. Regional planning provides a means to maintain, protect, and restore natural resources within the Kern Region while also enhancing the quality of life for residents in the Region. The Kern IRWMP provides a means to support environmental protection, quality of life issues, and economic development using the watershed boundary as the planning framework. This IRWMP allows for stakeholders in the community to join together in creating a vision for water resources in the Kern Region.

In creating the opportunity for collaboration, this IRWMP process facilitates the establishment of partnerships between local and state governments, community organizations and any other groups with the common goal of protecting water resources within the Kern Region. It is through the IRWMP process that community efforts can be coordinated to create a regionally focused plan to more efficiently reach the identified objectives and goals. Moreover, preparation of a regional plan allows for the communities to address water supply, water quality, flood management, and environmental and land use issues within the physical boundaries of local watersheds rather than political boundaries.

The environmental benefits of preparing this IRWMP are clear: enhanced water supply reliability, improvements in water quality, protecting natural habitats and open space areas for their water resource function, controlling flooding and maintaining community culture and land uses. The community benefits are, however, even more important in the Kern Region. This is exemplified by the coordination and collaboration of the subregions, which was formed for the purposes of carrying out this IRWMP. The fact that the subregions, the Executive Committee, and all the stakeholders who participated in the planning of this IRWMP, have come together to develop an action plan to address their concerns over water resources in the Kern Region, is an exemplary contribution to water management for the future.

12.3.1 Benefits of Plan Implementation

The primary benefit of the Kern IRWMP is development of a process and framework supportive of collaborative regional planning. This IRWMP allows Stakeholders in the community to create a vision for watershed planning in the Region and identify appropriate means to achieve this vision. Creation of the IRWMP has facilitated partnerships between local, State, and Federal entities.

For example, several of the projects proposed in this IRWMP are being jointly sponsored by multiple local entities. The IRWMP process fosters coordination, collaboration and communication among entities in the Region and has resulted in greater efficiencies (e.g., efforts are not duplicated, information is shared), will enhance public services, and will facilitate public support for watershed projects. As part of preparing this IRWMP, the regional agencies have provided input as to their ongoing research and data collection projects. Knowledge of these research and data collection projects assists other agencies from duplicating efforts.

Efficiencies have also been achieved by cooperating on regional efforts rather than separate localized efforts.

A regional planning effort ensures that all potential components of watershed planning are considered rather than one particular area or project type dominating. Regional planning improves the likelihood that benefits and impacts are shared instead of one group or area reaping the benefits while another bears the impacts. Regional planning efforts also increase the likelihood that projects that implement one particular objective (e.g., water supply) are considerate of other objectives (e.g., flood control or habitat preservation). As part of project integration, projects can be refined so that they achieve multiple objectives and benefits.

The IRWMP will allow otherwise separate agencies to speak as a region and to improve policies, regulations and laws related to water demand, water supply, water quality, operational efficiency, and resource stewardship. The range of projects identified by this IRWMP meets all objectives identified by the Stakeholders:

- Increase water supply
- Improve operational efficiency
- Improve water quality
- Promote land use planning and resource stewardship
- Improve regional flood management

Full implementation of this IRWMP will result in multiple benefits associated with these objectives. In addition, the IRWMP will provide for the following specific benefits through implementation of these projects:

- Water Supply Projects. The majority of projects submitted by Stakeholders relate to water supply, particularly storm water capture, groundwater recharge, and development of recycled water supplies. Storm water capture and subsequent groundwater recharge provides for increased use of local supplies rather than imported water. These projects assist in maintaining the long-term sustainability of the groundwater supply. Depending on project specifics, these projects can also serve to decrease peak flood flows and provide opportunities for habitat improvement and restoration. Recycled water supplies, likewise, offset demand for imported water. Recycled water can be used to offset potable water demand, recharge groundwater basins, and create and restore wetland areas.
- Operational Efficiency Projects. Several projects are proposed to improve water infrastructure, including projects for intertie improvements, distribution system expansions, consolidation of mutual water companies, and projects to replace outdated and poorly functioning infrastructure. These projects have benefits related to reduced maintenance costs and decreased system water loss. For example, in the case of the sewer relocation project (project #CK-8), a primary water quality benefit would be the reduced risk of damage to the sewer and potential for a sewage spill. As another example, consolidation of mutual water companies (project #KR-1), would result in economies of scale and would ensure each connection is metered (thus encouraging water conservation). In addition, projects which improve operational efficiency can reduce GHG emissions by reducing energy use and system losses, thereby providing climate change mitigation benefits.

- Water Quality Improvement Projects. Projects that affect water quality include installation of surface water quality monitoring stations, treatment of arsenic or 1,2,3-TCP, and enhancement of secondary treatment of wastewater treatment plants to tertiary treatment. The primary benefit from implementing these water quality projects would be the reduced potential for human exposure to potentially harmful substances. These projects would also improve the efficiency of both water and wastewater treatment processes. Besides improving drinking water, these projects could potentially benefit other types of water users, such as agricultural water users and water dependent wildlife habitat.
- Land use planning and resource stewardship Projects. Representative projects that address land use planning and resource stewardship include the Cuddy Creek restoration project (project #CK-9), and invasive weed control project on the South Fork Kern River (Project #KR-4). These projects can also reduce flooding impacts by removing obstructions in streams that could result in significant erosion and damage to public facilities.
- Flood Management Projects. Projects that would benefit the IRWMP's flood management objectives include stormwater control projects (project #WS-6, #SC-21), weed control on the Kern River (project #KR-4), retention and detention studies (project #CK-2). These types of projects help to reduce flooding and plan for runoff events within the watershed context rather than on an isolated basis.

12.3.2 Plan Beneficiaries

The potential beneficiaries of the Kern IRWMP are the residents of the Region and Stakeholders represented by the Executive Committee, and include: water agencies, local, State and Federal agencies, businesses, water purveyors, wildlife and associated habitats, the agricultural/farm industry, the general public, and others within the jurisdictions served by IRWMP projects. These beneficiaries are represented by members of the Executive Committee, and the larger RWMG.

Potential benefits and impacts from Plan implementation are summarized in **Table 12-1**.

12.3.3 Interregional Benefits

Coordination with and recognition of potential nexus with adjacent IRWMPs prepared by other Regions, if appropriate, is important to the Kern IRWMP, and the most direct way to maximize interregional benefits. The Kern Region is adjacent to eight other existing or developing IRWMP planning regions: Poso Creek, Southern Sierra, Inyo-Mono, Antelope Valley, Upper Santa Clara River, the Watersheds Coalition of Ventura County, Santa Barbara, and San Luis Obispo (see **Figure 1-3**). Overlapping areas exist with three of the other Regions: 1) San Luis Obispo, 2) Antelope Valley, 3) Poso Creek, and 4) Fremont Basin.

For example, it may be that issues of importance to the entire Tulare Lake Hydrologic region, or to the San Joaquin Valley as a whole, could be addressed by linking multiple IRWMPs to solve common problems. Linkage of these IRWMPs will provide mutual benefits and potential joint funding partnership opportunities for entities within the Tulare Lake Hydrologic Region. It is anticipated that there will be opportunities to link the Kern IRWMP to plans from other adjacent areas. To enable such linkage to other IRWMPs, the geographic area and stakeholders for this IRWMP are broadly defined.

TABLE 12-1: Plan Implementation Benefits and Impacts

Program	Within the Kern Region		Inter-regional	
	Potential Benefits	**Potential Impacts**	**Potential Benefits**	**Potential Impacts**
Water Conservation	-Increase water supply availability -reduce energy usage -reduce equipment and chemical usage -reduce runoff -reduces GHG emissions	-reduced revenue from conservation -staff training is needed -reduced recharge -wastewater treatment plants affected	-water transfers can be benefited -reduce dependency on imported water	-reduction of recharge water available
Water Supply Enhancement	-inreased supplies and reliability -reduced dependence on imported water -wetland restoration -recharge & subsidence mitigation -improved groundwater quality	-project impacts evaluated in CEQA -increased pumping costs -impacts to other facilities -land use dedicated to water projects -reduced GHG emissions	-groundwater supply increased -drought relief -increased employment -water quality improved	-reduced downstream flows -reduced imported water in some cases
Water Quality Improvements	-reduced exposure to pollutants -improved water recreation and habitat -water treatment -address DAC and EJ issues -protect public health	-project impacts evaluated in CEQA -increased treatment and O&M costs -concentrated contaminant disposal	-reduce contaminants in aquifer	-additional operations staff are needed
Watershed Rehabilitation	-water quality improvmeent -water recreation -flood mitigation -climate change mitigation	-project impacts evaluated in CEQA -downstream impacts	Kern Region benefits apply	Kern Region impacts apply
Resource Stewardship	-improve habitat quality -reduced erosion -reduced fire risk -improved water supply and quality	-project impacts evaluated in CEQA -downstream impacts -lose of urban uses of land and revenue	Kern Region benefits apply	Kern Region impacts apply
Flood Management	-improve habitat quality -reduced erosion -improved recharge -reduced risk to property and persons -climate change mitigation	-project impacts evaluated in CEQA -lose of wetlands -permitting timeline and costs -land use restrictions	-reduced downstream flooding -reduced recovery costs	-downstream impacts
DAC, Tribal, and EJ Concerns	-reduced costs for community -improved health and life of people -protection of habitat -community improvements	-temporary construction impacts -other impacts discussed above depending upon the project type.	-reducing community impacts	-none

12.4 Impacts of Plan Implementation

The IRWMP Guidelines require an evaluation of potential negative or adverse impacts within the Kern Region and in adjacent areas from implementation of the IRWM Plan projects. Negative impacts that may be associated with implementing the submitted projects include (1) short-term, site specific impacts related to site grading and construction, and (2) long-term impacts associated with project operation. For the purposes of this IRWMP, impacts are discussed at a screening level below.

It has been determined that the IRWMP itself is exempt from CEQA, The IRWMP itself does not lead to the implementation of any specific project. Project-specific and/or programmatic environmental compliance processes (consistent with CEQA and, if applicable, the National Environmental Policy Act) will evaluate the significance of the impacts. Under CEQA, impacts determined to be significant must be mitigated to a level of non-significance (unless the lead agency makes findings of overriding consideration).

CEQA review of specific projects will provide an evaluation of impacts in much greater detail than discussed below:

- Aesthetics. Projects that include construction activities and new infrastructure have the potential to affect aesthetics. However, it is likely that projects would be constructed in areas that are already disturbed or would include mitigation measures that would return disturbed areas to their pre-construction conditions.
- Air Quality. Short-term air quality impacts could result from construction of the projects. However, through the CEQA process potential air emissions would be minimized through application of BMPs identified by the air quality management district or mitigation measures. GHG emissions are also required to be studied and calculated using the California Emissions Estimator Model (CalEEMod).
- Biological Resources. Short-term biological impacts could result from construction activities as well as non-native plant removal. Long-term biological impacts could result from on-going operations of a project. Most of these negative effects would be avoided or minimized through mitigation efforts related to CEQA. Additionally, the IRWMP includes preservation of ecosystem health as one of its objectives. Thus, if implemented, projects could result in overall benefits to biological resources.
- Cultural Resources. Impacts to cultural resources (historical, archeological, and paleontological resources) could result from construction activities from the projects. As part of the CEQA process it will be necessary to develop mitigation measures to avoid or minimize these potential impacts.
- Geology and Soils. Projects with the potential to impact geologic resources would be required to undergo geological feasibility studies which would specify the appropriate engineering standards the contractor would have to comply with during construction. Compliance with these standards would mitigate project site geological and soil impacts.
- Hydrology and Water Quality. It is anticipated that impacts to hydrology and water quality would be generally beneficial because in the long-term projects are intended to improve water supply reliability and water quality. For short-term erosion or sedimentation, project specific BMPs would be identified as part of the National Pollutant Discharge Elimination System (NPDES) permitting process. Several projects proposed in this IRWMP are groundwater recharge projects using either storm water or recycled water.

Because recycled water generally contains more salts than other water sources in the Kern Region, recharge with recycled water could increase the salinity of the local groundwater. This issue merits particular analysis in project specific CEQA documentation.

- Land Use and Planning. Projects were evaluated as to their compatibility with other planning documents for the Kern Region, including local and regional General Plans. Therefore, no significant land use changes or inconsistencies with policies are anticipated.
- Noise. Noise impacts could result from construction activities from some of the proposed projects. However, through the CEQA process most of these activities would be minimized through mitigation efforts and no long-term noise impacts are expected.
- Population and Housing. No adverse impacts to population and housing are anticipated. IRWMP implementation would help to meet the water demands of the existing and anticipated future population.
- Public Services and Utilities. Many of the projects are intended to enhance water supply, water quality, and improve storm water management and flood control. These types of projects would benefit the utilities and service systems in the Kern Region.
- Recreation. One of the objectives of the IRWMP is to preserve and enhance water dependent recreation. Therefore, impacts to recreation from IRWMP implementation are likely to be beneficial.
- Transportation and Circulation. Transportation and circulation could be temporarily impacted during construction of some of the projects. Construction can temporarily increase traffic congestion due to transportation of equipment and trips by workers. Construction of projects located near roadways can result in temporary lane closures and detours. However, through the CEQA process most of these activities would be avoided or minimized and no long-term transportation and circulation impacts are expected.

12.4.1 Impacts to Energy

The Kern Region has a variety of efforts planned to reduce water consumption and energy use, and to develop local energy supply sources. These efforts include water conservation, recycled water use, and utilization of renewable resources, such as WWTP digester gas recovery, hydropower, and solar power. The reduction of water use will also reduce energy usage, as the treatment and distribution of water supply is an energy intensive activity. In addition, the development of local recycled water supplies will reduce the need for imported water and the associated uses of energy to transport that supply. These projects, in conjunction with the development of local renewable energy sources, will provide environmental benefits through reduction of GHG emissions as well as the reduced need for utility transmission and distribution facilities. Through implementation of these projects and the Kern IRWMP, there is the potential for an overall benefit to energy resources within the Kern Region.

12.4.2 Other Impacts

The IRWMP Guidelines require an evaluation of potential negative or adverse impacts from implementation of the IRWMP projects, specifically including those directly affecting DAC, and Environmental Justice related concerns, and Native American tribal communities, and including the benefits of environmental stewardship. The net result of the IRWMP projects is to improve

water reliability, water quality, and enhance resources stewardship. These actions have broad benefits to all groups participating in the IRWMP. Implementation of the high priority strategies identified by this plan is unlikely to unduly burden a specific minority group or DAC.

12.5 Institutional Structure for Plan Implementation

The RWMG and Stakeholder Group discussed in a number of stakeholder meetings the type of governance structure that will be needed to sustain the Kern IRWMP in the years following the completion and approval of the IRWMP. The following summary shows the existing governance structure provided for in the Participation Agreement signed in 2008. The Participants and Executive Committee will use this dialogue to continue discussions about regional planning and changes to the IRWMP over the long term.

12.5.1 Governance Structure

The Governance Structure based on the Participation Agreement established the Kern RWMG and prescribed the preliminary roles and responsibilities for the RWMG. The members of the RWMG that signed the Agreement in October 2008 are referred to as “Participants”. RWMG Participants are involved in the decision-making process during development of the Kern IRWMP by each having one vote, and a vote of approval is required by a majority of Participants. The formal Governance Structure is documented in **Appendix I**. Any future changes to the Governance Structure will be reflected in **Appendix I**.

Currently, this type of governance (MOU-based) is voluntary on the part of the signatories to the MOU and relies on the members of the RWMG to choose to collaborate. Efforts continue to be made for outreach and to dispense information about the planning activities associated within this region. As part of the governance, a stakeholder group has been incorporated thus allowing any entity to participate in the IRWMP process. In addition to stakeholders and the RWMG, an Executive Committee has been formed. This group is a composite of 10 stakeholders representing the various regions and represents the working group of the RWMG. The current Executive Committee is shown on the Kern IRWMP website at http://www.kernirwmp.com/aboutus.html. The Kern IRWMP participants are provided in **Table 1-1**.

The same level of effort required to develop the IRWMP will not be required to administer the IRWMP. Consultant support will be available as an option, however, at a minimum, 10 to 12 hours monthly will be required to manage the administrative activities required to sustain the IRWMP. Administrative activities include a wide variety of activities, including administrative services, website management, document production, meeting preparation, funding program tracking, etc. This governance structure proposes that the Executive Committee assumes the responsibility for administration of the IRWMP, which will require consideration of staffing either in-house, through in-kind services, or through hiring of an outside consultant.

Section 13: Finance Plan

13.1 Funding of the IRWM Plan

Initial funding for the Kern IRWMP effort was provided by the Kern RWMG Participants through the MOU. Kern RWMG Participants have also funded periodic IRWM Plan Updates to revise project information, revise project priorities, and as necessary to maintain compliance with DWR requirements. Future funding will be needed to implement all of the projects proposed in this IRWMP as well to sustain the Kern IRWMP into the future. There are opportunities for grant and low interest loan funding that are available to the stakeholders in the Region that are well suited to many of the projects in this IRWMP. Sources of implementation funds may include: appropriations, grants, loans, water and wastewater general funds, capital improvement funds, general funds from local cities, county departments, private organizations, member dues, etc. Local taxpayers may also fund these projects through rate increases, bond measures, and tax increases.

This section identifies the various funding sources and their associated requirements and guidelines to assist with implementation of the Kern IRWMP projects.

13.2 Appropriations

Funding for large projects can be obtained through federal or state earmark appropriation. Appropriations require extensive political support and effort and can take many years, even in the most favorable political and economic climates. Local agencies have been successful with obtaining appropriations through the U.S. Environmental Protection Agency (EPA), State and Tribal Assistance Grants (STAG), as well as Title XVI Grants through the United States Bureau of Reclamation (Reclamation or USBR). Budget challenges and competing priorities still exist at both the state and federal level that continue to make obtaining future appropriations difficult. However, given the length of time necessary, it may be prudent for the Kern IRWM Group collectively, in smaller groups, and/or as individual agencies to initiate efforts to seek a federal and/or state funding appropriation.

13.2.1 **EPA's Safe Drink**ing Water on Tribal Lands Program

Website: https://www.epa.gov/tribaldrinkingwater

This is an opportunity for tribal governments, tribal utilities, and tribal members to have EPA work collaboratively with them to implement the Safe Drinking Water Act (SDWA). The goal of this collaboration is to improve access to safe drinking water on tribal lands.

13.2.2 Water Resources Development Act (WRDA) 2018

Website: https://www.usace.army.mil/Missions/Civil-Works/Project-Planning/Legislative-Links/wrda_2018/wrda2018_impguide/

The USACE receives appropriations for water projects primarily through its Environmental Infrastructure program. Projects are authorized through the Water Resources Development Act which is generally enacted every two years. Under this program, the local sponsor provides

matching funds to the USCOE appropriation and USCOE executes the program. For investigations, the local sponsor's matching share is 50 percent and for design and construction the local sponsor matching share is 25 percent. The Water Resources Development Act of 2018 is comprehensive legislation that was signed into law as Title I of the America's Water Infrastructure Act by President Trump on October 23, 2018. WRDA addresses water infrastructure needs critical for the Nation's economic competitiveness and domestic security. The USACE develops implementation guidance for WRDA provisions in coordination with the Assistant Secretary of the Army for Civil Works.

WRDA is strictly authorizing legislation. The funding to implement authorized studies, projects, and activities is provided separately through the annual appropriations budgetary process.

13.2.3 USBR Title XVI WIIN - Water Reclamation and Reuse

Website: https://www.usbr.gov/watersmart/title/

Title XVI of P.L. 102-575, as amended (Title XVI), provides authority for Reclamation's water recycling and reuse program, titled "Title XVI." Through the Title XVI program, Reclamation identifies and investigates opportunities to reclaim and reuse wastewaters and impaired ground and surface water in the 17 Western States and Hawaii. Title XVI includes funding for the planning, design, and construction of water recycling and reuse projects in partnership with local government entities. Reclamation last released a funding opportunity announcement (FOA) for water reclamation and reuse research studies that is scheduled to close on September 23, 2019. This FOA is a funding opportunity for entities to submit research proposals that address water supply challenges by establishing or expanding the use of water reclamation and reuse, improving existing water reuse facilities, and/or streamlining the implementation of state-of-the-art technology for new facilities.

13.3 Grants and Loans

Grant and loan funding sources have been identified based on currently available information. State and Federal budgets are currently featuring many different opportunities for funding water projects. The failure of California's last water bond (Proposition 3) in November 2018 will limit the long-term availability of California's funding for water projects. The long-term availability of Federal funds for water projects would be affected by another economic downturn.

This section includes a discussion of funds available through various grant and loan programs and specifies eligibility requirements. State and Federal grant and loan programs come with many eligibility requirements, legal requirements, terms, and conditions that cannot be completely summarized here, but are important for potential applicants to understand before applying (as sometimes they can be "deal breakers"). Costs to prepare applications, administer funds, and comply with funding contracts or agreements must also be factored in decisions related to pursuing them. Nevertheless, obtaining grants or loans often make the difference in getting projects or programs done.

13.3.1 DWR - IRWM Implementation Grants

Website: https://water.ca.gov/Work-With-Us/Grants-And-Loans/IRWM-Grant-Programs/Proposition-1/Implementation-Grants

DWR administers the IRWM Implementation Grant Program that provides funding for implementation projects that meet the intent of Proposition 1, Chapter 7. The Kern IRWM Group has been very successful in landing IRWM grants and completing projects they fund. IRWM Implementation grants are designed to encourage integrated regional management of water resources and provide funding for projects that support integrated water management planning and implementation. To continue applying for IRWM Implementation grants, project proponents must coordinate through the Kern IRWM Group, and the Kern IRWM Group must in turn coordinate with other groups within the Tulare\Kern Funding Area.

DWR currently plans to award grants on a competitive basis in at least two funding rounds. The Round 1 Proposal Solicitation Package was released April 22, 2019; the Kern IRWM Group is pursuing this funding. DWR is soliciting proposals to award funding on a competitive basis in two funding categories:

- DAC Implementation Project: DAC Implementation Projects include only those projects that provide at least 75% of its benefits directly to DACs. Funding awarded under this category will count toward the 10% minimum required to be awarded to implementation projects that directly benefit a DAC.
- General Implementation Project: General Implementation Projects include all other eligible implementation projects.

Approximately $222 million in grant funding is being made available for implementation projects with approximately $23.6 million being made available for projects that provide benefits to Disadvantaged Communities. After Round 1 grants, the Tulare/Kern Funding Area will have $1,190,000 remaining in Chapter 7 funding for DAC Implementation Projects and $11,524,056 remaining for General Implementation Projects.

13.3.2 State Water Resource Control Board Grants and Loans

13.3.2.1 Stormwater Grant Program

Website: https://www.waterboards.ca.gov/water_issues/programs/grants_loans/water_recycling/proposition1_funding.shtml

The SWRCB promotes the beneficial use of storm water and dry weather runoff in California by providing financial assistance to eligible applicants for projects that provide multiple benefits while improving water quality. The SWRCB's vision is to change the perception of storm water and dry weather runoff as a contaminant source to a valuable resource, to recharge groundwater aquifers, reuse for domestic purposes, support watershed processes, and beautify communities creating habitat and open spaces. The purpose of the SWGP is to fund storm water and dry weather runoff projects that best advance the Water Board's policy goals of improving water quality and realizing multiple benefits from the use of storm water and dry weather runoff as a resource. The SWGP Unit was established after the passage of Proposition 84 (Prop 84), the Safe Drinking Water, Water Quality and Supply, Flood Control, River and Coastal Protection Bond Act of 2006. That source of funding is now closed.

In November 2014, California voters approved Prop 1, Water Quality, Supply and Infrastructure Improvement Act of 2014 (AB 1471) which authorized $7.545 billion in general obligation bonds for water projects including surface and groundwater storage, ecosystem and watershed protection and restoration, and drinking water protection. The State Water Board administers

Prop 1 funds for five programs. Of the $7.545 billion, Prop 1 (Section 79747) provides $200 million in grant funds for multi-benefit storm water management projects.

Storm Water Resource Plans, or functionally equivalent plan(s), are required to obtain grant funds for storm water and dry weather capture projects. The SWRCB awarded $10 Million in planning grants in 2016. A Kern Storm Water Resource Plan for the Kern and Poso IRWM Groups was prepared in December of 2016.

Implementation grants for multi-benefit storm water management projects which may include, but shall not be limited to, green infrastructure, rainwater and storm water capture projects and storm water treatment facilities have been made available. $80 Million in Round 1 Implementation grants were awarded in August 2018 and the "Summer of 2019" is the solicitation period for $90 Million in Round 2 Implementation grants.

13.3.2.2 Drinking Water State Revolving Fund (DWSRF)

Website: https://www.waterboards.ca.gov/drinking_water/certlic/drinkingwater/DWPfunding.html

The EPA administers the DWSRF program as a federal-state partnership to help ensure safe drinking water. Created by the 1996 Amendments to the Safe Drinking Water Act (SDWA), the program provides financial support to water systems and to state safe water programs. The Division of Financial Assistance of the SWRCB administers California's DWSRF to provide funding opportunities to public water systems that correct public water system deficiencies based upon a prioritized funding approach that addresses the systems' problems that pose public health risks, systems with needs for funding to comply with requirements of the Safe Drinking Water Act, and systems most in need on a per household affordability basis.

13.3.2.3 Clean Water State Revolving Fund (CWSRF)

Website: https://www.waterboards.ca.gov/water_issues/programs/grants_loans/srf/

The Clean Water State Revolving Fund (CWSRF) program is a federal-state partnership that provides communities a permanent, independent source of low-cost financing for a wide range of water quality infrastructure projects. The CWSRF was established by the 1987 amendments to the Clean Water Act (CWA) as a financial assistance program for a wide range of water infrastructure projects, under 33 U.S. Code §1383 that replaced EPA's Construction Grants program. California's SWRCB has the flexibility to fund a range of projects that address their highest priority water quality needs. The CWSRF is structured with 83% Federal and 17% state funds as a five-year funding program for projects from less than $1 Million to over $100 Million.

The SWRCB operates CWSRF as a "Revolving Infrastructure Bank" that uses Federal and State funds to make low interest loans for water quality projects. Loan payments recharge reserves and repay bond holders that provide additional funding to leverage local agency funding. Eligible projects are discussed at the website above.

Additional subsidization can be provided in the form of principal forgiveness, negative interest loans, or grants. The recipient must be a municipality or intermunicipal, interstate, or state agency and the subsidy can only be used to help address affordability issues or to implement a project that addresses water or energy efficiency goals; mitigates stormwater runoff; or encourages sustainable project planning, design, and construction. The State prioritizes Small Severely Disadvantaged Communities and Small Disadvantaged Communities.

13.3.2.4 Water Recycling Funding Program (WRFP)

Website: https://www.waterboards.ca.gov/water_issues/programs/grants_loans/water_recycling/proposition1_funding.shtml

The SWRCB administers the WRFP to promote water recycling by providing technical and financial assistance to local agencies and other stakeholders in support of water recycling projects and research. The WRFP functions through a number of core activities and supporting activities.

The SWRCB approved the Strategic Plan in January 2007 for its first three years and has continued operating under that plan. The Plan establishes a strategic goal, sets program objectives, and identifies specific measures and targets for tracking program performance. Guidelines for Implementing the Water Recycling Funding Program were Adopted June 16, 2015. One percent financing was committed through the Clean Water State Revolving Fund in February of 2015 and 2019.

The WRFP provides funding for planning, pilot projects, and construction through loans and grants and is funded by:

- Proposition 1 provides for $625 million in funding for recycled water projects. Financial assistance is provided through Loans and grant for planning and construction activities.
- Proposition 13, approved by voters in 2000, provided financial assistance through loans and grants for planning and construction activities. The funding capacity under this authority is now very limited.
- Clean Water State Revolving Fund (CWSRF) Program, which provides low-interest loans to public agencies for planning, design, and construction of water recycling projects.

13.3.2.5 Prop 1 – Small Community Wastewater Programs – Grants and Loans

Website:
https://www.waterboards.ca.gov/water_issues/programs/grants_loans/small_community_wastewater_grant/projects.html

Section 79723 of Prop 1 allocates $260 million to the Clean Water State Revolving Fund (CWSRF) Small Community Grant (SCG) Fund. The State Water Board has an annual SCG appropriation of $8 million dollars, which is administered consistent with the CWSRF Intended Use Plan (IUP), and the CWSRF Policy. The Prop 1 funds will supplement existing SCG authority. Administering these funds as a part of the CWSRF Program allows grant funds to be easily leveraged with low-interest financing available through the CWSRF Program. CWSRF applications are accepted on a continuous basis, and eligible projects are funded as applications are completed and approved.

13.3.2.6 Federal 319 Nonpoint Source Pollution (NPS) Control Program

Website: https://www.waterboards.ca.gov/water_issues/programs/nps/319grants.html

The SWRCB's NPS Program administers grant money it receives from United States Environmental Protection Agency through Section 319(h) of the Federal Clean Water Act and from the state Timber Regulation and Forest Restoration Fund. These grant funds can be used to implement projects or programs that will help to reduce NPS pollution. Projects that qualify for funding must be conducted within the state's NPS priority watersheds. Project proposals that address Total Maximum Daily Load implementation and those that address problems in impaired waters are favored in the selection process. In addition, the NPS Grant Program funds projects that implement forest management measures on forest lands to improve water quality.

There is also a focus on implementing management activities that lead to reduction and/or prevention of pollutants that threaten or impair surface and ground waters.

The 2019 NPS Grant Program is supported by funds from a U.S. EPA Clean Water Act section 319 grant to the SWRCB, and from the Timber Regulation and Forest Restoration Fund should such funds be made available to the SWRCB (through federal budget allocation and/or the fiscal year 2019/2020 California Budget Act). Staff anticipates the CWA 319 grant will be $4,000,000 and that the California Legislature and Governor will appropriate $2,000,000 from the Timber Fund for 2019/2020. Unencumbered funds from previous grant years may be used for eligible projects in accordance with the 2019 Nonpoint Source Grant Program Preferences and source fund requirements. Proposals for both the CWA 319 grant and Timber Fund must include a funding match, unless the applicant qualifies and applies for a full or partial match waiver.

13.3.2.7 Agricultural Drainage Management Loan Program

Website: https://www.waterboards.ca.gov/water_issues/programs/grants_loans/agdrain/agdrain_mgmt.shtml

The Agricultural Drainage Management Loan Program, created by Proposition 204 and distributed through the Agricultural Drainage Management Subaccount, which has $10.44 Million remaining. The program provides loan funding for Drainage Water Management Units for the treatment, storage, conveyance, reduction or disposal of agricultural drainage water that, if discharged untreated, would pollute or threaten to pollute the waters of the State.

This program is available to any city, county, district, joint power authority, or other political subdivision of the State involved with water management. Eligible Applicants include any city, county, district, joint powers authority or other political subdivision of the State involved with water management.

There is $6.67M available with a funding cap of $5M for implementation and $100,000 for feasibility studies and a loan repayment period of up to 20 years.

13.3.3 US Department of Agriculture (USDA) Loans and Grants

13.3.3.1 Community Facilities Direct Loan & Grant Program

Website: https://www.rd.usda.gov/programs-services/community-facilities-direct-loan-grant-program/ca

The USDA, through its Rural Development Program provides low interest direct loans, grants, a combination of the two, loan guarantee, and combination with commercial funding to develop essential community facilities in rural areas. An essential community facility is defined as a facility that provides an essential service to the local community for the orderly development of the community in a primarily rural area, and does not include private, commercial or business undertakings. Eligible borrowers include: public bodies, community-based non-profit corporations, federally-recognized Tribes. Eligible rural areas include cities, villages, townships and towns including Federally Recognized Tribal Lands with no more than 20,000 residents according to the latest U.S. Census Data.

Funds can be used to purchase, construct, and/or improve essential community facilities, purchase equipment and pay related project expenses. The list of eligible facilities is extensive and provided at the website above. Funding is provided through a competitive process.

13.3.3.2 Water and Waste Disposal Loan & Grant Program

Website: https://www.rd.usda.gov/programs-services/water-waste-disposal-loan-grant-program

This program provides long-term, low-interest loans and combined grant for clean and reliable drinking water systems, sanitary sewage disposal, sanitary solid waste disposal, and storm water drainage to households and businesses in eligible rural areas.

This program assists qualified applicants who are not otherwise able to obtain commercial credit on reasonable terms. Areas that may be served include: rural areas and towns with populations of 10,000 or less, tribal lands in rural areas, and Colonias.

Loan term is up to 40 years based on useful life of facilities financed, fixed interest rates depend on the need for the project and the median household income of the area to be served. Electronic applications are accepted year-round.

13.3.4 USBR WaterSMART (Sustain and Manage America's Resources for Tomorrow)

Website: https://www.usbr.gov/watersmart/

The American West faces serious water challenges. Wide-spread drought, increased populations, aging infrastructure, and environmental requirements all strain existing water and hydropower resources. Adequate and safe water supplies are fundamental to the health, economy, and security of the country. Through WaterSMART, Reclamation continues to work cooperatively with states, tribes, and local entities as they plan for and implement actions to increase water supply through investments to modernize existing infrastructure and attention to local water conflicts. The following nine programs and the above-described Title XVI Program are components of WaterSMART.

13.3.4.1 USBR Water and Energy Efficiency Grants (WEEG)

Website: https://www.usbr.gov/watersmart/weeg/index.html

Reclamation provides 50/50 cost share funding to irrigation and water districts, tribes, states and other entities with water or power delivery authority for projects that result in quantifiable water savings and support broader water reliability benefits. These projects conserve and use water more efficiently; increase the production of hydropower; mitigate conflict risk in areas at a high risk of future water conflict; and accomplish other benefits that contribute to water supply reliability in the western United States. Projects are selected through a competitive process generally every year depending on congressional appropriations and the focus is on projects that can be completed within two or three years. A Funding Opportunity Announcement (FOA) posted August 8, 2019 covers two application submittal periods:

1. Proposals received before October 3, 2019 will be considered for FY 2020 funding, contingent on appropriations.
2. Proposals received after October 3, 2019 4:00 p.m. MDT and before September 30, 2020, 4:00 p.m. MDT, will be considered for FY 2021 funding, contingent on appropriations.

Federal Funding amounts for two funding groups are as follows:

- Group I: Up to $300,000 per agreement, will be funded on an annual basis, for a period of up to 3 years, with a maximum of $1,500,000 available for the entire project.

- Group II: Up to $1,500,000 per agreement. Only a small number of awards are expected to be made for projects in Funding Group II.

Approximately 15-20 projects are expected to be funded per application period. Collaboration with NRCS programs improves project scoring.

13.3.4.2 USBR Water Marketing Strategy Grants

Website: https://www.usbr.gov/watersmart/watermarketing/index.html

Since 2017, USBR provides financial aid states, tribes, and local governments to conduct planning activities to develop water marketing strategies that establish or expand water markets or water marketing activities between willing participants, in compliance with state and Federal laws. The objective recognizes that water markets between willing buyers and sellers can be used to help water users meet demands efficiently in times of shortages, thereby helping prevent conflicts. Projects have been selected through a competitive process every year depending on congressional appropriations. The last funding opportunity closed July 31, 2019.

Eligible applicants include states, tribes, irrigation districts, water districts, or other organizations with water or power delivery authority.

Projects funded require 50% or greater local cost-share and require collaborative planning efforts to develop water markets that will proactively address water supply reliability and increase water management flexibility. Pilot activities integral to the development of a strategy – i.e. the movement of water on a pilot basis in compliance with applicable laws – can also be included. Two funding groups were included in the last funding opportunity:

- Funding Group I: • Up to $200,000 in Federal funds, completed within 2 years, smaller project scope, can be less complex, few partners involved, smaller geographic area, builds on prior work
- Funding Group II: • Up to $400,000 in Federal funds, completed within 3 years, large project scope, more partners, larger geographic area, more complex water markets

Three required project components include: outreach and partnership building, scoping and planning activities, and development of a water marketing strategy document.

13.3.4.3 USBR Small-Scale Water Efficiency Projects (SSWEP)

Website: https://www.usbr.gov/watersmart/swep/index.html

Reclamation provides 50/50 cost share funding up to $75,000 for projects with total construction costs of no more than $200,000 to irrigation and water districts, tribes, states and other entities with water or power delivery authority for small water efficiency improvements that have been identified through previous planning efforts. Projects eligible for funding include installation of flow measurement or automation in a specific part of a water delivery system, lining of a section of a canal to address seepage, or other similar projects that are limited in scope. The first funding opportunity opened in January 2019 with awards announced in July 2019. This program will likely also become an annual opportunity subject to congressional appropriation.

13.3.4.4 USBR Desalination

Website: https://www.usbr.gov/watersmart/desalination/index.html

The Water Infrastructure Improvements for the Nation (WIIN) Act, which became law at the beginning of 2017, provides new authority to Reclamation to develop a desalination construction program that will provide a path for ocean or brackish water desalination projects to receive Federal funding.

Reclamation developed the new WaterSMART Desalination Construction Program to allocate $32 Million in funding for desalination projects through a competitive grant program for eight projects with feasibility studies that met requirements contained in Reclamation Manual Directives and Standards WTR 11-01 (which are extensive). The first funding opportunity opened in April 2019 and closed in June 2019.

13.3.4.5 USBR Basin Studies

Website: https://www.usbr.gov/watersmart/bsp/index.html

Basin Studies are collaborative studies, cost-shared with non-Federal partners, to evaluate water supply and demand and help ensure reliable water supplies by identifying strategies to address imbalances in water supply and demand. Each study includes four key elements:

- State-of-the-art projections of future supply and demand by river basin.
- An analysis of how the basin's existing water and power operations and infrastructure will perform in the face of changing water realities.
- Development of strategies to meet current and future water demands.
- A trade-off analysis of strategies identified.

A basin study for California's Sacramento-San Joaquin Basin, including the Central Valley portion of Kern County was completed in 2014 and focused on the Central Valley Project (see https://www.usbr.gov/mp/ssjbasinstudy/). Recent opportunities are focused on other states.

13.3.4.6 USBR Site Specific Pilots, web site

Website: https://www.usbr.gov/watersmart/pilots/index.html

Reclamation is conducting pilot studies to identify possible improvements to reservoir operations by incorporating improved scientific information and enhancing operational flexibility to maximize benefits from the existing system. Reclamation's reservoirs are operated using criteria to meet a number of different water management priorities, including reliable water deliveries, power generation, environmental requirements, navigation, and flood control management. Reservoir management practices are being evaluated to determine if there are opportunities to update these criteria to optimize reservoir operations.

In 2015, Reclamation selected five regional pilot studies to evaluate potential improvements to reservoir operations. Regional pilots were initiated, and work began on the pilot studies in January 2016. The five pilot studies identified include the following:

- Great Plains: Upper Washita, Fort Cobb and Foss Reservoirs
- Mid-Pacific: Klamath River Basin, Klamath Project
- Pacific Northwest: Ochoco Creek and Crooked River
- Upper Colorado: Upper Colorado River Drought Contingency Plan, Climate and Operations Assessment Methodology
- Lower Colorado: Salt River Project, Salt and Verde Rivers

The studies were scheduled to be conducted from January 2016 through December 2017. The Washita Basin (Oklahoma) Pilot Study Report has been published. Reclamation says it identifies innovative approaches to improve drought resiliency within that basin and the approach can be applied anywhere across the Western United States. The web site does not list a current funding opportunity.

13.3.4.7 USBR Applied Science Grants

Website: https://www.usbr.gov/watersmart/appliedscience/index.html

Beginning in 2019 Reclamation offers grants or funding agreements to support projects to develop hydrologic information and water management tools and improve modeling and forecasting capabilities. Reclamation desires increased access to information and improved modeling and forecasting capabilities that will help avoid water conflicts and improve ability to meet a variety of water management objectives, including: support for water supply reliability, management of water deliveries, water marketing activities, drought management activities, conjunctive use of ground and surface water, water rights administration, ability to meet endangered species requirements, watershed health, conservation and efficiency, and other water management objectives.

A current FOA, with an application deadline of October 30, 2019 provides funding for projects that improve use of forecasts to inform water availability and the use of technology to increase water reliability consistent with Sections 3 and 4 of the October 9, 2018 Presidential Memorandum on Promoting the Reliable Supply and Delivery of Water in the West. Funding for two groups is offered:

- Funding Group I: Up to $150,000 of Federal funds for projects that should generally be completed within 2 years of grant award
- Funding Group II: Up to $300,000 in Federal funds for per agreement for projects that generally should be completed in 3 years from the date of award

Fiscal Year (FY) 2019 funding is $2 million. Applications submitted in 2019 may be considered for FY 2020 funding, contingent on appropriations. The FOA will be updated to provide a second application deadline in FY 2020 for proposals to be considered for FY 2020 funding, contingent on appropriations. Approximately 8-12 agreements are anticipated in each fiscal year and have the following features:

- Maximum 50% Federal cost share of total project cost from all Federal sources
- Generally non-Federal share of project costs must be expended at the same or greater rate than Federal share.

Eligible applicants include:

- Category A: States, Native American tribes, irrigation districts, water districts, and other organizations with water or power delivery authority in the Western United States, American Samoa, Guam, Northern Mariana Islands, and the Virgin Islands.
- Category B: Universities, nonprofit research institutions, and nonprofit organizations

Eligible projects are applied science projects to develop or improve hydrologic information, water management tools, and modeling and forcasting capabilities. Results from these projects will be used by water managers to increase water supply reliability, provide flexibility in water operations, and improve water management. Project results must be readily applicable by water managers, resulting in tools and information that can be used to: support water supply reliability, management of water deliveries, water marketing activities, drought management activities,

conjunctive use of ground and surface water, water rights administration, ability to meet endangered species requirements, watershed health, conservation and efficiency, and other water management objectives.

13.3.4.8 USBR Cooperative Watershed Management Program (CWMP)

Website: https://www.usbr.gov/watersmart/cwmp/index.html

The CWMP provides funding to watershed groups (self-sustaining, non-regulatory, consensus-based group that is composed of a diverse array of stakeholders, which may include, but is not limited to, private property owners, non-profit organizations, Federal, state, or local agencies, and tribes) to encourage diverse stakeholders to form local solutions to address their water management needs. Funding is provided on a competitive basis for watershed group development and watershed restoration planning as well as implementation of those plans.

In 2012, Reclamation began providing funding for watershed group development, watershed restoration planning, and watershed management project design (Phase I). As part of Phase I activities, applicants may use funding to develop bylaws, a mission statement, complete stakeholder outreach, develop a watershed restoration plan, and watershed management project design. For Phase I projects, Reclamation will award a successful applicant up to $50,000 per year for a period of up to two years with no non-Federal cost-share required. A new Phase I FOA is planned for 2019.

In 2017, Reclamation began providing cost-shared financial assistance to watershed groups to implement watershed management projects (Phase II). These on-the-ground projects, collaboratively developed by members of a watershed group, address critical water supply needs and water quality concerns, helping water users meet competing demands and avoid conflicts over water. Reclamation will award up to $100,000 per project over a two-year period. For Phase II projects, applicants must contribute at least 50% of the total project costs. A FOA for Phase II Projects closed on Feb 20, 2019. Applications are being reviewed.

13.3.4.9 USBR Drought Response Program

Website: https://www.usbr.gov/drought/

Reclamation's Drought Response Program supports a proactive approach to drought by providing assistance to water managers to develop and update comprehensive drought plans as well as implement projects that will build long-term resiliency to drought. Program areas include:

- Contingency Planning: Reclamation will provide financial assistance of up to $200,000 on a competitive basis for applicants to develop a drought contingency plan or to update an existing plan to meet the required elements described in the Drought Response Framework.
- Resiliency Projects: Drought Resiliency is the capacity of a community to cope with and respond to drought. Under this element of the program, Reclamation will provide funding for projects that will help communities prepare for and respond to drought. Typically, these types of projects are referred to as "mitigation actions" in a drought contingency plan. Reclamation invite states, tribes, irrigation districts, water districts, and other organizations with water or power delivery authority to leverage their money and resources by cost sharing with Reclamation on Drought Resiliency

Projects that will increase the reliability of water supplies; improve water management; and provide benefits for fish, wildlife, and the environment to mitigate impacts caused by drought.

  - Funding Group I: Up to $300k and completed within 2 years
  - Funding Group II: Up to $750k and completed within 3 years

- Emergency Response Actions: Reclamation will continue to undertake emergency response actions under the Drought Response Program to minimize losses and damages resulting from drought, relying on the authorities in Title I of the Drought Act. Emergency response actions are crisis driven actions in response to unanticipated circumstances. Eligible emergency response actions are limited to temporary construction activities and other actions authorized under Title I that do not involve construction of permanent facilities, including water purchases and use of Reclamation facilities to convey and store water.

This grant program has been offered annually since 2015 and depends on congressional appropriations. A FOA for Drought Resiliency Projects for Fiscal Years 2020 and 2021 was released August 8, 2019 on GRANTS.GOV. It covers two application submittal periods:

  - Application due date for FY 2020 funding is October 16, 2019
  - Application due date October 14, 2020 for FY 2021 funding

This FOA supports projects that are generally in the final design stage, environmental and cultural resources compliance may have been initiated, and the non-Federal funding, necessary permits, and other required approvals have been secured. Projects that improve forecasts of water availability and improve use of technology to increase water reliability consistent with sections 3 and 4 of the October 19, 2018, Presidential Memorandum on Promoting the Reliable Supply and Delivery of Water in the West can be funded as well.

13.3.5 FEMA and CAL OES - Grants for Pre and Post Disaster Assistance

Website: https://www.fema.gov/hazard-mitigation-grant-program and
https://www.caloes.ca.gov/cal-oes-divisions/hazard-mitigation

FEMA and California Office of Emergency Services (OES) collaboratively offer grants to assist a variety of entities, including public agencies, Indian tribes, and non-profit organizations to better prepare for disasters and cope with them after they occur. Hazard Mitigation Grants (HMGP) are pre-disaster mitigation funding. Local Hazard Mitigation Plans (HMP) that are periodically updated are required as a first step (see Section 10.2.5 regarding the HMP for Kern County).

In recent years CAL EMA, who helps FEMA administer its HMGP program in California has sought projects that improve flood protection, drought protection, and prevent land surface subsidence. These competitive grant programs that can fund mitigation for many other types of disasters and can provide up to 75% Federal cost share. Funding changes depending upon recent disaster declarations in California. Recent rounds have funded projects of $5 Million or more.

13.3.6 USFWS - North American Wetlands Conservation Act Grant

This grant provides funds for projects that provide long-term protection of wetlands, and the fish and wildlife that depend upon wetlands. Applicants must provide local match equal to that requested. Entities that are eligible include organizations and individuals who have developed partnerships to carry out wetlands conservation projects in the US, Canada, and Mexico. Applications are continuously accepted by the US FWS for this grant.

13.3.7 EPA - Source Reduction Assistance Grant Program (SRA)

Website: https://www.epa.gov/p2/grant-programs-pollution-prevention

EPA SRA originally as the Pollution Prevention (P2) Grant Program (formerly Pollution Prevention Incentives for States) under the authority of the Pollution Prevention Act of 1990. The program funds two-year Pollution Prevention (P2) assistance agreements for projects expected to be performed in each EPA region that provide technical assistance and/or training to businesses/facilities to help them adopt source reduction approaches.

This program depends on congressional appropriations for each fiscal year. The web site gives FY 2017 funding levels as an example of expected funding in FY 2018 and 2019 (approximately $9.38 million in federal P2 grant funding for these two-year assistance agreements (approximately $4.69 million in FY 2018 funds and approximately $4.69 million in FY 2019 funds). The application period for the last RFP (FY 2018 and FY 2019) closed August 23, 2018.

The match requirement was 5 percent. Along with other requirements, proposals must address one of the following statutory/regulatory criteria to merit further review:

- Offer practical pollution prevention (P2) tools or approaches to measurably improve the environmental footprints of state agencies, federally-recognized tribes, intertribal consortia, businesses, municipal/local governments and/or local communities while also supporting efficiency to reduce resource use, expenditures, waste and liability costs.
- Adhere to the statutory authorities for this program by using one or more of these technical assistance methods: a) research, b) investigation, c) experiments, d) education, e) training, f) studies and/or g) demonstration of innovative techniques – to carry out source reduction/P2 activities.
- Place additional emphasis on documenting and sharing P2 best practices and innovations identified and developed through these grants so that others can replicate these approaches and outcomes.
- Focus project activities on **one or more** of the P2 Program's National Emphasis Areas: Business-Based Pollution Prevention Solutions Supporting Toxic Substances Control Act (TSCA) Priorities and Chemical Safety; Food and Beverage Manufacturing and Processing; and, Hazardous Materials Source Reduction Approaches in States or Communities.

Individual grant awards were expected to be in the range of $20,000-$260,000 for the two-year funding period. However, some EPA regions may have lower award caps. Forty grants were anticipated in the last solicitation.

13.3.8 EPA - Wetland Program Development Grants and EPA Wetlands Grant Coordinators (WPDGs)

Website: https://www.epa.gov/wetlands/wetland-program-development-grants-and-epa-wetlands-grant-coordinators

WPDGs provide eligible applicants an opportunity to conduct projects that promote the coordination and acceleration of research, investigations, experiments, training, demonstrations, surveys and studies relating to the causes, effects, extent, prevention, reduction and elimination of water pollution.

WPDGs assist state, tribal, local government (S/T/LG) agencies and interstate/intertribal entities in building programs to protect, manage and restore wetlands. States, tribes, local governments, interstate associations, and intertribal consortia are eligible to apply for the Regional WPDG Request for Proposals (RFPs). Nonprofits, interstate associations and intertribal consortia are eligible to apply for the National WPDG RFPs.

WPDGs provide applicants an opportunity to develop and refine comprehensive state/tribal/local government wetland programs. These programs are meant to build the capacity of state/tribal/local governments to increase the quantity and quality of wetlands in the U.S. by conserving and restoring wetland acreage and improving wetland condition.

RFPs are typically put out in the springtime. The application period for FY 2019-20 closed April 19, 2019. The total amount of federal funding available in the last RFP was approximately $3,126,950 depending on Agency funding levels, which may vary from year to year, and other applicable considerations. Approximately 8 to 14 awards were anticipated under Track One and approximately 4 to 10 awards under Track Two. Awards will likely range from $50,000 to $500,000 in federal funds.

13.3.9 Natural Resources Conservation Service (NRCS) - Watershed Protection and Flood Prevention Grant

The purpose of the program is to support activities that promote soil conservation and that promote the preservation of the watersheds of rivers and streams throughout the US. This program seeks to preserve and improve land and water resources via the prevention of erosion, floodwater, and sediment damages. The program supports improvement of: (1) flood prevention including structural and land treatment measures; (2) conservation, development, utilization, and disposal of water; or (3) conservation and proper utilization of land. Successful applicants under this program receive support for watershed surveys and planning, as well as watershed protection and flood prevention operations. Funding for watershed surveys and planning is intended to assist in the development of watershed plans to identify solutions that use conservation practices, including nonstructural measures, to ultimately solve problems.

Matching funds are not required; however, applicants must generally provide matches ranging from 0 to 50 percent in cash or in-kind resources depending on such factors as project type and the kinds of structural measures which a project proposes.

Eligible entities include: states, local governments, and other political subdivisions; soil or water conservation districts; flood prevention or control districts; and tribes. Potential applicants must be able to obtain all appropriate land and water rights and permits to successfully implement proposed projects.

13.3.10 California IBank - Infrastructure State Revolving Fund (ISRF) Program

Website: http://www.ibank.ca.gov/infrastructure-state-revolving-fund-isrf-program/

The ISRF Program provides financing to public agencies and non-profit corporations, sponsored by public agencies, for a wide variety of infrastructure and economic development projects (excluding housing). ISRF Program funding is available in amounts ranging from $50,000 to $25 million with loan terms for the useful life of the project up to a maximum of 30 years. Applications are accepted continuously.

Eligible applicants include but are not limited to any subdivision of a local government, cities, counties, special districts, assessment districts, joint powers authorities and non-profit corporations (as deemed eligible). Eligible projects and costs are provided at the website above.

13.3.11 California Natural Resources Agency - Trails and Greenways Grant Program

Website: http://resources.ca.gov/grants/trails/

The Trails and Greenways grant program, funded by Proposition 68, will fund projects that provide non-motorized infrastructure development and enhancements that promote new or alternate access to parks, waterways, outdoor recreational pursuits, and forested or other natural environments to encourage health-related active transportation and opportunities for Californians to reconnect with nature. Grants will be awarded on a competitive basis. Final guidelines are anticipated to be released mid to late August 2019.

13.4 Other Financing Mechanisms

Energy utilities provide technical assistance and incentives for energy efficiency, curtailment programs, renewable energy, and other public purpose programs that can assist with costs for planning, design, and construction of projects. These include Pacific Gas & Electric Company https://www.pge.com/, Southern California Edison https://www.sce.com/, and Southern California Gas Company https://www.socalgas.com/. The Power and Water Resources Pooling Authority http://www.pwrpa.org/pwrpa_org/ is a mechanism for its members to finance projects and looks to invest in affordable renewable projects to add to its portfolio.

Environmental organizations and other NGOs are increasingly getting involved in providing assistance with water projects. Self-Help Enterprises (https://www.selfhelpenterprises.org/) has received Technical Assistance funding from the State to assist DACs with planning, investigations, and engineering design.

With very low interest rates in recent years conventional bank financing often works to provide very low interest loans for water projects that offer far fewer “strings” than government programs or bond financing.

Many consultants offer assistance for a fee to apply for grants and loans or assist with public or private debt offerings that can bring expertise and funding that otherwise couldn’t be obtained.

13.5 Selected Plan Project Cost Estimates

Project cost data contained within the Project Submittal Forms are based on the project costs of the date the form was submitted. The forms also include the estimated project operations and maintenance costs and a discussion of funding sources (i.e. funding needed from grants and available local funding). It is understood that operations and maintenance costs for projects that implement the IRWMP plan are the responsibility of the sponsoring agency and are typically ineligible for grant or loan funding. Sponsoring entities will be expected to operate and maintain IRWMP projects through user fees and other non-grant revenues.

13.6 Grant Funding Package Strategy

Securing funding for the projects proposed in the Kern IRWMP can be best accomplished with a focused, deliberate, packaging strategy. As seen from the descriptions above, there are many funding programs within and outside of the Kern Region that could provide financial opportunities for the stakeholders' projects. As these funding opportunities become available, Plan Projects are integrated to fit the future funding criteria.

Section 14: Technical Analyses, Data Management, and Plan Performance

This section is organized into three parts to summarize the information used to support the technical analyses, the means and methodologies for data management and monitoring within the Region, and plans for data collection, reporting and performance of the Kern Region IRWMP.

14.1 Technical Analyses

The Kern IRWMP objectives, discussed in Section 9, were developed to allow progress of the overall IRWMP to be measured. Examples of projects that would benefit these objectives, either current projects, or concepts, are provided in Section 11.3.1. Projects proposed for implementation in the Kern IRWMP must be supported by technical studies and reports that document not just their feasibility, but also their ability to meet these objectives.

The Kern IRWMP was prepared using information and guidance provided by an extensive mix of water suppliers, municipalities, town councils, regulatory, environmental, agricultural, and land use planning entities that represent all areas of the Kern Region. Extensive information and data on the Kern Region have been prepared by these various agencies and groups. Early in the development process these stakeholders were asked to submit their plans, reports, and studies to the region's IRWMP resource library to ensure that the Kern IRWMP accurately reflects each stakeholder's individual perspectives, while fostering recognition of opportunities for partnering to resolve common issues. That information was reviewed and evaluated as part of this IRWMP and served as the technical foundation for the development of this plan, as described below.

The following documents contain the baseline information used in the development of the Kern IRWMP. Information from the documents have been incorporated into subregion sections. Updates to the documents discussed below will be incorporated into future updates to the Kern IRWMP that occur every 5 years.

14.2 Local Water Planning Documents

14.2.1 Water Resource Management Reports and Plans

These reports document the reliability and availability of the Region's water supplies to meet current and projected demands. These reports include UWMPs and AB 3030 Groundwater Management Plans. Since 2009, with the passage of the Comprehensive Water Package (SBX7) by the Legislature, some additional planning processes have been proscribed; these include AWMPs and groundwater monitoring protocols.

The California Urban Water Management Planning Act (a part of the CWC) applies to public and private municipal water suppliers with more than 3,000 connections or supplying more than 3,000 AFY. The act requires suppliers to describe and evaluate sources of water supply, impacts of hydrology on water supplies, demand management measures (DMMs),

implementation strategy and schedule, and other relevant information and programs. This information is used by the urban water supplier to develop a UWMP, which is submitted to DWR in years ending in five and zero (e.g., 2015, 2020). An additional requirement since 2009 is SBX7-7, Part 2.55, which requires all urban retail water suppliers subject to the UWMP Act to contribute to the achievement of a 20 percent reduction in statewide urban water use in gpcd by 2020. Information from each of the UWMPs were incorporated into the subregion descriptions.

Assembly Bill 3030 (AB 3030), the Groundwater Management Act (also a part of the CWC), authorized local agencies to prepare groundwater management plans for groundwater basins not subject to adjudication or other form of regulation. AB 3030 lays out a procedure for development of a groundwater management plan. The act also specifies twelve technical components which can be included in a groundwater management plan, including replenishment strategy, mitigation of overdraft, mitigation of contaminated groundwater, and avoidance of saline intrusion. Information from each of these plans were incorporated into the subregion descriptions.

The Agricultural Water Management Planning Act (SBX7-7, Part 2.8), part of the CWC, applies to agricultural water suppliers providing water to more than 10,000 irrigated acres. It requires applicable agricultural water suppliers to adopt AWMPs, on a schedule parallel to UWMPs. The purpose for the plans is to facilitate management and conservation of water by suppliers, and to guide and document the implementation of EWMPs used to meet the conservation goals. To promote the use of demand-based practices and help meet water conservation goals, SBX7-7 requires agricultural water suppliers to implement a number of EWMPs. Some of the EWMPs are critical (mandatory) for all affected agricultural water suppliers. Other additional EWMPs are to be implemented by suppliers if the measures are locally cost effective and technically feasible. Information from each of these AWMPs were incorporated into the subregion descriptions.

Table 14-1 presents a listing of the water resource management reports and plans reviewed for the Kern IRWMP, and that were collected as part of the Kern Region document library.

Table 14-1: Water Resource Management Reports and Plans

Agency	Reference	Date
UWMPs		
City of Bakersfield	2015 UWMP	June 2017
Improvement District No. 4	2015 UWMP	June 2016
Oildale MWC	2015 UWMP	October 2016
North of the River MWD	2015 UWMP	September 2016
West Kern WD	2015 UWMP	June 2016
Vaughn Water Company	2015 UWMP	July 2016
Tehachapi Regional	2015 UWMP - TCCWD, Bear Valley CSD, City of Tehachapi, Golden Hills CSD, Stallion Springs CSD	July 2016
City of Shafter	2015 UWMP	June 2016
City of Wasco	2015 UWMP	May 2017
California Water Service	2015 UWMP - Bakersfield District	June 2016
California Water Service	2015 UWMP - Kern River Valley District	June 2016
Arvin CSD	2015 UWMP	November 2016
Lamont PUD	2014 UWMP	November 2014
City of Delano	2015 UWMP	July 2017
East Niles CSD	2015 UWMP	June 2016
Tejon Castac WD	2010 UWMP	
Other Urban Water Purveyor Documents		
Miscellaneous Agencies	Consumer Confidence Reports	
Improvement District No. 4	Report on Water Conditions - 2018	February 2019
Kern County Water Agency	2011 Water Supply Report	
Groundwater Management Plans		
Arvin Edison WSD	Groundwater Management Plan	June 2003
Kern Delta WD	Groundwater Management Plan	October 2013
Rosedale-Rio Bravo WSD	Groundwater Management Plan	February 2013
Wheeler Ridge-Maricopa WSD	Groundwater Management Plan	November 2007
Buena Vista WSD	Groundwater Status and Management Plan	2002
Bear Valley CSD	Groundwater Management Plan	1998
West Kern WD	Groundwater Management Plan	1997
Agricultural Water Management Plans		
Arvin-Edison WSD	Water Management Plan Update	October 2015
Belridge WSD	2015 Agricultural Water Management Plan Update	December 2015
Berrenda Mesa WD	2012 Agricultural Water Management Plan	April 2013
Buena Vista WSD	2015 Agricultural Water Management Plan	February 2016
Dudley Ridge WD	2012 Agricultural Water Management Plan	December 2012
Lost Hills WD	2012 Agricultural Water Management Plan	April 2013

14.2.2 Facilities Plans and Master Plans

A facilities plan and/or master plan is a physical development plan that provides the framework by which future planning decisions are made. It is an action plan for a particular resource or service such as recycled water, flood control, and wastewater, and can include planned facilities. **Table 14-2** presents a listing of the facilities plans and master plans reviewed for the Kern IRWMP, and that were collected as part of the Kern Region document library.

TABLE 14-2: Facilties Plans and Master Plans

Agency	Reference	Date
California Water Service	2008 Master Plan Update	2008
City of Arvin	Drainage Master Plan Update	August 2009
City of Bakersfield	2005 Hydraulic Modeling Report	2005
City of Bakersfield and County of Kern	2014 Storm Water Management Plan	2014
City of Tehachapi	Water Model Report	June 2005
City of Tehachapi	Indirect Potable Reuse Conceptual Study	September 2016
City of Tehachapi	Sewer Model Report	June 2005
City of Wasco	2007 Final Water Master Plan	2007
County of Kern	Caliente Creek Feasibility Study	June 2017
North of River SD	Master Sewer Plan Update	March 2018

14.2.3 Stormwater Resource Plan

The Stormwater Resource Planning Act (SB 985 CWC 10562 (b)(7)) requires the development of a stormwater resource plan (SWRP) in order for a grant applicant (excluding some DACs) to receive grant money for stormwater and dry weather runoff capture projects after January 2014. The purpose of a SWRP is to identify and prioritize stormwater and dry weather runoff capture projects for the purpose of augmenting surface water supplies, improving water quality, and reducing the need for groundwater pumping.

A SWRP was prepared for the Kern Region, which include the Kern IRWMP and the Poso Creek IRWMP regions. This Kern SWRP was self-certified and submitted to the SWRCB for verification in June 2017. With the adoption of this Kern IRWMP Update, the participants are also incorporating and adopting this the Kern SWRP.

14.2.4 Resource Conservation Plans

Resource conservation plans in this context are those watershed, river, and conservation plans that study the natural, biological, recreational, and historical resources of a particular watershed, or Region. **Table 14-3** presents a listing of the resource conservation plans reviewed for the Kern IRWMP, and that were collected as part of the Kern Region document library.

Table 14-3: Resource Conservation Plans

Agency	Reference	Date
CDFW Sequoia National Forest, Sequoia National Park	Upper Kern Basin Fishery Management Plan	1995
City of Bakersfield	Metropolitan Bakersfield Habitat Conservation Plan	1994
City of Bakersfield	2007 Recreation and Parks Master Plan	2007
City of Bakersfield and County of Kern	Kern River Plan Element	2007
County of Kern	Draft Kern County Valley Floor Habitat Conservation Plan	2006
County of Kern	Kern Flood Control and Mitigation for Kern Lake Basin	
County of Kern	Kern River Specific Trails Plan	2003
Desert Moutain Resource Conservation and Development Council (RC&DC)	Desert Mountain RC&DC 5-year Plan, 2009-2013	2009
Kern Water Bank Authority	Habitat and Natural Community Conservation Plan	1997
USFW	Kern and Pixley National Wildlife Refuges Comprehensive Conservation Plan	2005

14.2.5 Water Quality Plans

Water quality plans are generally designed to preserve and enhance water quality and protect beneficial uses of water.

Specifically, the CVRWQCB Basin Plan, which protects the beneficial uses of water within the Central Valley hydrologic region, designates beneficial uses for surface and ground waters, sets narrative and numerical objectives that must be attained or maintained to protect the designated beneficial uses and conform to the state's anti-degradation policy, and describes implementation programs to protect all waters in the Region. In addition, the Basin Plan incorporates (by reference) all applicable State and Regional Board plans and policies and other pertinent water quality policies and regulations. As conditions change, such as the identification of new TMDLs or water quality standards, the Basin Plan is amended. Following adoption by the CVRWQCB, the Basin Plan and subsequent amendments are subject to approval by the SWRCB, the State Office of Administrative Law, and the US EPA.

DWR provide ongoing monitoring of the SWP through the Municipal Water Quality Investigations Committee; it prepares the SWP Sanitary Survey every five years in accordance with state law. USBR provides a Baseline Water quality Report for the CVP.

14.2.6 SGMA

As discussed in Section 2.11.6.2, SGMA became law in November 2014. GSAs are responsible for developing and implementing GSPs. GSPs are to be prepared by 2020. Once

these GSPs are available, the Kern IRWMP will be updated with information, data, projections, and recommended projects that are to be contained within each GSP.

14.2.7 Disadvantaged Communities Study

In 2011, the County of Tulare was awarded a grant to develop DAC study for the Tulare Lake Basin to analyze regional water and wastewater solutions. The study covers areas in Fresno, Kern, Kings, and Tulare counties. The final report was completed in August 2014 and includes recommendations for planning, infrastructure, and other management actions to help communities solve critical water issues. The results of this study were used in the Kern IRWMP update and will continue to be utilized for developing and implementing future DAC projects.

14.3 Land Use Planning Documents

14.3.1 City, County, and Federal Land Use Plans

Land use plans provide for the scientific, aesthetic, and orderly disposition of land, resources, facilities and services of urban and rural communities. General plans are a compendium of city or county policies regarding long-term development, in the form of maps and accompanying text. In California, general plans have seven mandatory elements (circulation, conservation, housing, land use, noise, open space, safety and seismic safety) and may include any number of optional elements (such as water, air quality, economic development, hazardous waste, and parks and recreation). Most local general planning documents generally have identified water management resource strategies that integrate with land use planning efforts. By law, each city and county are required to update the Housing Element of its general plan every five years and the Governor's Office of Planning and Research recommends that the remaining elements be reviewed every eight to ten years.

14.3.1.1 Kern Regional Blueprint Program

The Kern Regional Blueprint Program, led by the Kern Council of Governments (KernCOG), is part of a larger eight-county, San Joaquin Valley-wide process. At both the County and Valley levels, the Blueprint process will result in a preferred regional transportation, land use, and environmental vision responding to the many challenges associated with anticipated population growth over the next 40 years. Part of Kern's portion of a valley-wide blueprint will include growth principles and scenario planning tools for both local and regional level planning activities. It is also another means for collecting economic, transportation/planning, environmental, and GIS data for the Region.

The final product, to be known as the San Joaquin Valley Regional Blueprint, will include a visual representation of the goals expressed in general plans and individual regional transportation plans. The following is a list of the city, county, and specific land use planning documents reviewed for the Kern IRWMP, and that were collected as part of the Kern Region document library.

Table 14-4: Land Use Planning Documents

Agency	Reference	Date
General Plans		
County of Kern	General Plan	2009
Kern Council of Governments	Regional Blueprint Report	2008
City of Bakersfield and County of Kern	Metropolitan Bakersfield General Plan	2003 (2016 Update)
City of Taft	General Plan	2009
City of Delano	General Plan	2005
City of Wasco	2040 General Plan	2016
City of Shafter	General Plan	2005
City of McFarland	General Plan	2011
City of Arvin	General Plan	2012
City of Tehachapi	General Plan	2012
Specific Plans		
County of Kern	Greater Tehachapi Area Specific Plan	2010
County of Kern	Frazier Park / Lebec Specific Plan	2003
County of Kern	Kern River Valley Specific Plan	2011
County of Kern	Tejon Industrial Complex Specific Plan	2005
County of Kern	Tejon Mountain Village Specific and Community Plan	2009

Other Specific Plans are located at the following link:
https://kernplanning.com/planning/planning-documents/specific-plans/

14.4 Data Management

Collection of data can be used to help quickly identify data gaps, assess project and program performance, support statewide data needs, and integrate with other regional and statewide programs. Within the Region, there are a several entities that collect and maintain data on the Region's water and environmental resources.

The Kern Fan Monitoring Committee (KFMC) was established by various MOUs among the Kern Fan area entities. The members of the Committee include both banking project participants and adjoining entities (those entities whose lands and/or banking projects are adjacent to the banking projects). The KFMC is responsible for collecting data from participants/adjoining entities and reporting that data in the KMFC's "Kern Fan Area Operations and Monitoring Report." Other discretionary activities/authorities of the committee include hiring technical consultants, determining the need for/placement of additional monitoring sites and dispute resolution. Data that is collected and published in the Operations and Monitoring Report includes the following: groundwater levels, groundwater elevation and water quality sampling results. Regional banking programs such as the Kern Water Bank collect annual statistical data in accordance with AB3030, the Groundwater Management Planning Act, and providing groundwater monitoring data for the Region.

The Kern River Interests are those valley floor entities with Kern River rights; they include: Buena Vista WSD, Kern Delta WD, North Kern WSD, City of Bakersfield and KCWA. More specifically, North Kern and City of Bakersfield has rights below the "first point of measurement," Kern Delta and Buena Vista have "second point of measurement" rights and the Agency has lower river (a.k.a. high flow) rights. The Kern River Interests collectively have hired a

Watermaster to maintain records at the first point of measurement. Buena Vista WSD also is responsible for the collection and maintenance of second point records.

KCWA is the primary means for collecting data on groundwater and surface water supplies and water quality. Since its formation in 1961, the Agency or through other water districts has collected information on the water supply and demand characteristics of the San Joaquin Valley portion of Kern County. Since 1977, the Agency has published it annual Water Supply Report to present these statistics in one document and to assist water leaders and users in making water management decisions. The latest report was prepared for 2011; much of the future dataset that was maintained under these reports will now be managed and distributed under SGMA through GSAs.

Each of these committee's and/or agencies are collecting data that is important to the Region, have methods for data collection that are similar, and thus have opportunities for streamlining or maximization of efficiencies for creating region-wide datasets and databanks.

With the implementation of SGMA, GSAs will be collecting data related to surface water, groundwater, hydrology, and other datasets. A data management system (DMS) will be utilized by the GSAs to manage, evaluate, and distribute information.

Data is vitally important to agencies trying to maximize operating efficiency and design projects with limited budgets. The types of data available, current relevance and trends, and knowledgeable people that can interpret the data are all important. Equally important is the opportunity for Federal and State agencies to view local data for their own monitoring needs and to better understand local conditions.

Creation of data management tools that recognize these similarities in methodology, the repetitiveness in data harnessing, and inefficiencies in data reporting are additional strategies that can be implemented in order to streamline efforts on not just a local, but a region-wide scale as well. The ongoing data collection and management efforts for the IRWMP will be directed by the Executive Committee, which will establish a means to collect and maintain the data as well as to update and maintain the IRWMP website via an outside consultant.

14.4.1 Monitoring

14.4.1.1 Surface Water Monitoring

The Kern River Watermaster is the main local entity for monitoring Kern River surface water and is responsible for the operation of Isabella Reservoir and dam, representing all downstream water rights entities. Unless the integrity of the dam is jeopardized, the Kern River Watermaster is responsible for giving the daily instructions on the amount of water to be released from the Isabella Reservoir by the Army Corps of Engineers. The Watermaster is also responsible for preparing and keeping complete daily records on Kern River flows, which dates back to 1977 according to records from the City of Bakersfield Water Resources Department since 1977 (Kern River Valley Specific Plan, County of Kern, October 2006). KCWA monitors SWP supply availability to the Region, and Arvin-Edison, as the largest Friant entity in the Region, monitors the CVP surface supply.

14.4.1.2 Irrigated Lands Regulatory Project

As discussed in Section 2.10.8, the Irrigated Lands Regulatory Program's goal is to prevent agricultural runoff from impairing surface water and groundwater. Much of the lands within the Kern Region have obtained regulatory coverage under a coalition that assists with compliance with the General Order. There are multiple coalitions in the Kern Region and each works directly with its members to assist with compliance, monitoring, and reporting.

14.4.1.3 Urban Water Management Plan (UWMP) and AB3030 Compliance Monitoring and Reporting

Sources of data for water supply quantities include the individual agency UWMPs and AB3030 plans that are updated every 5 years (ending in 0). These include the evaluation of single-dry and multi-dry year demands under different hydrologic scenarios and an assessment of supply vs. demand. Monitoring of surface and groundwater supplies as appropriate are conducted to support these analyses. Water loss audit reports are required on an annual basis in accordance with SB 555.

14.4.1.4 Safe Drinking Water Act (SDWA) Compliance Monitoring and Reporting

All public water systems are required to produce water that complies with the SDWA. To this end, specific monitoring information is required and conducted routinely. Results of the monitoring are reported to DPH. In addition, monitoring information is required to be published in an annual Consumer Confidence Report.

14.4.1.5 Surface Water Quality Monitoring

TMDL compliance monitoring is required by the RWQCB and performed on an ongoing basis in order to determine if a watershed is in compliance with an identified TMDL. A compliance monitoring program for implementing a TMDL would generally include the anticipated compliance points for the monitoring program, parameters to be measured, analytical methods and their sensitivity for reliably detecting the regulated chemicals, frequency of measurements, etc. With such information it will be possible to evaluate whether the proposed compliance monitoring could be expected to be adequate for detecting significant violations of the requirements set forth in the TMDL.

14.4.2 Data Reporting

Reporting requirements in California are used to obtain data and information on a variety of water resources issues, such as demand, supply, and quality. Much of this information is now collected in a format that can be rolled up from the local to region scale level, to the larger California Water Plan. The Kern IRWMP will serve as a vein of information to the California Water Plan. Refer to Section 14.5.1 for additional State data reporting programs.

14.4.2.1 Municipal National Pollutant Discharge Elimination System Permits

Municipal NPDES Permits require developers of certain developments/redevelopments to prepare engineering documents to prevent potential pollutants from entering storm drain systems. Examples are Urban Storm Water Mitigation Plans (USMP) and/or Storm Water Pollution Prevention Plans (SWPPP). The municipal NPDES requires the owner/operator to submit an Annual Storm Water Permit Report and Assessment to the local RWQCB (in the case of the Kern IRMWP, the Central Valley RWQCB). The Annual Reports include the information

necessary to assess compliance relative to the permit, and the effectiveness of implementation of permit requirements on storm water quality.

14.4.2.2 Watershed Sanitary Survey Reporting

Watershed Sanitary Surveys are required by DPH every 5 years or when there are major changes to the watershed. Municipalities that use surface water for drinking water, such as KCWA and the City of Bakersfield, are also required to prepare these.

14.4.2.3 Annual Consumer Confidence Reports

The preparation of Consumer Confidence Reports (CCRs) is required by the California Health and Safety Code §116470 and the CDPH, as well as the SDWA and US EPA. This code requires every public water system, as a condition of its operating permit, to annually prepare a report and provide a copy of that report to each customer. It also requires public water systems with more than 10,000 service connections that detect contaminants above their public health goals (PHGs) to provide PHG exceedence reports every three years and to hold public hearings regarding their reports. The CCR includes information on a system's source water, the levels of any detected contaminants, and compliance with drinking water regulations, plus some educational material. Contaminants typically reported include turbidity, coliform, lead/copper, unregulated contaminants, and those contaminants of concern specific to a particular location.

14.4.3 Identified Data Gaps

Numerous data sets and reports were reviewed for their applicability to the Kern Region and in conjunction with statewide data needs. In addition to reviewing these documents and reports, stakeholder meetings allowed for public participation in voicing known technical gaps and/or avenues for further data collection. Together, this knowledge provided the information necessary to identify data gaps and deficiencies to illuminate in the IRWMP. Data gaps represent information crucial to a greater understanding of the Region and help develop context for future projects and water management actions.

Some of the data gaps and deficiencies identified that are of most importance to the Region include the following:

- Agricultural groundwater pumping
- Individual water use and losses in districts with no meters
- Groundwater return flows
- Total urban water demand, and water demand by urban water use sector for the Kern Region, (i.e., residential, commercial, industrial)
- Subsurface flow
- Consumptive use losses in the basin
- Amount of water available for recovery through stormwater capture
- Natural groundwater recharge
- Historical and current groundwater pumping records
- Population data for specific subregions
- Socioeconomic data for specific subregions
- Well closures due to poor water quality

- DAC impacts due to poor water quality

A major issue in the Region is collection of various types of data by a wide variety of public and private entities, at both the state and local levels. This data is not compiled into a central database, although the KCWA Water Supply Report has attempted to serve at least part of that function in the past; GSPs will serve this function in the future. A potential function of the Kern IRWMP would be to serve as a comprehensive data collection point (see Plan Performance Section 13.2.1.). It is recommended that additional monitoring and studies be conducted to fill in these data gaps.

14.5 Monitoring Plan Performance

In general, the success of the Kern IRWMP depends on how well the IRWMP objectives are accomplished. Achievement of all objectives will, in large part, determine the success of local integrated regional water management planning processes.

As described in Section 12.7, IRWMP updates will occur at a minimum every five years and the project prioritization process will occur annually. This IRWMP is a dynamic document and is part of an ongoing local effort to achieve integrated local water management. The process, through Stakeholder participation and plan revisions, will continue for many years and will be an effective mechanism for addressing the water management issues facing the Region. Consequently, IRWMP objectives, regional priorities, and statewide priorities will continue to be reviewed for relevance and modified as needed to ensure the overall IRWMP reflects regional changing needs and continues to be effective. Additionally, proposed projects will be reviewed and evaluated on a regular basis to ensure that current plan objectives will be met and that the resulting Plan Projects offer the greatest benefit possible. Periodically, a new set of Plan Projects will be selected to address revised IRWMP objectives and State and regional priorities. This ongoing review and update allows the plan to undergo “adaptive management”; e.g., allow the IRWMP to evolve in response to changing conditions and as better data is developed. IRWMP revisions will result in:

1. An updated evaluation of information and data related to watershed conditions
2. An evaluation of projects/actions and their contribution to meeting IRWMP measurable objectives
3. Revised objectives, strategies, and projects based on new conditions and past project successes

As discussed in Section 9, in developing the IRWMP objectives, the Participants and Executive Committee members determined that it was important that they not only be measurable, but also that the existing conditions of the resources at issue be quantified so that change/progress could be reasonably ascertained at a later date. These performance measures were developed to allow progress of the individual projects to be measured and to gauge the impact of the overall IRWMP.

As projects are implemented in the Region as part of this IRWMP, project performance will be assessed and outcomes will be monitored, and the results from this monitoring will be used to guide future project implementation. If monitoring reveals, for example, that a project is progressing as planned and regional changes do not necessitate revisiting project

implementation, then changes to project prioritization would not be anticipated. However, if monitoring reveals that a project, or suite of projects, are not producing the anticipated result, corrective actions (whether it be improving a specific project, changing the project prioritization, strengthening the measures by which those projects are being monitored, etc.) can be implemented. This information will feed into future updates of the plan and keeps it a living document.

14.5.1 Data Collection and Integration into State Programs

As described in Section 14.4, groundwater, surface water, and water quality monitoring already takes place within the Region. Many of the mechanisms by which KCWA, the subregions and the cities collect data are described by the monitoring programs and procedures described therein.

Data collected as part of this IRWMP can be used to support existing state programs such as the Surface Water Ambient Monitoring Program (SWAMP), the Groundwater Ambient Monitoring and Assessment (GAMA), and the California Environmental Resources Evaluation System (CERES), as well as water use efficiency and demand reduction data collected by the SWRCB.

- Surface Water Ambient Monitoring Program (SWAMP). All the surface water data collected as part of the IRWMP will be consistent with SWAMP database compatibility guidelines and will be exported annually to the state database using the required data submission formats. Where appropriate, IRWMP sampling activities will be performed according to SWAMP quality assurance requirements.
- Groundwater Ambient Monitoring and Assessment (GAMA). Groundwater data collection efforts as part of the IRWMP will be coordinated with the needs of the GAMA program and will be consistent with database specifications so that the data can be easily submitted, shared, and integrated into the GAMA database. Field sampling efforts will be coordinated with the GAMA program to eliminate duplicative data collection efforts and fill data gaps.
- California Environmental Resources Evaluation System (CERES). All data and reports will be sent to CERES so that information will be available and useful to a wide variety of users.
- California Statewide Groundwater Elevation Monitoring (CASGEM). On November 4, 2009 the State legislature enacted SBX7-6, which mandates a permanent statewide, locally-managed groundwater elevation monitoring program for California's groundwater basins and sub-basins identified in DWR Bulletin 118. To achieve that goal, the law directs that groundwater elevations be regularly and systematically monitored, and groundwater elevation data collected under collaboration between local monitoring entities and DWR.

  The primary objective of the CASGEM monitoring program is to define the seasonal and long-term trends in groundwater elevations in California's groundwater basins. The scale for this evaluation is a static regional groundwater table or potentiometric surface. A secondary objective is to provide sufficient data to draw representative contour maps of the elevations. These maps are to be used to estimate changes in groundwater storage and to evaluate potential areas of overdraft and subsidence. In the Kern Region, the

agricultural water districts that overly usable groundwater are designated as monitoring entities under CASGEM and are submitting the required dataset to the State.

14.5.2 Dissemination of Data

Dissemination of data to Stakeholders, agencies, and the general public is integrated into the IRWMP process to ensure overall success. A requirement of the implementation grant program is the routine reporting on project performance. The routine collection of data that occurs as part of other processes will support the data reporting that is required as part of the IRWMP process. A database for maintaining project information is available to each Stakeholder for proposing new, or updating current or old, projects for inclusion in the IRWMP. Although updating the data is not stipulated in the Governance structure, it is in the best interest of the Participants group to keep the database current, so the most updated information is used to evaluate projects using the project prioritization framework as outside funding sources become available. Data collected or produced as part of the IRWMP will then be presented and disseminated during future meetings.

A public website, www.kernirwmp.com, has been created to store data and information about the IRWMP process so that the public can find information about public meeting dates, agendas, and notes. The website provides information on the IRWMP process and posts relevant documents that can be downloaded. Data collected during the process will be available on the website, as well as links to other existing monitoring programs to promote data between these programs and the IRWMP. This will provide a means to identify data gaps (e.g., information needed to provide a more complete assessment of the status of a specific issue or program) and to ensure that monitoring efforts are not duplicated between programs.

The Executive Committee will direct the management of the website, via an outside consultant, who will be responsible for maintaining the website by updating and tracking IRWMP documents. The website will serve as a means to track, store, and disseminate data related to the IRWMP including monitoring data and data within State databases. The website will also serve as a means to share data within the watershed and with adjacent planning regions, as well as to facilitate the use of project-specific monitoring efforts to improve the RWMG's ability to implement future projects in the IRWMP.

Section 15: Coordination and Outreach

This section provides information on the coordination and outreach efforts with local and state agencies, DACs, and the broader public, undertaken as part of the Kern IRWMP development.

15.1 Coordination with Local Land Use Planning

The Kern IRWMP establishes broad objectives and planning targets for the entire Kern Region. Projects and programs implemented by the IRWMP participants will likely remain the primary means by which the IRWMP's objectives are contributed. As noted in a number of the stakeholder meetings, many of the local agencies increasingly acknowledge the value of collaboration in the planning, design, implementation, funding, monitoring and maintenance of integrated projects. Implementation of the Kern IRWMP supports the development of integrated projects, provides a comprehensive framework that can support planning by individual agencies and jurisdictions, and encourages integrated planning for those issues that could benefit from a regional approach.

Municipal and county governments and special districts include local jurisdictions and land use planning agencies that are involved in the identification of issues, formation of objectives, and development of projects contained in this IRWMP. Their participation provides a link between local planning agencies and this IRWMP by offering discussion in meetings, providing accurate, consistent land use planning information, and incorporating a wide variety of local planning documents and goals into the project objectives. The cities of Bakersfield, Tehachapi, Delano, Arvin and Wasco, the County of Kern, KCRMA, and Kern Council of Governments are examples of land use agencies and entities participating in the meetings.

15.1.1 Linkages Between the IRWMP and Local Planning Documents

Numerous plans and studies related to water resources and land use management in the Kern Region has contributed to the development of the IRWMP. These documents are described in detail in Sections 14.2 and 14.3. The Kern IRWMP has been developed from and is consistent with local planning efforts in the Kern Region, as discussed below.

- Regional Description: The Kern IRWMP has utilized information from the Kern County General Plan, the General Plans from the cities of Bakersfield, Wasco, Taft, Delano, Arvin, Tehachapi, and Shafter, the Kern River Valley Specific Plan, the on-going Kern Regional Blueprint Program, as well as discussions with city and County planning staff to describe the Region and subregions. The IRWMP relies on these planning documents to describe the existing setting of the Region and subregions, including existing and planned land uses (see Section 2). In addition to providing information on the social and cultural makeup of the regional community, these plans also provided information on population projections, economic conditions and trends and special environmental resources and environmental water demands. Increasingly, local land use agencies are collaborating with water purveyors to more effectively manage the Region's water demand and infrastructure with respect to climate change impacts. Regional land use planning agencies regularly participate in the IRWMP. Their input, specifically with regard to climate change, will help to potentially offset climate change impacts to water supply in California.

- Regional Issues, Needs, and Objectives: Stakeholders were asked to identify major water issues and problems. Specific consideration of regional water supplies and issues was informed with data from multiple local planning documents, but primarily from UWMPs prepared by the local water agencies. Water quality issues were examined using information contained in the CVRWQCB's Basin Plan and its amendments. Habitat, species, and resource stewardship issues were examined based on general plans, the Valley Floor and MBHCPs and other environmental stewardship plans. Based on the issues identified, Stakeholders were then asked to develop IRWMP objectives.
- Involvement of Land Use Decision Makers: Land use decisions have the potential to affect the way water is managed in the Kern Region, and the way the resource management strategies are utilized in the Kern IRWMP, as land use can affect population growth, water demand, and surface water quality. The implementation of stormwater capture projects may require acquisition of land which could displace existing uses and may warrant consideration of modifications to land use policies and practices. In addition, the passage and implementation of water conservation or floodplain management ordinances can further address IRWMP objectives. In developed areas, the land use decision makers are primarily cities and counties. In open space areas, the USFS, Bureau of the Land Management, National Park Service, and California State Parks have regulatory responsibility for the conservation and preservation of those spaces. Additionally, many 'open spaces' in the Kern Region are undeveloped rural lands under jurisdiction of the County of Kern. All of these agencies and jurisdictions have been involved in the development of the IRWMP as part of the stakeholder process.

15.1.2 Participation by Local Planning Entities

As mentioned above, local planning entities, such as the municipalities, the County of Kern Development Services Agency, and Kern COG participated in development of the IRWMP and will participate in continuing IRWMP implementation. These local planning entities participated in Stakeholder meetings, provided updated data (as described above), reviewed and commented on IRWMP sections, sponsored projects, and participated in the prioritization of projects. As described in Section 12, these planning agencies, along with the general Stakeholder group, will be asked to participate in all updates of the IRWMP, by participating in meetings, providing information and data necessary to revise objectives, by making recommendations regarding project ranking, and by sponsoring projects.

15.2 Coordination with State and Federal Agencies

15.2.1 Participation in IRWMP Development

Several State and Federal regulatory and resource agencies were involved in the identification of issues, formation of objectives, and development of projects for this IRWMP. Coordination with these agencies is essential to the development and implementation of all recommended projects due to the need for regulatory and environmental approval prior to implementation. Furthermore, these agencies have had the chance to address items of concern on these projects at the stakeholder meetings. Their roles and responsibilities are to ensure that this IRWMP consider resource management, resource enhancement, and regulatory compliance

standards. The agencies include the DWR, DDW, SWRCB, CDFW, CVRWQCB, USBR, USFWS, and USFS.

15.2.2 Participation in IRWMP Implementation

As described in Section 12, the RWMG intends to continue coordination with State and Federal agencies as the IRWMP is updated through time. It is anticipated that State and Federal agencies will continue to participate in the IRWMP as participants and project proponents. Ongoing participation by these entities will enhance the technical data and knowledge in the IRWMP. These agencies will also be able to identify and recommend funding sources for IRWMP implementation. In addition, implementation of Plan Projects will require coordination with multiple Federal and State agencies, such as:

- DWR. DWR as the state agency with oversight of IRWM Planning, DWR will review the Plan for compliance with the IRWM Guidelines. This will include review of all components of the Plan, including Governance, Projects and Data Management. DWR also has oversight of the grant funding application process and grant award program. Depending on the lists of IRWM Projects submitted for specific funding rounds by the RWMG, DWR will have some level of approval authority.
- CDFW and USFWS. CDFW and USFWS oversee implementation of the California and Federal ESA and regulate activities that may impact endangered species and their habitats (Fish and Game Code, Sections 2050 et seq.). Any Plan Projects with potential impacts to sensitive species will require consultation with these agencies. CDFW also oversees any activity that will substantially modify a river, stream, or lake (Fish and Game Code Sections 1600 et seq.). Before undertaking any activity that would result in modification of a river, stream, or lake, it will be necessary to obtain a Lake or Streambed Alteration Agreement from CDFW.
- DDW. DDW regulates public water systems, including allowable treatment technologies for drinking water and the treatment and distribution of recycled water. Any Plan Projects that involve treatment of drinking water or recycled water will require coordination with DDW.
- Central Valley RWQCB. The CVRWQCB sets goals for groundwater and surface water quality in Kern County. Based on these goals, the CVRWQCB regulates discharges to groundwater and surface water, including storm water runoff. Any Projects that could result in storm water runoff or which could result in a change in discharges to surface or groundwater may have to coordinate with the CVRWQCB. Under the CWA Section 401, every applicant for a federal permit or license for any activity which may result in a discharge to a water body must obtain State Water Quality Certification (called a 401 Certification) to ensure that the proposed project will not violate state water quality standards. Most 401 Certifications are issued in connection with US ACE permits for dredge and fill discharges. The CVRWQCB reviews projects for 401 Certification.
- USACE. USACE has regulatory authority over all discharges of dredge and fill materials within navigable waters and waters (such as intermittent streams and wetlands) with significant connection to navigable waters. The USACE regulates such projects through the issuance of permits. Any IRWM Plan Projects that could result in discharge of dredge and fill material to a water body may have to coordinate with the USACE.

15.3 Public Outreach/Disadvantaged Community Outreach

Public participation is a critical component of the IRWMP process. The water resources in Kern County are utilized for such varied purposes that development of the Kern IRWMP requires participation from all water users. To reach members of the public at large, the Kern IRWMP established a public website that includes meeting information and handouts, points of contact and links to relevant documents and internet webpages, including DWR's IRWM webpage. Additionally, meeting information was periodically posted on news websites (both English and Spanish) and online public message/information boards. Staff also worked diligently to identify possible representatives of specific public interest groups, such as DACs, Native American Tribal communities, and water recreationists. Once identified, staff sent emails and made phone calls to directly contact these individuals and organizations. Additionally, mailers were sent to public mailing lists provided by the County of Kern and several other participants. The goal of the outreach effort was to inform individuals and organizations of the IRWM program, Kern IRWMP efforts to date and methods of participation. Recognizing that attendance at and participation in meetings, even evening meetings, might not be possible, members of the public were encouraged to submit comments via phone or email so that their concerns and issues could be listed and addressed even in their absence.

Recognizing the importance of community participation, particularly from DACs and Tribal communities, while understanding that personal and professional obligations may inhibit participation in the Kern IRWMP, the Kern Group also relied on participation from community organizations, including Self-Help Enterprises (http://www.selfhelpenterprises.org/) and Community Water Center (http://www.communitywatercenter.org/). Self-Help Enterprises and Community Water Center both work with DACs in the San Joaquin Valley, and both groups are actively involved in water-related issues. Self-Help Enterprises has experience working with Kern County communities on a variety of topics, including water supply and quality related concerns. Through their work, Self-Help Enterprises has created list of community water projects, which was provided to the Kern IRWMP Executive Committee in order to highlight some of the concerns in the region. Community Water Center has experience and knowledge similar to that of Self-Help Enterprises. Community Water Center has actively participated in the Kern IRWMP and continues to share their knowledge with the Kern RWMG. Through the participation of these community organizations, the Kern IRWMP has been able to expand our outreach and gain valuable knowledge regarding community water needs that otherwise may not have been possible.

To further encourage public participation, the Kern IRWMP held evening meetings on multiple occasions. These meetings were advertised on local news websites and public message boards. In addition to locally held subregion meetings, the Kern Group also maintains an open invitation to participants to request local participant meetings be held. To date, one such request has been received, made by participants from the Kern River Valley area, located in the northern portion of the Mountains and Foothills subregion, who wanted to increase public participation in their area by hosting a meeting. On June 15, 2009, an evening meeting was held at the Kern River Valley Veterans/Senior Center in Lake Isabella, CA. The meeting was open to all members of the public. Similar to other Kern IRWMP outreach efforts, the meeting was spent providing the public with information on the IRWM program, the Kern IRWMP and methods of participation. Additional time was spent discussing the Kern IRWMP's relationship with the Southern Sierra IRWMP and possible project partnerships that could be established in the region. As a result of this meeting we were able to nearly double our participant contact list for the area.

More recently, the Kern IRWM Group has been participating in the Disadvantaged Community Involvement Program (DACIP). The Tulare/Kern Funding Area, which includes seven IRWM Regions, received funding for this program through Proposition 1 to assist the IRWMPs with outreach and planning efforts related to DACs. The objectives of the DACIP include (1) working collaboratively to involve DACs, CBOs, and stakeholders in IRWM planning efforts; (2) increase understanding and identify water management needs of DACs in the area; and (3) develop strategies and long-term solutions to address DAC water management needs. In January 2019, a Preliminary Needs Assessment was released to the Funding Area, which updates the assessment from the Tulare Lake Basin DAC Study. The DACIP also provides funding for project development work items for DACs. On May 21, 2019, a workshop was held with about a dozen DACs to discuss the funding and the potential DAC projects that could utilize the funding. Seven (7) DACs from the Kern Region are pursuing this funding source; it is expected that over $250,000 is anticipated to be distributed to these DACs in August 2019.

15.3.1 Tribes

Open channels of communication and good working relationships are already established between the Kern IRWMP and the Tubatulabal Tribe of Kern Valley. The Tubatulabal Tribe of is a participating stakeholder and has provided input into the development of this IRWMP. The Tejon Indian Tribe received Tribal re-affirmation (Federal recognition) in January 2012. The Tejon Indian Tribe does not currently have communal lands, but in June 2019, the Tribe has partnered with Hard Rock International to pursue a hotel and casino development 25 miles south of Bakersfield (Tejon Indian Tribe, 2019). The Kern IRWMP will continue to collaborate with these tribes regarding water issues. It is noted that Tribes are sovereign nations, and as such coordination with Tribes is on a government-to-government basis.

15.3.2 Environmental Justice

Concerns for environmental justice will need to be addressed as part of IRWMP implementation. As the Kern Region continues to develop, care will need to be taken to prevent creating environmental justice issues that unfairly affect certain communities, in particular, DACs. The Kern IRWMP objectives of increasing water supplies, improving operational efficiencies, improving water quality, promoting land use planning and environmental stewardship, and improving regional flood management, must be consistently applied to future projects so as to ensure greatest regional benefits without placing an undue burden on a specific community.

Section 16: Climate Change

Climate change refers to significant changes in temperature, precipitation, wind patterns and other weather that occur over several decades and beyond. Climatic changes observed in recent decades are occurring due to rising average global temperatures that are the result of elevated levels of gases released primarily by human activities, which trap heat in the atmosphere in a process known as the greenhouse effect. These so-called greenhouse gases (GHGs) include, among others, water vapor, carbon dioxide (CO2) and methane (CH4).

Climate change is impacting California water resources in many ways, including through rising sea levels, reduced snowpack, and more frequent and severe droughts. Impacts and vulnerabilities vary by region resulting in the need for tailored actions to ensure the viability of regional watersheds, including the Kern Region. These actions focus on reducing the intensity of climate change through mitigation measures and adapting to climate change effects.

This section identifies the potential climate change vulnerabilities in the Kern Region as well as potential future actions to mitigate the vulnerabilities to climate change. The climate change vulnerability assessment presented in this section includes the checklist assessment in the Department of Water Resources (DWR's) Climate Change Handbook for Regional Water Planning and is consistent with climate change requirements in the IRWM Guidelines.

16.1 Climate Change Projections Overview

A climate change assessment is performed using the output of computer models that project future conditions from inputs on GHG emissions. These models are not predictive but provide projections of potential future climate scenarios that can be used for planning purposes.

Climate change has the potential to have significant impacts on the Kern IRWM Region. The USBR, the State of California and others continue to study climate change and its potential impacts on water and other resources in the western states.

The primary climate variables projected by global climate models (GCMs) that are important for water resources planning in California are changes in air temperature, changes in precipitation patterns, and sea level rise. Changes in precipitation patterns affect the amount, intensity, timing, quality and variability of runoff and recharge. The State of California 2009 Climate Change Impacts Assessment (California Climate Change Center 2009) provides the scientific basis for developing statewide climate change impact projections. The 2009 assessment provided future climate projections to support water resources decision making in California. A set of six GCMs were run for two GHG emissions scenarios, A2 and B1, selected from the Intergovernmental Panel on Climate Change (IPCC) Special Report on Emissions Scenarios (SRES). The IPCC report provides a family of common scenarios that cover a range of plausible trends in GHG emissions over the 21st century as a result of economic, technological, and population change (IPCC 2007). Scenario A2 assumes higher GHG emissions and high growth in population and represents a more competitive world that lacks cooperation in development (similar to business as usual), while B1 is a lower GHG emission scenario that represents social consensus for sustainable development. Each GCM was used to simulate a historical period from 1950-1999 and a future projection period from 2000 to 2100. The 1950-1999 period serves as a baseline or "present condition" for the models so that future conditions

can be projected. **Table 16-1** lists the six GCM models and their sponsoring organization, the combination of which were used to evaluate climate change impacts in the Kern Region.

TABLE 16-1: Summary of Global Climate Models

GCM	Sponsoring Organization and Model Name
NCAR-PCM1[(a)]	National Center for Atmospheric Research (NCAR) Parallel Climate Model (PCM)
GFDL-CM21[(a)]	National Oceanic and Atmospheric Administration (NOAA) Geophysical Fluids Dynamics Laboratory (GFDL) model, version 2.1
NCAR-CCSM3[(a)]	NCAR Community Climate System Model (CCSM)
MPI-ECHAM5	Max Plank Institute ECHAM5/MPI-OM Used by DWR for its climate change analysis for the 2011 Reliability Report, but the 2013 Draft Report Update uses Bay Delta Conservation Plan (BDCP) LLT CC5 input hydrology.
MIROC32	MIROC 3.2 medium-resolution model from the Center for Climate System Research of the University of Tokyo and collaborators
CNRM-CM3[(a)]	French Centre National de Recherches Météorologiques (CNRM) models
Four Model Average[(a)]	Cal-Adapt website. Average of the following four GCMs: NCAR-PCM1, GFDL-CM21, NCAR-CCSM3, and CNRM-CM3. Used in this analysis for Kern River Region

Note: (a) Model used by Cal-Adapt.

DWR used the MPI-ECHAM5 model with the A2 emissions scenario when preparing the 2011 State Water Project Delivery Reliability Report. MPI-ECHAM5 represents the median of the six GCMs listed in the table. However, the 2013 Delivery Reliability Report (December 2013) uses the climate change input hydrology developed for the Bay Delta Conservation Plan (BDCP) for the Late Long Term planning horizon and the 5th climate change region (BDCP LLT CC5 input hydrology). This had the effect of lowering State Water Project (SWP) long-term future reliability, from 60% to 58%.

The California Energy Commission's Public Interest Energy Research Program (PIER) recently established the Cal-Adapt website (http://cal-adapt.org/), whose purpose is to explore California's climate change research. In part, the website provides output from four climate models (NCAR-PCM1, GFDL-CM21, NCAR-CCSM3, and CNRM-CM3) and two GHG emission scenarios (A2 and B1) downscaled to any location in California. The four GCMs are a subset of the six GCMs identified in the table. Because the BDCP LLT CC5 GCM is not included in Cal-Adapt, an average of the four GCMs (also provided by Cal-Adapt) with the A2 emission scenario was used in this analysis for the Kern Region.

16.2 Kern Region Climate Change Projections

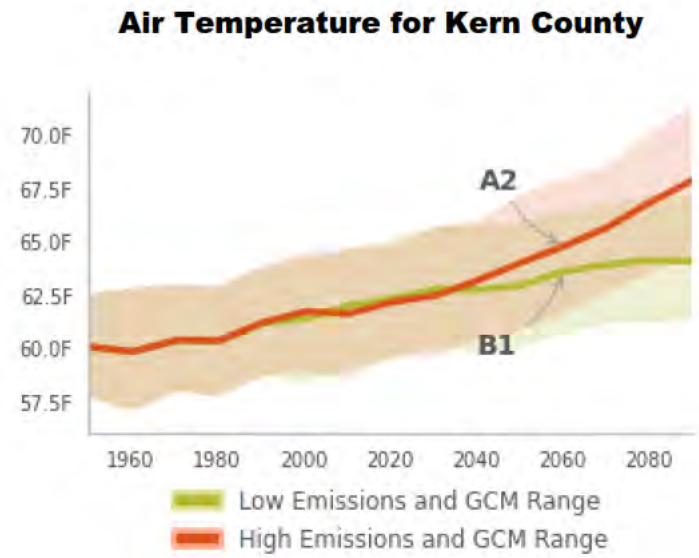
Climate change is expected to have various impacts on the Kern Region including: (1) changing hydrology, and the resultant impacts to conjunctive use operations, due to a shift from snow to rain precipitation, (2) higher wildfire risk due to warmer, drier conditions over the year, and associated impacts on water quality and flooding, (3) fluctuations in temperature resulting in longer and drier conditions over the year, and associated impacts on water quality and flooding,

(4) longer and more severe multi-year droughts, (5) greater summer water demand from all categories of users and (6) impacts to habitats and species.

16.2.1 Temperature

Cal-adapt projects that locally, overall air temperatures are expected to rise from 1degree Fahrenheit (°F) to 2.3°F over the next few decades. The historical average annual temperature in the Kern region is 61.4°F; the A2 and B1 scenarios project increases of 3.5°F and 6.3°F by the end of the 21st century. Figure 16-1 shows the projected air temperature change for the four GCMs averaged from 2000 through 2100, compared with the historical baseline from 1950- 2000. The projected temperature increases begin to diverge at mid-century so that, by the end of the century, the temperature increases projected in the higher emissions scenario A2 are almost twice as high as those projected in the lower emissions scenario B1.

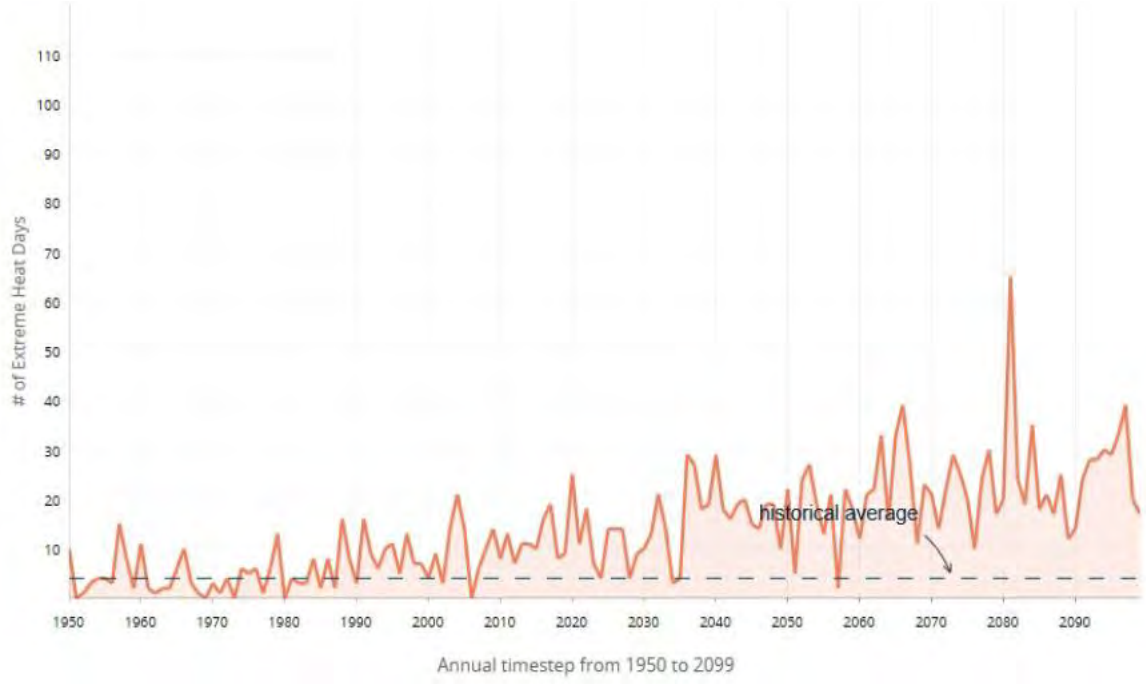
Figure 16-1: Historical and Projected Annual Average Air Temperature for Kern County



Source: Cal-adapt.org. Bakersfield Area

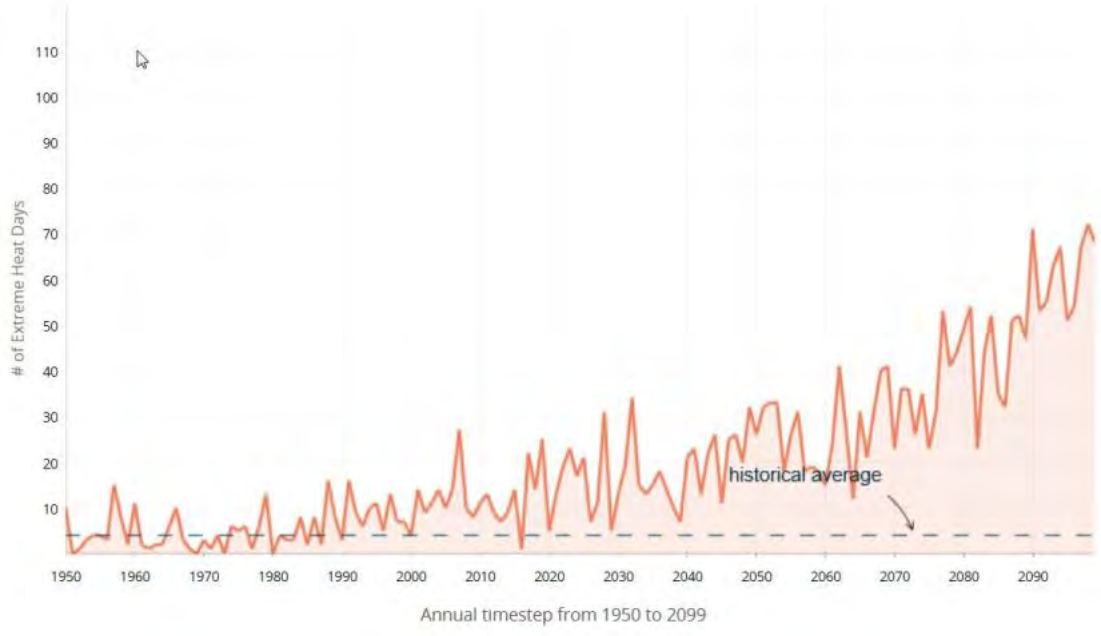
In addition to overall temperature increases, the region is projected to encounter higher incidences of extreme temperatures. **Figure 16-2** and **Figure 16-3** show the projected increases in extreme temperature days in Kern County for the B1 and A2 emission scenarios. This chart displays a count of the number of days that the selected area on the map is projected to exceed the area's calculated "extreme heat threshold" of 101°F for each year 1950-2099. The historical annual average number of extreme heat days is four. Both scenarios project that number will increase to about 30 days by mid-century and either 40 or 70 days by the end of the century, depending on the emissions scenario. The increased temperatures will likely increase evaporation, leading to drier soils, increased crop evapotranspiration, and a longer growing season.

Figure 16-2: Number of Extreme Heat Days (Low Emission Scenario)



Source: Cal-adapt.org. Bakersfield Area

Figure 16-3: Number of Extreme Heat Days (High Emission Scenario)



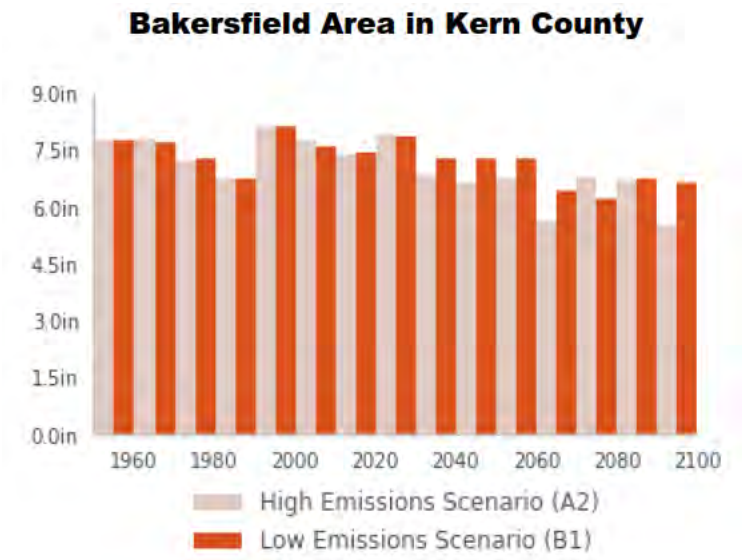
Source: Cal-adapt.org. Bakersfield Area

16.2.2 Precipitation

Precipitation in the Kern Region is essentially all in the form of rain, and significant shifts in the timing of precipitation are not expected to occur. On average the projections indicate little change in total annual precipitation in California. Furthermore, among several models, precipitation projections do not show a consistent trend during the next century. The Mediterranean seasonal precipitation pattern is expected to continue, with most precipitation falling during winter from North Pacific storms. One of the four climate models projects slightly wetter winters, and another projects slightly drier winters with a 10 to 20 percent decrease in total annual precipitation. However, even modest changes would have a significant impact because California ecosystems are conditioned to historical precipitation levels and water resources are nearly fully utilized.

Figure **16-4** shows the decadal precipitation projections from 1960 through 2100 for the Bakersfield area in Kern County. There appears to be continued variable precipitation over the next century, with an overall consistent decrease. Drier conditions may result in a reduction in effective precipitation for crop irrigation needs and higher wildfire risk in the Region.

Figure 16-4: Projected Annual Precipitation for the Bakersfield Area in Kern County



Source: Cal-adapt.org. Bakersfield Area

16.2.3 Wildfire

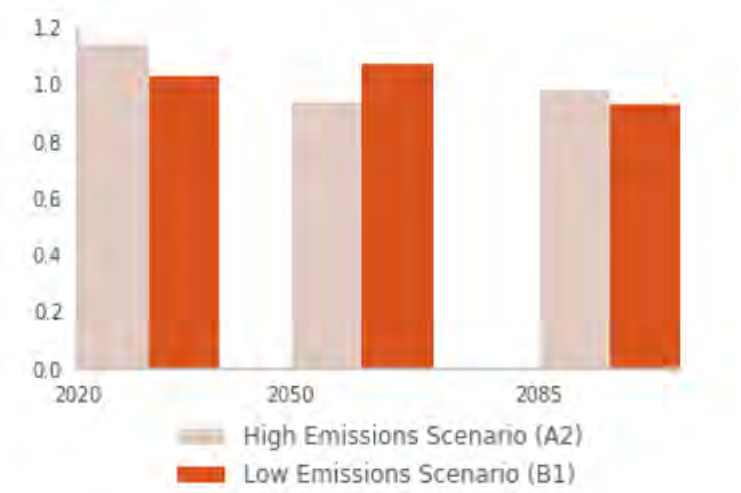
Fire is an important ecosystem disturbance. It promotes vegetation and wildlife diversity, releases nutrients into the soil, and eliminates heavy accumulation of underbrush that can fuel catastrophic fires. Statewide, the area projected to be burnt by wildfire toward the end of the century will increase substantially, especially in mountainous areas. As climate changes, it appears that summer dryness will begin earlier, last longer and become more intense. These

changes may exacerbate fire occurrences, which have historically peaked in late summer and early fall. If temperatures rise into the medium warming range, the risk of large wildfires in California could increase by as much as 55 percent, which is almost twice the increase expected if temperatures stay in the lower warming range.

Because wildfire risk is determined by a combination of factors including precipitation, winds, temperature, landscape and vegetation conditions, future risks will not be uniform throughout the state. In years with wet winters, annual vegetation growth is plentiful. But accentuated dryness during summer would produce a hazardous fuel load that worsens the wildfire problem in some of Southern California wildlands. With expanding development into the urban/wildland interface, threats to human safety and property are even greater. The spread of invasive species that are more fire-prone, coupled with more frequent and prolonged periods of drought, all increase the risk of fires, and reduce the capacity of native species to recover. Wildfires are also bad news for the region in terms of air quality, human health, soil erosion and stress on watersheds.

Figure 16-5 shows projected increases in potential area burned in the Bakersfield area of Kern County. The y-axis represents the ratio of additional fire risk for an area compared to the expected burn area. These data are modeled solely on climate projections and do not take landscape and fuel sources into account.

Figure 16-5: Projected Increase in Potential Area Burned in the Bakersfield Area of Kern County



Source: Cal-adapt.org. Bakersfield Area

Fire is an important process in maintaining a diverse ecosystem in the Region. It is unclear at this time whether projected increased wildfire risk will be beneficial or harmful to long term ecosystem health and habitat maintenance but will likely negatively impact water quality with increased turbidity loading to water supplies.

16.3 Resources in the Kern Region Vulnerable to Climate Change

This section identifies the resources within the Kern Region, its related areas that are potentially affected, and their collective potential vulnerability to climate change. **Table 16-2** provides a general overview of the water-related resources that are considered important in the Kern Region and potentially sensitive to future climate change. Resources that are likely to be vulnerable to climate change are considered for further analysis in the preceding subsections. The table also highlights those resources in the Region that are unlikely to be affected by climate change and therefore they do not warrant further analysis and consideration at this time. The summary table provides the main categories applicable to water planning in the Kern Region with a general overview of the qualitative assessment of each category with respect to anticipated climate change impacts. **Table 16-3** in Section 16.4 below provides the complete assessment of the regional vulnerability to the potential climate change impacts using the 'Vulnerability Assessment Checklist', found in the Climate Change Handbook for Regional Water Planning (DWR, 2011).

Table 16-2: Climate Change Vulnerability Assessment Overview Watershed Characteristics General Overview of Vulnerabilities

Watershed Characteristics	General Overview of Vulnerabilities
Water Demand	Urban and Agricultural Water Demand – Changes of hydrology in the Region as a result of climate change could lead to changes in water demand, both in quantities and patterns. Increased irrigation (outdoor landscape or agricultural) is anticipated to occur with temperature rise, increased evaporation losses with warmer temperature and longer growing season.
Water Supply	Imported Water – State Water Project (SWP) and Central Valley Project (CVP) water via the California Aqueduct and the Friant-Kern Canal are an important portion of the water resources available to the Region. Potential impacts on SWP and CVP water availability resulting from climate change directly affect the amount of imported water supply delivered to the Region, part of which will be delivered to recharge groundwater banking programs in the Kern Region. Groundwater – Changes in local hydrology could affect natural recharge to the local groundwater aquifers and the quantity of groundwater that could be pumped sustainably over the long-term. Decreased inflow from runoff, increased evaporative losses, warmer and shorter winter seasons can alter natural recharge of groundwater, as well as conjunctive use operations. Alternatively, if more precipitation occurs as rain, short-term high flows could result, and will require the Region to adapt to the faster runoff which will impact the timing of conjunctive uses. In addition, additional reductions in the imported water imposed by climate change would lead to more reliance on local groundwater, resulting in reductions in base flows, reduced groundwater outflows, increased depth to groundwater and increased land subsidence. .

Watershed Characteristics	General Overview of Vulnerabilities
Water Quality	Imported Water – Sea level rise could result in increases in chloride and bromide (a disinfection by product precursor), potentially requiring changes in drinking water treatment. Increased temperatures could result in an increase in algal blooms and taste and odor events. Regional Surface Water – Increased temperature could result in lower dissolved oxygen, increased algal blooms, and task and odor affect to the Kern River and its tributaries. Decrease in annual precipitation could result in higher concentrations of contaminants in these surface waters during droughts. Increased wildfire risk and flashier storms could increase turbidity loads for water treatment, irrigation filtration systems and spreading basins (sedimentation and loss of percolation rates). Return flows from groundwater banking programs have inherent water qualities. Increased use of banking projects is leading to replacement of higher quality snowmelt surface water (Kern River and Friant CVP), as these supplies are being diverted further upstream than historical diversions to effect transfers and exchanges, and replaced with groundwater supplies that are higher in salt constituents (TDS, nitrates, etc.).
Sea Level Rise	The Kern Region is not directly subject to sea level rise. However, potential effects of sea level rise would affect imported water supply conditions. As discussed above, the principal concern is the potential for sea water intrusion to increase Sacramento-San Joaquin Delta (Delta) salinity. While sea level rise is not a direct regional concern, pursuant to the California Ocean Protection Council Resolution adopted March 11, 2011, it should be considered in the project selection/prioritization process.
Flooding	Local surface flows could change as a result of more frequent and intense storm events, leading to more areas susceptible to flooding, and increasing risk of direct flood damage in the Kern Region.
Ecosystem and Habitat	Increased temperature and potential decreases in annual precipitation could put stress on sensitive ecosystems and alter habitats. Water-dependent recreation could also be affected by water quality impacts. In addition, the Kern Region may be subject to increased wildfire risk, which could alter habitat.
Hydropower	Hydropower production in the Kern Region is small, however power through the Western Area Power Administration operated by the BOR does provide power to the CVP. Because of the amount of hydropower used in comparison to the size of the Region is relatively small, climate change effects on hydropower are not considered to be significant.

Climate change processes are supported by extensive scientific research and are based on a vast number of peer-reviewed and published technical literature. Much of the available literature presents general information, but there is relatively little information that presents

specific tools on how to assess impacts in the context of addressing climate change impacts on water resources. In addition, far less information is available on smaller geographic areas and the spatial resolution of the existing climate change models is still quite low. One additional challenge is that precipitation projections cannot be easily converted directly into surface runoff and groundwater recharge effects to connect with the local water resources planning activities.

The following sections present the vulnerability of each sector identified in **Table 16-2** with respect to climate change projections given the existing tools and available data. This is an initial attempt using projections specific to the Kern Region for the vulnerability assessment in support of the IRWMP. The outcome of this initial assessment is intended to help understand the potential impacts, to integrate climate change into long-term planning, and to improve understanding of the uncertainties associated with climate change effects. Consistent with the water resources planning horizon in the Kern Region through 2050, the vulnerability analysis considers projections for mid-21st century (2050), consistent with DWR's modeling approach to climate change.

16.3.1 Water Demand

Increasing air temperatures due to climate change will result in increased evaporation leading to drier soils, increased plant evapotranspiration (ET), and a longer growing season. All of these factors generally increase water demand however there are not sufficient data available to estimate a total volume.

The Cal-Adapt A2 emissions scenario projects an average temperature increase for the Kern Region of about 3.3°F by the mid-century (2050) and increase of about 6.3°F by the end of century (**Figure 16-1**). Characterizing the impacts of temperature rise on water demand is a difficult task and discussed on a qualitative basis. While water use varies considerably depending on other factors such as regional economy, population, and land use, a qualitative assessment of water demand increase can be noted based on the projected temperature increase from the Cal-Adapt emission scenarios.

An important effect of changing weather conditions is likely to be on landscape and agricultural demand. Higher temperature generally increases ET rates; but some research studies also suggest higher CO2 levels and higher temperature increase rates of plant growth and can shorten the time to plant maturity (Hanak and Lund, 2008). This would reduce the overall plant water uptake, partially compensating for potential reductions in agricultural water supply. Thus, the net effect on agricultural crops is still uncertain (Kiparsky and Gleick, 2005) and remains an important area of on-going research.

Qualitatively, the ET projections with climate change suggest water demand for agriculture in the Region is anticipated to increase during months where ET is high and decrease in months where ET is low. As a result of increased ET, urban water demand is anticipated to increase as well because of greater outdoor water use for landscape irrigation and agriculture.

Demand management is an important adaptation given decreased water supply as a result of climate change. Agriculture has a variety of water demand management options including fallowing fields of annual crops and changing the crop itself to one that may be less water intensive, yet economically viable. Additionally, in some cases, farmers may be able to switch their water source from surface water to groundwater. Demand management options for the

urban landscape sector range from climate appropriate plants to improved irrigation methods. Water demand management strategies are discussed in Section 11.2.

16.3.2 Water Supply

For long-term water supply planning, coping with variability is a challenge. With potential additional changes imposed by climate change, there will be a heightened need to evaluate and respond to increased water supply variability. Climate change is expected to affect Regional imported water supplies as follows:

- Total precipitation is expected to decrease in the Sierra Nevada sources, reducing runoff to surface supplies.
- Snow pack is projected to decrease as precipitation shifts toward more rain and less snow.
- Timing of runoff is expected to shift to earlier in the year, affecting reservoir storage especially in the spring and summer months, as well as groundwater recharge activities.
- Sea level rise may impact Delta water deliveries.

Climate change is expected to affect Regional surface and groundwater supplies as follows:

- Total precipitation is not projected to change significantly, however the trend is decreasing.
- Variability in annual precipitation is expected to continue, with vulnerability to droughts. This is especially important for the highly variable Kern River system.
- More intense storms are anticipated that may affect surface water runoff, surface storage and groundwater recharge.

Climate change is expected to affect Regional oil and gas activities. Oil and gas drilling in the county could be impacted by decreasing water availability, particularly in times of drought by limiting the amount of water available for cooling, fuel extraction, and power generation. The effects of climate change and water availability on the oil and gas sector include a combination of potential direct and indirect impacts. Water is required in many different stages of the oil and gas value chain, from exploration to processing to transport, and the volume of water used in these activities varies, with the largest volume used in the refining process. Among exploration and production processes, the largest volume of water is used as a supplemental source.

Because the Kern Region relies heavily on imported supplies, any reduction or change in the timing or availability of those supplies could have negative impacts on the Region. Reductions in imported water supplies would lead to increased reliance on local groundwater, recycled water or other sources of supplies if demand was not reduced. Changes in local hydrology could affect surface storage of water and natural recharge to the local groundwater and the quantity of groundwater that could be pumped in a sustainable manner. The following sections describe potential climate change impacts to the region's water supplies.

16.3.2.1 Imported Supplies

Imported water deliveries to the Kern Region are from the SWP and CVP via the California Aqueduct, and the Friant-Kern Canal. Increasing development and environmental demands on water availability and quality for agricultural, municipal and industrial (M&I), and groundwater banking purposes, coupled with curtailments of imported SWP and CVP deliveries due to

prolonged drought and regulatory restrictions, have intensified the competition for available water supplies in the Kern Region. Climate change impacts are likely to exacerbate these challenges.

Regarding the SWP, recent studies have found that flow seasonal pattern shift will become a major climate change factor and sea level rise a secondary factor, leading to a half million-acre feet of Delta export reduction as well as a roughly 25% decrease of North-of-Delta carryover storage by around 2060. The primary culprit for these negative impacts on the SWP/CVP system is the flow seasonal pattern shifts due to earlier snow melting and more precipitation falling as rain due to warming. These extra flows occurring in the winter and early spring seasons cannot be conserved in reservoirs to meet high demand in the summer. The extra water is released as flood water in these seasons but most of the released water become Delta outflow (DWR, 2018).

In 2014, USBR completed the Central Valley Project Integrated Resource Plan, which evaluated the performance of the CVP under six potential future climate scenarios. Under scenarios where the climate is hotter and drier, the CVP is able to meet fewer of its contract demands, resulting in greater water supply shortages than currently experienced. Over the 21st century, simulated average annual unmet demands range from 2.7 to 8.2 MAF/year across the range of socioeconomic-climate scenarios. The unmet demands occurred predominantly in the South-of-Delta Divisions (USBR, 2014).

16.3.2.2 Groundwater

One of the longest-standing issues in the Kern Region is groundwater overdraft. Groundwater provides approximately 39 percent of local water needs; however, it is estimated to be as much as 60 percent in dry years.

The Kern Region is well-known for its long-established and successful conjunctive use and banking programs. These programs overlie the major portions of the groundwater basin and can access surface supplies from the Kern River, the SWP, the Friant-Kern Canal, and more. In times of high flows, these surface supplies are recharged and stored to help to lessen the effects of dry period conditions when the Region relies on the groundwater basin.

The groundwater in the Kern Region may also be subject to decreasing reliability related to the extent and duration of longer drought periods that may occur due to climate change. While the basins have supply exceeding the future projected pumping levels, based on the basins' characteristics and their natural recharge processes, changes in local hydrology and natural recharge are anticipated to have a direct impact on available groundwater storage. Warmer winters would increase the amount of runoff available for groundwater recharge, but reductions in inflow from runoff and increased evaporative losses could reduce the amount of natural recharge. The extent to which climate change will change the natural recharge processes and the impact of that change are not exactly known and are difficult to quantify.

Under SGMA, GSPs developed in the Region are required to analyze the impacts of climate change on water supplies. Information and data developed through these GSPs will be incorporated into future updates of the Kern IRWMP once GSPs are completed in 2020. A better understanding of groundwater supplies will be important to continued resiliency against climate change, as water supply management becomes a more important issue in the Region.

16.3.3 Water Quality

Improving water quality is a Kern Region Plan objective that may be impacted by climate change. Studies of potential climate change impacts on water quality exist, but few trends in relationships between hydroclimate (hydrology and weather variables) have been identified. Key climate vulnerabilities potentially important to the Kern Region include increasing temperature and changes in precipitation patterns. Increased wildfire risk is another potential factor that could affect water quality in the Kern Region. Outside the Kern Region, sea level rise in the Delta is expected to impact water quality of imported SWP water.

Surface waters in the Region are expected to be more directly vulnerable to water quality impacts of climate change, while water quality impacts to groundwater sources would be indirect, as conjunctive use and banking programs can increase the amount of salts in the underlying aquifer dependent on the source of the recharge water.

16.3.3.1 Imported Water Quality

SWP water currently meets or exceeds applicable standards. However, there is concern with some constituents that are approaching SWP acceptance criteria, particularly arsenic and selenium. SWP and CVP water is vulnerable to potential effects of climate change at the source in the Delta and in storage in Regional reservoirs. Sea-level rise will increase the intrusion of salinity into the Delta and its exported water. This will increase chloride and bromide (a disinfection byproduct [DBP] precursor that is also a component of sea water) concentrations in the SWP and CVP imported water. In addition, decreased freshwater flows into the Delta could increase the concentration of organic matter, which contribute to potentially higher DBP formation concentrations, in the SWP and CVP water. However, CVP water from the Friant system is of very high-quality as it originates from Sierra snowmelt and is similar in characteristics to Kern River supplies.

Extreme storm events, although rare, may cause quick response time thereof in canal flow rates, which may be more intense due to climate change and may present treatment challenges for source water and sedimentation issues in recharge basins because of increased turbidity. In the past, high turbidity events in reservoirs and conveyance facilities have required modification of the treatment processes (primarily additional chemical usage) for extended periods. In addition, an intense winter rainfall event after a wildfire in a watershed that burned the prior year can result in extremely high turbidities and fine organic matter in the water. The additional sludge production can overwhelm the treatment plants' solids handling equipment and require plants to be shut down or reduce their capacities for brief periods of time perhaps requiring capital investment to enlarge solids handling facilities. Similarly, turbidity events can negatively impact porosity in recharge basins, lessening their absorptive capacity. This combination of more intense rainfall events and increased wildfire risk is more likely under projected climate change conditions.

The warmer temperatures could also lead to increased taste and odor events triggered by algal blooms; which are characterized by water quality changes during the spring and summer such as increases in DO and DO saturation, pH and fluorescence. Water treatment plants can be designed to address taste and odor events through pre-ozonation but use of higher ozone dosages to control taste and odor events must also consider the need to control bromate formation (from the oxidation of bromide), which could increase due to greater bromide levels in the imported SWP and CVP water affected by climate change. Local canals would have to deal with the algae and effects thereof with higher treatment cost (i.e. copper sulfate).

16.3.3.2 Regional Surface Water Quality

The primary regional surface water in the Kern Region is the Kern River. Local minor streams, many of which are ephemeral, provide additional local surface water. A very small percentage of minor stream runoff is collected and used as irrigation for agriculture; the majority of these irregularly occurring flows serve to recharge local groundwater basins. However, the Kern River serves as a major source of supply to groundwater banking programs in the Region.

The Kern River and its tributaries, while generally considered a high quality supply, are vulnerable to potential water quality impacts due to climate change as a result of increased temperature, more frequent heavy rainfall events, increased wildfire risk, and longer periods of low natural stream flow from decreased annual precipitation. Increased water temperature generally reduces DO and can promote algal blooms if nutrients are available in the source. The storm events can transport sediments and other pollutants along the river, while long periods of low flow can increase concentrations of pollutants from wastewater plant and non-point discharges. Increased wildfires may contribute to the turbidity events. Key water quality constituents of concern are nitrogen and chloride, in addition to reduced DO and increased algae growth, turbidity and sedimentation. Taken together these can impact drinking water supplies as well as supplies utilized for groundwater recharge.

Imported water stored in Isabella Reservoir will also be vulnerable to climate change when considering reduced runoff volumes which could affect turbidity and increasing water temperatures, dissolved oxygen (DO) levels, and pH.

16.3.3.3 Groundwater Quality

Groundwater quality throughout the region is typically suitable for most urban and agricultural uses with only localized impairments including high TDS (salts), sodium chloride, sulfate, nitrate, organic compounds, boron and arsenic. High TDS, arsenic, boron, and nitrates are the primary groundwater quality issues. Various constituents can impact agricultural uses and M&I uses in different ways. Any water quality impacts to groundwater sources due to climate change are expected to be indirect, primarily due to decreased recharge from lower precipitation, increased periodic recharge from earlier/faster snowmelt runoff and increased use of groundwater to make up loss of imported or local surface water supplies. Decreased recharge and increased groundwater pumping may allow concentrations of groundwater contaminants such as perchlorate and volatile organic compounds to increase, which may trigger additional treatment requirements and increase groundwater treatment costs. Increased use of lower quality groundwater may also have some concerns associated with soil properties over a long period.

16.3.4 Flooding

Flooding is one of the most costly and destructive natural disaster; thus, a change in flood risk is a potential significant effect of climate change that could have great implications for the Kern Region. Local minor streams are the second-largest source of local surface water to the Region after the Kern River. Streams with measurable runoff are grouped into four separate watershed areas: Poso, Caliente, El Paso, and San Emigdio. Under certain hydrologic conditions, some of these streams carry very large flows that can be quite damaging. Examples include flooding in the Kelso Creek area, and in the area around the cities of Arvin and Lamont. Regional efforts to address flooding and to better manage such flow events have been initiated among various parties in the Region, including the County of Kern, KCWA and the affected areas.

The FEMA Flood Insurance Rate Map for the Kern Region designates multiple areas as "High Risk," areas with a 1 percent or greater risk of flooding in any year and a 26 percent chance of flooding over the life of a 30-year mortgage. The area at greatest flood risk is the area surrounding the communities of Lamont, Weedpatch, and the city of Arvin. The area is also prone to wildfires, which impact water quality when rain washes fire debris into waterways. Other large flood area includes the Buena Vista lakebed as well as areas in the historic Tulare lakebed and nearby drainage areas. Areas along the Kern River and other local streams like Tejon, El Paso and Grapevine in the southern region are also considered to have a high flood risk. These areas are depicted in **Figure 2-8**.

Regional efforts to address flooding and to better manage such flow events have been initiated among various parties in the Kern Region, including the County of Kern, KCWA and the affected areas.

While the Cal-Adapt climate change model projects precipitation decrease of 10 percent by 2050 on the long-term basis, research data suggest that there is a risk of increased flooding in California (Kiparsky and Gleick 2005). Flooding depends not only on average precipitation but on the timing and intensity of precipitation. Climate change projections are not sensitive enough to assess short term extreme events such as flooding, but the general expectation is that more intense storms would occur. This could present larger areas susceptible to flooding and increase the risk of direct flood damage in the Region.

16.3.5 Ecological Health and Habitat

Ecosystem health and habitat protection are important to the Kern Region. Increased temperature, changes in precipitation patterns, and increased wildfire risk projected for potential climate change scenarios are potential stressors to ecosystems and habitat in the Region.

Environmental resources of the Kern Region include the Kern River, Sequoia National Forest, several wildlife refuges, and the unique flora and fauna of the Tejon Pass area and Transverse Ranges. The riparian forest along the South Fork Kern River in the vicinity of Onyx and Weldon is one of the highest quality and most extensive stands of that vegetation type in California. This section of the river has the largest populations of Southwestern willow flycatchers and yellow-billed cuckoos in California. Much of this forest is conserved in the USFS South Fork Wildlife Area, Audubon California's Kern River Preserve, and CDFW's Canebrake Ecological Reserve. All of these species and habitats have acclimated to the historical climate and water resources and may or may not to adapt to potential changes due to future climate change.

Increased air temperature will increase water temperature in rivers, tributary streams, ponds, and lakes, with resulting decreases in DO. This combination may stress fish and biota that depend on higher DO levels and colder water which may impact their sustainability. The increased annual average air temperatures may also alter plant habitat by changing the length and timing of the growing season and/or allowing non-native species to outcompete native species and disrupt ecosystems that depend on the present habitats. Thus, measures to control non-native species may be needed to maintain habitats. Water available for plant habitat could be impacted by potential decreases in annual precipitation and increases in ET due to projected increases in temperature. Decreased precipitation could also directly affect formation of vernal ponds.

Ackerly et al. (2012) summarizes existing research on the relationship between climate and biodiversity and how changes in climate historically have and will in the future impact habitat. In terrestrial systems, the impacts of rising temperature and changing precipitation patterns have the largest effect and that in estuarine and intertidal areas, sea-level rise results in the most important direct impact. These habitats may be affected directly by habitat loss through erosion, or indirectly via human responses such as coastal armoring (e.g., construction of sea walls) and other infrastructural changes.

16.4 Regional Vulnerability Assessment

Table 16-3 provides an assessment of the regional vulnerability to the potential climate change impacts using the 'Vulnerability Assessment Checklist', found in the 'Climate Change Handbook for Regional Water Planning' (DWR, 2011). This checklist provides a further evaluation of the effects on regional water demands and supplies, as well as water quality, flooding events, environmental and ecosystems, and hydropower systems within the Kern Region.

In addition to the assessment of vulnerabilities provided in **Table 16-3**, the Kern Region prioritized the identified vulnerabilities during a Stakeholder meeting in August 2014. The results are displayed in the Climate Change Vulnerabilities Prioritization Table provided in **Appendix J**.

Table 16-3: Vulnerability Assessment Checklist

Resource Checklist Item	Kern Regional Condition
Water Demand	
Are there major industries that require cooling/process water in your planning region?	Kern County is characterized by its traditional industries, agriculture, oil and gas production, as well as increasing urbanization and population growth. Oil and gas drilling in the county could be impacted by decreasing water availability, particularly in times of drought by limiting the amount of water available for cooling, fuel extraction, and power generation. Additionally, process water is required in packing plants and other locations for processing crops harvested from the field, further contributing to the significance of the use.
Does water use vary by more than 50% seasonally in parts of your region?	Yes. A significant amount of water in the Kern Region is used for agricultural purposes, the demand for which fluctuates greatly in the summer compared to the winter.
Are crops grown in your region climate-sensitive? Would shifts in daily heat patterns, such as how long heat lingers before night-time cooling, be prohibitive for some crops?	Yes. The Kern Region is the second largest agricultural county in the state in economic value, and produces over 250 different crops, including over 30 types of fruits and nuts, over 40 types of vegetables, over 20 field crops, lumber, nursery stock, livestock, poultry and dairy products. Many of these are climate-sensitive and could be prohibitively affected by shifts in daily heat patterns.
Do groundwater supplies in your region lack resiliency after drought events?	With only six (6) inches per year of average rainfall, groundwater is necessary to maintain a sufficient water supply in the semi-desert climate of the Region. It is estimated that on average groundwater accounts for 39 percent of total water supply to the Region; however, it is estimated to be as much as 60 percent during dry years. Long- established and successful conjunctive use and banking programs. These programs overlie the major portions of the groundwater basin and can access surface supplies from the Kern River, the SWP, the Friant- Kern Canal, and more. In times of high flows, these surface supplies are recharged and stored to help to lessen the effects of dry period conditions when the Region relies on the groundwater basin.
Are water use curtailment measures effective in your region?	Stakeholders of this IRWMP have identified water use efficiency as an important component of water supply planning. One of the stated objectives of this IRWMP is to “Pursue and implement cost effective water use efficiency programs.” In addition to direct water use efficiency, stakeholders have expressed a desire to improve system operation, reduce system water loss, and decrease energy use related to water infrastructure. Another objective of this IRWMP is to “Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions.” Lastly, implementation of agricultural land fallowing programs within the Region also help to curtail water use.

Resource Checklist Item	Kern Regional Condition
Are some instream flow requirements in your region either currently insufficient to support aquatic life, or occasionally unmet?	No. However, since 1994, the two large projects that import water into the Kern Region, the CVP and the SWP, have been incrementally impacted by environmental and regulatory requirements that have served to diminish the ability of the projects to reliably deliver water supplies. A large proportion of recent imported water cutbacks has stemmed from fishery issues in the Sacramento-San Joaquin Delta, where the pumping plants for the CVP and SWP are located, as well as San Joaquin River Settlement or Public Law 111-111 where water previously supplied to the CVP Friant Division for M&I and agricultural irrigation is being diverted into the San Joaquin River for in-stream flows.
Water Supply	
Does a portion of the water supply in your region come from snowmelt?	Yes. The Kern River is fed by annual snowmelt from the Southern Sierra Nevada, including Mount Whitney. The SWP, CVP and Friant system are also fed by Sierra snowmelt.
Does part of your region rely on water diverted from the Delta, imported from the Colorado River, or imported from other climate-sensitive systems outside your region?	Yes. The Kern Region receives SWP and CVP water delivered through the Delta, which is affected by climate change. Friant CVP also has a Delta connection with the San Joaquin River Restoration Program as well as San Joaquin River Exchange Contractor rights.
Does part of your region rely on coastal aquifers? Has salt intrusion been a problem in the past?	The Kern Region does not rely on coastal aquifers. While salt intrusion from coastal aquifers is not applicable, salt management is still an issue in the region with regard to increasing salinity in groundwater. Salt in imported water supplies such as the SWP and CVP is the major source of salt which circulates throughout the groundwater in Kern County.
Would your region have difficulty in storing carryover supply surpluses from year to year?	There is limited carryover available for SWP and CVP water in San Luis Reservoir. Carryover of Friant CVP water in Millerton Lake/Friant Dam has limited capacity. Carryover of Kern River water in Isabella Reservoir is limited by the Reservoir's flood control purpose and US Army Corps of Engineers Regulations. However, there are opportunities to expand the Region's groundwater storage capabilities.
Has your region faced a drought in the past during which it failed to meet local water demands?	No. Water demands have been met through the use of groundwater which, during drought, can result in significant declines in groundwater levels. To the extent that surface water supplies are reduced in the future (as a result of climate change and/or regulatory constraints), recharge will be reduced, which will affect the availability of groundwater for meeting local water demands.

Resource Checklist Item	Kern Regional Condition
Does your region have invasive species management issues at your facilities, along conveyance structures, or in habitat areas?	Yes. Aquatic pests, including invasive plants have been fought on the Kern River for decades. Prevention and control of invasive species is an ongoing battle by many resource agencies such as the Kern River Preserve Audubon Society, and the Kern River Ranger District. Canal operators treat aquatic weeds, mainly with use of copper sulfate.
Water Quality	
Are increased wildfires a threat in your region? If so, does your region include reservoirs with fire-susceptible vegetation nearby which could pose a water quality concern from increased erosion?	Yes. Parts of the Kern Region are prone to wildfires, which impact water quality when rain washes fire debris into waterways. In July 2008, the Piute Fire burned a significant area in the region. It was soon followed by a summer thunderstorm, which washed fire debris into the South Fork and ultimately down the Kern River. Many water purveyors were forced to switch from Kern River water to alternate sources to avoid contamination of settling ponds and costly treatment of the water.
Does part of your region rely on surface water bodies with current or recurrent water quality issues related to eutrophication, such as low dissolved oxygen or algal blooms? Are there other water quality constituents potentially exacerbated by climate change?	Yes. The Kern River, the primary native surface supply in Region, is generally considered a high quality supply. However, Isabella Lake which serves as the source for the lower Kern River is listed on the 303(D) list for dissolved oxygen, mercury and pH. Climate change could exacerbate these water quality conditions from increased temperatures. Banking return flows result in replacement of higher quality snowmelt water with groundwater.
Are seasonal low flows decreasing for some waterbodies in your region? If so, are the reduced low flows limiting the waterbodies' assimilative capacity?	Possibly. Annual Kern River flows and flows in local ephemeral streams could be decreasing through time.
Are there beneficial uses designated for some water bodies in your region that cannot always be met due to water quality issues?	No. Water is intended for many beneficial uses including agricultural water supplies, groundwater recharge, water replenishment, recreation, wildlife habitat, rare and endangered species, and wetland ecosystems. Most of these are met within the Kern Region; however, there are three TMDLs for Lake Isabella with regard to DO, mercury and pH.
Does part of your region currently observe water quality shifts during rain events that impact treatment facility operation?	No.
Sea Level Rise	
Has coastal erosion already been observed in your region?	No. The Kern Region is located in the Southern San Joaquin Valley, and concerns regarding coastal regions are not applicable.
Are there coastal structures, such as levees or breakwaters, in your region?	No.

Resource Checklist Item	Kern Regional Condition
Is there significant coastal infrastructure, such as residences, recreation, water and wastewater treatment, tourism, and transportation) at less than six feet above mean sea level in your region?	No.
Are there climate-sensitive low-lying coastal habitats in your region?	No.
Are there areas in your region that currently flood during extreme high tides or storm surges?	No.
Is there land subsidence in the coastal areas of your region?	No.
Do tidal gauges along the coastal parts of your region show an increase over the past several decades?	No.
Flooding	
Does critical infrastructure in your region lie within the 200- year floodplain?	Yes. The FEMA Flood Insurance Rate Map for the Kern Region designates multiple areas as "High Risk", areas with a 1 percent or greater risk of flooding in any year and a 26 percent chance of flooding over the life of a 30-year mortgage. **Figure 2-8** (in the November 2011 Kern IRWM Plan) shows the areas that are within the 100- and 500-year floodplain. Flooding can result in the inundation of structures, causing water damage to structural elements and contents, as well as impact damage to structures, roads, bridges, culverts, and other features from high velocity flows and from debris carried by floodwaters.
Does part of your region lie within the Sacramento-San Joaquin Drainage District?	No.
Does aging critical flood protection infrastructure exist in your region?	Yes. In general, many Kern County communities are older and the physical components of their water systems are aging and outdated. Aging infrastructure is a particular issue for rural communities and DACs.

Resource Checklist Item	Kern Regional Condition
Have flood control facilities (such as impoundment structures) been insufficient in the past?	Yes. The primary flood control facility in the Region is Isabella Dam on the Kern River. The dam protects the urban Bakersfield area and about 350,000 acres of agricultural land and oilfields. Kern River had an unregulated flow until 1954 when the Isabella Dam and Reservoir were constructed by the Army Corps of Engineers. Unfortunately, due to seepage and earthquake concerns, the flood control capacity of the reservoir has recently been limited. Other areas near Lamont in the southern portion of the Region also have infrastructure that could be impacted.
Are wildfires a concern in parts of your region?	Yes. Parts of the Kern Region are prone to wildfires, which impact water quality when rain washes fire debris into waterways.
Ecosystem and Habitat Vulnerability	
Does your region include inland or coastal aquatic habitats vulnerable to erosion and sedimentation issues?	Coastal aquatic habitats are not applicable to the Region. However, aquatic pests, including invasive plants have been fought on the Kern River for decades. Prevention and control of invasive species is an ongoing battle by many resource agencies such as the Kern River Preserve Audubon Society, and the Kern River Ranger District.
Does your region include estuarine habitats which rely on seasonal freshwater flow patterns?	No.
Do climate-sensitive fauna or flora populations live in your region?	Environmental resources of the Region include the Kern River, Sequoia National Forest, several wildlife refuges, and the unique flora and fauna of the Tehachapi Mountains, Tejon Pass area and Transverse Ranges. The riparian forest along the South Fork Kern River in the vicinity of Onyx and Weldon is one of the highest quality and most extensive stands of that vegetation type in California. This section of the river has the largest populations of Southwestern willow flycatchers and yellow- billed cuckoos in California. All of these resources could be potentially affected by climate change.
Do endangered or threatened species exist in your region? Are changes in species distribution already being observed in parts of your region?	Yes. There are threatened and endangered species in the Kern Region including the bald eagle, burrowing owl, California condor, California red-legged frog, least bell's vireo, and the San Joaquin kit fox to name a few. Whether or not changes in species distribution have occurred is unknown.
Does the region rely on aquatic or water-dependent habitats for recreation or other economic activities?	Yes. Water-dependent recreation includes a wide variety of outdoor activities that can be divided into two (2) categories. The first category includes fishing, boating, swimming, and rafting, which occur on lakes, reservoirs, and rivers. The second category includes recreation that is enhanced by water features but does not require actual use of the water, such as wildlife viewing, picnicking, camping, and hiking.

Resource Checklist Item	Kern Regional Condition
Are there rivers in your region with quantified environmental flow requirements or known water quality/quantity stressors to aquatic life?	No.
Do estuaries, coastal dunes, wetlands, marshes, or exposed beaches exist in your region? If so, are coastal storms possible/frequent in your region?	There are several wildlife refuges within the Kern Region including the Kern National Wildlife Refuge that manages some wetlands. Coastal storms are not possible in the Region, due to its location in the southern San Joaquin Valley.
Does your region include one or more of the habitats described in the Endangered Species Coalition's Top 10 habitats vulnerable to climate change?	Yes, the Kern Region's eastern boundary is the southern Sierra Nevada, which is listed on the Top 10 habitats list.
Are there areas of fragmented estuarine, aquatic, or wetland wildlife habitat within your region? Are there movement corridors for species to naturally migrate? Are there infrastructure projects planned that might preclude species movement?	Yes. There are many wildlife habitats in the Kern Region. Most notably is the Kern National Wildlife Refuge which provides habitat for wintering and migrating waterfowl, shorebirds, and marsh birds and also provides habitat for upland and riparian bird species. However, there are no infrastructure projects planned in the Region that are known to preclude species movement.
Hydropower	
Is hydropower a source of electricity in your region?	Yes. Within the Kern Region is the Rio Bravo Hydro Project Hydro Power Plant which has a design capacity of 14 mega watts (MWe). However, most of the energy provided in the Kern Region comes from its 37 high-efficiency cogeneration facilities that produce two sources of energy in the form of steam and electricity.
Are energy needs in your region expected to increase in the future? If so, are there future plans for hydropower generation facilities or conditions for hydropower generation in your region?	Yes. Energy needs in the Region will increase in the future as a result of several factors, which include changes in land use from agricultural uses to urban uses, increasing population and increases in groundwater pumping. However, the Kern Region has a variety of efforts planned to reduce energy use, and to develop local energy supply sources. These efforts include utilization of renewable resources, such as wastewater treatment plant digester gas recovery, hydropower, and solar power.

16.4.1 Vulnerability Prioritization

This section discusses a list of prioritized vulnerabilities based on stakeholder input on the importance of these sectors to the Kern Region. The watershed vulnerability assessment identifies the water resource characteristics for each sector most vulnerable to potential climate change projections. The Region can use the assessment results to prioritize the sectors with vulnerabilities and develop adaptive strategies to respond to potential climate change impacts.

The sector vulnerability prioritization is defined as follows (1 being the sector most prioritized [high risk] and 4 being the sector least prioritized [low risk] with respect to climate change vulnerability):

1. Water Supply; Water Quality
2. Water Demand; Flooding
3. Ecosystem and Habitat
4. Sea Level Rise and Hydropower

The vulnerability assessment and prioritization was conducted based on the Climate Change Vulnerability Checklist provided as Table 16-3, data currently available and inputs from the stakeholders involved in the preparation of this study for the Kern Region. This assessment can be improved in the future with further data gathering and analyzing of the prioritized vulnerabilities.

16.5 Climate Change Adaptations

The Kern IRWMP (Plan) identifies strategies to address adapting and mitigating the general effects of climate change. The objectives for the Kern Region address adapting and mitigating the general effects of climate change, including changes in the amount, intensity, timing, quality, and variability of runoff and recharge. These “no regrets” adaptations recognize the current water management context for the region. In addition, mitigation strategies addressed by the objectives for the Kern IRWMP include energy efficiency improvements, emissions reductions, and carbon sequestration through vegetation growth. The Climate Change Handbook (DWR, 2011) was used to help develop these adaptation and mitigation strategies, which are listed in Table 10-2.

For this technical memorandum, potential adaptation strategies have been grouped by water resource and priorities developed in the climate change vulnerability analysis. This approach will allow the Kern Region to incorporate climate change adaptation and GHG mitigation measures in projects developed and evaluated as part of the IRWMP process. While the focus of this discussion is adaptation, some of the adaptation strategies will overlap with and enhance GHG mitigation measures.

16.5.1 Vulnerability Priority 1 (Highest) Sectors: Water Supply and Quality

Water supply and water quality were identified as the highest priority sectors that could potentially be impacted by climate change. The potential impacts due to climate change and the suggested regional adaptation strategies are summarized below.

16.5.1.1 Water Supply

Climate change projections suggest continued highly variable annual precipitation with slightly drier climate by mid-century. The overall impact will include reductions in Kern River, SWP and CVP imported water and greater reliance on groundwater supplies with the potential to affect long-term planning.

Suggested Regional adaptation strategies to address potential reductions in water supply include the following:

- Expand water storage and conjunctive management of surface and groundwater resources.

- Encourage local projects to increase regional self-reliance.
- Enhance use of recycled water for appropriate uses as a drought-proof water supply.
- Enhance practices of water exchanges and water banking outside the Region to supplement water supply.
- GSAs to develop and implement GSPs.
- Develop plans for local agencies in the Kern Region to monitor the elevation of their groundwater basins.
- Encourage cities and the county agencies in the Kern Region to adopt local ordinances that protect the natural functioning of groundwater recharge areas.

16.5.1.2 Water Quality

Climate change projections suggest increased temperature and continued highly variable annual precipitation with slightly drier climate by mid-century that could degrade water quality.

Suggested Regional adaptation strategies to address potential water quality impacts include the following:

- Consider water quality improvements associated with water transfers and water banking on Regional water supply.
- Encourage projects (ex. conjunctive use) that improve water quality of contaminated groundwater sources.
- Increase implementation of low impact development (LID) techniques to improve stormwater management.
- Comply with NPDES permits to ensure water quality protection.

16.5.2 Vulnerability Priority 2 Sectors: Water Demand and Flooding

Water demand and flooding were identified as the second highest priority sectors that could potentially be impacted by climate change. The potential impacts due to climate change and the suggested regional adaptation strategies are summarized below.

16.5.2.1 Water Demand

Climate change projections suggest increases in average annual air temperature by mid-century and increased evaporative losses are expected to increase both urban and agricultural water demand. Suggested Regional adaptation strategies to address potential increases in water demand include the following:

- Aggressively increase cost effective water use efficiency.
- Encourage agricultural users to adopt efficient water management practices.
- Encourage landscape water users to adopt efficient water management practices, including xeriscaping.

16.5.2.2 Flooding

Climate change projections are not sensitive enough to assess short term extreme events such as flooding, but the general expectation is that more intense storms will occur. Suggested Regional adaptation strategies to address potential increases in flood risk include:

- Improve emergency preparedness and response capacity in anticipation of potential increases in extreme events.
- Practice and promote integrated flood management among water and flood management agencies.
- Flood management should be integrated with watershed management on open space, agricultural, wildlife areas, and other low-density lands.
- Avoid significant new development in areas that cannot be adequately protected from flooding.
- Encourage land use policies including LID that maintain or restore historical hydrological characteristics.
- Development of a Kern Region Flood Protection Plan.

16.5.3 Vulnerability Level 3 Sector: Ecosystem and Habitat

Ecosystem Health and Habitat was identified as the third highest priority sector category that could potentially be impacted by climate change. The potential impacts due to climate change and the suggested regional adaptation strategies are summarized below. Climate change projections of increasing annual average temperature suggest potential environmental stressors that may affect the sustainability of existing ecosystems and habitat. Suggested Regional adaptation strategies to address potential Ecosystem Health and Habitat impacts include the following:

- Promote water resources management strategies that restore and enhance ecosystem services.
- Provide or enhance connected “migration corridors” for animals and plants to promote increased biodiversity and allow the plants and animals to move to more suitable habitats to avoid serious impacts and support increased biodiversity.
- Consider projects that provide seasonal aquatic habitat in streams and support corridors of native riparian forests that create shaded riverine and terrestrial habitat.

16.5.4 Vulnerability Priority 4 Sectors: Sea Level Rise and Hydropower

Sea level rise and hydropower were identified as the lowest priority sectors for the Kern Region.

16.5.4.1 Sea Level Rise

Climate change projections suggest sea level rise off most of the California Coast of over half a meter by mid-century and by about one meter by the end of the century. Suggested Regional adaptation strategies to address potential reductions in water supply include the following:

- Support DWR/USBR strategies that minimize the impact of sea level rise on salinity intrusion into the Delta and impact water quality deliveries in the SWP and CVP.
- Support DWR/USBR strategies for protecting levees in the Delta from the potential effects of projected sea level rise.

16.5.4.2 Hydropower

Climate change projections suggest continued highly variable annual precipitation with slightly drier climate by mid-century, affecting hydropower generation. Strategies to address potential reductions in hydropower include the following:

- Support alternative economically viable energy projects within the region including solar energy and wind energy.

16.6 Data Gaps and Next Steps

16.6.1 Data Improvement

The climate change assessment conducted in this Plan update is qualitative in some areas due to limited data, high level of uncertainty, and, in some cases, because impacts to a given sector are not expected to be severe. The intent of future data gathering is to address gaps in the current vulnerability assessment, to improve the understanding of climate change impacts and vulnerabilities, and to enable a more quantitative analyses. Recommended future data gathering efforts will include data that facilitate more quantitative analysis of the vulnerability, as described in the following sections. The preparation of GSPs under SGMA will help provide more quantitative data and analyses that can be incorporated into the next Kern IRWMP update.

This section describes potential areas of future data gathering efforts for the priority sectors identified earlier. The recommendations focus on the top four priority sectors; namely, water supply, water quality, water demand, and flooding. The lower priority sectors include ecosystem health and habitat and fire, which require a lesser degree of data collection. Climate change vulnerability of ecosystem health and habitat is difficult to quantify, and reliance on generalized studies will likely satisfy the Region's needs. Thus, the Kern Region should prioritize data gathering efforts for the sectors most vulnerable to climate change impacts.

16.6.1.1 Climate Change Models and Scenarios

Cal-Adapt modeling results for the Kern Region were used for projections of temperature, ET, precipitation, and runoff for the Region. The California Energy Commission maintains the Cal-Adapt site and will update the modeling tools as new climate change modeling results, based on more refined data, become available from the ICCC. Thus, to the extent feasible, the available climate change tools and projections for the Region will be reviewed periodically and the vulnerability assessment updated in future versions of the Plan.

16.6.1.2 Updates on Climate Change Research

Research on the climate change impacts on water resources is ongoing and continues to evolve with further analysis and more refined methodologies. During the preparation of this Plan update, key literature resources on climate change have been reviewed. New scientific findings will be reviewed periodically and incorporated into the climate change vulnerability assessment, especially the findings pertinent to the sectors most vulnerable to the climate change in the Region.

16.6.1.3 Vulnerability Assessment Update

As noted above, a goal of further data collection is to enable a more quantitative analysis of the high priority watershed sectors that are more vulnerable to climate change in future Plan updates. Water supply and water quality were identified as the highest priority sectors and water demand and flooding were identified as the second highest priority sectors that could potentially be impacted by climate change.

16.6.1.4 Water Demand

Cal-Adapt projections suggest water demand in the Region is likely to increase as a result of higher temperature with the greatest temperature increase anticipated during dry months compared to wet months. Historical records of annual water demand data currently available are not specific enough to quantify the effects from increasing temperature. As discussed earlier in the vulnerability assessment, the most important effect of changing weather conditions is likely to be on agricultural demand, but the overall effects on agricultural water demand is uncertain.

Suggestions for future data gathering efforts to quantify the climate change effects on municipal and agricultural water demand include the following:

- Collect and analyze historical monthly records of water demand data for the Region to quantify the weather effects on water use and seasonal variations in response to changes in historical temperature.
- Collect and analyze historical monthly records of water demand data for each purveyor in the Region to demonstrate purveyor-specific patterns in response to changes in climate.
- Based on the water demand and temperature data, develop a regression analysis correlating water demand to temperature on a monthly or seasonal basis for the Region and each purveyor. The historical response can be used to infer future response with the projected changes in temperature with climate change.
- Characterize the variations in indoor and outdoor water use, both for the Region and each purveyor. Future data gathering should focus on the seasonal and monthly patterns both in indoor and outdoor usage to evaluate the effects of weather conditions on each use category.
- Collect and analyze historical agricultural water demand to quantity the weather effects on water use and seasonal variations in response to changes in historical temperature.
- Identify the major industries in the Region that require cooling and/or process water. As water temperature increases, cooling water needs may also increase.

16.6.1.5 Water Supply

Future assessment of water supply climate change vulnerability will incorporate the most up-to-date data available from DWR and the most current groundwater supply availability. Suggestions for future data gathering efforts to quantify the climate change effects on water supply include the following:

- Update DWR SWP Delivery Capability Report projections - DWR provides an updated analysis and report every two years.
- Review or request other reports (e.g., USBR, Army Corp of Engineers, etc).
- Update available groundwater supply projections – Groundwater production in a given year varies depending on hydrologic conditions. Changes in local hydrology and natural recharge are anticipated to have a direct impact on available groundwater storage and may affect current safe operating ranges.
- Evaluate the effects of reduction in precipitation from climate change on the groundwater operational ranges and quantify the potential reduction in groundwater supply due to reduction in precipitation from climate change.

16.6.1.6 Water Quality

Collection of historical water quality data within the Region would greatly improve the understanding of Regional water quality and how it may be impacted by climate change. For imported SWP water, the vulnerability analysis relied on DWR projections of water quality impacts in the Delta due to sea level rise and increases in salinity. Future analyses will incorporate updated DWR or other agency studies on the potential impacts of climate change on SWP quality.

Suggestions for future data gathering efforts to quantify the climate change effects on water quality include:

- Monitor future and collect historical water quality data within the Region during storm events.
- Develop a long-term water quality record for the Kern River that would assist in improving the understanding of Regional water quality.
- Collect long-term weather records associated with air temperature, precipitation, and ET to assess potential correlations with seasonal water quality.
- Develop, to the extent possible, a long-term surface/ground/aerial deposition model that can be continuously updated and refined with newly available data. Model should be ready accessible to stakeholders and in a user-friendly format to allow better understanding of trends over time.

16.6.1.7 Flooding

A quantitative assessment of the potential impacts of climate change on flooding cannot be performed as climate projections are not sensitive enough to project short-term extreme events such as flooding. Rather, the 100-year and 500-year floodplains were used to define flooding risk zones that should be considered in location of water infrastructure.

Suggestions for future data gathering efforts to address the potential climate change effects on flooding include the following:

- Perform an inventory of runoff monitoring stations in the Region to see if a more robust runoff record can be developed. Those data may allow an analysis of historical storm events correlated with precipitation events as well as annual precipitation to provide a better understanding of conditions that may lead to more extreme flooding conditions.

As recommended by DWR's Climate Change Handbook for Regional Water Planning, future work should focus on gathering the 200-year floodplain maps for the Region after DWR develops them under the authorization of Senate Bill 5 (SB 5) enacted in 2007. Currently, the 100-year and 500-year floodplain maps are available from FEMA.

- Coordinate with the Region stakeholders for advanced flood preparation and quick response and document the protocol(s).
- Perform an inventory of critical infrastructure located in floodplains, especially those that were impacted during the historical flood events in 1969 and 1983.
- Update the projections of runoff with climate change as updates from Cal-Adapt become available.
- Work with local flood plain managers and/or equivalent to determine areas of concern as information from FEMA evolves.

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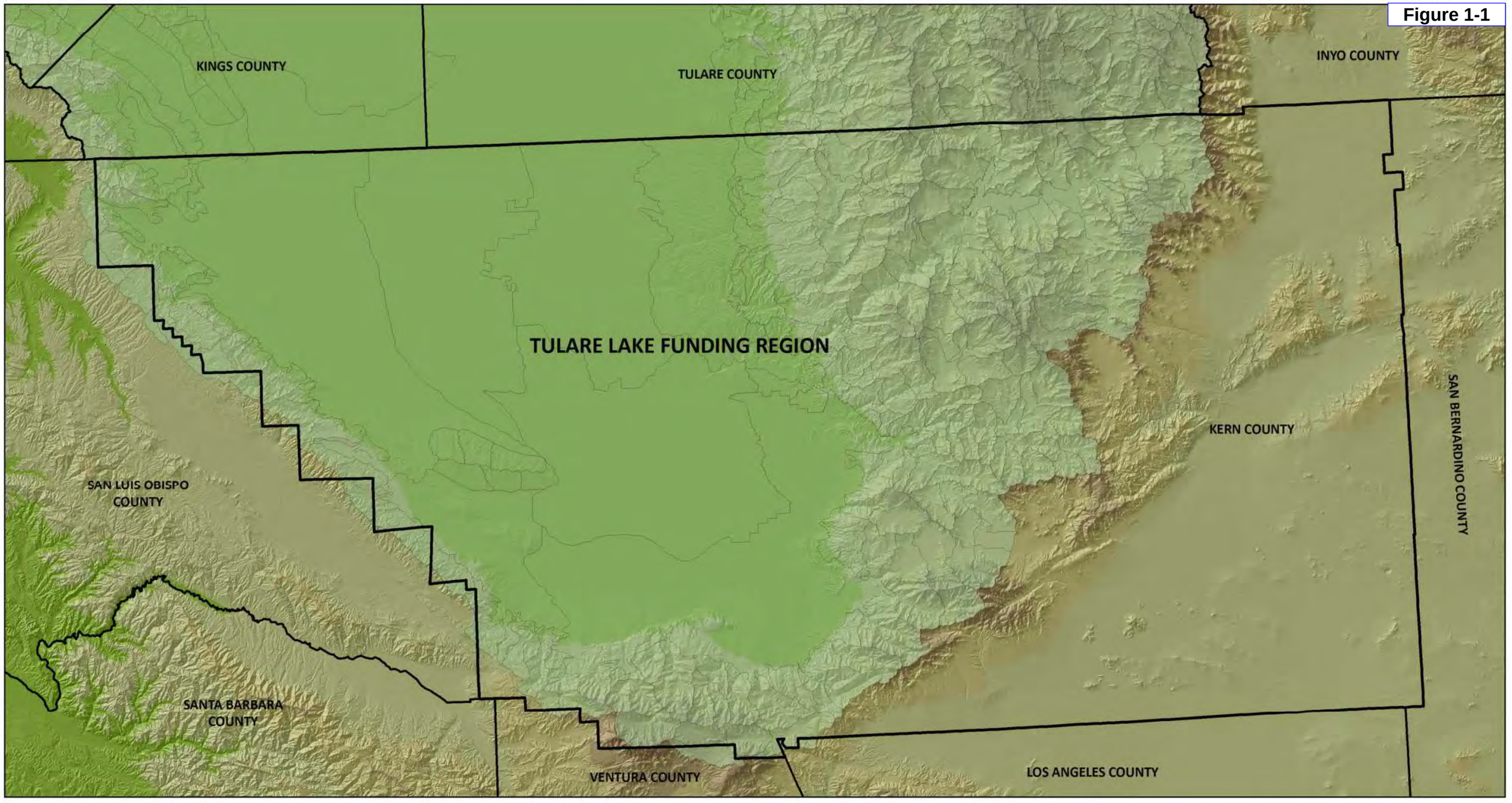
FIGURES

Figure 1-1



TULARE LAKE FUNDING REGION BOUNDARY

KERN COUNTY
WATER AGENCY
Bakersfield, CA

Created: 2009-0320, S. Chambless
Revised: 2009-1015, S. Chambless
Filename: Tulare_Lake_Funding_Area_09-0320.mxd

N

0 2.5 5 10 15 20 Miles

1 inch = 10 miles

Figure 1-2



TULARE LAKE BASIN PORTION OF KERN COUNTY REGION

(KERN REGION)

KERN COUNTY
WATER AGENCY
Bakersfield, CA

Created: 2009-0318, S. Chambless
Revised: 2009-1015, S. Chambless
Filename: TLBKC_Boundary_Region_09-0318.mxd

N

0 5 10 20 30 Miles

1 inch = 15 miles

Figure 1-3

FRESNO COUNTY
KINGS COUNTY
TULARE COUNTY
INYO COUNTY
MONTEREY COUNTY
TULE IRWMP
SOUTHERN SIERRA IRWMP
INYO-MONO IRWMP
POSO CREEK IRWMP
KERN COUNTY
SAN LUIS OBISPO IRWMP
KERN REGION IRWMP
FREMONT BASIN IRWMP
SAN LUIS OBISPO COUNTY
SAN BERNARDINO COUNTY
PACIFIC OCEAN
ANTELOPE VALLEY IRWMP
SANTA BARBARA IRWMP
VENTURA IRWMP
UPPER SANTA CLARA RIVER IRWMP
LOS ANGELES COUNTY
SANTA BARBARA COUNTY
VENTURA COUNTY

ADJACENT IRWMP PLANNING REGIONS

KERN COUNTY WATER AGENCY
Bakersfield, CA

Created: 2009-0325, S. Chambless
Revised: 2011-0824, S. Chambless
Filename: Adjacent_IRWMP_Regions_11-0726.mxd

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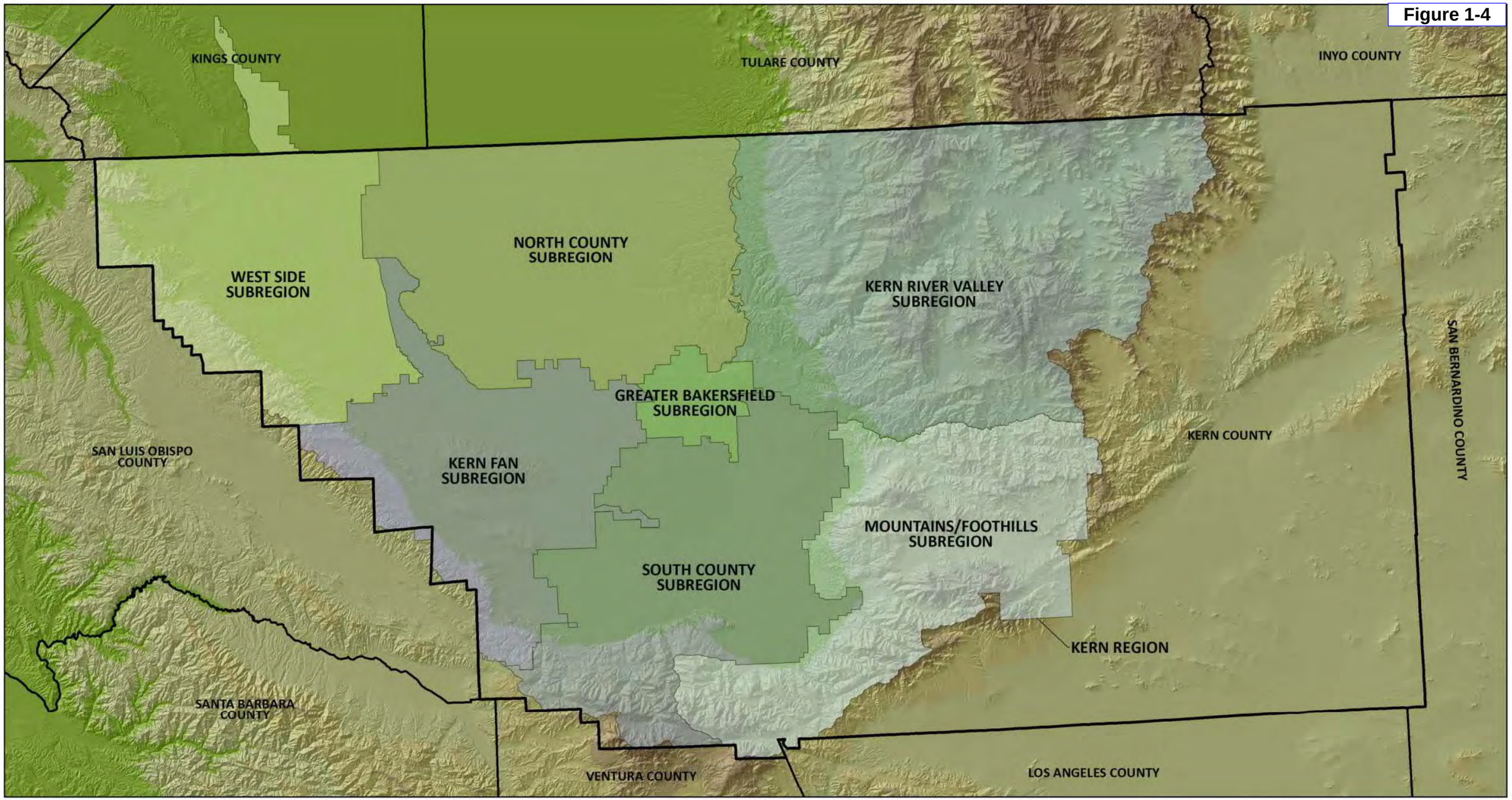
1 inch = 15 miles

Figure 1-4



KERN IRWMP SUBREGIONS

KERN COUNTY WATER AGENCY
Bakersfield, CA

Created: 2009-0323, S. Chambless
Revised: 2011-0824, S. Chambless
Filename: Subregions_09-0323.mxd

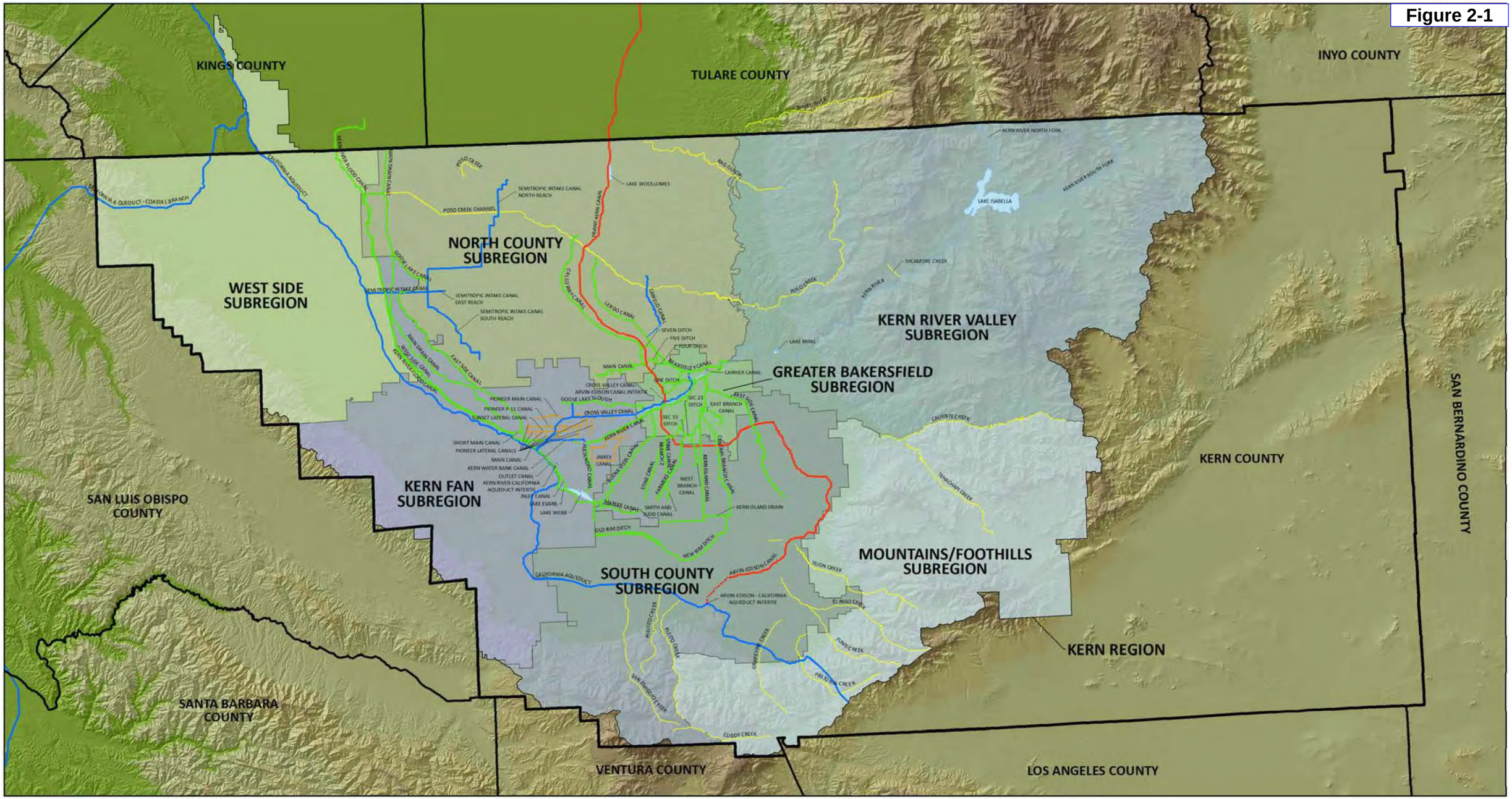
NOTE: Kern County Water Agency and County of Kern subregions not shown.

N

0 2.5 5 10 15 20 Miles

1 inch = 10 miles

Figure 2-1



WATER RELATED INFRASTRUCTURE WITHIN THE KERN REGION

KERN COUNTY WATER AGENCY
Bakersfield, CA

Created: 2009-1019, S. Chambless
Revised: 2011-0824, S. Chambless
Filename: Water_Features_Infrastructure_11-0721.mxd

NOTE: Kern County Water Agency and County of Kern subregions not shown.

LEGEND

KERN COUNTY CANALS
(BY WATER TYPE)

- STATE WATER PROJECT
- CENTRAL VALLEY PROJECT
- KERN RIVER
- BANKING
- SAN JOAQUIN VALLEY MAJOR CREEKS

N

0 2.5 5 10 15 20 Miles

1 inch = 10 miles

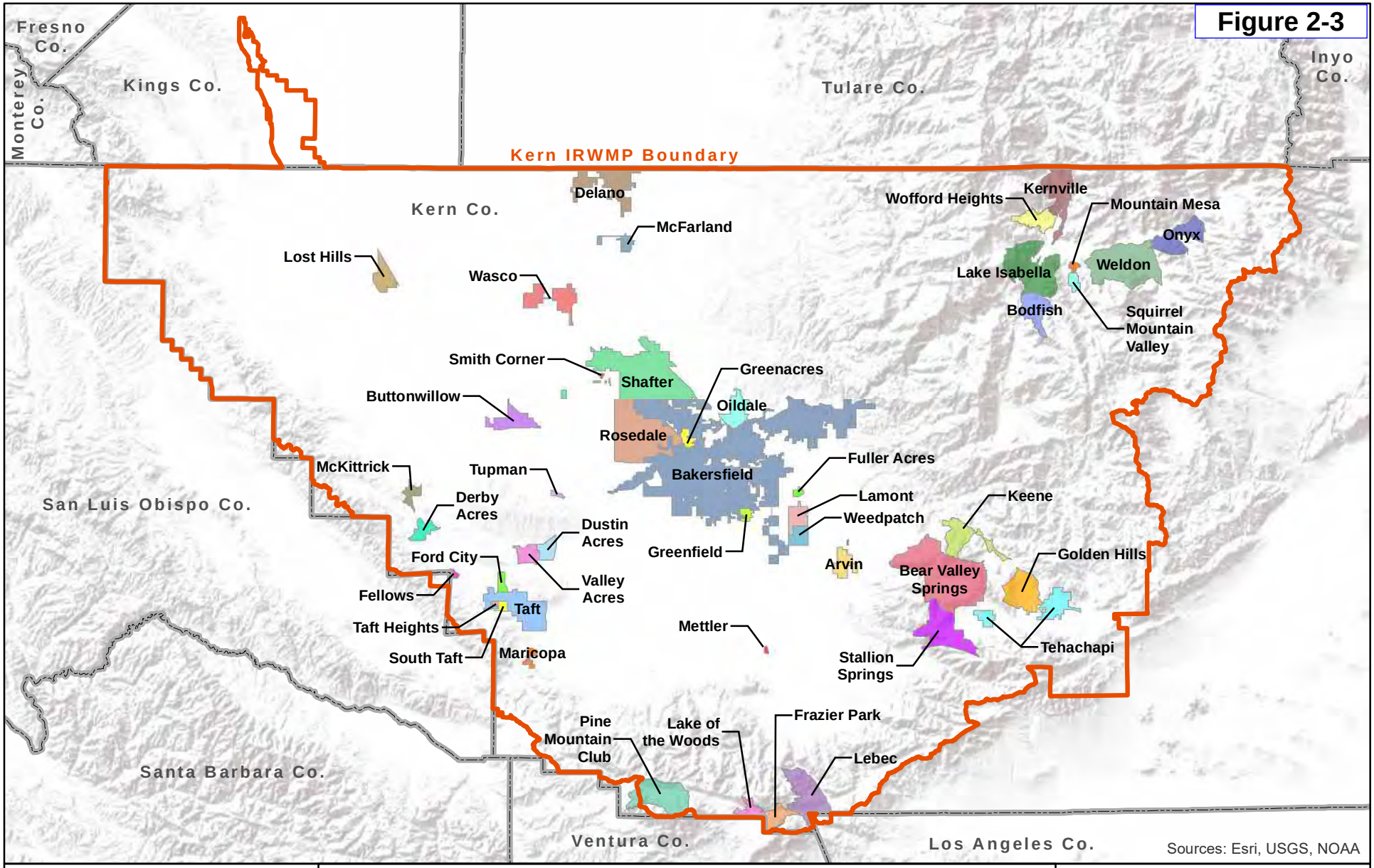


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Figure 2-4

KINGS COUNTY
TULARE COUNTY
INYO COUNTY
SAN BERNARDINO COUNTY
KERN COUNTY
SAN LUIS OBISPO COUNTY
SANTA BARBARA COUNTY
VENTURA COUNTY
LOS ANGELES COUNTY
TULARE LAKE BASIN OF KERN COUNTY
DETAIL
DUDLEY RIDGE
DEVILS DEN WD
DELANO EARLIMART ID
RAG GULCH WD
LOST HILLS WD
SOUTHERN SAN JOAQUIN MUD
KERN-TULARE WD
BERRENDA MESA WD
SEMITROPIC WSD
NORTH KERN WSD
CAWELO WD
NON-DISTRICTED AREA
SHAFTER WASCO ID
ROSEDALE-RIO BRAVO WSD
ROSEDALE RANCH ID
IMPROVEMENT DISTRICT NO. 4
OLCESE WATER DISTRICT
BELRIDGE WSD
BUENA VISTA WSD
CITY OF BAKERSFIELD 2800
BERRENDA MESA
ARVIN-EDISON WSD
KERN DELTA WD
WEST KERN WD
HENRY MILLER WD
TEHACHAPI-CUMMINGS CO WD
WHEELER RIDGE-MARICOPA WSD
OILDALE MUTUAL WATER COMPANY
CALIFORNIA WATER SERVICE
NORTH OF THE RIVER MWD - OILDALE MUTUAL WATER COMPANY
VAUGHN WATER COMPANY
CALIFORNIA WATER SERVICE
CITY OF BAKERSFIELD
EAST NILES COMMUNITY SERVICES DISTRICT
IMPROVEMENT DISTRICT NO. 4
LEBEC COUNTY WD
TEJON-CASTAC WD
FRAZIER PARK PUD
PURVEYORS WITHIN IMPROVEMENT DISTRICT NO. 4

WATER AGENCIES AND SPECIAL DISTRICTS WITHIN THE KERN REGION

KERN COUNTY WATER AGENCY
Bakersfield, CA

Created: 2009-0316, S. Chambless
Revised: 2009-1119, S. Chambless
Filename: Water_Districts_09-0316.mxd

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1 inch = 10 miles

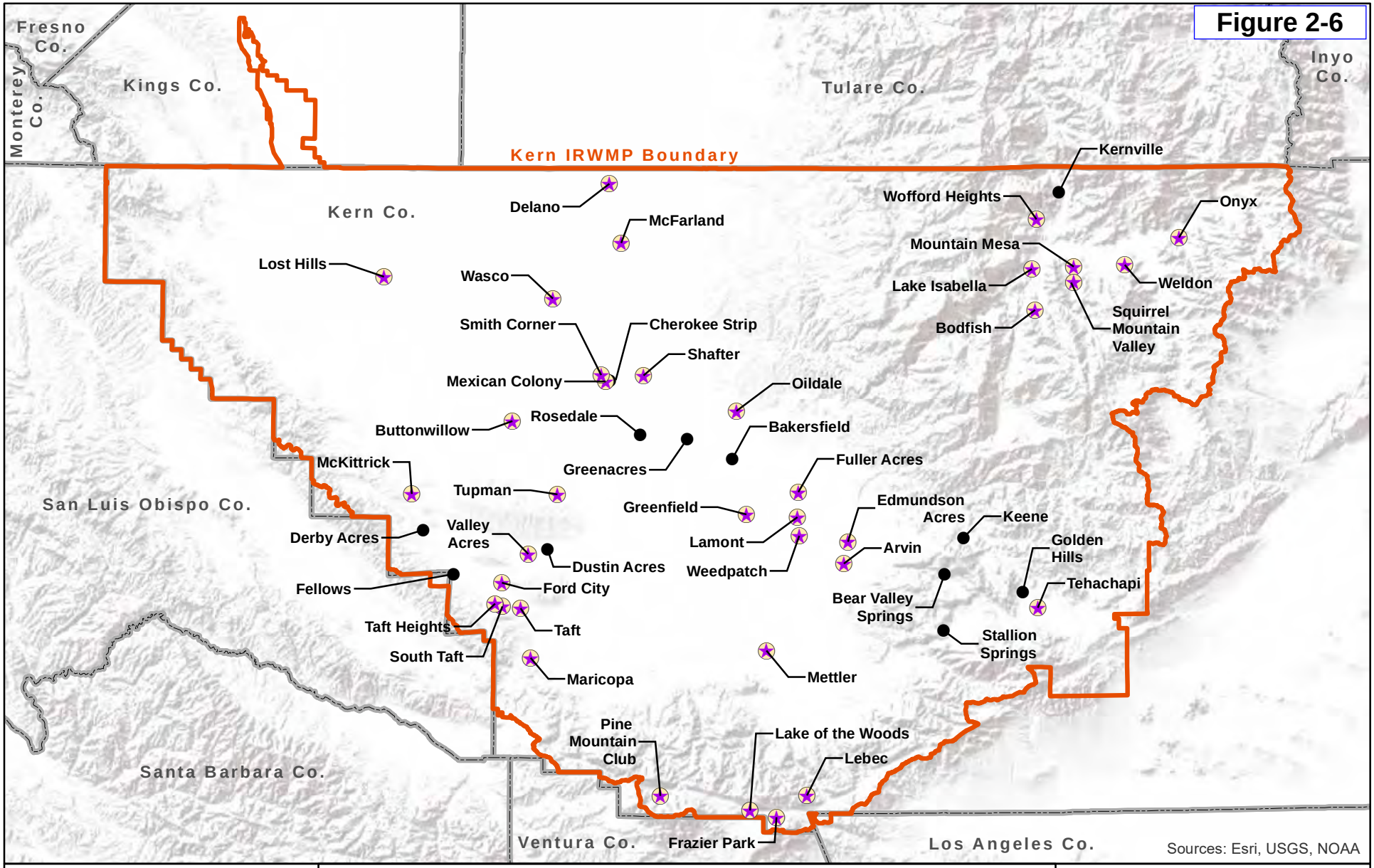

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Figure 2-7

KINGS COUNTY

TULARE COUNTY

INYO COUNTY

KERN RIVER VALLEY BASIN

WALKER BASIN CREEK VALLEY BASIN

SAN JOAQUIN VALLEY BASIN

SAN BERNARDINO COUNTY

KERN COUNTY

SAN LUIS OBISPO COUNTY

TEHACHAPI VALLEY WEST BASIN

CUMMINGS VALLEY BASIN

TEHACHAPI VALLEY EAST BASIN

BRITE VALLEY BASIN

KERN REGION

CUDDY VALLEY BASIN

MIL POTRERO AREA BASIN

CUDDY RANCH AREA BASIN

CASTAC LAKE VALLEY BASIN

SANTA BARBARA COUNTY

CUDDY CANYON VALLEY BASIN

VENTURA COUNTY

LOS ANGELES COUNTY

DWR BULLETIN 118 GROUNDWATER BASINS WITHIN THE KERN REGION

KERN COUNTY WATER AGENCY
Bakersfield, CA

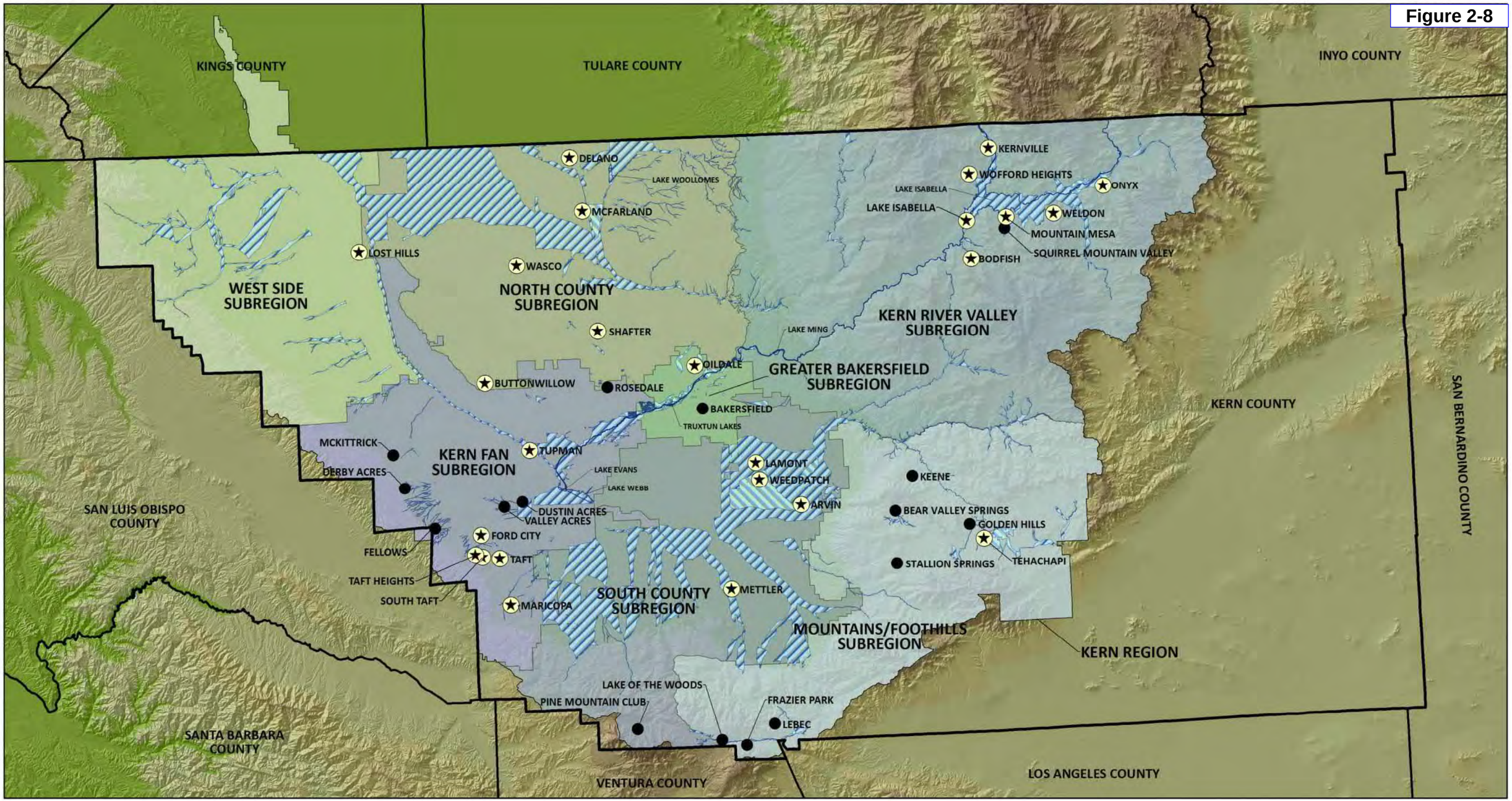
Created: 2009-0409, S. Chambless
Filename: 2009-1015, S. Chambless
Filename: DWR_Bulletin_118_GW_Basins_09-0409.mxd

N

0 2.5 5 10 15 20 Miles

1 inch = 10 miles

Figure 2-8



FEMA DESIGNATED HIGH RISK FLOOD AREAS WITHIN THE KERN REGION

KERN COUNTY WATER AGENCY
Bakersfield, CA

Created: 2009-0409, S. Chambless
Revised: 2011-0824, S. Chambless
Filename: Floodplains_11-0721.mxd

NOTE: Kern County Water Agency and County of Kern subregions not shown.

LEGEND

FEMA FLOOD ZONES
- 100 YEAR FLOOD PLAIN
- 500 YEAR FLOOD PLAIN

CITIES*
- CITY / COMMUNITY
- DISADVANTAGED COMMUNITY

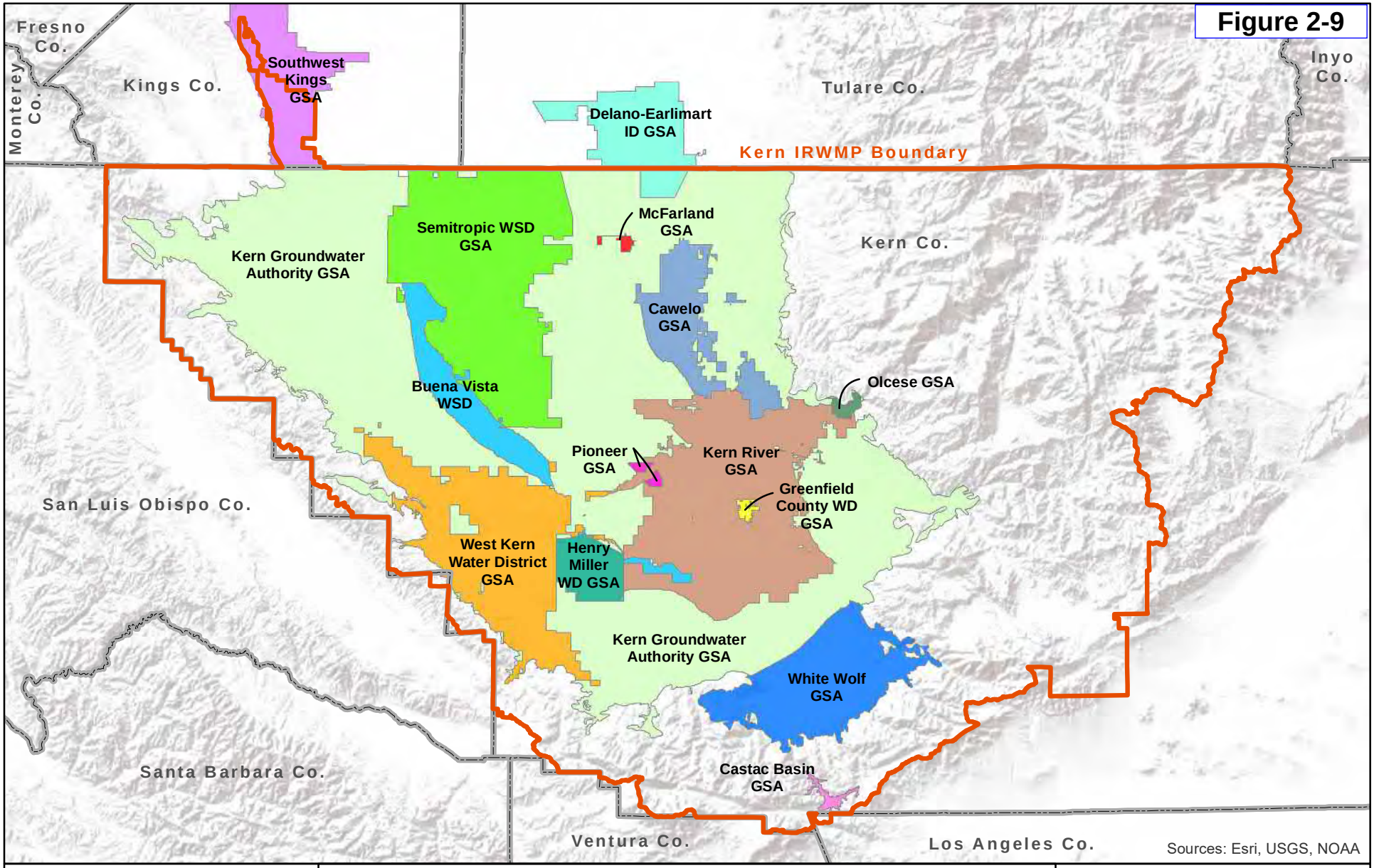
*Data taken from U.S. Census Bureau; specifically the Census 2000 TIGER/Line.

N

0 2.5 5 10 15 20 Miles

1 inch = 10 miles

Figure 2-9



EST. 1968
PROVOST& PRITCHARD
CONSULTING GROUP
An Employee Owned Company

N

0 5 10
Miles

Kern IRWMP Area

County

Groundwater Sustainability Agencies (GSA)

Kern IRWMP

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Figure 2-10

Kern IRWMP

DAC and SDAC Communities
Water Quality Compliance

Kings Co.
Tulare Co.
Kern Co.

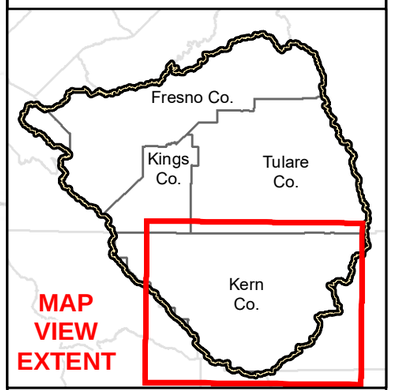
BLACKWELLS CORNER
LOST HILLS
BUTTONWILLOW
MIRASOL COMPANY WATER SYSTEM
MCKITTRICK
TUPMAN
VALLEY ACRES
FORD CITY
TAFT
TAFT HEIGHTS
SOUTH TAFT
MARICOPA
WEST MARICOPA
OILDALE
RIVERDALE VILLAGE
CASA LOMA WATER CO. INC.
EAST NILES
COUNTRY ESTATES
WILSON ROAD
V.R. S TRAILER PARK
REXLAND ACRES
OASIS PROPERTY OWNERS ASSOCIATION
DE RANCHOY MOBILE VILLA WATER
LAMONT
PANAMA ROAD PROPERTY OWNERS ASSOCIATION
GREENFIELD COUNTY WD
ARVIN
BONANZA FARMS
OPAL FRY AND SON
METTLER
KRISTA MUTUAL WATER COMPANY
LEBEC
PINON PINES MWC
FRAZIER PARK
LAKE OF THE WOODS
VALLEY VIEW ESTATES
GLENNVILLE
RIVERNOOK
BURLANDO HEIGHTS MHP
SIERRA MEADOWS
FRONTIER TRAIL HOMEOWNERS ASSOC, INC.
SPLIT MOUNTAIN
COUNTRYWOOD
ARDEN
PINEBROOK
FOURTH STREET
HUNGRY GULCH
SQUIRREL MOUNTAIN VALLEY
BELLA VISTA
ONYX
VALLEY ESTATES
SOUTH LAKE
LAKELAND
LAKE ISABELLA
LAKEVIEW RANCHOS
REEDER TRACT
KERNVALE
JUNIPER HILLS
LOWER BODFISH
UPPER BODFISH
TEHACHAPI
WEST TEHACHAPI
PINON HILL WATER COMPANY
99
5

Legend

- Prop 1 Funding Area
- Kern IRWMA
- County
- Major Road
- Highway / Interstate
- Major Canal

Water Quality Compliance Status

- IN COMPLIANCE
- RETURNED TO COMPLIANCE
- OUT-OF-COMPLIANCE



EST. 1988
PROVOST & PRITCHARD
CONSULTING GROUP
An Employee Owned Company

N

0 4 8
Miles

Sources: Esri, USGS, NOAA

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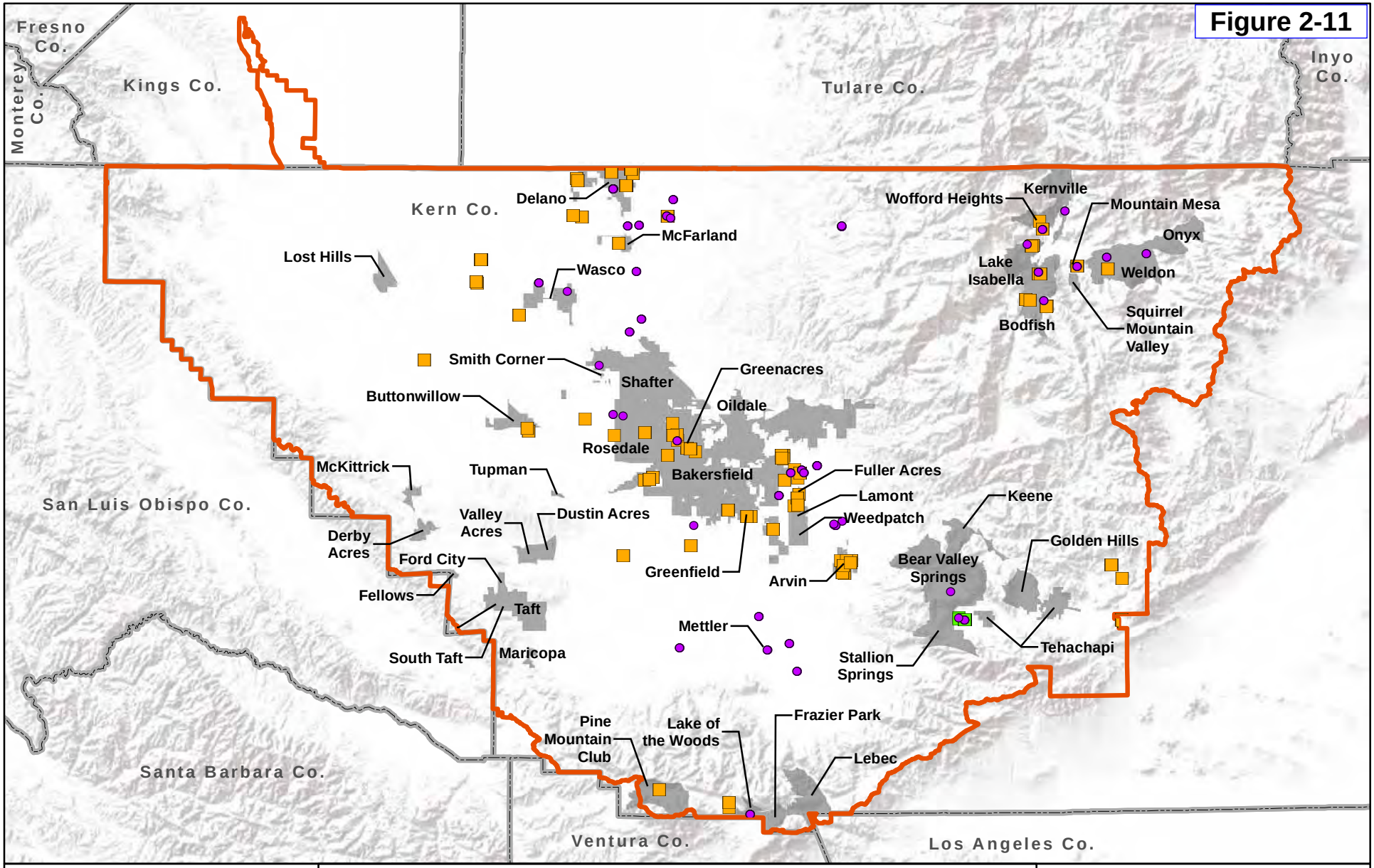

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APPENDICES

Appendix A

Letter Agreements

27 April 2009

Mr. Ralph Svetich
State of California
Department of Water Resources
Division of Planning and Local Assistance

Subject: Integrated Regional Water Management – Letter of Agreement to Collaborate on Common Areas

Dear Mr. Svetich:

This Letter of Agreement establishes that the undersigned Regional Water Management Groups (RWMGs) acknowledge a common area that currently exists based on Antelope Valley's existing Integrated Regional Water Management Plan (IRWMP) boundary and the proposed boundary for the Tulare Lake Basin of Kern County (Kern Region) IRWMP.

A small portion of the Kern Region's south easterly boundary breaks from following the Tulare Lake Basin watershed boundary to overlap with the northern portion of the Antelope Valley watershed based boundary where the Tehachapi-Cummings County Water District (TCCWD) shares infrastructure with the Antelope Valley-East Kern Water Agency. TCCWD is a member unit of the Kern County Water Agency, and provides imported water supplies and groundwater management services to its service area. TCCWD did not participate in the Antelope Valley IRWMP planning effort, and is currently involved in the Kern IRWMP planning effort. The Kern Region boundary extends into the Antelope Region in order to keep the entire TCCWD service area within the Kern Region.

Both the Kern RWMG and the Antelope Valley RWMG acknowledge the existence of an overlap of boundaries and have agreed to work collaboratively to address issues of common interests in this area as both regions advance their respective efforts.

On behalf of the Kern Regional Water Management Group:

William Miller Kern IRWMP, Co-chair	William Taube Kern IRWMP, Co-chair

Lead Agency: Kern County Water Agency
Contact: Lauren Bauer, Water Resources Planner II
Phone Number: (661) 634-1411

On behalf of the Antelope Valley Regional Water Management Group:

_____

David Rydman, Engineer with Los Angeles County Waterworks District No. 40, Antelope Valley
Phone number: (661) 300-3351

cc: Tracie Billington, Department of Water Resources
Jim Lin, Department of Water Resources

INYO-MONO INTEGRATED REGIONAL WATER MANAGEMENT PLANNING PROJECT

TO: Mr. Svetich

State of California
Department of Water Resources
Division of Planning and Local Assistance

FROM: Dr. Mark Drew, Project Manager, Inyo-Mono IRWMP Launch Project

SUBJECT: Integrated Regional Water Management-Letter of Agreement on Regional Boundaries

DATE: 4/17/2009

CC: Tracie Billington, Department of Water Resources
Jim Lin, Department of Water Resources

Dear Mr. Svetich:

This Letter of Agreement establishes that the undersigned Regional Water Management Groups (RWMGs) accept a common shared boundary for purposes of defining their respective IRWM Regions, as set forth in the Department of Water Resources' (DWR) 2009 *Final IRWM Region Acceptance Process Guidelines*. The shared boundary between the Kern RWMG and the Inyo-Mono RWMG is defined in the paragraph below.

Shared Boundary Description:

The Kern RWMG and the Inyo-Mono RWMG abut one another in the northeastern portion of Kern County. The shared boundary between the Kern RWMG and the Inyo-Mono RWMG will follow the crest of the Sierra Nevada Mountains, a delineation based on a watershed boundary.

On behalf of the Kern Regional Water Management Group:

William Miller
Kern IRWMP, Co-chair

William Taube
Kern IRWMP, Co-chair

Lead Agency: Kern County Water Agency
Contact: Lauren Bauer, Water Resources Planner II
Phone number: (661) 634-1411

On behalf of the Inyo-Mono Regional Water Management Group:

KERN IRWMP
Integrated Regional Water Management Plan

October 10, 2018

Ted Daum
Department of Water Resources
Division of Integrated Regional Water Management
Financial Assistance Branch

RE: Integrated Regional Water Management - Letter of Agreement to Collaborate on Common Areas

Dear Mr. Ted Daum:

This Letter of Agreement establishes that the undersigned Regional Water Management Groups (RWMGs) acknowledge a common area that currently exists on the southeastern portion of Kern County (Kern) Integrated Regional Water Management (IRWM) Plan boundary and the proposed boundary for the Fremont Basin IRWM Plan.

The Fremont Basin IRWM Region desires to modify their original boundary, approved by DWR in 2011, to reflect a combination of the Fremont Valley Groundwater Basin (FVGWB) boundary and the Fremont Valley Watershed boundary. In the southwestern portion of the Fremont Basin IRWM Region, the proposed Region boundary follows the 2011 boundary and then incorporates the FVGWB where appropriate, creating an approximately 4,700-acre overlap with the current Kern IRWM Region (see Figure below). It is important for the Fremont Basin IRWM Region to encompass the entirety of the FVGWB since it is the most significant water supply for the Fremont Basin IRWM Region. The boundary modification is the most inclusive, contiguous area that represents the common water management issues and needs of the Fremont Basin Region.

For the Kern IRWM Region, it is also important to retain this area as it is part of the Tehachapi-Cummings County Water District (TCCWD) service area and shares infrastructure with the Antelope Valley-East Kern Water Agency. TCCWD is a member unit of the Kern County Water Agency and provides imported water supplies and groundwater management services to its service area. TCCWD has been involved in previous Kern IRWM Plan planning efforts and did not participate in the Fremont Basin IRWM Plan development.

Both the Kern RWMG and the Fremont Basin RWMG acknowledge the existence of an overlap of boundaries and have agreed to work collaboratively to address issues of common interests in this area as both regions advance their respective efforts. It should be noted that overlaps between the Fremont Basin IRWM Region and two other neighboring Regions are being handled in separate agreements.

On behalf of the Kern Regional Water Management Group:

William Taube
Kern IRWM Plan, Co-chair

Doug Nunneley
Kern IRWM Plan, Co-chair

Lead Agency: Kern County Water Agency
Contact: Lauren Bauer, Water Resources Planner
Phone Number: (661) 634-1411

On behalf of the Fremont Basin Regional Water Management Group:

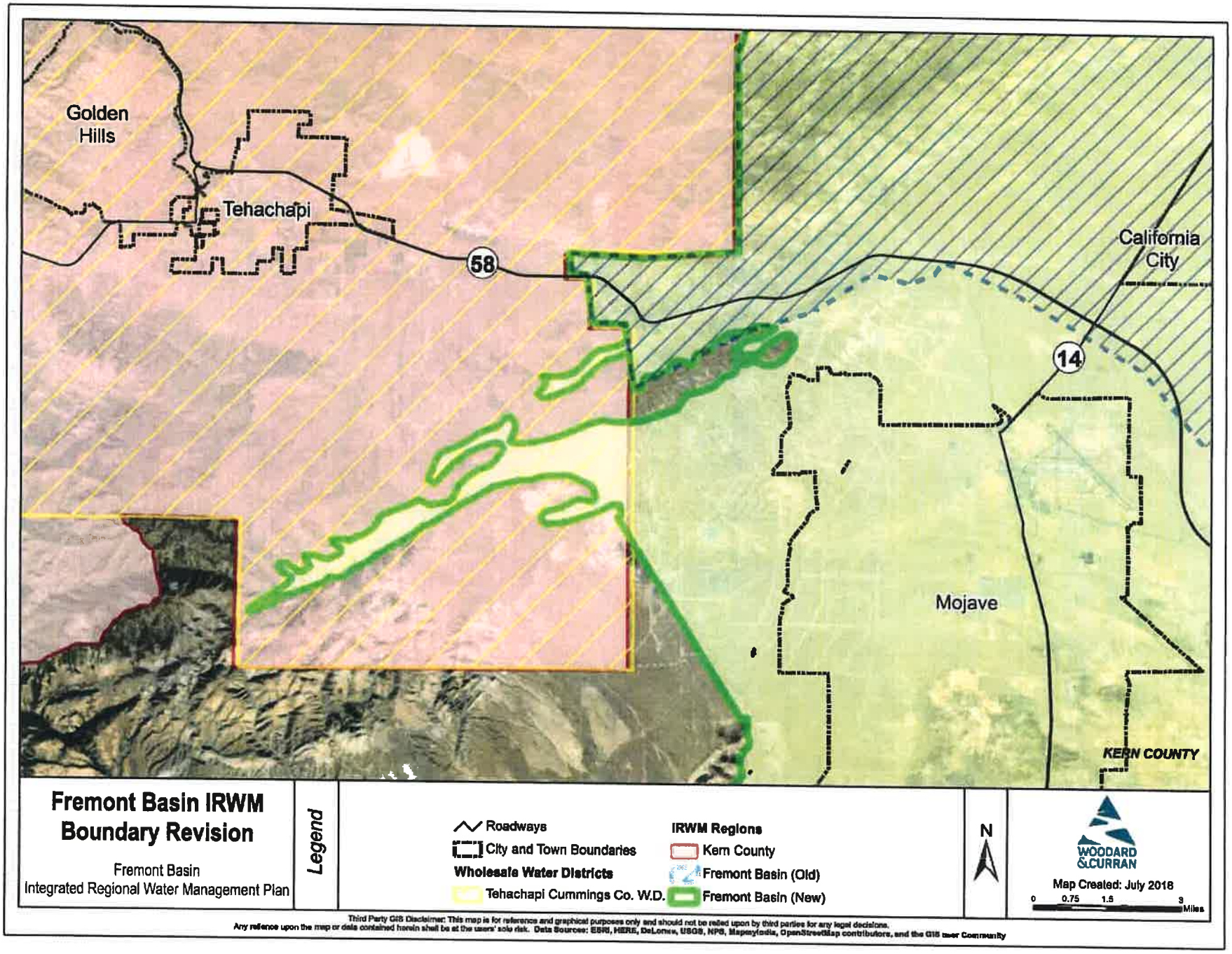
Craig Platt
Fremont Basin IRWM, RWMG member

Bee Coy
Fremont Basin IRWM, RWMG member

Matt Knudson
Fremont Basin IRWM, RWMG member

Lead Agency: City of California City
Contact: Craig Platt, California City Public Works Director
Phone Number: (760) 373-7297

cc: Carmel Brown, Chief of the Financial Assistance Branch
Department of Water Resources


Golden Hills
Tehachapi
58
California City
14
Mojave
KERN COUNTY
Fremont Basin IRWM Boundary Revision
Fremont Basin
Integrated Regional Water Management Plan
Legend
Roadways
City and Town Boundaries
Wholesale Water Districts
Tehachapi Cummings Co. W.D.
IRWM Regions
Kern County
Fremont Basin (Old)
Fremont Basin (New)
N
WOODARD &CURRAN
Map Created: July 2018
0 0.75 1.5 3 Miles
Third Party GIS Disclaimer: This map is for reference and graphical purposes only and should not be relied upon by third parties for any legal decisions.
Any reliance upon the map or data contained herein shall be at the users' sole risk. Data Sources: ESRI, HERE, DeLorme, USGS, NPS, MapmyIndia, OpenStreetMap contributors, and the GIS user Community

Appendix B

Participation Agreement

Directors:

Fred L. Starrh
Division 1

Terry Rogers
Division 2

Vacant
Division 3

Michael Radon
Division 4

Adrienne J. Mathews
President
Division 5

William W. Van Skike
Division 6

Gene A. Lundquist
Division 7

James M. Beck
General Manager

Amelia T. Minaberrigarai
General Counsel

150.8 Water Conservation

August 25, 2009

IRWMP Participant List

RE: Participation Agreement for Development of an Integrated Regional Water Management Plan for the Tulare Lake Basin Portion of Kern County

To Whom It May Concern:

Enclosed is an executed copy of the Participation Agreement for Development of an Integrated Regional Water Management Plan.

If you have any questions, please feel free to contact Lauren Bauer of my staff at lbauer@kcwa.com or (661) 634-1411.

Sincerely,

Curtis Creel
Water Resources Manager

Enclosure

(661) 634-1400

Mailing Address
P.O. Box 58
Bakersfield, CA 93302-0058

Street Address
3200 Rio Mirada Dr.
Bakersfield, CA 93308

PARTICIPATION AGREEMENT
FOR DEVELOPMENT OF AN INTEGRATED REGIONAL WATER MANAGEMENT PLAN
FOR THE TULARE LAKE BASIN PORTION OF KERN COUNTY

This Participation Agreement (Agreement), made and entered into on this 29 day of January by and between the Kern County Water Agency, hereinafter "Agency," County of Kern, City of Bakersfield, City of Delano, City of McFarland, City of Shafter, City of Taft, City of Wasco, Arvin Community Services District, Arvin-Edison Water Storage District, Belridge Water Storage District, Berrenda Mesa Water District, Buena Vista Water Storage District, Dudley Ridge Water District, East Niles Community Services District, Frazier Park Public Utility District, Henry Miller Water District, Improvement District No. 4, Kern Delta Water District, Kern Water Bank Authority, Lost Hills Water District, Mettler County Water District, North of the River Municipal Water District, Olcese Water District, Rosedale-Rio Bravo Water Storage District, Tehachapi-Cummings County Water District, West Kern Water District, Wheeler Ridge-Maricopa Water Storage District, Oildale Mutual Water Company, California Water Service, and the other undersigned signatories, hereinafter "Participants:"

WITNESSETH

Whereas, the parties are collectively designated as a "Regional Water Management Group" under the California Water Code Division 6, Part 2.2, known as the Integrated Regional Water Management Planning Act of 2002, hereinafter referred to as "Act;" and

Whereas, section 10531 of the Act includes the following declarations:

(a) Water is a valuable natural resource in California, and should be managed to ensure the availability of sufficient supplies to meet the state's agricultural, domestic, industrial, and environmental needs. It is the intent of the Legislature to encourage local agencies to work cooperatively to manage their available local and imported water supplies to improve the quality, quantity, and reliability of those supplies.

(b) Improved coordination among local agencies with responsibilities for managing water supplies and additional study of groundwater resources are necessary to maximize the quality and quantity of water available to meet the state's agricultural, domestic, industrial, and environmental needs.

(c) The implementation of the Integrated Regional Water Management Planning Act of 2002 will facilitate the development of integrated regional water management plans, thereby maximizing the quality and quantity of water available to meet the state's water needs by providing a framework for local agencies to integrate programs and projects that protect and enhance regional water supplies.

Whereas, section 10537 of the Act states that "Regional Water Management Group" means a group in which three or more local public agencies, at least two of which have statutory authority over water supply, participate by means of a joint powers agreement, memorandum of understanding, or other written agreement, as appropriate, that is approved by the governing bodies of those local public agencies; and

Whereas, under the Act, the parties propose to collaboratively prepare an Integrated Regional Water Management Plan for the Tulare Lake Basin region of Kern County, hereinafter referred to as "Plan", as set forth in this Agreement; and

Whereas, the Act further provides at sections 10545 and 10546 that the Act does not affect any powers granted to any local agency, nor authorizes a regional water management group to decline or otherwise determine the water rights of any person or entity; and

Whereas, the study area for the Plan includes that portion of Kern County which is within the Tulare Lake Basin Funding Region as designated in Exhibit A, which shall be adjusted to reflect all Participants when known; and

Whereas, the Agency and Participants are willing to engage third-party consultants ("Consultants") to prepare the Plan; and

Whereas, the Consultants' Scope of Work to prepare the Plan is provided as Exhibit B; and

Whereas, the Agency and Participants are willing to provide Consultants with the necessary data to prepare the Plan and to review and comment on the draft versions of the Plan; and

Whereas, the "Consultants' Costs" for preparation of the Plan consist of all amounts paid to Consultants upon completion of the Plan; and

Whereas, the Consultant Costs are currently estimated to amount to $420,000 plus a not to exceed amount of 15 percent for a contingency; and

Whereas, the Final Plan is defined to be the version of the Plan that is deemed ready for adoption by 51 percent or more of the Participants, where each individual Participant has one representative; and

Whereas, the Adopted Plan is defined to be the version of the Plan that is adopted by the governing bodies of at least 51 percent or more Participants, two of which have statutory authority over water supply, as evidenced by resolutions substantially similar to the sample included as Exhibit C.

Now, therefore, in consideration of the mutual benefits to be derived by the parties and of the promises herein contained, it is hereby agreed as follows:

(1) Agency and Participants agree that this Agreement shall become effective when agencies representing 80 percent of the Plan Preparation Costs as defined in Exhibit D, which shall be adjusted to reflect all Participants when known, have signed the Agreement.

(2) Agency agrees:

a. To administer Consultants contracts for development of the Plan and oversight of the Consultants' services, including the processing of Consultants invoices.

b. To act as fiscal agent for funds collected from Participants and used to pay Consultants for development of the Plan.

c. To provide administrative support for development of all phases of the Plan.

d. To offer its facilities for stakeholder meetings on an as-available basis.

e. To appoint one (1) representative and one (1) alternate to the Executive Committee.

f. Unless provided directly by Consultants, to provide Participants with copies of the draft and final versions of technical reports prepared in support of the Plan, including the draft and Final Plan, within seven (7) calendar days from the date of receipt of said documents from Consultants, and to transmit comments to Consultants within seven (7) calendar days from the date of receipt of said documents from each party.

g. To provide and share all necessary and relevant information, data, studies, and/or documentation for the Plan in its possession as may be requested by Consultants (and is not exempt from disclosure under applicable law) within a time period specified by the Executive Committee of the request by the Consultants or such information and data.

h. To participate in development of the Plan by attending meetings and reviewing and commenting on the draft and final versions of technical reports and the draft Plan within a time period specified by the Executive Committee for inclusion in the Final Plan.

i. To present the Final Plan to its Board of Directors for consideration and adoption within forty-five (45) calendar days from the date of receipt of the Final Plan.

j. To provide a contribution towards the Consultants Costs collectively shared by the Participants in the amounts shown on Exhibit D.

k. To invoice Participants on a quarterly basis for contributions towards the Consultants' Costs in the amounts shown on Exhibit D.

(3) Participants agree:

a. To offer their facilities for stakeholder meetings on an as-available basis.

b. To appoint one (1) representative and one (1) alternate to the Executive Committee for each respective suibregion as defined Exhibit E, which shall be adjusted to reflect all Participants when known.

c. To provide and share all necessary and relevant information, data, studies, and/or documentation for the Plan in its possession as may be requested by Consultants (and is not exempt from disclosure under applicable law) within a time period specified by the Executive Committee for inclusion in the Final Plan.

d. To participate in development of the Plan by attending meetings and reviewing and commenting on the draft and final versions of technical reports and the draft Plan within twenty-one (21) calendar days from the date of receipt of said documents from the Agency or Participants' comments may not be incorporated in the Final Plan.

e. To present the Final Plan to their respective governing bodies for consideration and adoption within forty-five (45) calendar days from the date of receipt of the Final Plan.

f. To provide a contribution towards the Consultants' Costs collectively shared by the Participants not to exceed the amounts shown on Exhibit D.

g. To pay invoices of the Kern County Water Agency for Participants' contributions within thirty (30) calendar days from the date of receipt of said invoices.

(4) The Executive Committee shall have the following powers and authorities:

a. The Executive Committee will consist of one representative and one alternate from each subregion as identified in Exhibit E. The representative, alternate and any replacements will be chosen by the Participants of the respective subregions.

b. Call and conduct Participant meetings as necessary.

c. Call and conduct Executive Committee meetings as necessary.

d. Retain and dismiss Consultants.

e. Approve or disapprove Consultant invoices for payment.

f. Approve or disapprove expenditures of the contingency funds

g. Approve or disapprove agendas and materials for meetings related to development of the Plan.

h. Coordinate with Agency management on matters related to development of the Plan.

i. Determine the appropriate timeframe for the completion and submission of data, executed agreements, and other relevant information and actions.

j. The Executive Committee will pick two (2) of its members as co-chairs, one (1) from the agricultural sector and one (1) from the urban sector.

k. The co-chairs will conduct and direct meetings of the Regional Water Management Group.

l. The co-chairs, acting as signatories for the Regional Water Management Group, may execute third-party agreements for integration with other Regional Water Management Groups with the approval of at least 51 percent of the Participants.

(5) It is mutually understood and agreed as follows:

a. Other entities may become a Participant by signing this Agreement and by a vote of approval by a majority of the Participants, with each Participant having one vote.

b. If the governing body of a Participant does not adopt the Plan within forty-five (45) calendar days from the date of receipt of the Final Plan, such action or inaction shall constitute withdrawal from the Regional Water Management Group. A Participant which withdraws from the Regional Water Management Group may be reinstated when the Participant adopts the Final Plan and agrees to any additions and/or amendments to the Agreement.

c. Withdrawal from the Regional Water Management Group by any Participant shall not reduce the Participant's responsibility under this Agreement to make payments of the full amount shown on Exhibit D.

d. Upon completion of the Adopted Plan, the Agency shall prepare a final accounting of all final, actual Consultants' Costs for review by the Participants.

e. If the funds deposited with the Agency exceed the Consultants' Costs based upon the Accounting, the Agency will refund the excess funds to the Participants in proportion to their contribution towards the Consultants' Costs. The Agency shall refund the excess funds within sixty (60) days after completion of the Plan.

f. This Agreement may be amended or modified only by mutual written consent of all parties.

g. This Agreement shall terminate when (1) there is an Adopted Plan and (2) all obligations, financial or otherwise, incurred under this Agreement are resolved.

h Any and all liability or expenses (including attorneys' and experts' fees and related costs) to the Agency for claims by third parties or Consultants and injury to third parties or Consultants, arising from or relating to this Agreement shall be allocated among the parties on the basis of the percent of contribution required of each party under this Agreement. The term "injury" shall have the meaning prescribed by section 810.9 of the Government Code. This provision shall survive termination of this Agreement.

i. Any correspondence, communication, or contact concerning this Agreement shall be directed to the following:

Kern County Water Agency:
Mr. James M. Beck
General Manager
P.O. Box 58
Bakersfield, CA 93302-0058

j. In signing below, each of the parties warrants and represents to each of the other parties that each is a duly organized or constituted entity, with all requisite power to carry out its obligations under this Agreement, and that the execution, delivery and performance of this Agreement have been duly authorized by all necessary action of the board of directors or other governing body of such party, and shall not result in a violation of such party's organization documents.

k. This Agreement may be executed in counterparts, each of which shall be deemed an original and all of which, taken together, shall constitute one and the same instrument. Signatures sent by facsimile shall be deemed originals and treated in all respects as originals.

l. This Agreement shall bind and inure to the benefit of the respective successors and assigns of the parties; provided, however, no party shall assign or transfer its rights or obligations under this Agreement without the prior written consent of all other parties.

m. The parties agree to take such further action and execute and deliver such additional documents as may be reasonably required to effectuate the terms and conditions of this Agreement.

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

J. M. B.
Name

General Manager
Title

1/29/09
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

City of Taft
Participant Name

Name Paul Linder

Mayor
Title

October 21, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

North of the River MWD
Participant Name

William R. Miller
Name

General Manager
Title

11/07/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Buena Vista Water Storage Dist.
Participant Name

W. BJ
Name

ENGINEER-MANAGER
Title

11-7-08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency Participant Name	Olcese Water District Participant Name
Name	James L. Nickel, President Name
General Manager Title	Title
Date	November 14, 2008 Date
Participant Name	Participant Name
Name	Name
Title	Title
Date	Date
Participant Name	Participant Name
Name	Name
Title	Title
Date	Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Stallion Springs C.S.D.
Participant Name

David Aranda
Name

General Manager
Title

11-11-08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

DUDLEY RIDGE W.D.
Participant Name

Name

MANAGER-ENGINEER
Title

11-13-08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

East Niles Community Svcs Dist.
Participant Name

Name

General Manager
Title

11-18-2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

BEAR VALLEY COMMUNITY SERVICES DISTRICT
Participant Name

John C. Yeakley
Name

GENERAL MANAGER
Title

11-14-08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Ravenbirk Valley Mutual Water
Participant Name

Maysha Kelpe
Name

Utility Mgr.
Title

11/15/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Rosedale - Rio Bravo WSD
Participant Name

Name

General Manager
Title

November 14, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Vaughn Water Company Inc.
Participant Name

Michael L. Hubbard
Name

General Manager
Title

11-18-08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

John D. Guinn
Name

City Manager
Title

11/19/2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Mettler County Water District
Participant Name

Brian C BLACKSTOCKS
Name

Chairman of the Board
Title

November 11, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Buttonwillow County Water District
Participant Name

Name

Chairman to the Board
Title

11/19/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

California Water Service Co.
Participant Name

Name Mike Rossi

Vice President
Title

Nov. 10, 2008
Date

for JAS

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Wheeler Ridge-Maricopa WSD
Participant Name

Name

Engineer-Manager
Title

November 24, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

TEHACHAPI RESOURCE CONSERVATION DISTRICT
Participant Name

Name

BOARD PRESIDENT
Title

NOVEMBER 12, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

City of Bakersfield
Participant Name

Name - Florn Core

Water Resources Manager
Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Arvin-Edison Water Storage District
Participant Name

Name Steve Collup

Engineer-Manager
Title

November 18, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Tehachapi-Cummings County Water Dist.
Participant Name

Harry Covar
Name

President
Title

Date

Tehachapi-Cummings County Water Dist.
Participant Name

Name

General Manager
Title

11/20/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Long Canyon Water
Participant Name

David R Price
Name

Pres.
Title

11/23/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Oildale Mutual Water Company
Participant Name

Name

General Manager
Title

12/3/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

BELRIDGE WATER STORAGE DISTRICT
Participant Name

Name

GENERAL MANAGER
Title

11/21/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

HENRY MILLER WATER DISTRICT
Participant Name

David Cosyns
Name

PRESIDENT
Title

11/19/08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Kern Delta Water District
Participant Name

Name

General Manager
Title

November 26, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Tejon Castac water District
Participant Name

Dennis Atkinson
Name

President
Title

12-01-08
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

County of Kern
Participant Name

Name

Chairman - Board of Supervisors
Title

December 9, 2008
Date

DEC 09 2008

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

LOST HILLS WATER DISTRICT
Participant Name

Philip N Moss
Name

Manager
Title

1-08-09
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency Participant Name	Kern Water Bank Authority Participant Name
Name	Name
General Manager Title	General Manager Title
Date	12-15-08 Date
Participant Name	Participant Name
Name	Name
Title	Title
Date	Date
Participant Name	Participant Name
Name	Name
Title	Title
Date	Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Wm Scott Kissack
Participant Name

Wm Scott Kissack
Name

Vice President - Mt. Mesa Water Co.
Title

1-9-09
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

City of McFarland
Participant Name

Name Kenneth Russom

Mayor
Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Greenfield County Water District
Participant Name

By
Name David Rasmussen

President
Title JANUARY 12, 2009
~~November 10, 2008~~

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Valley Estates POA, Inc.
Participant Name

Michael A. Higgins

Vice President / Treasurer
Title

December 8, 2008
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

CITY OF TEHACHAPI
Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

City of Arvin
Participant Name

Tim Tarver
Name

Mayor
Title

February 10, 2009
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

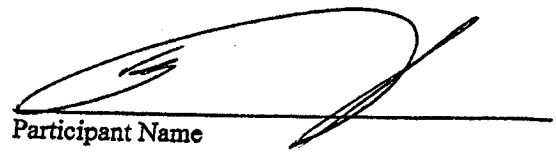
Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date



Participant Name

Abdel Salem
Name

City Manager
Title

February 17, 2009
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Lost Hills Utility District
Participant Name

Name

President
Title

March 5, 2009
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Berrenda Mesa Water Dist.
Participant Name

Name

G.M.
Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

WEST KERN WATER DISTRICT
Participant Name

Name

GENERAL MANAGER
Title

3/30/09
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

X Frazier Park Public Utility
Participant Name

X
Name

President - Board of Director
Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

ARVIN COMMUNITY SERVICES DISTRICT
Participant Name

Robert P. Rodriguez
Name

Board President
Title

3-30-09
Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

In witness whereof, the parties hereto have caused this Agreement to be executed by their respective officers, duly authorized to enter into this Agreement.

Accepted:

Kern County Water Agency
Participant Name

Name

General Manager
Title

Date

Participant Name

Name

Title

Date

City of Maricopa
Participant Name

Robert E. Wilken
Name

City Manager
Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Participant Name

Name

Title

Date

Appendix C

Stakeholder Meeting Materials

(Refer to www.KernIRWMP.com
for recent Meeting Materials)

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan

Participant Meeting
April 15, 2010 1:00 pm – 5:00 pm
Kern County Water Agency
Stuart T. Pyle Water Resources Center
3200 Rio Mirada Drive, Bakersfield, CA 93308

Meeting Objectives:

- Project Prioritization

AGENDA

1:00	**I.**	**Welcome and Introductions** A. Meeting purpose and agenda B. Introduction of new participants *Lauren Bauer, KCWA*
1:05	**II.**	**Project Prioritization** A. Updating the Project Prioritization Process *Lauren Bauer, KCWA*
4:45	**III.**	**Next Steps** A. Next Meeting B. Objectives Homework *Lauren Bauer, KCWA*
4:55	**IV.**	**Public Comment**
5:00		***Close***

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan

Participant Meeting
May 4, 2011 1:00 pm – 3:30 pm
Kern County Water Agency
Stuart T. Pyle Water Resources Center
3200 Rio Mirada Drive, Bakersfield, CA 93308

Meeting Objectives:

- Program Management
- Plan Governance
- Project Prioritization

AGENDA

1:00	**I.**	**Welcome and Introductions** A. Meeting purpose and agenda B. Introduction of new participants *Lauren Bauer, KCWA*
1:10	**II.**	**Project Prioritization** A. Review of the Project Prioritization Process workshop B. Consider adopting new Project Prioritization Process *Lauren Bauer, KCWA*
2:10	**II.**	**Plan Governance** A. Review of draft governance structure B. Consider options for long-term management of the Kern IRWMP *Lauren Bauer, KCWA*
2:55	**III.**	**Program Funding** A. Consider drafting budget for FY 2011-2012 *Lauren Bauer, KCWA*
3:10	**IV.**	**Next Steps** A. Next Meeting *Lauren Bauer, KCWA*
3:15	**V.**	**Public Comment**
3:30		***Close***

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan

August 15, 2011 1:00 pm – 3:30 pm
Kern County Water Agency
Stuart T. Pyle Water Resources Center
3200 Rio Mirada Drive, Bakersfield, CA 93308

Meeting Objectives:

- Update on IRWM Program and Kern IRWMP
- Project Prioritization
- Governance

AGENDA

1:00	**I.**	**Welcome and Introductions** A. Meeting purpose and agenda B. Introduction of new participants *Lauren Bauer, KCWA*
1:10	**II.**	**DWR Update** A. Update on the IRWM Program *Alex Vdovichenko, DWR*
1:20	**III.**	**Kern IRWMP Update** A. Kennedy/Jenks staff changes B. Plan Completion Timeline *Lauren Bauer, KCWA*
1:30	**IV.**	**Project Prioritization** A. Re-consider adopting new Project Prioritization Process *Lauren Bauer, KCWA*
2:30	**V.**	**Plan Governance** A. Review of draft governance structure B. Update on consultant RFQ *Lauren Bauer, KCWA*
3:00	**VI.**	**Next Steps** A. Next Meeting *Lauren Bauer, KCWA*
3:15	**VII.**	**Public Comment**
3:30		***Close***

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan

September 19, 2011 8:30 am – 10:00 am
Kern County Water Agency
Stuart T. Pyle Water Resources Center
3200 Rio Mirada Drive, Bakersfield, CA 93308

Meeting Objectives:

- Governance
- Timeline

AGENDA

8:30	**I.**	**Welcome and Introductions** A. Meeting purpose and agenda B. Introduction of new participants *Lauren Bauer, KCWA*
8:40	**II.**	**General Information Items** A. Final RAP B. Planning Grants C. Local Levee Grant Program D. Tulare DAC Study Advisory Group *Lauren Bauer, KCWA*
9:00	**III.**	**Kern IRWMP Update** A. Governance *Lauren Bauer, KCWA*
9:30	**VI.**	**Next Steps** A. Review of Timeline *Lauren Bauer, KCWA*
9:50	**VII.**	**Public Comment**
10:00		***Close***

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan

October 13, 2011 10:00 am – 12:00 pm
Kern County Water Agency
Stuart T. Pyle Water Resources Center
3200 Rio Mirada Drive, Bakersfield, CA 93308

Meeting Objectives:

- Kern IRWMP Draft Review

AGENDA

10:00	**I.**	**Welcome and Introductions** A. Meeting purpose and agenda B. Introduction of new participants *Lauren Bauer, KCWA*
10:10	**II.**	**General Information Items** A. DWR Grant Timeline B. Consultant RFQ/P Update C. Project Submission Deadline *Lauren Bauer, KCWA*
10:30	**III.**	**Review of Draft Kern IRWMP** A. Review of Draft Kern IRWMP *Kennedy/Jenks*
11:40	**VI.**	**Next Steps** A. November Meeting *Lauren Bauer, KCWA*
11:45	**VII.**	**Public Comment**
12:00		***Close***

Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan

November 14, 2011 10:00 am – 12:00 pm
Kern County Water Agency
Stuart T. Pyle Water Resources Center
3200 Rio Mirada Drive, Bakersfield, CA 93308

Meeting Objectives:

- Kern IRWMP Draft Review

AGENDA

10:00	**I.**	**Welcome and Introductions** A. Meeting purpose and agenda B. Introduction of new participants *Lauren Bauer, KCWA*
10:10	**II.**	**General Information Items** A. Project Submission Deadline B. Planning Grants C. Consultant RFQ/P Selection D. Funding Allocation Discussion *Lauren Bauer, KCWA*
10:40	**III.**	**Review of Draft Kern IRWMP** A. Review of Draft Kern IRWMP *Lauren Bauer, KCWA*
11:20	**VI.**	**Next Steps** A. Plan Adoption B. December Meeting *Lauren Bauer, KCWA*
11:40	**VII.**	**Public Comment**
12:00		***Close***

Appendix D

SWP Water Quality Data

Parameter	Count	Average	Max	Min
1,1,1,2-Tetrachloroethane	41	ND	ND	ND
1,1,1-Trichloroethane	41	ND	ND	ND
1,1,2,2-Tetrachloroethane	41	ND	ND	ND
1,1,2-Trichloroethane	41	ND	ND	ND
1,1-Dichloroethane	41	ND	ND	ND
1,1-Dichloroethene	41	ND	ND	ND
1,1-Dichloropropene	41	ND	ND	ND
1,2,3-Trichlorobenzene	41	ND	ND	ND
1,2,3-Trichloropropane	41	ND	ND	ND
1,2,4-Trichlorobenzene	41	ND	ND	ND
1,2,4-Trimethylbenzene	41	ND	ND	ND
1,2-Dibromo-3-chloropropane (DBCP)	41	ND	ND	ND
1,2-Dibromoethane (EDB)	41	ND	ND	ND
1,2-Dichlorobenzene	41	ND	ND	ND
1,2-Dichloroethane	41	ND	ND	ND
1,2-Dichloropropane	41	ND	ND	ND
1,3,5-Trimethylbenzene	41	ND	ND	ND
1,3-Dichlorobenzene	41	ND	ND	ND
1,3-Dichloropropane	41	ND	ND	ND
1,4-Dichlorobenzene	41	ND	ND	ND
2,2-Dichloropropane	41	ND	ND	ND
2,4,5-T	41	ND	ND	ND
2,4,5-TP (Silvex)	41	ND	ND	ND
2,4-D	41	0.15	0.3	0.1
2,4-DB	41	ND	ND	ND
2-Chlorotoluene	41	ND	ND	ND
3-Hydroxycarbofuran	41	ND	ND	ND
4-Chlorotoluene	41	ND	ND	ND
4-Isopropyltoluene	41	ND	ND	ND
Alachlor	41	ND	ND	ND
Aldicarb	41	ND	ND	ND
Aldicarb sulfone	41	ND	ND	ND
Aldicarb sulfoxide	41	ND	ND	ND
Aldrin	41	ND	ND	ND
Aminomethylphosphonic Acid (AMPA)	14	ND	ND	ND
Atrazine	41	ND	ND	ND
Azinphos methyl (Guthion)	41	ND	ND	ND
Benfluralin	41	ND	ND	ND
Benzene	41	ND	ND	ND
BHC-alpha	41	ND	ND	ND
BHC-beta	41	ND	ND	ND
BHC-delta	41	ND	ND	ND
BHC-gamma (Lindane)	41	ND	ND	ND
Bicarbonate (HCO3-)	1	54	54	54
Bromacil	41	ND	ND	ND
Bromobenzene	41	ND	ND	ND
Bromochloromethane	41	ND	ND	ND

Data from station KA017226 (Check 21)
California Aqueduct near Kettleman Check 21
Data range 12/17/1997 to 8/16/2011

Parameter	Count	Average	Max	Min
Bromodichloromethane	51	86.7	130	50
Bromoform	51	13	16	11
Bromomethane	41	ND	ND	ND
Captan	41	ND	ND	ND
Carbaryl	41	ND	ND	ND
Carbofuran	41	ND	ND	ND
Carbon tetrachloride	41	ND	ND	ND
Carbonate (CO3--)	1	ND	ND	ND
Carbophenothion (Trithion)	41	ND	ND	ND
Chlordane	41	ND	ND	ND
Chlorobenzene	41	ND	ND	ND
Chloroethane	41	ND	ND	ND
Chloroform	51	267	520	190
Chloromethane	41	ND	ND	ND
Chlorothalonil	41	ND	ND	ND
Chlorpropham	41	ND	ND	ND
Chlorpyrifos	82	ND	ND	ND
cis-1,2-Dichloroethene	41	ND	ND	ND
cis-1,3-Dichloropropene	41	ND	ND	ND
Conductance (EC)	182	458	883	190
Cyanazine	82	ND	ND	ND
Dacthal (DCPA)	82	0.16	0.16	0.16
Demeton (Demeton O + Demeton S)	41	ND	ND	ND
Diazinon	41	0.01	0.01	0.01
Dibromochloromethane	51	37	76	14
Dibromomethane	41	ND	ND	ND
Dicamba	41	ND	ND	ND
Dichloran	41	ND	ND	ND
Dichlorodifluoromethane	41	ND	ND	ND
Dichlorprop	41	ND	ND	ND
Dicofol	41	ND	ND	ND
Dieldrin	41	ND	ND	ND
Dimethoate	41	ND	ND	ND
Dinoseb (DNPB)	41	ND	ND	ND
Dissolved Aluminum	68	0.05	0.109	0.013
Dissolved Ammonia	136	0.022	0.09	0.01
Dissolved Antimony	135	ND	ND	ND
Dissolved Arsenic	181	0.002	0.004	0.001
Dissolved Barium	68	0.06	0.074	0.051
Dissolved Beryllium	141	ND	ND	ND
Dissolved Boron	176	0.17	0.6	0.1
Dissolved Bromide	167	0.215	0.43	0.05
Dissolved Cadmium	68	ND	ND	ND
Dissolved Calcium	176	20	70	11
Dissolved Chloride	176	69	133	18
Dissolved Chromium	181	0.003	0.008	0.001
Dissolved Chromium, hexavalent (Cr6+	24	0.0003	0.0006	0.0002

Parameter	Count	Average	Max	Min
Dissolved Copper	181	0.002	0.009	0.001
Dissolved Fluoride	131	0.12	0.3	0.1
Dissolved Hardness	104	98	158	50
Dissolved Iron	181	0.02	0.087	0.005
Dissolved Lead	181	0.001	0.001	0.001
Dissolved Lithium	1	ND	ND	ND
Dissolved Magnesium	176	12.3	25	5
Dissolved Manganese	176	0.007	0.016	0.005
Dissolved Mercury	66	ND	ND	ND
Dissolved Molybdenum	1	ND	ND	ND
Dissolved Nickel	141	0.001	0.003	0.001
Dissolved Nitrate	175	2.9	7.2	0.3
Dissolved Nitrate + Nitrite	137	0.64	1.9	0.06
Dissolved Organic Carbon	146	3.28	7.1	2
Dissolved Ortho-phosphate	92	0.68	0.13	0.02
Dissolved Selenium	133	0.001	0.005	0.001
Dissolved Silver	68	ND	ND	ND
Dissolved Sodium	176	49	88	17
Dissolved Strontium	1	0.134	0.134	0.134
Dissolved Sulfate	176	39.3	298	17
Dissolved Thallium	6	ND	ND	ND
Dissolved Zinc	181	0.007	0.01	0.005
Disulfoton	41	ND	ND	ND
Diuron	41	0.65	1.5	0.27
Endosulfan sulfate	41	ND	ND	ND
Endosulfan-I	41	ND	ND	ND
Endosulfan-II	41	ND	ND	ND
Endrin	41	ND	ND	ND
Endrin aldehyde	41	ND	ND	ND
Esfenvalerate	24	ND	ND	ND
Ethion	41	ND	ND	ND
Ethyl benzene	41	ND	ND	ND
Formetanate hydrochloride	36	ND	ND	ND
Glyphosate	41	ND	ND	ND
Hardness	72	103	278	65
Heptachlor	41	ND	ND	ND
Heptachlor epoxide	41	ND	ND	ND
Hexachlorobutadiene	41	ND	ND	ND
Hydroxide (OH-)	1	ND	ND	ND
Isopropylbenzene	41	ND	ND	ND
m + p Xylene	40	ND	ND	ND
Malathion	41	ND	ND	ND
MCPA	41	ND	ND	ND
MCPP	41	ND	ND	ND
Methidathion	41	ND	ND	ND
Methiocarb	39	ND	ND	ND
Methomyl	41	ND	ND	ND

Parameter	Count	Average	Max	Min
Methoxychlor	41	ND	ND	ND
Methyl tert-butyl ether (MTBE)	41	ND	ND	ND
Methylene chloridec	41	ND	ND	ND
Metolachlor	41	0.1	0.1	0.1
Mevinphos	41	ND	ND	ND
Molinate	24	ND	ND	ND
m-Xylene	2	ND	ND	ND
Naled	41	ND	ND	ND
Naphthalene	41	ND	ND	ND
Napropamide	41	ND	ND	ND
n-Butylbenzene	41	ND	ND	ND
Norflurazon	41	ND	ND	ND
n-Propylbenzene	41	ND	ND	ND
o,p'-DDE	25	ND	ND	ND
Ortho-phosphate	45	0.08	0.13	0.04
Oxamyl	41	ND	ND	ND
Oxyfluorfen	41	ND	ND	ND
o-Xylene	41	ND	ND	ND
p,p'-DDD	41	ND	ND	ND
p,p'-DDE	41	ND	ND	ND
p,p'-DDT	41	ND	ND	ND
Parathion (Ethyl)	41	ND	ND	ND
Parathion, Methyl	41	ND	ND	ND
PCB-1016	41	ND	ND	ND
PCB-1221	41	ND	ND	ND
PCB-1232	41	ND	ND	ND
PCB-1242	41	ND	ND	ND
PCB-1248	41	ND	ND	ND
PCB-1254	41	ND	ND	ND
PCB-1260	41	ND	ND	ND
Pendimethalin	41	ND	ND	ND
Pentachloronitrobenzene (PCNB)	41	ND	ND	ND
Pentachlorophenol (PCP)	41	ND	ND	ND
Permethrin	24	ND	ND	ND
pH	177	7.61	9	5.5
Phorate	41	ND	ND	ND
Phosalone	41	ND	ND	ND
Phosmet	41	ND	ND	ND
Picloram	41	ND	ND	ND
Profenofos	41	ND	ND	ND
Prometryn	41	ND	ND	ND
Propargite	17	ND	ND	ND
Propetamphos	41	ND	ND	ND
p-Xylene	1	ND	ND	ND
s,s,s-Tributyl Phosphorotrithioate (DEF	41	ND	ND	ND
sec-Butylbenzene	41	ND	ND	ND
Simazine	41	0.053	0.12	0.02

Parameter	Count	Average	Max	Min
Styrene	41	ND	ND	ND
tert-Butylbenzene	41	ND	ND	ND
Tetrachloroethene	41	ND	ND	ND
Thiobencarb	65	ND	ND	ND
Toluene	41	ND	ND	ND
Total Alkalinity	177	73.6	100	40
Total Aluminum	5	0.19	0.293	0.155
Total Antimony	5	ND	ND	ND
Total Arsenic	5	0.002	0.002	0.001
Total Barium	5	ND	ND	ND
Total Beryllium	5	ND	ND	ND
Total Cadmium	5	ND	ND	ND
Total Chromium	5	0.001	0.001	0.001
Total Copper	5	0.002	0.002	0.002
Total Dissolved Solids	186	260	593	107
Total Iron	5	0.34	0.395	0.204
Total Kjeldahl Nitrogen	136	0.38	1.2	0.1
Total Lead	5	ND	ND	ND
Total Manganese	5	0.044	0.066	0.022
Total Nickel	5	0.002	0.002	0.001
Total Organic Carbon	276	3.8	10.7	1.7
Total Phosphorus	136	0.97	0.2	0.01
Total Selenium	5	ND	ND	ND
Total Silver	5	ND	ND	ND
Total Suspended Solids	194	9.6	102	1
Total Zinc	5	ND	ND	ND
Toxaphene	41	ND	ND	ND
trans-1,2-Dichloroethene	41	ND	ND	ND
trans-1,3-Dichloropropene	41	ND	ND	ND
Trichloroethene	41	ND	ND	ND
Trichlorofluoromethane	41	ND	ND	ND
Triclopyr	41	ND	ND	ND
Trifluralin	41	ND	ND	ND
Turbidity	204	8.24	71	1
Vinyl chloride	41	ND	ND	ND
Volatile Suspended Solids	196	2.25	9	1

Appendix E

Water Management Strategies versus
Kern IRWMP Projects

APPENDIX E

WATER MANAGEMENT STRATEGIES VS. KERN IRWMP PROJECTS

			Reduce Water Demand		Improve Operational Efficiency and			Increase Water Supply					Improve Water Quality						Practice Resource Stewardship									Improve Flood Mgmt	People & Water				
Subregion / Form #	Project Sponsor	Project Name	Ag. Water Use Efficiency	Urban Water Use Efficiency	Conveyance - Delta & Regional/Local	System Reoperation	Water Transfers	Conjunctive Mgmt. & GW Storage	Desalination -Brackish/Seawater	Precipitation Enhancement	Recycled Municipal Water	Surface Storage - CALFED* & Regional/Local*	Drinking Water Treatment & Dist.	GW/Aquifer Remediation	Matching Quality to Use	Pollution Prevention	Salt & Salinity Management	Urban Runoff Management	Ag. Lands Stewardship	Ecosystem Restoration	Forest Management	Land Use Planning & Mgmt	Recharge Area Protection	Urban Land Use Management	Watershed Management	Sediment Management	Flood Risk Management	Economic Incentives	Water-dependent Recreation	Outreach and Engagement	Water and Culture
CK-1	County of Kern	South Shafter Sewer			X	X					X					X				X			X								
CK-2	County of Kern	Caliente Creek Habitat Restoration & GW Recharge			X			X				X								X		X	X		X	X	X				
CK-3	County of Kern	Lakeshore Pines Leachfield Replacement				X										X				X			X		X						
CK-4	County of Kern	Lake Isabella Detailed Sewer Study			X						X					X						X									
CK-5	County of Kern (Krista MWC)	Krista Mutual Water Company Water Project		X	X			X					X			X															
CK-6	County of Kern	Reeder Tract WWT Facility				X										X									X						
CK-7	County of Kern	Sandy Creek Bank and Erosion Protection														X				X					X		X				
CK-8	County of Kern	South Taft Sewer Improvements			X	X					X					X				X			X								
CK-9	County of Kern	Cuddy Creek Restoration Project														X		X		X		X			X		X				
CK-10	County of Kern	Reconstruction of Adams/Jefferson St - Ford City			X											X		X								X	X				
CK-11	County of Kern	Disadvantaged Community Leak Detection Program		X	X			X					X			X											X				
GB-1	Improvement District No. 4	Recharge Improvement Project	X	X	X															X					X				X		
GB-2	Improvement District No. 4	Beardsley Pipeline		X	X	X	X						X																		
GB-4	Improvement District No. 4	Groundwater Monitoring Wells	X	X				X						X											X						
GB-6	Improvement District No. 4	Surface Water Quality Monitoring Stations						X					X		X	X									X						
GB-7	Kern Delta Water District	Cross River Pipeline	X		X	X	X	X								X											X	X			
GB-8	City of Bakersfield	River Canal Weir Restoration and Expansion Project			X	X	X	X								X				X					X	X	X		X		
GB-9	Improvement District No. 4	Cross Valley Canal Extension Lining Project -- Pool No. 8	X	X	X		X	X																							
GB-10	City of Bakersfield	Water Conservation Project for Metropolitan Bakersfield		X				X																				X	X		

APPENDIX E

WATER MANAGEMENT STRATEGIES VS. KERN IRWMP PROJECTS

			Reduce Water Demand		Improve Operational Efficiency and			Increase Water Supply					Improve Water Quality						Practice Resource Stewardship									Improve Flood Mgmt	People & Water			
Subregion / Form #	Project Sponsor	Project Name	Ag. Water Use Efficiency	Urban Water Use Efficiency	Conveyance - Delta & Regional/Local	System Reoperation	Water Transfers	Conjunctive Mgmt. & GW Storage	Desalination -Brackish/Seawater	Precipitation Enhancement	Recycled Municipal Water	Surface Storage - CALFED* & Regional/Local*	Drinking Water Treatment & Dist.	GW/Aquifer Remediation	Matching Quality to Use	Pollution Prevention	Salt & Salinity Management	Urban Runoff Management	Ag. Lands Stewardship	Ecosystem Restoration	Forest Management	Land Use Planning & Mgmt	Recharge Area Protection	Urban Land Use Management	Watershed Management	Sediment Management	Flood Risk Management	Economic Incentives	Water-dependent Recreation	Outreach and Engagement	Water and Culture
KF-2	Kern Water Bank Authority	Kern Water Bank Short-Term Storage Program		X	X		X	X				X	X										X				X				
KF-4	Buena Vista WSD	Conservation Easement Water Acquisition and Management Project						X				X		X	X				X	X		X	X		X			X			
KF-6	Tulare Basin Wildlife Partners	Goose Lake Wetlands Reserve Program Residual Value Purchase	X		X	X	X	X						X	X	X			X	X					X	X		X		X	X
KF-7	Tulare Basin Wildlife Partners	Goose Lake Conservation Plan and DFG CAPP	X		X	X	X	X						X	X	X			X	X					X	X		X		X	X
KF-8	Tulare Basin Wildlife Partners	Riparian and Wildlife Corridor Planning Area - Kern River	X		X	X	X	X						X	X	X			X	X					X	X		X		X	X
KF-9	Buena Vista WSD	Water Exchange Project	X		X	X	X	X	X			X		X	X										X		X	X			
KF-10	Buena Vista WSD	On-Farm Water Use Efficiency	X		X	X	X	X					X		X	X									X			X			
KF-11	Buena Vista WSD	Northern Improvement Project	X		X	X	X	X																							
KF-12	Buena Vista WSD	Kern Fan Direct Recharge and Recovery Project	X		X	X	X	X					X	X	X	X							X		X		X	X			
KF-14	Buena Vista WSD	James Groundwater Storage and Recovery Project	X		X	X	X	X				X								X			X		X		X	X			
KF-15	Rosedale Rio-Bravo WSD	Western Rosedale In-Lieu Service Area Project	X		X	X	X	X																							
KF-16	Kern Water Bank Authority	Recharge Enhancement Project	X		X	X	X	X				X								X			X		X		X	X			
KR-1	Kern County	Weldon Regional Water Project				X		X					X	X	X	X						X	X		X			X			
KR-2	Tubatulabal Tribal Water Board	Phase II Safe Drinking Water and Tribal Allotments Community Water System		X	X			X					X																	X	X
KR-3	Tubatulabal Tribal Water Board	Phase II Safe Drinking Water and Community Use Area - White Blanket Allotment		X	X			X					X																	X	X
KR-4	Desert Mountain Resources Conservation and Development Council	Eradication of Invasive Weeds in the Kern River Valley and Walker Basin	X	X	X			X								X				X		X			X	X	X		X	X
KR-5	County of Kern	Tradewinds Auxiliary Well or Uranium Treatment			X			X					X																		
KR-6	Long Canyon Water Company	Weldon Water Supply Project				X		X					X	X								X						X			

APPENDIX E

WATER MANAGEMENT STRATEGIES VS. KERN IRWMP PROJECTS

			Reduce Water Demand		Improve Operational Efficiency and			Increase Water Supply					Improve Water Quality						Practice Resource Stewardship									Improve Flood Mgmt	People & Water			
Subregion / Form #	Project Sponsor	Project Name	Ag. Water Use Efficiency	Urban Water Use Efficiency	Conveyance - Delta & Regional/Local	System Reoperation	Water Transfers	Conjunctive Mgmt. & GW Storage	Desalination -Brackish/Seawater	Precipitation Enhancement	Recycled Municipal Water	Surface Storage - CALFED* & Regional/Local*	Drinking Water Treatment & Dist.	GW/Aquifer Remediation	Matching Quality to Use	Pollution Prevention	Salt & Salinity Management	Urban Runoff Management	Ag. Lands Stewardship	Ecosystem Restoration	Forest Management	Land Use Planning & Mgmt	Recharge Area Protection	Urban Land Use Management	Watershed Management	Sediment Management	Flood Risk Management	Economic Incentives	Water-dependent Recreation	Outreach and Engagement	Water and Culture
MF-1	County of Kern	GHSC Force Main Project				X		X			X				X																
MF-4	Bear Valley CSD	Radio Nuclides Treatment Project			X			X					X																		
MF-5	Tehachapi-Cummings CWD	Cummings Basin Westerly Recharge Project - New Phase	X	X	X	X	X	X				X	X	X									X		X		X	X			
MF-6	Frazier Park Public Utility District	Cuddy Valley Water Supply Evaluation			X	X		X					X		X	X						X	X		X			X	X	X
NC-1	City of Shafter	Well No. 15			X			X					X																		
NC-2	City of McFarland	Browning Road Storage Tank and Booster Facility		X		X						X	X															X			
SC-1	Arvin-Edison WSD/Kern Delta WD	AEWSD Intake Canal and Kern Delta Buena Vista River Canal Intertie Project	X		X	X	X	X								X											X	X			
SC-3	Wheeler Ridge-Maricopa WSD	Groundwater Storage and Recover in White Wolf Basin	X		X		X	X											X			X	X					X			
SC-4	Arvin-Edison WSD	Wasteway Basin Improvement Project	X		X	X	X	X				X							X						X		X				
SC-5	Mettler CWD	Mettler Groundwater Protection Project											X			X						X						X			
SC-6	Wheeler Ridge-Maricopa WSD	Solar Power Generation						X								X												X			
SC-7	Arvin-Edison WSD	Forrest Frick Rehabilitation Project			X		X									X							X		X		X	X			
SC-9	Arvin-Edison WSD	Lateral Capacity Improvement Project	X		X	X		X				X																X			
SC-10	Arvin-Edison WSD	South Canal Balancing Reservoir	X		X	X						X			X												X	X			
SC-11	Arvin-Edison WSD	Improved Stormwater Management and Flood Control			X	X										X		X					X				X				
SC-12	Lamont PUD	Well No. 19 Arsenic Reduction Blending Project			X			X					X																		
SC-13	Lamont PUD	Water Quality Improvement Project for Well No. 16			X			X					X																		
SC-14	Lamont PUD	Renovation of Belowground Storage Reservoir		X		X		X					X															X			
SC-15	Arvin CSD	Arsenic Mitigation Project			X			X					X																		
SC-16	Mettler CWD	Mettler Well No. 4 Project			X			X					X																		
SC-17	Arvin-Edison WSD	Balancing Reservoir Well Discharge Pipeline	X		X	X						X			X												X	X			
SC-18	Arvin-Edison WSD	Groundwater Metering Project	X		X	X		X																					X			

APPENDIX E

WATER MANAGEMENT STRATEGIES VS. KERN IRWMP PROJECTS

			Reduce Water Demand		Improve Operational Efficiency and			Increase Water Supply					Improve Water Quality						Practice Resource Stewardship									Improve Flood Mgmt	People & Water			
Subregion / Form #	Project Sponsor	Project Name	Ag. Water Use Efficiency	Urban Water Use Efficiency	Conveyance - Delta & Regional/Local	System Reoperation	Water Transfers	Conjunctive Mgmt. & GW Storage	Desalination -Brackish/Seawater	Precipitation Enhancement	Recycled Municipal Water	Surface Storage - CALFED* & Regional/Local*	Drinking Water Treatment & Dist.	GW/Aquifer Remediation	Matching Quality to Use	Pollution Prevention	Salt & Salinity Management	Urban Runoff Management	Ag. Lands Stewardship	Ecosystem Restoration	Forest Management	Land Use Planning & Mgmt	Recharge Area Protection	Urban Land Use Management	Watershed Management	Sediment Management	Flood Risk Management	Economic Incentives	Water-dependent Recreation	Outreach and Engagement	Water and Culture
SC-19	Arvin-Edison WSD	Forrest Frick Pumping Plant Valve Replacement	X		X	X																									
SC-20	Athal MWC	Athal Waterline Replacement and Meter Project		X	X			X					X			X															
SC-21	City of Arvin	Sycamore Drainage Project Phase 2: Walnut Creek and Comanche Lines			X	X										X		X									X				
SC-22	Arvin-Edison WSD	Forrest Frick Pipeline and KDWD Eastside Canal Intertie	X		X	X	X	X								X											X	X			
SC-23	Arvin-Edison WSD	North In-Lieu Project -- Phase II	X		X	X	X	X				X		X														X			
SC-24	Arvin-Edison WSD	Eastside Spreading Works	X		X	X	X	X				X		X									X		X		X	X			
WA-4	Kern County Water Agency	ID3 Property Purchase Program			X			X								X				X		X	X		X	X	X	X		X	
WS-1	Lost Hills WD	Regional Brackish Water Treatment Project	X		X	X	X		X					X	X		X											X			
WS-2	Berrenda Mesa WD	Westside Districts' Groundwater Banking Project	X		X	X	X	X						X					X				X		X		X	X			
WS-3	Berrenda Mesa WD	Lost Hills Surface Water Treatment Plant		X	X	X							X		X																
WS-4	Lost Hills Utility District	Construction of a New Well to Provide a Firm Water Supply to the LHUD Users			X			X					X																		
WS-5	Lost Hills Utility District	Storage Tank Rehabilitation to the LHUD 2.0 MG Storage Tank		X		X		X					X															X			
WS-6	City of Taft	Storm Drain and Floodplain Basin Project			X	X										X		X									X				
WS-7	City of Maricopa	Maricopa Wastewater Project		X	X	X	X				X	X		X		X		X		X		X	X		X			X			
WS-8	Tulare Basin Wildlife Partners	Buena Vista Lake-Kern Lake Conservation Plan and DFG CAPP	X		X	X	X	X						X	X	X			X	X					X	X		X		X	X

APPENDIX E

WATER MANAGEMENT STRATEGIES VS. KERN IRWMP PROJECTS

Subregion / Form #	Project Sponsor	Project Name	Reduce Water Demand		Improve Operational Efficiency and			Increase Water Supply					Improve Water Quality						Practice Resource Stewardship									Improve Flood Mgmt	People & Water			
			Ag. Water Use Efficiency	Urban Water Use Efficiency	Conveyance - Delta & Regional/Local	System Reoperation	Water Transfers	Conjunctive Mgmt. & GW Storage	Desalination -Brackish/Seawater	Precipitation Enhancement	Recycled Municipal Water	Surface Storage - CALFED* & Regional/Local*	Drinking Water Treatment & Dist.	GW/Aquifer Remediation	Matching Quality to Use	Pollution Prevention	Salt & Salinity Management	Urban Runoff Management	Ag. Lands Stewardship	Ecosystem Restoration	Forest Management	Land Use Planning & Mgmt	Recharge Area Protection	Urban Land Use Management	Watershed Management	Sediment Management	Flood Risk Management	Economic Incentives	Water-dependent Recreation	Outreach and Engagement	Water and Culture
IRWM Implementation Grant Funded Projects																															
Proposition 84 - IRWM 2015 Implementation Grant																															
CK-13	Lake of the Woods MWC (County of Kern)	Lake of the Woods Emergency Water Distribution System Replacement & Meter Installation		X	X			X					X			X															
MF-7	Golden Hills CSD	Groundwater Conjunctive Use Project - Phase 2			X			X					X										X								
KF-5	Buena Vista WSD	Groundwater Recharge and Recovery Project	X		X	X	X	X	X				X	X	X										X			X			
Proposition 84 - IRWM 2014 Drought Grant																															
KF-13	Buttonwillow CWD	Waterline Replacement Project		X	X			X					X			X															
KF-3	Buena Vista WSD	Brackish Groundwater Remediation Project						X	X				X	X	X	X	X		X										X			
SC-8	Arvin-Edison WSD	In-Lieu Banking Program	X		X	X	X	X				X		X															X			
GB-3	Improvement District No. 4	CVC Extension Lining Project - Pool No. 7	X	X	X		X	X																								
Proposition 84 - Round 2 IRWM Implementation Grant																															
SC-2	City of Arvin	Sycamore Drainage Facilities			X	X										X		X									X				
GB-5	City of Bakersfield	Water Conservation Project for Metropolitan Bakersfield		X				X																				X	X		
KF-1	Kern Water Bank Authority	Kern Water Bank Recharge and Recovery Enhancement Project		X	X		X	X					X				X			X			X								
MF-2	Tehachapi-Cummings CWD	Tehachapi Regional Water Conservation Program		X				X																				X			
MF-3	City of Tehachapi	Public Facility Distribution Line and Nitrate Removal Program			X								X	X	X	X													X		

Subregion Abbreviations: CK=County of Kern, GB=Greater Bakersfield, KF=Kern Fan, KR=Kern River Valley, MF=Mountain/Foothills, NC=North County, SC=South County, WS=Westside, WA-Kern County Water Agency

Appendix F

Detailed Project Descriptions

Detailed Project Descriptions are located at the following website:
http://www.kernirwmp.com/documents.html

Appendix G

Prioritization Criteria

Project Submittal Form

KERN IRWMP
Integrated Regional Water Management Plan

Project Submittal Form

To the extent possible this form should be electronically filled out and e-mailed to:
KernIRWMP@kcwa.com.

Part 1. Lead Implementing Agency/Organizational Information

Please provide the following information regarding the project sponsor and proposed project.

Implementing Agency/ Organization / Individual:

Agency / Organization / Individual Address:

Possible Partnering Agencies:

Name:

Title:

Telephone: **Fax:**

Email:

Website:

Project Name:

Either the latitude/longitude or a location description is required. To determine the latitude/longitude, use the closest address or intersection. If the project is linear, use the furthest upstream latitude/longitude.

Project Latitude:		**Project Longitude:**	

Location Description:	

Regional Grouping: Identify the Regional Grouping your *agency* is located in, and the Regional Grouping your *project* is located in.

☐ Agency ☐ Project	Greater Bakersfield
☐ Agency ☐ Project	Kern County
☐ Agency ☐ Project	Kern County Water Agency
☐ Agency ☐ Project	Kern Fan
☐ Agency ☐ Project	Kern River Valley
☐ Agency ☐ Project	Mountains/Foothills
☐ Agency ☐ Project	North County
☐ Agency ☐ Project	South County
☐ Agency ☐ Project	West Side

Project Cooperating Agency(ies)/Organization(s)/Individual(s):

•
•
•
•

Project Status (e.g., new, ongoing, expansion, new phase):

Part 2. Project Need

It is important to understand the need(s) or issue(s) that the proposed project will address and the benefits that it will provide. Information provided in this section defines the need(s) or issue(s) that the proposed project will address and will help to catalog existing need(s) or issue(s) in the Tulare Lake Basin Portion of Kern County Region.

Please provide a 1-2 paragraph description of the need(s) or problem(s) that the project will address. As applicable, discuss the water supply need, operational efficiency need, water quality need, or resource stewardship need (e.g. ecosystem restoration, floodplain management) need. Discuss critical impacts that will occur if the proposal is not implemented.

Part 3. Project Description

A general description of the proposed project is needed. This section will provide information associated with the project concept, general project information, and readiness to proceed. It is recognized that much of the requested information may not be available for projects that are at a conceptual level of project development. We appreciate and need your ideas.

Please provide a 1-2 paragraph description of the project including the general project concept, what will be constructed/implemented, how the constructed project will function, and treatment methods, as appropriate.

If applicable, list surface water bodies and groundwater basins associated with the proposed project:

•
•
•
•

Please identify up to three available documents which contain information specific to the proposed project:

•
•
•

Is the proposed project an element or phase of a regional or larger program?	☐ Yes ☐ No
If yes, please identify the program	_____
Design life of the Project	
Proposed Construction/Implementation Start Date:	_____
Proposed Construction/Implementation Completion Date	_____
Ready for Construction Bid	☐ **Yes** ☐ **No** ☐ **NA**

Item	**Status (e.g., not initiated, in process, complete)**	**Date**
Conceptual Plans		**(mm/dd/yyyy)**
Land Acquisition/ Easements		**(mm/dd/yyyy)**
Preliminary Plans		**(mm/dd/yyyy)**
CEQA/NEPA		**(mm/dd/yyyy)**
Permits		**(mm/dd/yyyy)**
Construction Drawings		**(mm/dd/yyyy)**

For projects that do not include construction, please briefly describe the project readiness-to proceed.

Part 4. Project Benefits

Please provide a 1-2 paragraph description of the benefit(s) that the project will address. Information provided will be used in the assessment of project benefits.

Please describe the dominant existing land use type for the proposed project location.

Please describe the dominant existing land use type for areas upstream and downstream of the proposed project location
Upstream:
Downstream:

Does the project address any known environmental justice issues?		
☐ **Yes**	☐ **No**	☐ **Not Sure**

Is the project located within or adjacent to a disadvantaged community?		
☐ **Yes**	☐ **No**	☐ **Not Sure**

Does the project include disadvantaged community participation?		
☐ **Yes**	☐ **No**	☐ **Not Sure**
If yes, please identify the group or organization: _____		

Is the project located within, adjacent to, or benefits a Native American Tribal community?		
☐ **Yes**	☐ **No**	☐ **Not Sure**

Please provide the following project benefit information for all applicable components of the proposed project. Benefit categories include things such as water quality / flood management, water supply, and resource stewardship. PLEASE ATTEMPT TO SUPPLY ALL INFORMATION RELEVANT TO YOUR PROJECT. THIS INFORMATION WILL BE USED TO ANALYZE AND ASSESS PROJECT FOR FUTURE FUNDING.

WATER QUALITY BENEFITS / FLOOD MANAGEMENT BENEFITS

Water Quality Benefit Information	
Treatment technologies	_____
Design operational treatment capacity (million gallons/day)	_____
Targeted Contaminants (Check all that apply):	
☐ Chloride ☐ Nitrogen Compounds ☐ Coliform Bacteria ☐ Other (describe): _____	
Flood Management Benefit Information	
Maximum volume of temporary storage of storm runoff (acre-feet)	_____
Maximum increased conveyance capacity (cubic feet/second)	_____
Estimated area benefiting from flood damage reduction (acres)	_____
Estimated level of flood protection resulting from project implementation	_____
Estimated annual value of flood damage reduction provided by project ($/year)	_____
Acreage required for project implementation	_____

WATER SUPPLY BENEFITS
Project information provided will help to quantify water supply benefits from enhanced local water supply or reduced potable water demand.

Enhanced Water Supply or Demand Reduction Benefit Information		
Source of Increased Supply or Demand Reduction		
☐ Groundwater	☐ Groundwater treatment	☐ Increased surface water storage
☐ Recycled water	☐ Conservation/ water use efficiency	☐ Ocean desalination
☐ Transfer	☐ Other (describe): _____	
Type of enhanced supply or demand reduction: _____		
Annual Yield of Supply (acre-feet): _____		
Availability by Water-Year Type (acre-feet per year):		
Average Year	_____	
Dry Year	_____	
Wet Year	_____	
Availability by Season (check all that apply):		
☐ Summer	☐ Fall	☐ Spring ☐ Winter
Does the project have the potential to reduce the regions dependence on the Sacramento-San Joaquin Delta water supply?		
☐ Yes	☐ No	☐ Not Sure
Describe:		

Does the Project assist in adapting to the effects of climate change? Specifically how does the project address the following: • *Adaptation to the amount, intensity, timing, quality and variability of runoff and recharge that are caused by the effects of climate change;* • *Adaptation to the effects of sea level rise that impacts water supplies;* • *Adaptation of systems that are vulnerable to climate change effects in the region; and* • *Overall adaptation of the water management system.*
Does the Project achieve a reduction in greenhouse gas emissions? Discuss the following: • *Project's estimation of GHG emission reduction in comparison to other project alternatives,* • *Project's overall GHG emission reduction over a 20-year period,* • *Project's estimation of energy use reduction.*

For projects that include detention and groundwater recharge, please complete the following:

How many acres of land drain into this detention basin? (acres)	_____
Detention Basin area (acres)	_____
Detention basin max. operational depth (ft.)	_____
% of basin covered by wetlands	_____
Soil type	_____
If other than infiltration, identify method (e.g., injection) and recharge (acre-feet/year)	_____
Estimated basin annual inflow (acre-feet/year)	_____
Estimated basin annual outflow (acre-feet/year)	_____

RESOURCE STEWARDSHIP BENEFITS
Project information provided will help to quantify the benefits associated with projects related to resource stewardship and land management.

Non-treatment wetland area (acres)	_____
Treatment wetland area (acres)	_____
Riparian habitat area (acres)	_____
Non-developed open space area (acres)	_____
Multiple use/ recreation area (acres) – additionally, select the type of multiple use / recreation and associated acres by type:	
Single Sport Athletics	_____
Multiple Sport Athletics Acres	_____
Other Recreation Acres	_____
Pedestrian Trail Acres	_____
Equestrian Trail Acres	_____
Other Passive Activity	_____
Other Acres (describe)	_____
Description	_____
Total Project area (acres)	_____

Part 5. Project Cost Estimate

Project cost information is needed to assist in comparing benefits and cost. Additionally, knowledge of the project type and cost will assist in identifying funding sources for potential projects.

Please indicate the estimated costs of project implementation and associated funding source(s). These costs should include land purchase/easement, planning/design/engineering, construction/ implementation, environmental compliance, administration, and contingency.

Approximate Total Cost *(If project costs are variable, please include lower and upper range estimates.)*	
Funding Source *(If multiple sources, list each source and the percent or amount funded by each)*	
Funding Certainty & Longevity	
Operations & Maintenance Cost *(per year)*	
Operations & Maintenance Funding Source(s) *(i.e., annual budget, grant, etc. If multiple sources, list each source and the percent or amount funded by each.)*	
Operations & Maintenance Funding Certainty *(i.e., already included in organization's budget, contingent upon grant, etc.)*	

Part 6. Regional Objectives

Indicate below whether the project meets any of the Kern IRWMP regional objectives. Where necessary/appropriate, please provide a brief explanation as to how the Project meets the regional objective.

Kern IRWMP Objectives	Does the project meet the objective? Yes	No	Comments/Explanation
Increase Water Supply (WS)			
1. Through cooperation and collaboration with other regions restore water supplies to levels that will mitigate for water lost from the region and eliminate overdraft			
2. Pursue and implement cost effective water use efficiency programs			
3. Increase water storage capacity in the region by increasing recharge acreage and expanding groundwater banking programs before all prime recharge land has been developed			
4. Integrate management of water banking facilities to maximize conjunctive use over the planning horizon			
5. Increase/augment water supplies to meet region demands			
Improve Operational Efficiency (OE)			
1. Increase transfers and exchanges flexibility over the planning horizon			
2. Create tools to re-regulate water supplies within the region, including storage, storm flows, and operational flows over the planning horizon			
3. Increase distribution efficiencies and reduce energy usage over the planning horizon			
4. Increase the use of alternate energy sources (e.g. solar)			
5. Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions			
6. Increase the use of recycled water for direct reuse within the Kern Region			
7. Optimize local management of water resources to improve water supply reliability over the planning horizon			
8. Increase pool of qualified candidates to operate water and wastewater systems			

Improve Water Quality (WQ)		
1. Monitor and/or manage headwaters/areas of origin, natural streams, and recharge areas to prevent or mitigate contamination		
2. Identify and preserve prime recharge areas in the Kern fan area and other areas		
3. Improve water quality for disadvantaged communities and the watershed over the planning horizon		
4. Continue to provide drinking water that meets or exceeds water quality standards; and support efforts to attain appropriate standards throughout the planning horizon		
5. Maximize the use of lesser quality water for appropriate uses (landscaping, certain ag crops, "aesthetic" projects) throughout the planning horizon		
6. Coordinate and enhance aquatic pest control efforts from this point forward		
Promote Land Use Planning and Resource Stewardship (LU)		
1. Promote stewardship of the Kern River by applying appropriate measures in various reaches of the river from this point forward		
2. Encourage the removal of non-native invasive plant species that affect water quality, reliability, and operations		
3. Identify and promote the regeneration and restoration of native riparian habitat		
4. Coordinate agricultural and urban water suppliers to more effectively address land use planning issues from this point forward		
5. Improve the linkage between land use planning and water supply in the region throughout the planning horizon		
6. Increase educational opportunities to improve public awareness of water supply, conservation, and water quality issues throughout the planning horizon		
7. Improve and coordinate integrated land use planning to support stewardship of environmental resources, such as the Kern River and Kern Fan, and integrate with habitat conservation plans and other ongoing planning efforts from this point forward		
8. Preserve and improve ecosystem/watershed health throughout the planning horizon		

Improve Regional Flood Management (FM)		
1. Improve regional flood management by addressing preparedness, response, and post flood actions throughout the planning horizon		
2. Reduce the effects of poor quality runoff throughout the planning horizon		
3. Identify and promote innovative flood management projects to protect vulnerable areas		
4. Plan new developments to minimize flood impacts from this point forward		

Tier1 Project Prioritization Form

KERN IRWMP
Integrated Regional Water Management Plan

Kern IRWMP Tier 1 Scoring Form

Project Name:

Sub-Region:

SCORING
0 Points = Criteria does not apply
1 Point = Criteria may apply/need more information
2 Points = Criteria partially applies
3 Points = Criteria fully applies

Kern IRWMP Objectives	Comment	0 Points	1 Point	2 Points	3 Points	Total Points
Increase Water Supply (WS)						
1. Through cooperation and collaboration with other regions restore water supplies to levels that will mitigate for water lost from the region and eliminate						
2. Pursue and implement cost effective water use efficiency programs (qty: conserve 30,000 AF by 2030)	Yes					
3. Increase water storage capacity in the region by increasing recharge acreage and expanding groundwater banking programs before all prime recharge						
4. Integrate management of water banking facilities to maximize conjunctive use over the planning horizon						
5. Increase/augment water supplies to meet region demands (e.g., municipal and industrial, agricultural, environmental) by 2050.						
Improve Operational Efficiency (OE)						
1. Increase transfers and exchanges flexibility over the planning horizon						
2. Create tools to re-regulate water supplies within the region, including storage, storm flows, and operational flows over the planning horizon						
3. Increase distribution efficiencies and reduce energy usage over the planning horizon						
4. Increase the use of alternate energy sources (e.g. solar) (qty: 33 % of energy provided by alternative sources to the region by 2020)						
5. Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions (qty: less than 10% losses in urban systems; replace 10% of all systems)						
6. Increase the use of recycled water for direct reuse within the Kern Region (qty: 20% of produced wastewater annually)						
7. Optimize local management of water resources to improve water supply reliability over the planning horizon						
8. Increase pool of qualified candidates to operate water and wastewater systems (qty: 20% increase in employees trained by 2020; reduction in						

Improve Water Quality (WQ)						
1. Monitor and/or manage headwaters/areas of origin, natural streams, and recharge areas to prevent or mitigate contamination (qty: $10 million for						
2. Identify and preserve prime recharge areas in the Kern fan area and other areas (qty: 8,000 acres by 20XX; as soon as practicable)						
3. Improve water quality for disadvantaged communities and the watershed over the planning horizon						
4. Continue to provide drinking water that meets or exceeds water quality standards; and support efforts to attain appropriate standards throughout the						
5. Maximize the use of lesser quality water for appropriate uses (landscaping, certain ag crops, “aesthetic” projects) throughout the planning horizon						
6. Coordinate and enhance aquatic pest control efforts from this point forward						
Promote Land Use Planning and Resource Stewardship (LU)						
1. Promote stewardship of the local rivers and streams by applying appropriate measures from this point forward						
2. Encourage the removal of non-native invasive plant species that affect water quality, reliability, and operations (qty: no more than 5% of plant matter in						
3. Identify and promote the regeneration and restoration of native riparian habitat (qty: 460 acres of restored/regenerated riparian habitat)						
4. Coordinate agricultural and urban water suppliers to more effectively address land use planning issues from this point forward						
5. Improve the linkage between land use planning and water supply in the region throughout the planning horizon						
6. Increase educational opportunities to improve public awareness of water supply, conservation, and water quality issues throughout the planning horizon						
7. Improve and coordinate integrated land use planning to support stewardship of environmental resources, such as local rivers and streams and the Kern Fan, and integrate with habitat conservation plans and other ongoing						
8. Preserve and improve ecosystem/watershed health throughout the planning horizon						
Improve Regional Flood Management (FM)						
1. Improve regional flood management by addressing preparedness, response, and post flood actions throughout the planning horizon						
2. Reduce the effects of poor quality runoff throughout the planning horizon						
3. Identify and promote innovative flood management projects to protect vulnerable areas (qty: reduce flood flows by an average of 2% per year through						
4. Plan new developments to minimize flood impacts from this point forward						
Total Score		0	0	0	0	0

Tier2 Project Prioritization Form

Kern IRWMP Tier 2 Scoring Form

Project Name: Sub-Region:

Grant Readiness Criteria	Comments	0 Points	1 Point	2 Points	3 Points	Total Points
Does the Project comply with all applicable environmental review standards? (e.g., NEPA, CEQA, etc.)						
If applicable, are the Project design components complete? (e.g., engineering plans)						
Is the Project consistent with all applicable General and/or Specific Plans						
If applicable, is the Project Proponent compliant with AB 1420? (AB 1420 applies to Urban Water Suppliers)						
If applicable, are the Project Partners compliant with AB 1420?						
If applicable, is the Project Proponent compliant with AB 3030? (AB 3030 applies to groundwater projects and/or entities requiring a groundwater management plan)						
If applicable, are the Project Partners compliant with AB 3030?						
Does the Project conflict with one or more of the Kern IRWMP Objectives?						
Does the Project Proponent, and/or Partners, have the funding or ability to acquire the funding required to:						
Complete the grant application?						
Meet the grant funding match requirement?						
Does the Project demonstrate collaborative partnerships?						
Does the Project benefit a critical water need for a DAC or Native American Tribal community? (1 point for indirect benefit, 2 points for direct benefit to one DAC or Tribe, 3 points for multiple DACs or Tribes)						
Does the Project have benefits that address adaptation to the effects of climate change?						
Does the Project result in GHG reduction?						
Does the Project result in a reduction of reliance upon the Delta? (1 point)				X	X	
Does the Project have broad Kern IRWMP participant support?						
Total Score						

SCORING
0 Points = Criteria does not apply
1 Point = Criteria may apply/need more information
2 Points = Criteria partially applies
3 Points = Criteria fully applies

Appendix H

Prioritized List

APPENDIX H
Kern IRWM Region
Project Prioritization List

Form #	Subregion	Project Sponsor	Title **	Tier 1 Score	Subregion Top 5	Priority
CK-4	County of Kern	County of Kern	Lake Isabella Detailed Sewer Study	33	Y	High
CK-5	County of Kern	County of Kern (Krista MWC)	Krista Mutual Water Company Water Project	30	Y	High
CK-13	County of Kern	Lake of the Woods MWC (County of Kern)	Lake of the Woods Emergency Water Distribution System Replacement & Meter Installation	29	Y	High
CK-9	County of Kern	County of Kern	Cuddy Creek Restoration Project	28	Y	High
CK-11	County of Kern	County of Kern	Disadvantaged Community Leak Detection Program	27	Y	High
CK-8	County of Kern	County of Kern	South Taft Sewer Improvements	26		Low
CK-7	County of Kern	County of Kern	Sandy Creek Bank and Erosion Protection	24		Low
CK-6	County of Kern	County of Kern	Reeder Tract WWT Facility	22		Low
CK-2	County of Kern	County of Kern	Caliente Creek Habitat Restoration & GW Recharge	18		Low
CK-10	County of Kern	County of Kern	Reconstruction of Adams/Jefferson St - Ford City	13		Low
CK-1	County of Kern	County of Kern	South Shafter Sewer	9		Low
CK-3	County of Kern	County of Kern	Lakeshore Pines Leachfield Replacement	3		Low
GB-8	Greater Bakersfield	City of Bakersfield	River Canal Weir Restoration and Expansion Project	42	Y	High
GB-7	Greater Bakersfield	Kern Delta WD	Kern Delta / ID4 Cross River Pipeline	26	Y	High
GB-9	Greater Bakersfield	Improvement District No. 4	Cross Valley Canal Extension Lining Project -- Pool No. 8	24	Y	High
GB-2	Greater Bakersfield	Improvement District No. 4	Beardsley Pipeline	22	Y	High
GB-10	Greater Bakersfield	City of Bakersfield	Water Conservation Project for Metropolitan Bakersfield	20	Y	High
GB-1	Greater Bakersfield	Improvement District No. 4	Recharge Improvement Project	19		Low
GB-4	Greater Bakersfield	Improvement District No. 4	Groundwater Monitoring Wells	16		Low
GB-6	Greater Bakersfield	Improvement District No. 4	Surface Water Quality Monitoring Stations	10		Low
KF-14	Kern Fan	Buena Vista WSD	James Groundwater Storage and Recovery Project	33	Y	High
KF-16	Kern Fan	Kern Water Bank Authority	Kern Water Bank Recharge Enhancement Project	28	Y	High
KF-15	Kern Fan	Rosedale Rio-Bravo WSD	Western Rosedale In-Lieu Service Area Project	22	Y	High
KF-2	Kern Fan	Kern Water Bank Authority	Kern Water Bank Short-Term Storage Program	21	Y	High
KF-4	Kern Fan	Buena Vista WSD	Conservation Easement Water Acquisition and Management Project	20	Y	High
KF-11	Kern Fan	Buena Vista WSD	Northern Improvement Project	19		Low
KF-10	Kern Fan	Buena Vista WSD	On-Farm Water Use Efficiency	18		Low
KF-13	Kern Fan	Buttonwillow CWD	Waterline Replacement Project	18		Low
KF-6	Kern Fan	Tulare Basin Wildlife Partners	Goose Lake Wetlands Reserve Program Residual Value Purchase			Low
KF-7	Kern Fan	Tulare Basin Wildlife Partners	Goose Lake Conservation Plan and DFG CAPP			Low
KF-8	Kern Fan	Tulare Basin Wildlife Partners	Riparian and Wildlife Corridor Planning Area - Kern River			Low
KF-9	Kern Fan	Buena Vista WSD	Water Exchange Project			Low
KF-12	Kern Fan	Buena Vista WSD	Kern Fan Direct Recharge and Recovery Project			Low

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Kern IRWM Region
Project Prioritization List

Form #	Subregion	Project Sponsor	Title **	Tier 1 Score	Subregion Top 5	Priority
KR-2	Kern River Valley	Tubatulabal Tribal Water Board	Phase II Safe Drinking Water and Tribal Allotments Community Water System	48	Y	High
KR-4	Kern River Valley	Desert Mountain Resources Conservation and Development Council	Eradication of Invasive Weeds in the Kern River Valley and Walker Basin	47	Y	High
KR-1	Kern River Valley	County of Kern	Weldon Regional Water Project	39	Y	High
KR-3	Kern River Valley	Tubatulabal Tribal Water Board	Phase II Safe Drinking Water and Community Use Area - White Blanket Allotment	38	Y	High
KR-6	Kern River Valley	Self-Help Enterprises/Long Canyon Water Company	Weldon Water Supply Project	34	Y	High
KR-5	Kern River Valley	County of Kern	Tradewinds Auxiliary Well or Uranium Treatment	30	Y	High
MF-5	Mountains/Foothills	Tehachapi-Cummings CWD	Cummings Basin Westerly Recharge Project - New Phase	31	Y	High
MF-1	Mountains/Foothills	County of Kern	GHSC Force Main Project	27	Y	High
MF-7	Mountains/Foothills	Golden Hills CSD	Groundwater Conjunctive Use Project - Phase 2	26	Y	High
MF-4	Mountains/Foothills	Bear Valley CSD	Radio Nuclides Treatment Project	23	Y	High
MF-6	Mountains/Foothills	Frazier Park Public Utility District	Cuddy Valley Water Supply Evaluation	20	Y	High
NC-2	North County	City of McFarland	Browning Road Storage Tank and Booster Facility	37	Y	High
NC-1	North County	City of Shafter	Well No. 15	27	Y	High
SC-11	South County	Arvin-Edison WSD	Improved Stormwater Management and Flood Control	75	Y	High
SC-22	South County	Arvin-Edison WSD	Forrest Frick Pipeline and KDWD Eastside Canal Intertie	73	Y	High
SC-10	South County	Arvin-Edison WSD	South Canal Balancing Reservoir	67	Y	High
SC-24	South County	Arvin-Edison WSD	Eastside Spreading Works	64	Y	High
SC-1	South County	Arvin-Edison WSD/Kern Delta WD	AEWSD Intake Canal and Kern Delta Buena Vista River Canal Intertie Project	61	Y	High
SC-7	South County	Arvin-Edison WSD	Forrest Frick Rehabilitation Project	56		Moderate
SC-3	South County	Wheeler Ridge-Maricopa WSD	Groundwater Storage and Recover in White Wolf Basin	43		Moderate
SC-9	South County	Arvin-Edison WSD	Lateral Capacity Improvement Project	43		Moderate
SC-5	South County	Mettler CWD	Mettler Groundwater Protection Project	38		Moderate
SC-23	South County	Arvin-Edison WSD	North In-Lieu Project -- Phase II	33		Low
SC-17	South County	Arvin-Edison WSD	Balancing Reservoir Well Discharge Pipeline	33		Low
SC-4	South County	Arvin-Edison WSD	Wasteway Basin Improvement Project	32		Low
SC-20	South County	Athal MWC	Athal Waterline Replacement and Meter Project	26		Low
SC-18	South County	Arvin-Edison WSD	Groundwater Metering Project	25		Low
SC-21	South County	City of Arvin	Sycamore Drainage Project Phase 2: Walnut Creek and Comanche Lines	24		Low
SC-14	South County	Lamont PUD	Renovation of Belowground Storage Reservoir	20		Low
SC-15	South County	Arvin CSD	Arsenic Mitigation Project	16		Low
SC-13	South County	Lamont PUD	Water Quality Improvement Project for Well No. 16	14		Low
SC-19	South County	Arvin-Edison WSD	Forrest Frick Pumping Plant Valve Replacement	14		Low
SC-12	South County	Lamont PUD	Well No. 19 Arsenic Reduction Blending Project	12		Low
SC-6	South County	Wheeler Ridge-Maricopa WSD	Solar Power Generation	3		Low
SC-16	South County	Mettler CWD	Mettler Well No. 4 Project			Low

APPENDIX H
Kern IRWM Region
Project Prioritization List

Form #	Subregion	Project Sponsor	Title **	Tier 1 Score	Subregion Top 5	Priority
WA-1	Water Agency	Kern County Water Agency	Improvement District No. 3 Property Purchase Program	56	Y	High
WS-2	Westside	Berrenda Mesa WD	Westside Districts' Groundwater Banking Project	25	Y	High
WS-3	Westside	Berrenda Mesa WD	Lost Hills Surface Water Treatment Plant	19	Y	High
WS-4	Westside	Lost Hills Utility District	Construction of a New Well to Provide a Firm Water Supply to the LHUD Users	17	Y	High
WS-1	Westside	Lost Hills WD	Regional Brackish Water Treatment Project	13	Y	High
WS-5	Westside	Lost Hills Utility District	Storage Tank Rehabilitation to the LHUD 2.0 MG Storage Tank	11	Y	High
WS-6	Westside	City of Taft	Storm Drain and Floodplain Basin Project	8		Low
WS-8	Westside	Tulare Basin Wildlife Partners	Buena Vista Lake-Kern Lake Conservation Plan and DFG CAPP	8		Low
WS-7	Westside	City of Maricopa	Maricopa Wastewater Project	6		Low

Appendix I

Governance Structure

Governance Structure

The Governance Structure, based on the Participation Agreement, established the Kern RWMG and prescribed the preliminary roles and responsibilities for the RWMG. Using the Participation Agreement as a guide, the following outline the responsibilities of the Participants, the Executive Committee, and Stakeholders, for implementation and governance of the IRWMP.

Terms of Participation Agreement (or MOU)

The Participation Agreement addresses the following topics:

- Organization
- Roles
- Representation and Decision Making

Organization

The Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan (Kern IRWMP) will include three groups:

1. **Regional Water Management Group Members** – signatories to the Participation Agreement and First Amendment.
2. **Stakeholder Group** – an open group of interested people that participate in public meetings related to the update and implementation of the Kern IRWMP. Anyone may participate as part of the Stakeholder Group if they are willing to abide by the Code of Conduct.
3. **Executive Committee** – a ten (10) member subgroup of the Stakeholder Group, and *working group* comprised of one representative from each of the seven (7) subregions and two (2) overarching subregions (hereafter referred to singularly as "subregion" or collectively as "subregions") that comprise the Kern IRWMP: 1) Greater Bakersfield, 2) Kern Fan, 3) Mountains/Foothills, 4) Kern River Valley, 5) North County, 6) South County, 7) West Side, 8) KCWA, 9) the County of Kern and 10) one non-governmental organization (NGO) or community member (hereafter referred to as "Member-At-Large").

Roles

1. **The Regional Water Management Group (RWMG) Members will:**
    a. Offer their facilities for stakeholder meetings on an as-available basis
    b. Appoint one (1) representative and one (1) alternate to the Executive Committee for each respective subregion
        i. RWMG members may cast one (1) vote for the representative position and one (1) vote for the alternate position within their subregion

ii. If a RWMG member is a participant in more than one subregion, the member may only vote in their primary subregion, as defined in current Participation Agreement

c. Participate in RWMG meetings of the Kern IRWMP

d. Participate in subregion meetings for their primary subregion

e. Promote subregional cooperation among their respective agencies or organizations focused on implementing the IRWM Plan

f. Provide funding to support cooperative efforts focused on implementing the IRWM Plan

g. Provide financial oversight for efforts using shared funds

h. Approve (or deny) recommendations for use of shared funds made by the Executive Committee on behalf of the Stakeholder Group

i. Provide a decision mechanism (by majority vote where each representative has a single vote) in instances where facilitated broad agreement within the Stakeholder Group cannot be reached

j. Empower the Executive Committee to fulfill the roles outlined below

2. The **Stakeholder Group** participants may:

a. Offer their facilities for stakeholder meetings on an as-available basis

b. Participate in Stakeholder and RWMG meetings

c. Provide information and/or comments

3. The **Executive Committee** will:

a. Collaborate with the RWMG, Stakeholder Group and other entities

b. Call and conduct RWMG, Executive Committee and Stakeholder meetings as necessary.

c. The Executive Committee will elect two (2) of its members as co-chairs, one (1) from the agricultural sector and one (1) from the urban sector.

d. The co-chairs will conduct and direct meetings of the RWMG.

e. The co-chairs, acting as signatories for the RWMG, may execute third-party agreements for integration with other RWMGs with the approval of a simple majority of the Participants.

f. Provide quarterly progress reports and updates to the IRWMP

g. Initiate actions with the Stakeholder Group to identify, select and apply for appropriate funding opportunities

h. Recommend to the Stakeholder Group, hire, and manage consultants as needed

i. Gather, compile and manage data as defined in IRWMP and any grant related contracts received to implement the IRWMP

j. Identify and obtain needed expertise when appropriate

k. Prepare an annual budget each fiscal year (July to June) and present to the RWMG for approval

l. Manage operating funds as provided by the approved budget

m. Serve as central point of contact for RWMG and IRWMP Implementation. The Executive Committee will select one person to serve as the designated point of contact on behalf of the Implementation Governance Structure. This person may or may not be a member of the Executive Committee.

n. Provide facilitation for implementation process

o. Identify and coordinate with staff dedicated to supporting the roles of the Executive Committee

p. Coordinate with a legal entity willing to act on behalf of the Stakeholder Group to:

    i. Execute and manage contracts as approved by the RWMG

    ii. Oversee receipt and processing of financial transactions

    iii. Provide an annual report of financial transactions according to accepted accounting practices

q. Designate a fiscal agent to collect and manage funds

r. Initiate discussions related to long-term governance preferences

s. Provide a spokesperson or advocate to represent the Stakeholder Group and RWMG related to implementation of the IRWMP

Representation and Decision Making

1. Regional Water Management Group Members:

    a. Each signatory of the original RWMG Participation Agreement will continue as a member of the RWMG.

    b. New entities may join the RWMG by becoming a signatory to the current Participation Agreement if approved by a simple majority vote of the existing RWMG members.

    c. RWMG members may withdraw from the IRWMP by providing a written request to the Executive Committee. Withdrawal from the RWMG shall not reduce the member's responsibility to make payments of the full amount of their financial obligation under the approved budget for the year in which the request to withdraw is made.

    d. Each member of the RWMG will contribute their proportionate share of the adopted budget for the current fiscal year.

    e. Entities that are not members of the RWMG may contribute funding or in-kind services to support the activities of the Executive Committee and/or RWMG without becoming signatories to the Participation Agreement.

    f. Each organization that is a signatory to the Participation Agreement will appoint one representative to serve on the RWMG.

    g. Each member of the RWMG will have one (1) vote.

h. If broad agreement cannot be reached, actions may be taken by the RWMG based on a simple majority vote.

2. Executive Committee:

   a. Shall consist of ten (10) members selected by the RWMG to represent the Kern Subregion for staggered three year terms[1]:

      i. Kern County (2012)

      ii. Kern County Water Agency (2013)

      iii. West Side (2012)

      iv. Kern Fan (2013)

      v. North County (2014)

      vi. South County (2012)

      vii. Mountains/Foothills (2013)

      viii. Greater Bakersfield (2014)

      ix. Kern River Valley (2012)

      x. Member-At-Large (2013)

   b. Representatives and alternates to the Executive Committee will be elected as follows:

      i. Nominations for each category can be made by any member of the RWMG and will be made during a Stakeholder Meeting

      ii. If the person nominated is willing to serve on the Executive Committee as described, that person will be considered as a candidate by the RWMG members

      iii. RWMG members may cast one (1) vote for a representative and one (1) vote for an alternate within their subregion. RWMG members that belong to more than one subregion may only vote in their primary subregion

      iv. As the County of Kern is the sole RWMG member for the County of Kern subregion, a representative and alternate to the Executive committee shall be nominated and appointed either directly by or following a procedure set forth by the Kern County Board of Supervisors.

      v. As the Kern County Water Agency is the sole RWMG member for the Kern County Water Agency subregion, a representative and alternate to the Executive committee shall be nominated and appointed either directly by or following a procedure set forth by the Kern County Water Agency Board of Directors.

[1] Members for each category will be reselected in the year shown and every three years following.

vi. A representative and alternate for the Member-At-Large position shall be elected by a simple majority vote of the NGOs and community members belonging to the Stakeholder Group.

1) As the Member-At-Large position is representative of the entire Kern IRWMP, and not any one subregion, the election will be conducted by the Executive Committee.

2) Each NGO and community member may cast one (1) vote for a representative and one (1) voted for an alternate.

vii. If an Executive Committee position becomes vacant before the regularly scheduled reselection year, the same selection process described in this section will be used to select a replacement.

viii. Representatives or alternates to the Executive Committee cannot designate an alternate.

1) If the representative and alternate of a subregion are unable to participate in a meeting or vote, the subregion may elect a temporary alternate following the procedure described in this section.

ix. If the participants of a subregion are not satisfied with the performance of their Executive Committee representative or alternate, one or more RWMG members from that subregion can request that the RWMG members from that subregion conduct a new nomination and selection cycle, as described in this section, for the position (or positions) not being served satisfactorily. This request must be approved by a simple majority vote of the RWMG members from the subregion, as defined in Section 3(a).

1) The newly appointed representative or alternate will be subject to the same nomination and selection cycle, as described in this section.

2) The Executive Committee Co-chairs, or their appointed designee, shall be notified within forty-eight (48) hours of the selection of a new representative or alternate.

c. Members of the Executive Committee will strive to make decisions based on broad agreement. If broad agreement cannot be reached on a particular matter, actions may be taken by a simple majority vote of the Executive Committee members as defined in Section 3(b).

d. Participation at Executive Committee meetings will be limited to one (1) representative per subregion.

3. Voting:

a. Voting of the RWMG:

i. If broad agreement cannot be reached, actions may be taken by the RWMG by a simple majority vote.

ii. A simple majority vote is defined as a majority of the total number of RWMG members.

iii. Unless otherwise specified, any RWMG member who is unable to cast a vote in person, may submit their vote in writing to the Executive Committee Co-chairs, or their appointed designee, prior to the time of the vote.

iv. A vote may be taken on any item if motioned and seconded by members of the RWMG.

b. Voting of the Executive Committee:

i. A simple majority vote of the Executive Committee is required for all decisions and/or actions requiring approval of the Executive Committee.

ii. A simple majority vote is defined as a majority of the total number of Executive Committee representatives.

iii. A vote may be taken on any item if motioned and seconded by members of the Executive Committee.

4. Notification of Meetings and Document Availability:

a. RWMG Members shall receive notice of all meetings at least seventy-two (72) hours prior to each meeting. Meeting notices will be published to the IRWMP website, sent via electronic mail (e-mail) to the RWMG member email list and posted at the location of the meeting.

b. All documents requiring review by or approval of the RWMG, shall be published to the Kern IRWMP website and sent via electronic mail (e-mail) to the RWMG member email list at least forty-eight (48) hours prior to the meeting or vote.

Funding

1. Preparation of a Budget:
   a. The Executive Committee shall prepare a budget each fiscal year (July to June).
2. Allocation of Costs:

a. Costs will be allocated to the RWMG Participants proportionally based on each participant's budget, defined as:

i. Water districts, agencies, purveyors or other RWMG Members that exclusively manage water: The budget will be the total annual budget for the current fiscal year.

ii. For cities, agencies or other RWMG Members that manage or provide goods and/or services other than water management: The budget will be the total operating expenses related to all water management activities, including, but not limited to water supply, wastewater treatment and/or flood management.

iii. For RWMG Members that do not provide goods and/or services related to water management: The budget will be defined on a case-by-case basis and approved by a vote of the RWMG.

b. RWMG Members with a cost allocation of less than two hundred dollars ($200) will not be required to contribute funds. Their cost allocation will be paid by the remaining RWMG Members in proportion to their cost allocation.

c. If a RWMG Members is unable to contribute funds due to financial hardship, said Member may request a fee waiver from the Executive Committee.

i. All fee waivers will be considered on a case-by-case basis.

ii. The Executive Committee may require in-kind services to be provided in-lieu of a financial contribution.

iii. All fee waivers, including any terms or conditions assigned to the waiver, granted by the Executive Committee must be approved by a simple majority vote of the RWMG.

3. Accounting and Reporting:

a. The Executive Committee, or its designated fiscal agent, will provide an annual report of financial transactions according to accepted accounting practices.

b. An informal audit of the finances may be requested by a simple majority vote of the Executive Committee or RWMG.

c. A formal audit of the finances may be requested by a simple majority vote of the Executive Committee or RWMG.

i. A request for a formal audit must define a funding mechanism for the audit, if the funds for a formal audit were not included in the approved budget for the fiscal year in which the audit request is made.

Plan Adoption and Amendments

1. Adoption of the Kern IRWMP:

a. To adopt the Kern IRWMP, the Executive Committee or RWMG shall hold a public hearing to notify the public of their intent to adopt an integrated regional water management plan.

b. The Kern IRWMP shall be in full effect when at least three (3) public agencies, two (2) of which having statutory authority over water supply and management, sign and return to the Executive Committee, or their designee, the signature page of the plan.

i. Adoption of the plan by each entity seeking to do so shall be subject to the internal policies and practices of said entity.

2. Amendments to the Kern IRWMP:
    a. Amendments to the plan may be proposed by any member of the Stakeholder Group.
    b. Amendments to the plan shall require:
        i. Approval of the RWMG by a simple majority vote, as defined in Section 3(a).
        ii. Once approved by the RWMG, the Executive Committee or RWMG shall hold a public hearing to notify the public of the RWMG's intention to adopt an amended plan.
        iii. The amended plan shall be in full effect when at least three (3) public agencies, two (2) of which having statutory authority over water supply and management, sign and return to the Executive Committee, or their designee, the signature page of the plan.
    c. Changes to the plan's appendices may be proposed by any member of the Stakeholder Group.
    d. At a minimum, the following elements of the Kern IRWMP shall be contained in appendices to the plan:
        i. Kern IRWMP Governance Structure
        ii. Project Prioritization Process
        iii. Project List
    e. The plan's appendices may be amended by a simple majority vote of the RWMG, as defined in Section 3(a).
    f. Amendment of one or more of the appendices, in part or in whole, shall not require re-adoption of the plan by the RWMG.

IRWMP Term

The term of the Kern IRWMP will be 20 years from initial adoption, with updates and subsequent re-adoption by the parties described below, occurring a minimum of every five years within that 20 year timeframe, unless one or more of the following events triggers re-adoption prior to the scheduled five-year interval:

- Significant change in conditions as defined by the RWMG with input from the Stakeholders.
- Achievement of an objective which necessitates setting a revised or replacement regional objective.

- The need, as determined by the RWMG with Stakeholder input, to set new regional objectives.

Appendix J

Climate Change Vulnerabilities

Prioritization Table

Climate Change Vulnerabilities Prioritzation

Kern IRWMP Objectives	Climate Change Vulnerabilities	Prioritization (High, Medium, Low)
Increase Water Supply		
Through cooperation and collaboration with other regions restore water supplies to levels that will mitigate for water lost from the region and eliminate overdraft	Water Supply	H
Pursue and implement cost effective water use efficiency programs	Water Demand	M
Increase water storage capacity in the region by increasing recharge acreage and expanding groundwater banking programs before all prime recharge land has been developed	Water Supply, Sea Level Rise	H
Integrate management of water banking facilities to maximize conjunctive use over the planning horizon	Water Supply	H
Increase/augment water supplies to meet region demands (e.g., M&I, agricultural, environmental) by 2050.	Water Supply, Sea Level Rise	H
Improve Operational Efficiency		
Increase transfers and exchanges flexibility over the planning horizon	Water Supply	H
Create tools to re-regulate water supplies within the region, including storage, storm flows, and operational flows over the planning horizon	Water Supply	H
Increase distribution efficiencies and reduce energy usage over the planning horizon	Water Demand	M
Increase the use of alternate energy sources (e.g., solar)	Hydropower	M
Replace aging infrastructure to reduce system water losses, improve operational efficiencies, and reduce service interruptions	Water Supply, Flooding	M
Increase the use of recycled water for direct reuse within the Kern Region	Water Supply, Water Demand, Water Quality	M
Optimize local management of water resources to improve water supply reliability over the planning horizon	Water Supply	H
Increase pool of qualified candidates to operate water and wastewater systems	Water Quality	L
Improve Water Quality		
Monitor and/or manage headwaters/areas of origin, natural streams, and recharge areas to prevent or mitigate contamination	Ecosystem and Habitat, Water Quality	M
Identify and preserve prime recharge areas in the Kern fan area and other areas	Water Supply, Water Quality	H
Improve water quality for DACs and the watershed over the planning horizon	Water Supply, Water Quality	H
Continue to provide drinking water that meets or exceeds water quality standards; and support efforts to attain appropriate standards throughout the planning horizon	Water Supply, Water Quality	H
Maximize the use of lesser quality water for appropriate uses (landscaping, certain ag crops, “aesthetic” projects) throughout the planning horizon	Water Supply, Water Quality	M
Coordinate and enhance aquatic pest control efforts from this point forward	Ecosystem and Habitat, Water Quality, Water Supply	M
Promote Land Use Planning and Resource Stewardship		
Promote stewardship of the Kern River by applying appropriate measures in various reaches of the river from this point forward	Ecosystem and Habitat	M
Encourage the removal of non-native invasive plant species that affect water quality, reliability, and operations	Ecosystem and Habitat, Water Supply, Water Quality	M
Identify and promote the regeneration and restoration of native riparian habitat	Ecosystem and Habitat	M
Coordinate agricultural and urban water suppliers to more effectively address land use planning issues from this point forward	Habitat, Water Demand, Water Supply	M
Improve the linkage between land use planning and water supply in the region throughout the planning horizon	Ecosystem and Habitat, Water Supply	H
Increase educational opportunities to improve public awareness of water supply, conservation, and water quality issues throughout the planning horizon	Ecosystem and Habitat, Water Supply, Water Demand, Water Quality	H
Improve and coordinate integrated land use planning to support stewardship of environmental resources, such as the Kern River and Kern Fan, and integrate with habitat conservation plans and other ongoing planning efforts from this point forward	Ecosystem and Habitat, Water Supply	M
Preserve and improve ecosystem/watershed health throughout the planning horizon	Ecosystem and Habitat	M
Improve Regional Flood Management		
Improve regional flood management by addressing preparedness, response, and post flood actions throughout the planning horizon	Flooding	M
Reduce the effects of poor quality runoff throughout the planning horizon	Flooding. Water Quality	M
Identify and promote innovative flood management projects to protect vulnerable areas	Flooding	H
Plan new developments to minimize flood impacts from this point forward	Ecosystem and Habitat, Flooding	M

Tulare Lake Basin Portion of Kern County
Integrated Regional Water Management Plan

August 25, 2014 - 1:00 pm – 3:00 pm
Kern County Water Agency
Stuart T. Pyle Water Resources Center
3200 Rio Mirada Drive, Bakersfield, CA 93308

Meeting Objectives:

- Recommendations from DWR Plan Review Process:
- Climate Change Vulnerability Assessment Prioritization

PARTICIPANTS MEETING AGENDA

1:00	**I**	**Welcome and Introductions – Executive Committee Chair** Meeting purpose and agenda *A quorum of the EC was present as follows: Bill Taube, Chair, Regina Houchin, Jon Curry, Greg Fenton, and Lauren Bauer.*
1:05	**II**	**General Information Items** A. Revised/Updated Participant Funding Agreement – Lauren Bauer *Lauren described the process for obtaining indications from all signatories that they would be willing to execute the "First Amendment to the Agreement with KCWA for IRWM Plan Management Services." An email request for comments on the form of the agreement is currently being conducted; comments are due by COB September 1, 2014. After the Amendment is finalized, an email poll of signatories regarding their wiliness to execute will be conducted.*
1:20	**III**	**Funding Opportunities - KJ/P&P Team** A. Water Energy Draft PSP - $19M B. Update on Emergency Drought Funding Application *Mary Lou Cotton of Kennedy/Jenks Consultants gave a brief update on these items and referred to a handout of DWR's compiled list of applicants for the Emergency Drought Funding.*
1:30	**IV**	**IRWM Plan Status – KJ** ***A.*** Kern IRWM Plan DWR Plan Review Recommendations: Climate Change Vulnerability Assessment Prioritization – KJ and EC Members *Mary Lou described the draft Climate Change Technical Memo and Vulnerability Assessment table that were sent to the participants on August 20. She then described the Vulnerability Assessment and prioritization process, and led the group through a discussion of the vulnerabilities that could potentially impact the Tulare Lake Basin Portion of Kern County Region. The group collectively discussed and agreed upon the prioritization of the vulnerabilities, and directed Mary Lou to include it as part of the Climate Change package to be submitted to DWR by September 9, 2014.*
2:00	**V.**	**Public Comment** *Representatives from the Community Water Center reported that the Tulare Lake Basin Disadvantaged Community Study is ready and will be presented to the Tulare County Board of Supervisors on September 9. A draft of the report (prepared by Provost & Pritchard) is available on the Tulare County website. The report contains recommendations regarding DACs for various IRWM Regions.*
		Close

Appendix K

Public Comments (List of Commenters)

Tulare Lake Basin Portion of Kern County IRWMP

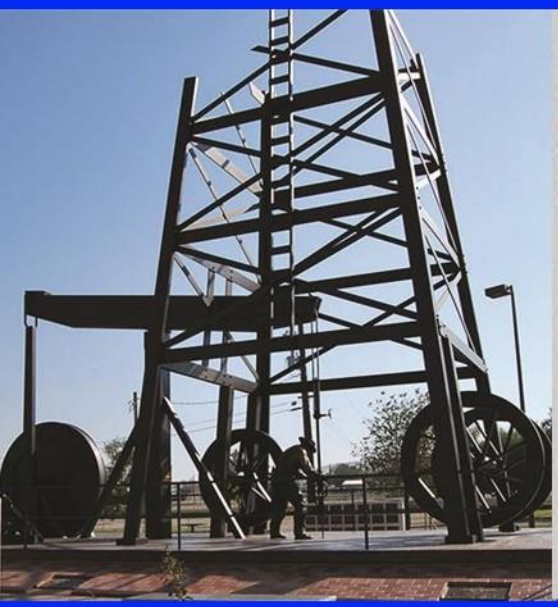
Comments by:	Date
Eric Averett - RRBWSD	6/18/2009
Greg Hammett - Belridge Water Stroage District	8/31/2009
Greg Hammett - Belridge Water Storage District	10/23/2009
Dale Melville - Dudley Ridge Water District	10/29/2009
Doug Nunneley - Oildale Mutual Water Co.	11/2/2009
Donna Miranda-Begay - Tubatulabals of Kern Valley	11/4/2009
Dan Allen - City of Wasco	11/16/2009
Mark Mulkay - Kern Delta Water District	11/17/2009
Chris Whitley - Cal Water	11/19/2009
Mike Higgins - Valley Estates POA, Inc.	11/19/2009
John Martin - Tehachapi-Cummings County Water District	11/20/2009
Jeevan Muhar - Arvin-Edison Water Storage District	11/23/2009
Mark Mulkay - Kern Delta Water District	11/24/2009
Donna Miranda-Begay - Tubatulabals of Kern Valley	11/25/2009
John Martin - Tehachapi-Cummings County Water District	11/25/2009
Dave Warner - Self Help Enterprises	11/27/2009
Dave Warner - Self Help Enterprises	12/9/2009
Dave Warner - Self Help Enterprises	12/9/2009
Dave Warner - Self Help Enterprises	12/9/2009
Dale Melville - Dudley Ridge Water District	11/2/2011
Dave Beard - ID4	11/2/2011
Carole K. Combs, Kathy Wood, Robert B. Hansen, Stephen A. Laym	11/3/2011
Jeevan Muhar - AEWSD	11/4/2011
Jon Parker - Kern Water Bank Authority	11/4/2011
Dr. Donna Miranda-Begay - Tubatulabal Tribe	11/4/2011
Laurel Firestone - Community Water Center	11/6/2011
Kris Lawrence - Westside District Water Authority	8/13/2019
Monica Tennant - Kern County Water Agency	8/28/2019
Tom Neisler - Tehachapi-Cummings County Water District	8/28/2019
David Warner - Self Help Enterprises	3/10/2020
Kevin Hamilton - County of Kern	3/11/2020

APPENDIX C

2020 URBAN WATER MANAGEMENT PLAN – WEST KERN WATER DISTRICT



West Kern Water District
Urban Water Management Plan
2020 Update







West Kern water district

June 2021

EST. 1968
PROVOST& PRITCHARD
CONSULTING GROUP

URBAN WATER MANAGEMENT PLAN
2020 UPDATE

West Kern Water District

June 2021



Date signed: 6-23-21

Prepared by:
Provost & Pritchard Consulting Group
1800 30th St., Suite 280, Bakersfield, CA 93301

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ABBREVIATIONS

AB	Assembly Bill
Act	California Urban Water Management Planning Act
ACWA	Association of California Water Agencies
AF	acre-feet
AFY	acre-feet per year
AWWA	American Water Works Association
BDCP	Bay Delta Conservation Plan
bgs	below ground surface
BMP	Best Management Practice
BVWSD	Buena Vista Water Storage District
CARB	California Air Resources Board
CASGEM	California Statewide Groundwater Elevation Monitoring Program
CAT	Climate Action Team
CCF	One Hundred Cubic Feet
CCR	Consumer Confidence Report
CDPH	California Department of Public Health
CEE	Consortium of Energy Efficiency
CEQA	California Environmental Quality Act
CIMIS	California Irrigation Management Information System
COG	Council of Governments
CRC	California Resources Corporation
CUWCC	California Urban Water Conservation Council
CVC	Cross Valley Canal
CVP	Central Valley Project
CWC	California Water Code

DBP	Disinfection by-products
DCR	Delivery and Capability Report
DDW	Division of Drinking Water
Delta	Sacramento-San Joaquin Delta
DHS	California Department of Health Services
DMM	Demand Management Measure
DOF	Department of Finance
DTSC	Department of Toxic Substances Control
DWR	California Department of Water Resources
eARDWP	electronic Annual Reports to the Drinking Water Program (SWRCB)
EC	Electrical conductivity
EDT	Electronic Data Transfer
ELT	Early Long-Term scenario
EPA	Environmental Protection Agency
ETo	reference evapotranspiration
FCTHSD	Ford City – Taft Heights Sanitation District
GIS	Geographic Information System
gpcd	gallons per capita per day
gpd	gallons per day
gpf	gallons per flush
gpm	gallons per minute
GSP	Groundwater Sustainability Plan
HCD	State Department of Housing and Community Development
HECW	High-Efficiency Clothes Washers
HET	High Efficiency Toilet
IRWM	Integrated Regional Water Management
IRWMP	Integrated Regional Water Management Plan
KCWA	Kern County Water Agency
KTWD	Kern Tulare Water District
LLC	limited liability company
M&I	Municipal and Industrial
MAF	million acre-feet
MCL	Maximum Contaminant Limit
MG	million gallons
mg/L	milligrams per liter
mgd	million gallons per day
MOU	Memorandum of Understanding
NPDES	National Pollutant Discharge Elimination System
PG&E	Pacific Gas and Electric
psi	pounds per square inch
PWS	Public Water System
PWSS	Public Water System Statistics
R&E	Research & Evaluation
RHNA	Regional Housing Needs Allocation Plan
RRBWSD	Rosedale-Rio Bravo Water Storage District
RWQCB	Regional Water Quality Control Board
SB	State Senate Bill

SBX7-7	Senate Bill 7 of Special Extended Session 7
SCAG	Southern California Association of Governments
SGMA	Sustainable Groundwater Management Act
SMCL	Secondary Maximum Contaminant Limit
SWP	State Water Project
SWRCB	State Water Resources Control Board
TDS	Total Dissolved Solids
TOC	Total Organic Carbon
UWMP	Urban Water Management Plan
UWMPA	Urban Water Management Planning Act
WDR	Waste Discharge Requirement
WHPA	Wellhead Protection Area
WKWD	West Kern Water District
WRR	Water Recycling Requirement
WSCD	Westside Cemetery District
WSCP	Water Shortage Contingency Plan
WSD	Water Storage District
WSRP	Water Shortage Response Plan
WSRPP	Westside Recreation & Parks District
WSS	WaterSense Specification
WWTF	wastewater treatment facility

Lay Description of Urban Water Management in West Kern Water District

This 2020 Urban Water Management Plan (UWMP) has been prepared for the West Kern Water District in Kern County, California and describes the District's water supply, water demands, water reliability, and water conservation efforts. This document provides estimated population growth and water demands through the year 2045 and serves as a long-range planning document for the District. This document is an update to the District's 2015 UWMP.

In 2020, the District had an estimated population of 22,172 and served water to 7,379 homes, businesses and industrial facilities. Currently, the District obtains its water from two sources: surface water imported from northern California through a series of canals and pipelines and groundwater that is pumped to the surface using several wells. Most of the surface water is recharged in large spreading areas providing long-term storage, and then pumped and used when needed. These sources are expected to provide adequate water through the year 2045.

The State of California set a goal for all urban water agencies to reduce their water use by 20% and to achieve this goal by the year 2020. To reach this goal, the District needs to limit water use to 189 gallons per day for each person. In 2020, the District met this goal with a per person use of 185 gallons per day and will continue water conservation programs to keep meeting this goal in the future. About 80 percent of the water in the District is used for industrial purposes, especially power plants and oil field operations. These uses were not considered in estimating the daily water use per person.

The District has special water conservation programs that can be implemented in the event of drought or other water supply issues. The District is also prepared to respond to a water supply interruption from an emergency. These measures are described in an updated Water Shortage Response Plan, which is included in this document. The District will typically not experience water shortages unless there is a catastrophic interruption of supply. The amount of recharged groundwater has grown to provide a ten-year backup supply. As a result, the District is not expected to have water shortages during droughts for the foreseeable future.

1 Introduction and Overview

1.1 Overview

This document presents the 2020 Urban Water Management Plan (Plan or UWMP) for the West Kern Water District (District, WKWD) service area. This section describes the general purpose of the Plan, background information on UWMP requirements, and the organization of the UWMP. This Plan satisfies requirements for a retail UWMP and covers the years 2016 to 2020. This plan is also an update to the District's 2015 UWMP.

1.2 Purpose

An UWMP is a planning tool that generally guides the actions of water management agencies. It provides managers and the public with a broad perspective on a number of water supply issues. It is not a substitute for project-specific planning documents, nor was it intended to be when mandated by the State Legislature. For example, the Legislature mandated that a plan include a section which "describes the opportunities for exchanges or water transfers on a short-term or long-term basis." (California Urban Water Management Planning Act, Article 2, Section 10630(d).) The identification of such opportunities, and the inclusion of those opportunities in a general water service reliability analysis, neither commits a water management agency to pursue a particular water exchange/transfer opportunity, nor precludes a water management agency from exploring exchange/transfer opportunities not identified in the plan. When specific projects are chosen to be implemented, detailed project plans are developed, environmental analysis, if required, is prepared, and financial and operational plans are detailed.

In short, this Plan is a management tool, providing a framework for action, but not functioning as a detailed project development or action. It is important that this Plan be viewed as a long-term, general planning document, rather than as an exact blueprint for supply and demand management. Water management in California is not a matter of certainty, and planning projections may change in response to a number of factors. It is an effort to generally answer a series of planning questions including:

- What are the potential sources of supply and what is the reasonable probable yield from them?
- What is the probable demand, given a reasonable set of assumptions about growth and implementation of good water management practices?
- How well do supply and demand figures match up, assuming that the various probable supplies will be pursued by the implementing agency?

Using these "framework" questions and resulting answers, the implementing agency will pursue feasible and cost-effective options and opportunities to meet demands. WKWD explores enhancing basic supplies and banking of water from the State Water Project (SWP) as well as other options. These include groundwater extraction, water exchanges, and water banking/conjunctive use. Specific planning efforts will be undertaken in regard to each option, involving detailed evaluations of how

each option would fit into the overall supply/demand framework, how each option would impact the environment, and how each option would affect customers. The objective of these more detailed evaluations would be to find the optimum mix of conservation and supply programs that ensure that the needs of the customers are met.

The California Urban Water Management Planning Act (Act) requires preparation of a plan that:

- Accomplishes water supply planning over a 20-year period in five-year increments. (WKWD is going beyond the requirements of the Act by developing a plan which spans 25 years.)
- Identifies and quantifies adequate water supplies for existing and future demands, in normal, single-dry, and multiple-dry years.
- Implements conservation and efficient use of urban water supplies.

In short, the Plan answers the question: *Will there be enough water for the customers of the West Kern Water District service area in future years, and what mix of programs should be explored for making this water available?*

It is the stated goal of WKWD to deliver a reliable and high-quality water supply for their customers, even during dry periods. Based on conservative water supply and demand assumptions over the next 25 years, in combination with conservation of non-essential demand during certain dry years, the Plan successfully achieves this goal.

1.3 Background

1.3.1 Urban Water Management Planning Act

The UWMP is a requirement of the Act (Division 6, Part 2.6 of the CWC §10610-10656). The UWMPs must be filed every five years and submitted to the Department of Water Resources (DWR). The submittal is required to meet the requirements of the Act, including the most current amendments that have been made. The Act applies to urban water suppliers with 3,000 or more connections being served or supplying more than 3,000 acre-feet (AF) of water annually. As of December 2020, WKWD had 7,379 active water connections and is therefore required to prepare an UWMP. UWMP requirements differ for retail and wholesale water agencies; WKWD is a retail water agency and this UWMP satisfies the retail agency requirements.

In 1983, SB797 altered Division 6 of the CWC by producing the Act. Since 1983, several amendments to the original document have increased the requirements of the UWMPs to include sections on recycled water use, demand management measures (DMMs), energy consumption, climate change, water shortage contingency plans, and other topics. See **Table 1-1** for the changes to the Water Code since the 2010 UWMPs.

Table 1-1: Changes to the Water Code Since 2010 UWMPs

Bill	Requirements
SB610 and AB901	Consideration of water availability when reviewing new large developments
SB318	Investigate possibilities of developing desalinated water
AB105	Submit UWMP to State Library
Water Conservation Bill (2009)	Urban water suppliers to reduce the statewide average per capita daily water consumption by 20% by December 31, 2020
AB 2067	Revises requirements on Demand Management Measures
SB 1420	Requires electronic submittal, standard forms and tables, and a report on distribution system losses
SB 1036	Urban suppliers to include energy-related information (optional) and analyze and define artificial water features
SB 606	This bill added several new requirements including, changes to the stages required by the Water Shortage Contingency Plan from four to six, preparation of a drought risk assessment to be included in the UWMP, and addition of a Lay Description to the UWMP.

1.3.2 Previous Urban Water Management Plan

The District has previously prepared a UWMP in 2015, which was approved and adopted by the Board of Directors. Following adoption, the 2015 UWMP was submitted to DWR. The UWMP was submitted with revisions requested by DWR and subsequently approved by DWR. A copy of this UWMP resides in the State Library.

This 2020 UWMP serves as an update to the 2015 UWMP and complies with all new requirements and regulations.

1.3.3 Plan Overview and Organization

This 2020 UWMP describes the District's water demands and supplies, water reliability and water conservation strategies. The UWMP includes data covering the years from 2016 to 2020. The UWMP has been prepared to include the recommended sections, discussions and data reporting required by the CWC and is based on the 2020 UWMP Guidebook provided by DWR. A checklist demonstrating compliance with applicable codes and legislations is included in **Appendix A** of this UWMP. **Appendix B** includes a copy of the resolution adopting the UWMP.

1.3.4 UWMP Organization

This 2020 UWMP is organized into the following sections.

- Section 1: Introduction and Overview

This section provides a discussion of the purpose and content of the 2020 UWMP and the extent of the District's water management planning efforts.

- Section 2: Plan Preparation and Adoption

  This section provides information on the District's development of the 2020 UWMP including the basis for plan preparation, UWMP characteristics, data format and coordination and outreach to nearby agencies. This section also details the steps taken by the District to adopt the UWMP and make it available to the public.

- Section 3: System Description

  This section provides a description of the District's water system including service area maps, climate information and service population and demographic information.

- Section 4: System Water Use

  This section describes the District's current and historic water uses, system losses, estimated water savings, and water use by lower income households.

- Section 5: Baselines and Targets

  This section includes a description of the District's chosen method for calculating their baseline, calculated baseline water use, and compliance with the 2020 target.

- Section 6: System Supplies

  This section includes a discussion of the District's water system supplies including groundwater and surface water, the District's future water projects, a summary of existing and future water sources, and energy consumption.

- Section 7: Water Supply Reliability

  This section describes the reliability of the District's water supply including a supply and demand assessment, drought risk assessment and regional reliability.

- Section 8: Water Shortage Contingency Planning

  This section provides a description of the District's Water Shortage Contingency Plan including stages of action, prohibitions, penalties, reduction methods, and catastrophic supply interruption.

- Section 9: Demand Management Measures

  This section explains the District's existing and historic efforts to promote water conservation and the District's plans to use Demand Management Measures to achieve their water use targets.

- Section 10: Bibliography/References

  List of relevant reports, studies, references, and data sources used in preparing the UWMP.

1.3.5 Report Tables

DWR has developed standardized tables to assist water managers in calculating per capita consumption, baseline consumption, water reduction targets, water use, etc. These tables are a required attachment to the UWMP document. However, they are not required in the body of the text and can be altered as needed to better reflect the water system. When appropriate and relevant, these tables have been included in the body of this text, but some are only found in **Appendix C**. It should be noted that some of the tables in the body of this document are not identical to the tables provided by DWR. Titles and substance may vary.

2 Plan Preparation and Adoption

2.1 Plan Characteristics

WKWD is a Public Water System (PWS), as defined by the California Health and Safety Code. The PWS number, and the number of connections and water delivered in 2020 are shown in the table below.

Table 2-1: Retail: Public Water Systems

Public Water System Number	Public Water System Name	Number of Active Municipal Connections 2020[1]	Volume of Water Supplied 2020[2]
1510022	West Kern Water District	7,379	16,338

1 – Includes residential, commercial and industrial meters and system losses. Does not include fire protection meters.
2 – Includes treated well water and raw surface water deliveries.

WKWD participates in several regional water management programs, including the Kern Integrated Regional Water Management Plan, efforts of the Kern County Water Agency, and coordinate basin-wide Sustainable Groundwater Management Act (SGMA) compliance as a member of the Kern Groundwater Authority. WKWD decided that an individual UWMP was the best option for the following reasons: 1) WKWD is fairly isolated from other urban water agencies; 2) WKWD has a unique customer base and unique water conditions; and 3) WKWD desires to use the UWMP for internal planning purposes.

Table 2-2: Plan Identification

☒	Individual UWMP
☐	Regional UWMP
No	Does this Regional UWMP include a Regional Alliance?

WKWD directly delivers water to customers and is therefore considered a retail water agency. Data in this UWMP is presented in acre-feet (AF) for each calendar year, which is consistent with the previous UWMP and the District's standard reporting procedures.

Table 2-3: Agency Identification

Name of Agency	
Select one or both	
☐	Agency is a wholesaler
☒	Agency is a retailer
Fiscal or Calendar Year	
☒	UWMP Tables Are in Calendar Years
☐	UWMP Tables Are in Fiscal Years
If Using Fiscal Years Provide Month and Day that the Fiscal Year Begins	
Day	*Month*
Units of Measure	
☒	Acre Feet (AF)
☐	Million Gallons (MG)
☐	Hundred Cubic Feet (CCF)

2.2 Coordination

Legal Requirements:

§10620(d)(2) Each urban water supplier shall coordinate the preparation of its plan with other appropriate agencies in the area, including other water suppliers that share a common source, water management agencies, and relevant public agencies, to the extent practicable.

2.2.1 Coordination and Outreach

Coordination for the UWMP and Water Shortage Contingency Plan (which is a component of the UWMP) updates included two components: 1) coordination with the general public; and 2) coordination with other water agencies. The coordination efforts followed water code requirements for retail water agencies. These efforts included: 1) notifying agencies of the plan to update the UWMP; 2) collecting data from some agencies; 3) making the Draft UWMP available at the WKWD office; 4) soliciting input on the draft UWMP; 5) publishing notices in local newspapers; and 6) holding a public hearing to solicit comments and adopt the UWMP. Copies of the public outreach materials are included in **Appendix D**. **Table 2-4** presents the timeline for public participation.

Table 2-4: Public Participation Timeline

June 8, 2021	Preliminary Draft UWMP	Preliminary Draft released to solicit input
June 22, 2021	Public Hearing/Adoption Hearing	Review contents of Draft UWMP and take comments/Adopt UWMP

2.2.2 Wholesale and Retail Coordination

The District has informed the following wholesale suppliers of projected water use in accordance with CWC §10631. The Kern County Water Agency provides SWP water to WKWD.

Table 2-5: Water Supplier Information Exchange

Wholesale Agency Name
Kern County Water Agency

2.2.3 Coordination with Other Agencies and the Community

Table 2-6 summarizes the coordination efforts with other public agencies and the general public.

Table 2-6: Coordination with Appropriate Agencies

Coordinating Agencies	Participated in Developing the Plan	Was Sent a Copy of the Draft Plan	Commented on the Draft	Attended Public Meetings	Contacted for Assistance	Was Sent a Notice of Intention to Adopt
City of Taft		✓				
City of Maricopa		✓				
Buena Vista WSD		✓				
Rosedale-Rio Bravo WSD		✓				
Kern County Water Agency		✓				
Kern Water Bank		✓				
County of Kern, Council of Governments		✓				
County of Kern		✓				
General Public						

2.3 Plan Adoption, Submittal, and Implementation

2.3.1 Notice of Public Hearing

Legal Requirements:

CWC 10621 (b)
Every urban water supplier required to prepare a plan shall… at least 60 days prior to the public hearing on the plan … notify any city or county within which the supplier provides waters supplies that the urban water supplier will be reviewing the plan and considering amendments or changes to the plan.
CWC 10642
The urban water supplier shall provide notice of the time and place of hearing to any city or county within which the supplier provides water supplies. A privately-owned water supplier shall provide an equivalent notice within its service area.

The following table lists the agencies that were notified, via letters, that WKWD was updating the UWMP, and of the date of the public hearing. Copies of the notification letters are included in **Appendix D**.

Table 2-7: Notification to Water Agencies

Names of Cities and Counties	60 Day Notice (CWC 10621 (b))	Notice of Public Hearing (CWC 10642)
City of Taft	☒	☐
City of Maricopa	☒	☐
Buena Vista WSD	☒	☐
Rosedale-Rio Bravo WSD	☒	☐
Kern County Water Agency	☒	☐
Kern Water Bank	☒	☐
County of Kern, Council of Governments	☒	☐
County of Kern	☒	☐

2.3.2 Public Hearing and Adoption

Legal Requirements:

CWC 10642
Prior to adopting a plan, the urban water supplier …shall hold a public hearing thereon.
CWC 10608.26
(a) In complying with this part, an urban retail water supplier shall conduct at least one public hearing to accomplish all of the following:
(1) Allow community input regarding the urban retail water supplier's implementation plan for complying with this part.
(2) Consider the economic impacts of the urban retail water supplier's implementation plan for complying with this part.
(3) Adopt a method, pursuant to subdivision (b) of Section 10608.20 for determining its urban water use target.
CWC 10642
After the hearing, the plan shall be adopted as prepared or as modified after the hearing

The District held a public hearing and adopted the 2020 UWMP and WSCP on June 22, 2021. A copy of the adopting resolution is included in **Appendix B**. Prior to the public hearing, a notice was published in the Taft Midway Driller newspaper (which is only published once per week) on June 10, 2021 and June 17, 2021 informing the public of the pending hearing. At the public hearing the District presented information on baseline values, water-use targets and an UWMP implementation plan. No comments were received from the public prior to or at the public hearing.

2.3.3 Plan Submittal

Legal Requirements:

> ***CWC 10621(d)***
> *An urban water supplier shall update and submit its 2015 plan to the department by July 1, 2016.*
> ***CWC 10644(a)***
> *An urban water supplier shall submit to the department, the California State Library, and any city or county within which the supplier provides water supplies a copy of its plan no later than 30 days after adoption.*
> ***CWC 10635 (b)***
> *The urban water supplier shall provide that portion of its urban water management plan prepared pursuant to this article to any city or county within which it provides water supplies no later than 60 days after the submission of its urban water management plan.*

After the UWMP and WSCP were adopted, copies were submitted to DWR electronically, the State Library and the public agencies listed in **Table 2-6**.

2.3.4 Public Availability

Legal Requirements:

> ***CWC 10645***
> *Not later than 30 days after filing a copy of its plan with the department, the urban water supplier and the department shall make the plan available for public review during normal business hours.*

The adopted UWMP and WSCP are available on the WKWD website at http://www.wkwd.org/. A copy of the UWMP and WSCP can also be viewed at the WKWD office during normal business hours.

2.3.5 California Environmental Quality Act Compliance

Legal Requirements:

> ***CWC §10652***
> *The California Environmental Quality Act (Division 13 (commencing with Section 21000) of the Public Resources Code) does not apply to the preparation and adoption of plans pursuant to this part or to the implementation of actions taken pursuant Section 10632. Nothing in this part shall be interpreted as exempting from the California Environmental Quality Act any project that would significantly affect water supplies for fish and wildlife, or any project for implementation of the plan, other than projects implementing Section 10632, or any project for expanded or additional water supplies.*

This UWMP and WSCP has been prepared in conformance with legislative requirements. Pursuant to CWC Section 10652 the preparation and adoption of this plan, along with the implementation of the Water Shortage Contingency Plan, are exempt from the California Environmental Quality Act (CEQA). This plan does however present projects that comprise the District's long-term water supply strategy. These projects are in various stages of planning and have been or will be evaluated consistent with CEQA requirements.

3 System Description

3.1 Service Area Physical Description

Legal Requirements:

§10631(a) Describe the service area of the supplier.
§10631(a) (Describe the service area) climate.

3.1.1 Location

WKWD was formed in May 1959, and includes the incorporated cities of Taft and Maricopa, together with the Westside communities of Taft Heights, South Taft, Ford City, Tupman, Dustin Acres, Valley Acres, Derby Acres, Fellows and McKittrick. The District has an irregular boundary and encompasses a service area of approximately 300 square miles. WKWD is located within the San Joaquin Valley approximately 30 miles west of metropolitan Bakersfield and 100 miles north of Los Angeles. A map of the District is shown below as **Figure 3-1**.

3.1.2 Land Use

A summary of land use by several categories is shown in the table below.

Table 3-1: Land Use Categories

Land use	Area (acres)	Percent of Total
Single Family Residential	2,511	1.1%
Multi-Family Residential	166	0.1%
Industrial	4,446	1.9%
Commercial	538	0.2%
Irrigated Agriculture	9,573	4.1%
Other Agricultural Lands[1]	157,457	67.7%
Government	50,241	21.6%
Natural Resources	3,372	1.5%
Miscellaneous / Vacant Land	4,175	1.8%
Total	232,480	100.0%
Source: Kern County Assessor Records (2015)		

1 - These fall under the general category of Agriculture according to County Records. This includes dryland farming, undeveloped land with the potential for agriculture, and oilfields with the potential for agriculture.

Only a small portion of the District is developed for residential use. A significant percentage of the water supply (~80%) is delivered to industrial customers, primarily oil development companies and power plants. Oil companies utilize the District's water to supplement their produced water supply for steam injection (referred to as "secondary recovery") which began during the mid-1960s. Electrical

power generating companies began operation within the District service area during the late 1990s. Domestic water sales account for the remaining twenty percent of the District annual sales.

The District also includes two correctional facilities including the Federal Taft Correctional Institution, whose water use falls under the Industrial category, and the Taft Community Correctional Facility, whose water use falls under the Commercial category. In May 2020, the Federal prison closed temporarily for renovations. The Taft Community Correctional Facility closed permanently in May 2021.

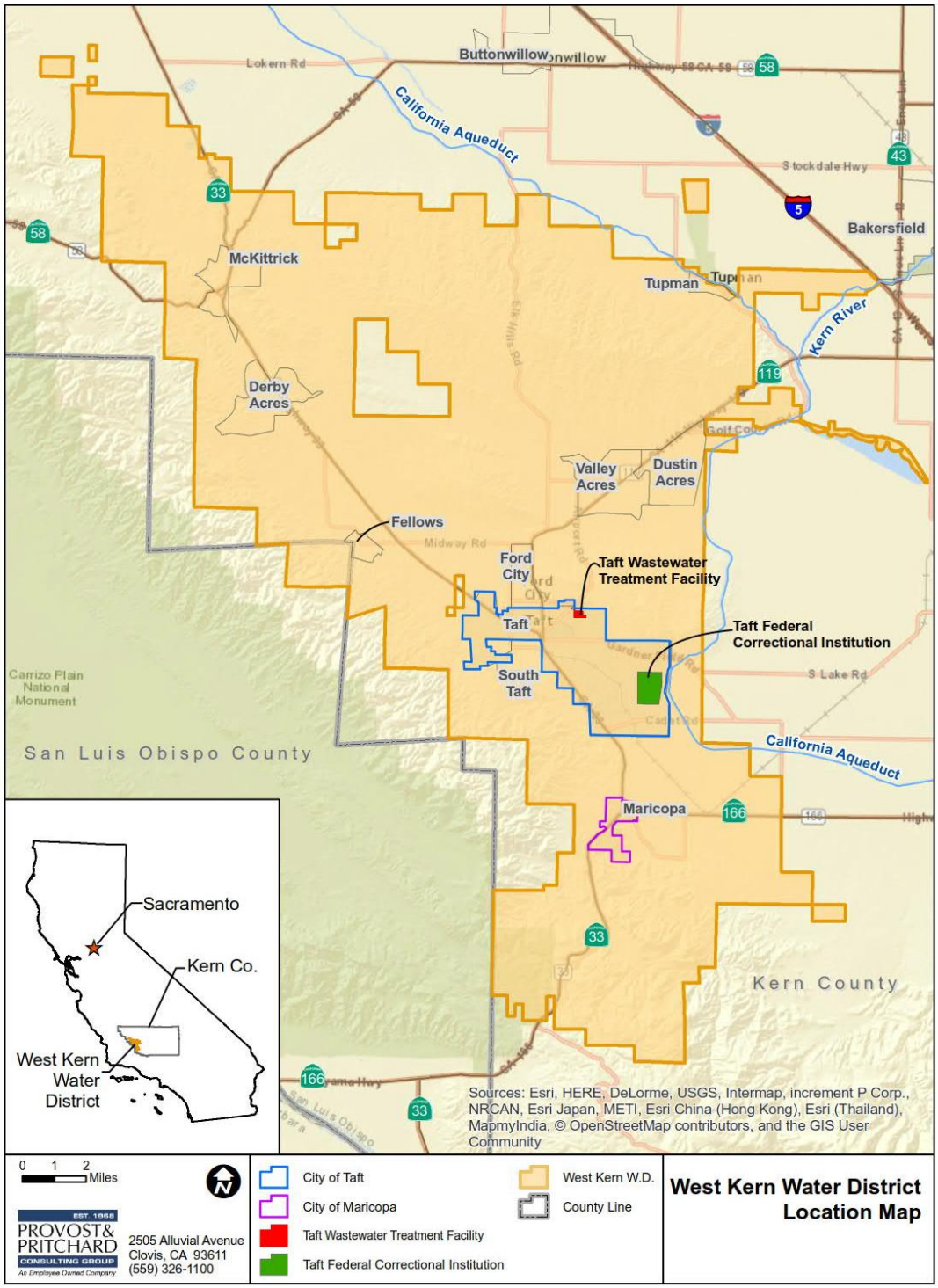

Figure 3-1: Location Map

3.1.3 Water Facilities

A map of the District's distribution system is found in **Appendix E**. The primary facilities in the District include the following:

- 13 active groundwater wells (1 inactive well)
- 26 above ground water storage tanks
- 15 booster pump stations
- 306 miles of distribution pipelines
- Recharge basins of approximately 415 acres
- Recharge basins in project vicinity of approximately 6,862 acres
- Recharge basins in Tule Elk reserve of approximately 729 acres

The District primarily pumps groundwater, but balances this extraction by recharging its SWP water and other supplemental water supplies. The District has an industrial customer with a contract for delivery of up to 5,500 AF of water directly from the California Aqueduct, however future usage is expected to be around 3,000 AF/year. The District water supply is obtained from wells located in the northeast corner of the district in the underflow area of the Kern River Basin and from an area north and adjacent to the State of California's Tule Elk Reserve. The District meters 100 percent of its service connections.

3.1.4 Climate

The greater Taft area, which functions as both the population and commercial center of the District, lies against the gently rolling foothills of the Temblor Range of the Sierra Madre Mountains at an elevation varying from 900 to 1,200 feet above sea level. About ten miles to the east, towards Bakersfield, the valley floor reaches a minimum elevation of 300 feet. The highest facility of the District lies immediately to the south of the City of Taft, where 25 Hill reaches the height of 1,700 feet.

The climate of the southwestern portion of the San Joaquin Valley is semi-arid. The average maximum temperature in the City of Taft for the month of July is 98.4 degrees Fahrenheit, and for the month of January, 57.8 degrees Fahrenheit. The average annual rainfall is 5.39 inches. **Table 3-2** presents the area's annual average climate data.

Table 3-2: Climate Characteristics

	Jan	Feb	Mar	Apr	May	Jun
Standard Monthly Average ETo[a]	1.38	2.29	3.94	5.59	7.43	8.06
Average Rainfall (inches)[b]	1.07	1.29	0.75	0.50	0.37	0.03
Average Max. Temperature (Fahrenheit)[c]	57.8	62.2	69.6	75.2	84.2	91.8

	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Standard Monthly Average ETo[a]	8.26	7.48	5.72	3.99	2.07	1.32	57.53
Average Rainfall (inches)[b]	0.00	0.01	0.06	0.28	0.38	0.65	5.39
Average Max. Temperature (Fahrenheit)[c]	98.4	97.3	91.8	79.6	66.1	58.4	77.7

Notes:
(a) ETo (evapotranspiration) data: Station 5 Shafter/USDA station, http://www.cimis.water.ca.gov/
(b) Average Monthly Rainfall data gathered from long-term average precipitation records from Taft gage (048752) during period 1948-2012. http://www.wrcc.dri.edu/
(c) Temperature data from long-term average precipitation records from Taft gage (048752) during period 1948-2012, http://www.wrcc.dri.edu/

3.2 Service Area Population and Demographics

Legal Requirements:

CWC Section 10631 (a)
Describe the service area of the supplier, including current and projected population . . . The projected population estimates shall be based upon data from the state, regional, or local service agency population projections within the service area of the urban water supplier and shall be in five-year increments to 20 years or as far as data is available.

The District service area includes the cities of Taft and Maricopa, together with the Westside communities of Taft Heights, South Taft, Ford City, Tupman, Dustin Acres, Valley Acres, Fellows and McKittrick. The Taft Sphere of Influence (planning area) includes the City of Taft and the unincorporated communities of South Taft, Taft Heights, and Ford City. This Sphere of Influence area accounts for the majority of the District's domestic water deliveries. The District also provides water to two correctional facilities which house approximately 2,860 inmates plus the prison workers. WKWD provides water to all virtually all residents within the District boundary. As a result, the total district population is equivalent to the population served water.

The 2010 UWMP had an estimated population of 18,048; however, this has been updated to 20,760 using 2010 Census Data (see Section 5.3 – Service Area Population for more details). The 2015 UWMP and this 2020 UWMP both assume that population growth would be slow, at a rate of about 0.4%/year. This rate is assumed into the future due to several factors that limit population growth. The low population growth within Taft is highly influenced by the lack of available property. Oil companies and government agencies control the majority of the land surrounding Taft, and land for development is generally not for sale.

The 2020 population estimate is based on an evaluation of the "persons per active residential connection" population method. Using the 2010 population, and number of residential connection in 2010, the persons per household is 20,760 residents/5,947 residential connections = 3.49 residents/connection. This results in a 2020 population estimate of 3.49 residents/connection x 6,353 residential connections in 2020 = 22,172. This is considered a reasonable method to estimate population. Using this method, the population growth was close to zero. The table below shows the anticipated District population through 2045, assuming a population growth rate of 0.4%, the same

growth rate assumed in the 2010 UWMP. The table also reflects a population loss of 512 in 2025 due to the closure of the Taft Community Correctional Facility in May 2021. This is based on the facility having 512 beds.

Table 3-3: Population – Current and Projected

Year	2020	2025	2030	2035	2040	2045
Service Area Population[1]	22,172	22,097	22,542	22,997	23,460	23,933

[1] *Service area population is defined as the population served by the distribution system.*

4 System Water Use

This section discusses current and anticipated water deliveries to different water use sectors, the methodology used in estimating future uses, a discussion on system water losses, and estimated water use for lower income households.

4.1 Recycled versus Potable and Raw Water Demand

The District delivers disinfected groundwater to residential, commercial and industrial customers. Raw water from the SWP is delivered directly to one industrial customer, the La Paloma Power Co. LLC (La Paloma). Wastewater effluent from the local wastewater treatment facility is currently used to irrigate fodder crops on adjacent agricultural land. The recycled water is not used to meet District demands, since the District does not provide irrigation water. The District evaluated a recycled water program but found it to be economically unfeasible (see **Section 6.7**). **Table 4-1** shows the current and estimated future demands for potable, raw and recycled water through 2040.

Table 4-1: Retail: Total Water Demands

Description	2020	2025	2030	2035	2040	2045
Potable Water	14,300	13,818	13,907	13,998	14,090	14,185
Raw Water	1,571	3,000	3,000	3,000	3,000	3,000
Recycled Water Demand	0	0	0	0	0	0
Losses	467	538	541	544	547	550
TOTAL WATER DEMAND	16,338	17,356	17,448	17,542	17,637	17,735

1 – Potable Water Demands = Residential, commercial and treated industrial water uses
See Section 4.2 below for details on how future water demands were estimated.

4.2 Water Use by Sector

Legal Requirements:

CWC 10631(e)
(1) Quantify, to the extent records are available, past and current water use, over the same five-year increments described in subdivision (a), and projected water use, identifying the uses among water use sectors, including, but not necessarily limited to, all of the following uses:
(A) Single-family residential.
(B) Multifamily.
(C) Commercial.
(D) Industrial.
(E) Institutional and governmental.
(F) Landscape.
(G) Sales to other agencies.
(H) Saline water intrusion barriers, groundwater recharge, or conjunctive use, or any combination thereof.
(I) Agricultural.
(2) The water use projections shall be in the same five-year increments described in subdivision (a).

This section describes historic and current water usage and the methodology used to project future demands within WKWD's service area. Water usage is divided into five sectors: residential, commercial, industrial (treated), industrial (raw water), and system losses. All water deliveries in WKWD are metered.

Figure 4-1 shows water usage in 2020 according to several water use categories. Industrial water has been the major water demand for many years and comprised about 75% of water demands from 2016-2020.

The District's billing system includes some large landscape water usage under the Industrial billing category. These include accounts for the local golf course (club house and turf irrigation), A.W. Noon Park, and Buena Vista Lake Recreation Park. To be consistent with UWMP reporting criteria, these demands (721 AF) were moved to the Commercial category for the per capita demand analysis presented in Section 5. Hence, the values shown for 2020 differ slightly from official district records, but include the same overall water use. These landscape demands do not include all large landscape water usage, since some is already billed under the Commercial category, and since some Commercial water users do not have dedicated irrigation meters.

Furthermore, the District serves water to two prisons, one federal and one community facility. The Federal Taft Correctional Institution (Federal Prison) water usage is billed to the Industrial category. This Federal Prison had a population of about 2,260 inmates in 2015 and has steadily decreased since that time (based on personal communication with prison staff). Water use for the Federal Prison is included in the Industrial Category. This facility temporarily closed in May 2020 for renovations, however, the inmate population when the prison reopens is unknown at this time. These demands (75 AF in 2020) were also moved to the Commercial category for per capita demand analyses.

The Taft Community Correctional Facility is a local facility with an estimated population of 512 (based on having 512 beds). The water usage for this facility is included in the Commercial category. This

facility closed permanently May 2021 with minimal water required for ground maintenance in the future.

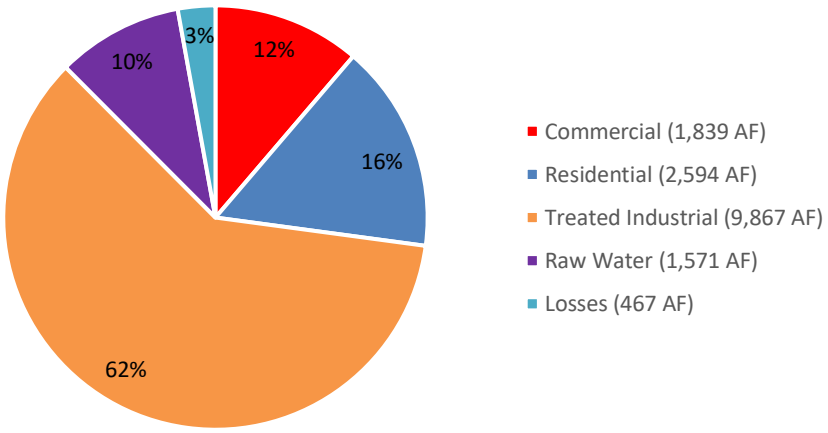

Figure 4-1: 2020 Annual Water Usage

Table 4-2 shows the actual 2020 water usage and projected demand for the planning period (up to 2045).

Table 4-2: Retail: Demands for Potable and Raw Water – Actual and Projected

Use Type	2020 Actual			2025	2030	2035	2040	2045
	Number of Connections	Level of Treatment	Volume					
Residential	6,353	Disinfection	2,594	2,585	2,637	2,690	2,744	2,800
Commercial	607	Disinfection	1,839	1,833	1,870	1,908	1,946	1,985
Industrial –Treated	379	Disinfection	9,867	9,400	9,400	9,400	9,400	9,400
Industrial – Raw (La Paloma Deliveries)	1	None	1,571	3,000	3,000	3,000	3,000	3000
Fire Protection	13	Disinfection	Not metered	-	-	-	-	-
Losses	NA	-	467	538	541	544	547	550
Total	7,379	-	16,338	17,356	17,448	17,542	17,637	17,735

The 2020 data in **Table 4-2** includes the most complete breakdown of water use available with District records. For instance, the District does not track single-family home usage versus multi-family home usage.

Future water demand estimates were based on the following criteria and assumptions:

1. In 2025 and beyond, residential and commercial demands are based on the 2020 water usage multiplied by the population growth rate (0.4% per year).
2. The net population is estimated to decline by 0.34% from 2020 to 2025 due to the anticipated closure of the State Prison. This results in a drop in residential and commercial water use of 0.34% for the entire 5-year period from 2020 to 2025, After 2025, water use is expected to grow at a rate of 0.4% per year.
3. Raw water demands to La Paloma will be a constant 3,000 AF/year in future years (their total contract supply is 5,500 AF/year)
4. Treated industrial demands remain constant over time due to conservation efforts and assumed limited growth in the industrial sector. They are assumed to be the average of 2016 to 2020 usage, or 9,400 AF/year.
5. Losses are estimated to be 3.2% of total deliveries, based on the actual loss rate in 2020 (groundwater pumping – deliveries).

Several other factors can affect demand projections, which are not included in the estimate above, including:

- Land use revisions
- New regulations
- Consumer choice
- Economic conditions
- Oil prices and oil demand
- Transportation needs
- Highway construction
- Environmental factors
- Conservation programs
- Plumbing codes

The foregoing factors affect the amount of water needed, as well as the timing of when it is needed. Past experience has indicated that the economy is the biggest factor in determining water demand projections. During an economic recession, there is a major downturn in development and a subsequent slowing of the projected demand for water. The projections in this Plan do not attempt to forecast recessions or droughts. Likewise, no speculation is made about future plumbing codes or other regulatory changes. Also, much of the industrial water demand is used by oil exploration companies. Predicting the oil economy and subsequent demand for water in the oil fields is not feasible.

4.3 Distribution System Water Losses

Legal Requirements:

CWC 10631(e)(1) and (2)
Quantify, to the extent records are available, past and current water use over the same five-year increments described in subdivision (a), and projected water use, identifying the uses among water use sectors, including, but not necessarily limited to, all of the following uses:…(J) Distribution system water loss
CWC 10631 (e)(3)
(A) For the 2015 urban water management plan update, the distribution system water loss shall be quantified for the most recent 12-month period available. For all subsequent updates, the distribution system water loss shall be quantified for each of the five years preceding the plan update.
(B) The distribution system water loss quantification shall be reported in accordance with a worksheet approved or developed by the department through a public process. The water loss quantification worksheet shall be based on the water system balance methodology developed by the American Water Works Association.

District water losses can be estimated using two different methodologies:

1. **Difference in Well Pumping and Customer Meter Readings.** This methodology was used resulting in the following estimated losses.

Table 4-3: System Losses (Groundwater Pumping minus Deliveries)

Year	Losses (AF)	Percent Loss
2016	2,325	14%
2017	2,485	16%
2018	2,474	16%
2019	481	3%
2020	467	3%

The District began using a new accounting software program in 2016. They were still learning the new program when the system was breached in 2017. The records were rebuilt in 2018, although some items were not included in the rebuild. As a result, the system losses reported for 2019 and 2020 are considered more accurate and typical for the water system. The District is continuously looking for ways to reduce water losses by implementing new programs and techniques (annual in-field meter calibrations, leak detection, meter testing, etc.)

2. **AWWA Water Audit Software.** System water losses were calculated using AWWA Free Water Audit Software (see results in **Appendix F**). The software uses inputs from volume of water supplied, volume of water delivered, metering error percentage, and metering confidence levels to calculate apparent, unauthorized, and real losses.

   The software assumes 1.25% of the total volume supplied is used for authorized, unmetered activities such as line flushing for mains and hydrants and firefighting.

   The difference between volume supplied and volume delivered plus the unmetered consumption is the calculated loss. This value is then broken into apparent loss (caused by

metering errors and data handling inaccuracies) and real loss, leakage, and unauthorized unmetered water consumption.

The table below shows the estimated losses using the AWWA audits. The 2020 losses were estimated as the average of the 2016-2019 losses. The 2020 audit is not due until October 2021 and is therefore not available.

Table 4-4: AWWA Water Audit Results

Year	Estimate Losses (AF/yr)	Losses (% of deliveries)
2016	2,068	13%
2017	2,486	16%
2018	357	2%
2019	1,310	8%
2020[1]	1,555	11%
Average	1,555	10%

1 – The 2020 water audit was not completed yet and was based on the average losses from 2016-2019.

The District was also given Water Audit Data Validity Scores ranging from 50 to 67, with an average of 59. This index scores the validity of the water use data based on factors such as metering, meter calibration, data management, auditing of customer records, etc. As stated above, the more recent water losses are considered more accurate.

4.4 Water Savings from Codes, Standards, Ordinances, or Transportation/Land Use Plans

Legal Requirements:

CWC §10631 (e)(4)
(A) If available and applicable to an urban water supplier, water use projections may display and account for the water savings estimated to result from adopted codes, standards, ordinances, or transportation and land use plans identified by the urban water supplier, as applicable to the service area.
(B) To the extent that an urban water supplier reports the information described in subparagraph (A), an urban water supplier shall do both of the following: (i) Provide citations of the various codes, standards, ordinances, or transportation and land use plans utilized in making the projections.(ii) Indicate the extent that the water use projections consider savings from codes, standards, ordinances, or transportation and land use plans. Water use projections that do not account for these water savings shall be noted of that fact.

The West Kern Water District has adopted policies and ordinances to reduce water waste. These ordinances and policies are better described in Sections 8 and 9. The District also meets its 2020 per capita goal, as described later in Section 5, and intends to continue meeting this goal.

Water savings from codes, standards, ordinances, or transportation and land use plans are also known as "passive savings." These various factors generally decrease the water use for new and future customers, compared to historical customers. These codes and ordinances may include

implementation of a landscape ordinance, the California Energy Commission Title 20 appliances standards for toilets, urinals, faucets, and showerheads, CALGreen Building Code, etc. Enforcing some of these standards is outside the jurisdiction of WKWD.

Passive savings have not been specifically incorporated into projected water demands. Instead, future water demands are projected based on population and the District's target per capita water use, as documented in Section 5, and discussed above. However, the District does expect that passive savings, such as continued implementation of water conservation efforts, rebate programs and modern plumbing codes will help the District continue to meet its target per capita water demand in the future.

4.5 Water Use for Lower Income Households

Legal Requirements:

> ***CWC 10631.1(a)***
> *The water use projections required by Section 10631 shall include projected water use for single family and multifamily residential housing needed for lower income households, as defined in Section 50079.5 of the Health and Safety Code, as identified in the housing element of any city, county, or city and county in the service area of the supplier.*
> *California Health and Safety Code 50079.5 (a)*
> *"Lower income households" means persons and families whose income does not exceed the qualifying limits for lower income families… In the event the federal standards are discontinued, the department shall, by regulation, establish income limits for lower income households for all geographic areas of the state at 80 percent of area median income, adjusted for family size and revised annually.*

Senate Bill 1087 requires that water use projections of an UWMP include the projected water use for single-family and multi-family residential housing for lower income households as identified in the local housing element or general plan.

Housing elements rely on the Regional Housing Needs Allocation Plan (RHNA) generated by the State Department of Housing and Community Development (HCD) to allocate the regional need for housing. Before the housing element is due, the HCD determines the total regional housing need for the next planning period for each region in the state, and allocates that need. The Kern Council of Governments (COG) then allocates to each local jurisdiction its "fair share" of the RHNA, broken down by income categories; very low, low, moderate, and above moderate, over the housing element's planning period. The current housing element (Kern COG, 2016) covers the planning period 2015-2023. Based on an evaluation of census block group data in the report, 6,880 people are identified as low and very low income in WKWD. This represents 6,880/22,172 = 31.0% of the population. This is close to the 30.7% of residents that were classified as low and very low income in the 2015 UWMP.

Table 4-5 shows the current and estimated future water demands for low-income households.

Table 4-5: Low-Income Projected Water Demands (units in AF)

Low Income Water Demands	2020	2025	2030	2035	2040	2045
Total Residential Demand	2,594	2,585	2,637	2,690	2,744	2,800
Low Income Demand (31%)	804	801	817	834	851	868

5 Baseline and Targets

This section describes the baseline (base daily per capita) water use, the 2015 and 2020 water use targets, and the 2020 actual water use. For additional details on how the per capita goals were established refer to the District's 2015 UWMP.

The UWMPA requires that the UWMP identify a baseline water demand, urban water use target, and interim urban water use target for the District.

Legal Requirements:

CWC § 10608.20
(e) An urban retail water supplier shall include in its urban water management plan . . . due in 2010 the baseline daily per capita water use, urban water use target, interim urban water use target, and compliance daily per capita water use, along with the bases for determining those estimates, including references to supporting data.

The base daily per capita use was the first step in determining the District's urban water use target. The historical per capita use set the "baseline" on which the urban water use target was determined. The District established an Interim 2015 water use target and a subsequent 2020 urban water use target to judge compliance with the 2020 use reductions set forth in the Water Conservation Bill of 2009.

5.1 SB X7-7 Forms and Summary Tables

The District calculated its baseline and targets in the 2010 and 2015 UWMPs and will use these previously calculated values to determine compliance with SB X7-7. The following subsections present the SB X7-7 Verification and Compliance forms, as discussed in the 2020 UWMP Guidebook.

The 2015 UWMP included a complete SB X7-7 Verification Form, which is provided for reference in **Appendix C**. The Verification Form is the set of spreadsheets documenting SB X7-7 calculations.

This 2020 UWMP includes a complete 2020 Compliance Form, as required, included in **Appendix C**. The District's 2020 Compliance Water Use Target was set in the 2015 UWMP at 189 gallons per capita per day (gpcd). The District does not need to modify that target based on any reasons provided in the 2020 UWMP Guidebook and will use the target to document compliance with SB X7-7. The District achieved a per capita water use of 185 gpcd in 2020, thereby meeting the Compliance Water Use Target set in the 2015 UWMP.

In addition to reporting compliance on the SB X7-7 Compliance Form, the District is also required to report compliance on the DWR Submittal Tables, 5-1 and 5-2, shown below.

Table 5-1: Baselines and Targets Summary

Baseline Period	Start Year	End Year	Average Baseline GPCD	Confirmed 2020 Target
10-15 year	2000	2009	237	189
5 Year	2005	2009	248	

Table 5-2: 2020 Compliance

2020 GPCD			2020 Confirmed Target GPCD	Did Supplier Achieve Targeted Reduction for 2020? Y/N
Actual 2020 GPCD	2020 TOTAL Adjustments	Adjusted 2020 GPCD *(Adjusted if applicable)*		
185	0	189	189	YES

5.2 Baseline and Target Calculations for 2020 UWMPs

WKWD has a unique water profile with approximately 75% of the water delivered to industrial customers. Per DWR guidelines for the calculation of gpcd, WKWD is permitted to subtract all industrial (process) deliveries to determine gross water use. Most industrial water supplies were therefore excluded in the per capita demand analyses, however, based on DWR revisions to the 2015 UWMP, water usage for the Federal Taft Correctional Institution and some landscape water demands were included (see **Section 4.2** for additional explanations).

Thus per capita demands were based on the commercial and residential demands (which included 796 AF moved from the industrial to commercial category) and 3.2 percent losses based on actual losses in 2020. Using a 2020 population of 22,172, the per capita water use is 185 gallons/day.

The District did not adjust its compliance GPCD using weather normalization, economic adjustment, distribution area expansion, distribution area contraction, or other extraordinary events. No deductions were made for exported water, change in distribution system storage, indirect recycled water, or water delivered for agricultural use. Gross water usage was based on customer meter readings and estimated losses. However, the District does feel that per capita water usage may have been lower if numerous opportunities to promote water conservation had not been cancelled in 2020 due to the COVID pandemic.

5.3 Historical Per Capita Water Use

Figure 5-1 below shows the per capita water use in WKWD from 2000 to 2020. The District has shown a gradual decline in per capita water use over the last 15 years and now meets their per capita water use goal.

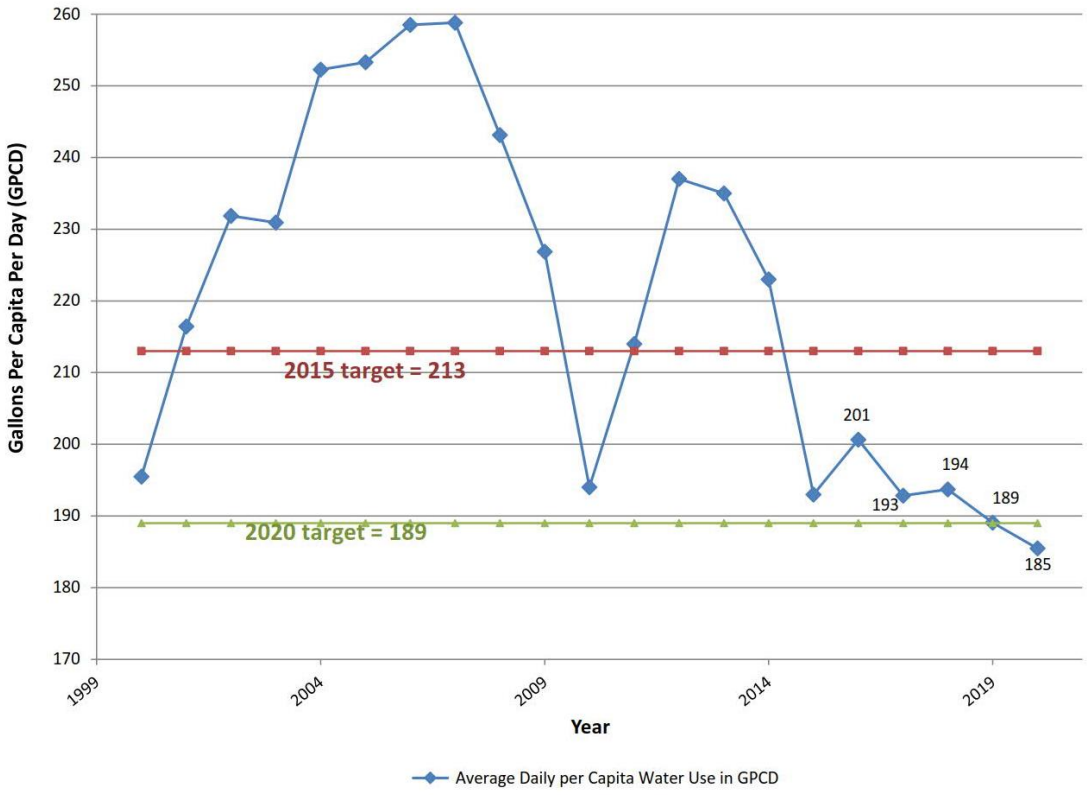

Figure 5-1: Daily Per Capita Water Use (2000-2020)

5.4 Other Factors Affecting Water Usage

Major factors that affect in the District are weather and the implementation of water conservation strategies. Historically, when the weather is hot and dry, water usage increases. The amount of increase varies according to the number of consecutive years of hot, dry weather and the conservation activities imposed. During cool-wet years, historical water usage has decreased to reflect less water usage for external landscaping. Water conservation measures employed within the WKWD service area will have a direct long-term effect on water usage.

In recent years, water conservation has become an increasingly important factor in water supply planning in California. The California plumbing code has instituted requirements for new construction that mandate the installation of ultra-low-flow toilets and low-flow showerheads. These code requirements are overseen by the City of Taft. WKWD continues to support the development

of water conservation measures and continually improve upon its conservation plan. Programs supported by WKWD include public information and education programs, metering programs, conservation coordination, water waste prevention, implementation of AWWA M36 methodology, and conservation pricing. A complete description of these programs and their implementation can be found in Section 9.

Residential, commercial, and industrial usage can be expected to decrease as a result of the implementation of more aggressive water conservation practices. The greatest opportunity for conservation is in developing greater efficiency and reduction in landscape irrigation especially in WKWD's service area where the evapotranspiration rate is high. The irrigation demand can represent as much as 50 percent of the water demand for residential customers depending upon lot size and amount of irrigated turf and plants.

6 System Supplies

Legal Requirements:

§10631(b) Identify and quantify, to the extent practicable, the existing and planned sources of water available to the supplier over the same five-year increments described in subdivision (a).

UWMPA requirements state that the water supplier must describe their existing and planned water supply sources for the next 20 years. The following description includes information on water contracts, surface water, groundwater, water quality, recycled water, exchanges and transfers, future water projects, and future water supplies.

6.1 Water Supply Facilities

Water supply facilities in the District include 13 wells (5 in the North Well Field and 8 in the South Well Field), 26 water tanks, and about 346 miles of pipelines. **Appendix C** includes a map of the District's facilities. The facilities are spread out over the entire district, which covers over 300 square miles.

6.2 Imported Water

The District has a contract to receive surface water from the SWP. The SWP is the largest state-built, multi-purpose water project in the country. It was authorized by the California State Legislature in 1959, with the construction of most initial facilities completed by 1973. Today, the SWP includes 28 dams and reservoirs, 26 pumping and generating plants, and approximately 660 miles of aqueducts. The primary water source for the SWP is the Feather River, a tributary of the Sacramento River. Storage released from Oroville Dam on the Feather River flows down natural river channels to the Sacramento-San Joaquin River Delta (Delta). While some SWP supplies are pumped from the northern Delta into the North Bay Aqueduct, the vast majority of SWP supplies are pumped from the southern Delta into the 444-mile-long California Aqueduct. The California Aqueduct conveys water along the west side of the San Joaquin Valley to Edmonston Pumping Plant, where water is pumped over the Tehachapi Mountains and the aqueduct then divides into the East and West Branches.

In the early 1960s, DWR began entering into individual SWP Water Supply Contracts with urban and agricultural public water supply agencies located throughout northern, central, and southern California. Kern County Water Agency (KCWA) is one of 29 water agencies (commonly referred to as "contractors") that have an SWP Water Supply Contract with DWR. Each contractor's SWP Water Supply Contract contains a "Table A" quantity, which lists the maximum amount of water an agency may request each year throughout the life of the contract. Table A is used in determining each contractor's proportionate share, or "allocation," of the total SWP water supply DWR determines to be available each year. The total planned annual delivery capability of the SWP and the sum of all contractors' maximum Table A amounts was originally 4.23 million acre-feet (MAF). The initial SWP storage facilities were designed to meet contractors' water demands in the early years of the SWP, with the construction of additional storage facilities planned as demands increased. However, essentially no additional SWP storage facilities have been constructed since the early 1970s. SWP conveyance

facilities were generally designed and have been constructed to deliver maximum Table A amounts to all contractors. After the permanent retirement of some Table A amounts by two agricultural contractors in 1996, the maximum Table A amounts of all SWP contractors now totals about 4.17 MAF.

WKWD contracted with KCWA in 1966 to receive an allotment of water through the SWP. KCWA holds a master contract with the State to receive water from the SWP. WKWD and 15 other local water districts, called member units, subcontract with KCWA. Currently, KCWA's annual Table A amount is 998,730 AF; of that amount WKWD is allocated **31,500 acre-feet per year (AFY)**. While these amounts represent the maximum amount of water that these two agencies can request, DWR determines the amount that will actually be delivered in a given year. The reliability of SWP is now estimated to be 59% in 2020 (see **Section 7.3**).

During wet years when high-flow water is available, an additional 10,000 AFY is available to WKWD. Historically, this high-flow water has been purchased or exchanged by WKWD to increase the storage in water banking program. The surface water indirectly available to WKWD consists of in-lieu surface water delivered to Buena Vista Water Storage District (BVWSD) and credited to WKWD as a banked supply . This water is either SWP water or high-flow Kern River water. The surface water is not currently used as a direct domestic water supply source.

WKWD also has two turnouts along the California Aqueduct that have been used to deliver untreated water directly to industrial customers. Currently only one of the turnouts, which supplies untreated water to La Paloma, is operated by the District,. An agreement was established in 2000 between WKWD and La Paloma for a maximum delivery of 6,500 AFY. Historically La Paloma has taken less than 6,500 AFY and WKWD utilizes the balance of the water for recharge to its water banking program or exchanges with other entities.

Appendix J includes a Reduced Delta Reliance analysis, which concludes that the District expects future SWP water demands to be less than historical baseline demands.

6.3 Surface Water

There are no natural surface water features in WKWD, largely due to the arid conditions. Surface water used in WKWD is imported from the SWP in Northern California, or from the Kern River.

6.4 Groundwater

This section presents information on WKWD's groundwater supplies including the local hydrogeology, groundwater levels, groundwater wells, groundwater quality and monitoring.

The 2015 Sustainable Groundwater Management Act (SGMA) requires governments and water agencies of high and medium priority basins to halt overdraft and bring groundwater basins into balanced levels of pumping and recharge. SGMA empowers local agencies to form Groundwater Sustainability Agencies (GSAs) to manage basins sustainably and requires those GSAs to adopt Groundwater Sustainability Plans (GSPs) for crucial groundwater basins in California.

In 2016 the WKWD GSA was formed for the WKWD service area. The GSA was later expanded to include non-districted areas in and around the WKWD service boundary. In January 2020 the WKWD GSA submitted a Management Area Plan (MAP) that describes projects and actions the WKWD GSA will pursue to sustainably manage groundwater in its portion of the Kern County Subbasin. WKWD GSA's MAP is part of a Subbasin-wide GSP for the Kern County Subbasin, that includes MAPs for several other GSAs and water districts. A copy of the GSP can be found at https://www.wkwd.org/menus/groundwater-sustainability-plan.html.

6.4.1 Groundwater Basin Description

Legal Requirements:

> ***CWC 10631 (b)*** *If groundwater is identified as an existing or planned source of water available to the supplier, all of the following information shall be included in the plan: (2) A description of any groundwater basin or basins from which the urban water supplier pumps groundwater.*

WKWD is located within the Tulare Lake Hydrologic Region (Region), San Joaquin Valley Groundwater Basin (see **Table 6-1**). The Region has 12 distinct groundwater basins and 7 subbasins of the San Joaquin Valley Groundwater Basin: Kings, Westside, Pleasant Valley, Kaweah, Tulare Lake, Tule, and Kern County. The interconnected depositional basins are grossly separated by a basement high known as the Bakersfield Arch, which trends roughly along and parallel to the Kern River. The District is within the Kern County Groundwater Sub-basin. The Sub-basin encompasses roughly 3,040 square miles and is bounded by the Sierra Nevada foothills on the east, the Tehachapi and San Emigdio Mountains and White Wolf Subbasin on the south, the Temblor Range on the west, and portions of the KGA jurisdictional boundary to the north. The Kettleman Plain, Tulare Lake and Tule sub-basins border the KGA jurisdictional line to the north. The WKWD area overlies the southwestern portion of the Sub-basin, along the western edge of Kern County, roughly 30 miles west of metropolitan Bakersfield.

According to Department of Water Resources, California Bulletin 118, the basin is in a water-short condition. It is also a non-adjudicated basin. It receives its recharge from the Kern River which traverses through a wide, flat bed. In the riverbed are 500 to 2,000 foot thick poorly sorted deposits of silt, sand, rock, and clay that originated from the Sierra Nevada, and that provide moderate to high permeability through the riverbed. Historically, floodwaters that overflowed on lands on both sides of the river contributed further to groundwater recharge. Although natural recharge is primarily from stream seepage along the eastern subbasin and the Kern River; recharge of applied irrigation water is the largest contributor to the recharge of the subbasin.

Table 6-1: San Joaquin Valley Groundwater Basin

Groundwater Basin	DWR Groundwater Basin Number	Surface Area (acres)	Groundwater Storage Capacity (1,000 AF)
San Joaquin Valley Groundwater Basin	5-22.14	1,945,000	4,000

The San Joaquin Valley is surrounded on the west by the Coast Ranges, on the south by the San Emigdio and Tehachapi Mountains, on the east by the Sierra Nevada and on the north by the Sacramento-San Joaquin Delta and Sacramento Valley. The northern portion of the San Joaquin Valley drains toward the Delta by the San Joaquin River and its tributaries, the Fresno, Merced, Tuolumne, and Stanislaus Rivers. The southern portion of the valley is internally drained by the Kings, Kaweah, Tule, and Kern Rivers that flow into the Tulare drainage basin including the beds of the former Tulare, Buena Vista, and Kern Lakes.

The geologic history and geometry of the valley is one of a continually sinking basin being filled with sediment. The sediment was supplied to the basin by the rising Coast Ranges (San Emigdio Mountains), the Transverse Ranges (Tehachapi Mountains), and the Sierra Nevada. The District produces groundwater from its South Well Field in the Tupman area, about 15 miles northeast of Taft, and the new North Well Field, located about three miles northwest of the South Well Field. The geologic units underlying the valley, and which are present underneath the District's wellfield area, are generally grouped into three broad categories. These include the crystalline rocks of ·pre-Tertiary age (>65 million years old), the marine sedimentary rocks of Tertiary age (from 65 million to roughly 20 million years old), and the continental sedimentary deposits of Tertiary and Quaternary age (20 million years old to present). Generally, the crystalline rocks and the marine deposits are non-waterbearing rocks in this area, and play no significant role in the ability of the District to produce groundwater.

Overlying the crystalline rocks and the marine sedimentary rocks is a thick sequence of continental, semi-consolidated to unconsolidated sediments. These continental sediments are several thousand feet thick in the thickest portions of the basin, near the central part of the San Joaquin Valley. Along the fringe of the basin, or on top of the Bakersfield Arch, the sediments are considerably thinner.

In the area of the District's wellfield, the continental rocks consist of the Plio-Pleistocene Tulare Formation, a thick sequence of water-laden sands, silts, and clays. Throughout much of the San Joaquin Valley, the Tulare Formation contains a regionally extensive lacustrine or lakebed clay, generally referred to as Corcoran Clay, which serves as a confining layer separating the shallow semi-confined to unconfined aquifer system from a deeper confined aquifer system. The water-producing portion of the groundwater basin is within the upper sections of the continental deposits and the overlying alluvium. The hydrogeology of the basin above the base of fresh water is an alluvial fan complex deposited by the Kern River.

6.4.2 Groundwater Management

Legal Requirements:

> ***CWC 10631 (b)*** *If groundwater is identified as an existing or planned source of water available to the supplier, all of the following information shall be included in the plan:*
> *A copy of any groundwater management plan adopted by the urban water supplier… or any other specific authorization for groundwater management.*
> *…For basins that a court or the board has adjudicated the rights to pump groundwater, a copy of the order or decree adopted by the court or the board and a description of the amount of groundwater the urban water supplier has the legal right to pump under the order or decree.*

The WKWD Groundwater Sustainability Agency (WKWD GSA) prepared a Management Area Plan (MAP), dated December 2019, to comply with the Sustainable Groundwater Management Act

(SGMA). The WKWD GSA jurisdictional area is defined by the District service area boundary with some additional proximal parcels owned and operated by oil production companies and other private landowners.

Continuous review of banking practices is necessary, and enables the District to gain the maximum benefit of its groundwater banking and water exchange efforts. WKWD continues to pursue active recharge programs that result in positive water level and water quality benefits. In an effort to expand the local recharge programs, evaluation of groundwater banking opportunities in areas surrounding the District's well fields and coordination with those entities is an on-going effort.

Water quality monitoring results will be used to augment the information obtained from historical water level readings. The combination of routine water quality monitoring and groundwater level measurements, allow the District to effectively manage its groundwater supply.

Hydrogeologic Basin Assessment

The District is within the Kern Groundwater Sub-Basin. The WKWD MAP , which is part of an overall umbrella GSP for the entire Sub-basin, included a hydrogeologic assessment of WKWD's portion of the subbasin . Elements of the MAP included:

- Compilation of historical data;
- Determination of the hydraulic parameters and characteristics of the basin that govern groundwater flow (and contaminant transport); and
- Evaluation of the recharge and discharge components of the basin that affect the ability of the District to pump water

Conjunctive Use Program

WKWD has historically practiced conjunctive water use, integrating surface and groundwater supplies, to meet current and future demand. Continuing this proactive approach will require an objective review of past and future procedures, including a review and assessment of:

- The effectiveness of past surface water recharge efforts.
- The effectiveness and impacts of recharge efforts conducted by neighboring groundwater users.
- The role WKWD will take in future conjunctive use programs.
- The continuing participation in banking and exchange programs currently in effect.
- The siting and construction of new or additional recharge facilities.
- WKWD efforts to maximize the amount and quality of surface water available for recharge purposes.
- Programs that stress water conservation efforts throughout WKWD.
- Existing and new domestic users landscape irrigation methods.
- Reuse of industrial water.
- Encouraging the use of domestic water saving devices.

Well Field Evaluation

The physical condition of WKWD's production wells is routinely evaluated and documented to identify potential issues related to the structural integrity and any change in production. WKWD

maintains a regular rehabilitation maintenance program designed to effectively evaluate and enhance well performance. Any issues are addressed immediately.

Monitoring Plan

In addition, as a member of the Kern Groundwater Authority, WKWD participates in a coordinated groundwater monitoring program the requires participants measure groundwater levels and collect groundwater quality samples from January 15 through March 30, and again from September 15 to November 15. WKWD is also required to conduct routine monitoring under their drinking water permit.

Groundwater Contamination Management

Groundwater contamination from anthropogenic or natural sources is one of paramount concern to WKWD.. Sources of contamination include, but are not limited to, leaking petroleum storage and distribution facilities, fertilizers or pesticides and septic systems. Although WKWD continues to meet water quality requirements of the SWRCB Division of Drinking Water, Drinking Water Source Assessment Program, the District will continue to assess the potential for source water contamination. Effective control of contamination problems will require:

- Coordinated efforts between all regulatory agencies
- Source control
- A comprehensive understanding of the regional hydrogeology
- Identifying sources of contamination.

6.4.3 Groundwater Levels and Overdraft Conditions

Legal Requirements:

CWC 10631(b)(2).*For basins that have not been adjudicated, (provide) information as to whether the department has identified the basin or basins as overdrafted or has projected that the basin will become overdrafted if present management conditions continue, in the most current official departmental bulletin that characterizes the condition of the groundwater basin, and a detailed description of the efforts being undertaken by the urban water supplier to eliminate the long-term overdraft condition.*

The Kern Groundwater Sub-Basin was identified as being "critically overdrafted" by the California Department of Water Resources (DWR, 2003). DWR also identified the basin as "High Priority" (through the State's CASGEM Basin Prioritization Process) due to overdraft, land subsidence and groundwater quality degradation. Similarly, the Kern Groundwater Sub-basin has been designated by SGMA as a high priority.

Figure 6-1 is a representative hydrograph in the District's South Well Field. The past 5 years (2015 to 2020) have seen an overall increase in groundwater levels. In the South Well Field, the groundwater level decreased from 2015 to 2016 (approximate end of a multi-year drought) and then increased significantly from 2016 to 2020 when active recharge occurred. By the end of 2019 groundwater levels were near historically high levels for the period of record.

Figure 6-2 is a representative hydrograph in the District's North Well Field. In the North Well Field groundwater levels generally decreased by approximately 25 feet from the summer of 2014 to the summer

of 2016. From the summer of 2016 to the winter of 2019/2020 groundwater levels increased by approximately 85 feet. From the winters of 2019/2020 to 2020/2021 levels fell approximately 12 feet.

WKWD recognizes the benefit of the banking operations and continues to support the efforts of sustainable groundwater management to further reduce declines.

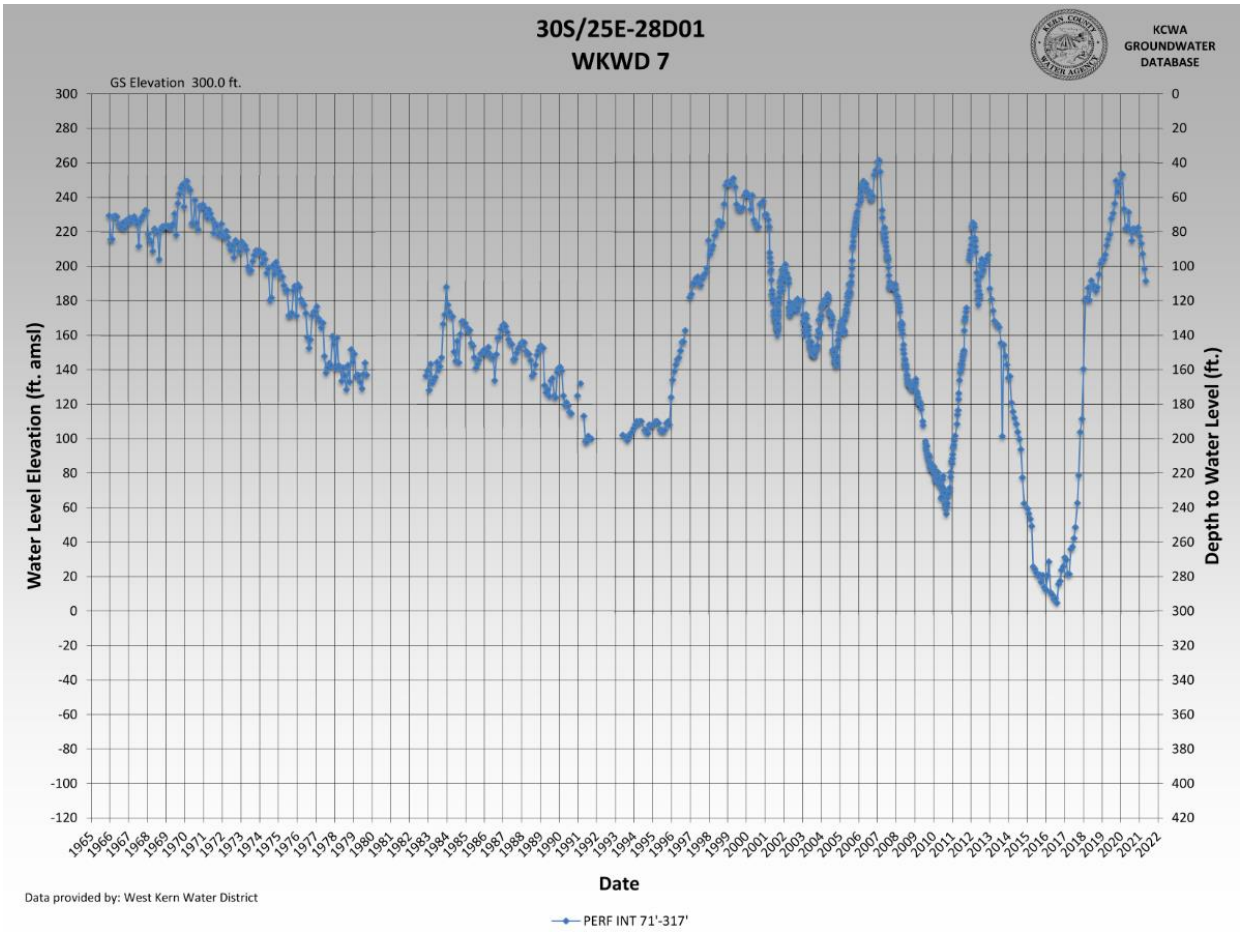

Figure 6-1: Historical Groundwater Levels – South Well Field

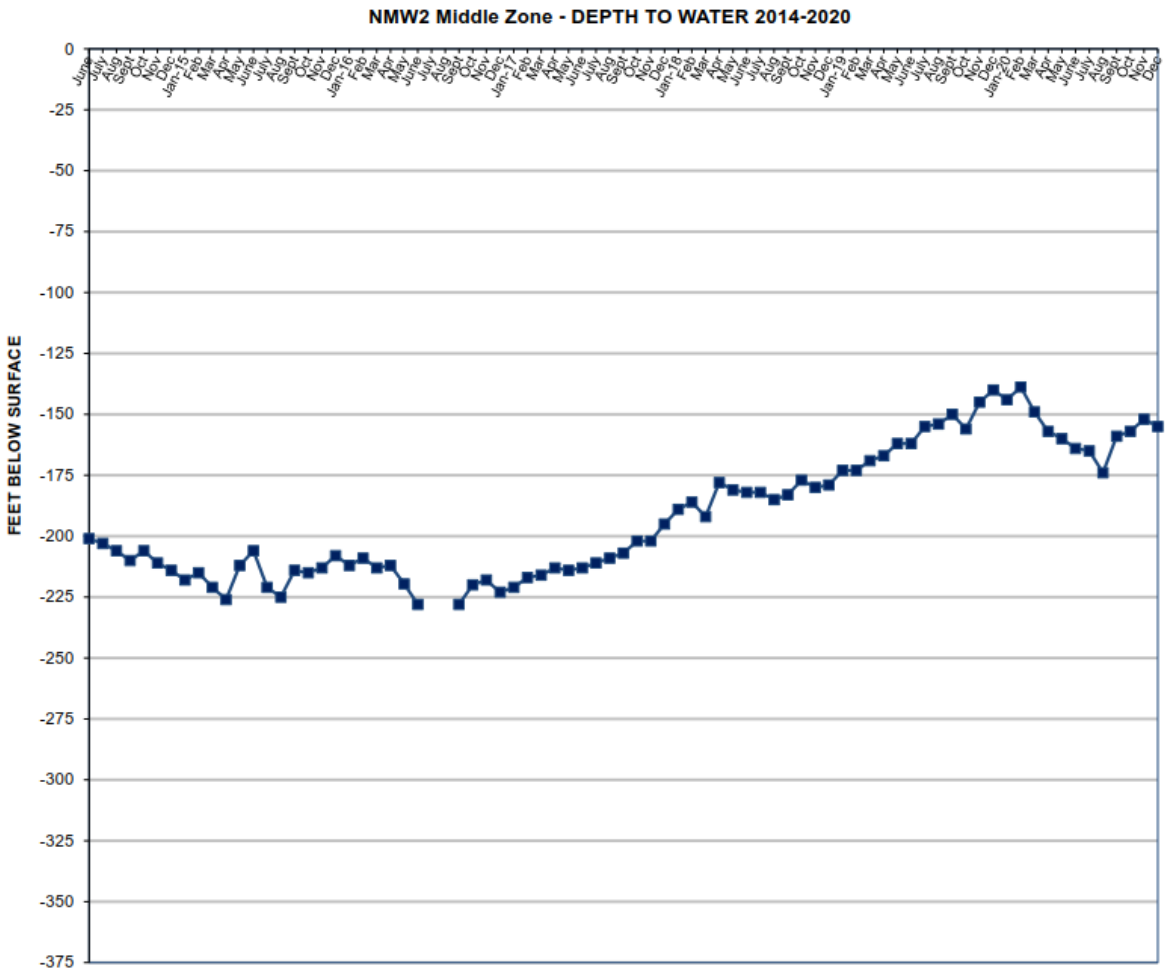

Figure 6-2: Historical Groundwater Levels – North Well Field

6.4.4 Historical Pumping

Legal Requirements:

> ***CWC 10631 (b)*** *If groundwater is identified as an existing or planned source of water available to the supplier, all of the following information shall be included in the plan:*
> *3) (Provide a) detailed description and analysis of the location, amount, and sufficiency of groundwater pumped by the urban water supplier for the past five years. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.*

Estimated groundwater pumping is shown in **Table 6-2**. All water is pumped from an alluvial aquifer, and no water is pumped from fractured bedrock. Water is pumped from the North and South Well Fields, as shown on the map in Appendix C. Groundwater pumping has declined in recent years as numerous conservation measures have been enacted by the District. The total volume pumped saw Approximately 14,275 AF less groundwater was pumped during the five-year period of 2016 to 2020 when compared to five-year period of 2011 to 2015, which was a period of a multi-year drought.

Table 6-2: Groundwater – Volume Pumped

Basin	Sub-Basin	2016	2017	2018	2019	2020
San Joaquin Valley Groundwater Basin	Kern River Alluvial Basin	16,300	15,392	15,765	15,487	14,767
Total (2016-2020)						77,711
Units in Acre-Feet, includes values pumped by WKWD and groundwater transfers						

6.4.5 Groundwater Recharge, Storage, and Banking

KCWA (according to DWR Bulletin 118) estimates total groundwater in storage in the Kern Groundwater Subbasin to be nearly 40,000,000 AF and dewatered storage to be 10,000,000 AF. Water banking by WKWD is performed in the Kern River Fan area and began in 1966. All the surface water deliveries to WKWD are banked and later recovered from wells, except for direct industrial water deliveries to La Paloma.

As part of the banking program WKWD has monitored and recorded groundwater levels in its production wells on a regular basis for several decades. DWR and the KCWA contribute additional water level data in the vicinity of the District's well fields. The compilation of WKWD, KCWA and DWR data provides an understanding of the groundwater flow patterns and trends in water levels.

WKWD delivers the majority of its SWP water by exchange with BVWSD as part of an in-lieu groundwater pumping/groundwater banking exchange program. BVWSD, which is located adjacent to WKWD's well fields, typically delivers water from the Kern River and from local groundwater pumping. In the exchange, BVWSD takes WKWD SWP water from the California Aqueduct for its in-district needs instead of pumping local groundwater. WKWD, in turn, can then pump or bank a volume of water equivalent to that which BVWSD would otherwise have pumped. This source of supply is typically stored Kern River water.

On average WKWD recharged approximately 23,100 AFY from 1976 – 2020. The total amount of water currently stored in WKWD's groundwater banking facilities is approximately 247,545 AF (see **Figure 6-3**). Currently, WKWD maintains a positive balance in its banking program and has approximately 10 years of supply currently banked. Therefore, while the Kern County Groundwater Sub-Basin is in a state of overdraft, WKWD has maintained a net positive balance and helped to reduce the overall overdraft.

Continued balanced pumping of groundwater and recharge of imported supplies has and will continue to be the operational norm for WKWD. Under this management action, recharge and recovery activity will continue to be monitored closely by WKWD to maintain balanced conditions.

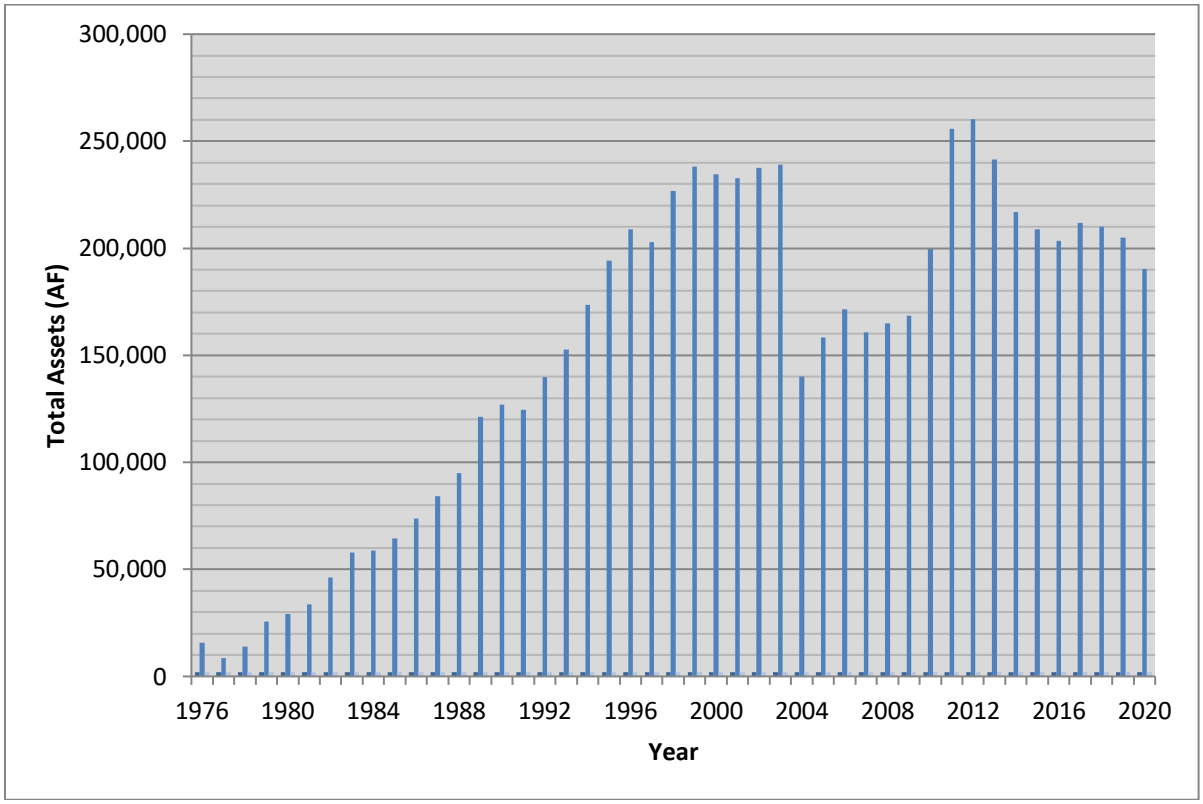

Figure 6-3: Historical Banking

6.5 Stormwater

WKWD experiences low rainfall (about 5.4 inches/year) and stormwater volumes are typically small. In addition, only a small part of the District is urbanized and has a stormwater collection system. As a result, stormwater is not considered a potential water supply for the District.

6.6 Water Quality

The quality of any natural water is dynamic in nature. This is true for the local groundwater of the Kern River Alluvial Fan Basin. During periods of intense rainfall or snowmelt, routes of surface water movement are changed; new constituents are mobilized that are often dependent on local land use and enter the water while other constituents are diluted or eliminated. The quality of water changes over the course of a year. These same basic principles apply to groundwater. Depending on water depth, groundwater will pass through different layers of rock and sediment and leach different materials from those strata. Water depth is a function of local rainfall and snowmelt. During periods of drought, the mineral content of groundwater increases. Water quality is not a static feature of water, and these dynamic variables must be recognized.

Water quality regulations also change. This is the result of the discovery of new contaminants, changing understanding of the health effects of previously known as well as new contaminants, development of new analytical technology, and the introduction of new treatment technology. All water purveyors who provide water for human consumption are subject to drinking water standards

set by the Federal EPA and the SWRCB DDW. WKWD pumps local groundwater to meet the potable water supply demands of its customers. An annual Consumer Confidence Report (CCR) is provided to all residents receiving water from WKWD. That report includes detailed information on water quality testing during the preceding year (WKWD, May 2020). WKWD's water supplies currently meet State and Federal drinking water standards.

This section provides a general description of the water quality of various water supplies. Water quality impacts on water reliability are discussed in **Section 7.2**.

6.6.1 Imported Water Quality

The District's primary supply is pumped groundwater, however, the source of groundwater recharge is imported surface supplies from the SWP and Kern River through the BVWSD Exchange Program. Water from the SWP is not directly delivered as a potable supply, but some SWP water is directly delivered to La Paloma for industrial use.

6.6.2 Groundwater Quality

Overall, groundwater quality in the vicinity of the District well fields is excellent. The water quality of the District's wells represents a family of water that is typical of water recharged by the Kern River. The water is typically a sodium bicarbonate water of low Total Dissolved Solids (TDS), although the upper portion of the aquifer contains a thin interval of calcium bicarbonate water, as indicated in several of DWR's multiple completion monitoring wells (Groundwater Management Plan, 1997). The water chemistry of the Kern River water tends to be a calcium sodium bicarbonate type. The calcium bicarbonate water recharged from the river apparently undergoes an ion exchange process as it infiltrates the deeper parts of the aquifer, changing it to a sodium bicarbonate type.

Groundwater quality in other parts of the District, especially the western portion, has high salinity and is generally unusable. This includes groundwater in the vicinity of Taft and the Taft Wastewater Treatment Facility. Groundwater quality generally improves to the east, which explains why the wellfields are located on the far eastern end of the District, nearly fifteen miles from Taft, the largest urban area in the District.

The local groundwater generally does not have microbial water quality problems. Parasites, bacteria, and viruses are filtered out as the water percolates through the soil, sand, and rock on its way to the aquifer. Even so, disinfectants are added to local groundwater when it is pumped by wells to protect public health. Local groundwater has very little TOC and generally has very low concentrations of bromide which minimizes the potential for DBP formation. Taste and odor problems from algae are not an issue with groundwater. The recharge waters and the local Kern River are very low in TDS thus the groundwater is also low.

Information in the WKWD GSA's MAP indicates that groundwater quality has generally been consistent in the past, including through the historically low groundwater levels of 2015. Groundwater quality does not appear to degrade with decreased groundwater elevations.

Groundwater from district wells have had occasional one-off detections of constituents of concern. In these instances, in cooperation with the State Water Resources Control Board, Division of Drinking

Water, the district has operated under approved temporary blending programs to ensure drinking water standards are maintained for delivered water.

WKWD maintains a telemetry system which allows for automated control of pumping, flow, tank levels and numerous other system operations. Production wells are manually prioritized in sequence, allowing for dominant flows from select wells, if needed. Once established, the process is monitored to ensure that proper blending is occurring to protect public health. WKWD, at a minimum, maintains daily records of the flow and hours of operation of each well used for blending. WKWD's blending plan includes:

1. WKWD shall maintain daily, theoretical blending calculations submit a copy of the daily blending calculations for the month by the 10th day of the following month.
2. WKWD shall collect samples of the blended effluent for analysis by an approved laboratory monthly. Results must be submitted by the laboratory to SWRCB DDW using the Electronic Data Transfer (EDT) method.
3. WKWD shall collect a blended sample of all wells utilized in blending, for analysis by an approved laboratory, quarterly. Results shall be submitted by the laboratory to SWRCB DDW using the EDT method.
4. WKWD shall calibrate the flow meters on the wells and the blended effluent discharge line at least annually.
5. SWRCB DDW must be notified if there is a failure in the blending operation.

6.6.3 Aquifer Protection

The District is working independently, and in cooperation with public agencies and oil companies, to address and correct any contamination threats to its groundwater. However, to date no significant threat to the groundwater has occurred as WKWD has met all state and federal MCLs and secondary MCLs.

6.7 Wastewater and Recycled Water

6.7.1 Recycled Water Coordination

Legal Requirements:

CWC 10633
The plan shall provide, to the extent available, information on recycled water and its potential for use as a water source in the service area of the urban water supplier. The preparation of the plan shall be coordinated with local water, wastewater, groundwater, and planning agencies that operate within the supplier's service area.

The District has been interested in developing a recycled water program to provide water to large landscaped areas in Taft and surrounding communities. Recycled water would be a new water source that could help the District meet sustainability requirements mandated by the Sustainable

Groundwater Management Act. It would also be a firm water supply, available every year, and much more reliable than their SWP supply. The District applied for and received a State grant to perform a Recycled Water Study.

In 2018 the District participated in a feasibility evaluation as to the use of recycled potable water produced by the Taft wastewater treatment facility in the City of Taft. The City of Taft and the Ford City-Taft Heights Sanitation District received a water recycling grant from the State Water Resources Control Board to assess the cost and feasibility of implementing tertiary treatment facilities and recycled water pipelines to irrigate large landscaped areas. This would expand current uses for of secondary treated wastewater already taking place under an agreement with a local alfalfa farmer to distribute treated water on City owned farmland. The study area included the City of Taft, Taft Heights, and Ford City.

The market best considered for recycled water in the Taft study area is predominantly landscape irrigation for public spaces such as cemeteries, parks, play fields and schools. Additional uses may include dust control on roadways and streets as well as use on construction projects. The goal of the study was to expand the existing recycled water program in Taft to augment potable water supplies by substituting potable water with recycled water whenever possible. Multiple alternatives were explored including the consequences of not expanding the current recycling program. Additionally, the study explored use of recycled water from a tertiary treatment facility and secondary level recycled water for irrigation and the associated costs of each approach.

It was concluded that reuse of all water produced by the Taft WWTF for ongoing alfalfa production on the 135-acre City-owned property was the best alternative given the service area's needs and the associated cost of implementation. The use of recycled water for urban landscaping was deemed uneconomical. Several factors were taken into consideration including but not limited to: current effluent management practices, low associated costs with ongoing use as irrigation water, existing infrastructure, the City's added benefit of receiving 5% of the net alfalfa cultivation, and groundwater quality improvement caused by natural nitrogen uptake by the alfalfa crop. Since the District does not provide agricultural water, the current and future planned use of the wastewater effluent does not impact District supplies and demands.

6.7.2 Wastewater Collection, Treatment, and Disposal

Legal Requirements:

> ***CWC 10633 (a)*** *(Describe) the wastewater collection and treatment systems in the supplier's service area, including a quantification of the amount of wastewater collected and treated and the methods of wastewater disposal.*
> ***CWC 10633 (b)*** *(Describe) the quantity of treated wastewater that meets recycled water standards, is being discharged, and is otherwise available for use in a recycled water project.*

WKWD provides water supply but does not oversee sewage collection or treatment. The City of Taft and Ford City-Taft Heights Sanitation District jointly own a Wastewater Treatment Facility (WWTF) just outside the Taft City limits. The WWTF treats wastewater from the City of Taft, Taft Heights, and Ford City (see location on **Figure 3-1** in **Section 3**). The treatment plant is operated by the Kern Sanitation Authority. Wastewater flows are primarily domestic and commercial in nature. Annual wastewater treatment is about 1,085 AF. The Federal Taft Correctional Institution also has a separate

wastewater treatment plant. Data on the correctional institution's effluent stream is not available and is not reported here.

The WWTF currently provides secondary level treatment which includes two aerated ponds and two settling ponds; chlorine contact basin (not in service); holding pond and effluent pumping station; solar sludge drying beds, and a 12.8 AF capacity reservoir which provides effluent storage prior to discharge to the effluent disposal area. The WWTF has a capacity of 1.5 MGD. In 2017, improvements were completed through the installation of the Biolac treatment process. A tertiary treatment facility would be needed to provide recycled water for landscape uses.

The wastewater effluent is currently used in the vicinity of the WWTF for irrigating non-edible fodder crops. No wastewater effluent is discharged to any water bodies. Some of the effluent percolates to the groundwater during the irrigation process. Area groundwater near the WWTF is at an approximate depth of 400 to 800 feet below ground surface and is of poor mineral quality with EC (electro-conductivity at 25°C) of 4,000 to 6,000 µmhos/cm and TDS greater than 4,000 mg/l, which rapidly diminishes in quality with depth. As a result, wastewater effluent that percolates into the ground flows to a saline sink and is no longer usable.

Table 6-3 and **Table 6-4** provide information on the existing treatment and water recycling program.

Table 6-3: Wastewater Generated within Service Area in 2020

Wastewater Collection Agency	Wastewater Treatment Agency	Treatment Plant Name	Is WWTP Located Within Service Area?	Is WWTP Operation Contracted to a Third Party?	Was Volume Measured or Estimated?	Volume of Wastewater Collected from the Service Area 2020
The City of Taft and Ford City-Taft Heights Sanitation District	The City of Taft & Ford City-Taft Heights Sanitation District	Taft Wastewater Treatment Facility	Yes	Yes	Yes	1,085 AF
					Total Wastewater Collected from Service Area	1,085 AF

Table 6-4: Wastewater Treatment and Discharge within Service Area in 2020

Name of Wastewater Treatment Plant	Discharge Location Description	Method of Disposal	Does this Include Wastewater Generated Outside the Service Area?	Treatment Level	2020 Volumes (AF)			
					Wastewater Treated	Discharged Treated Wastewater	Recycled Within Service Area	Recycled Outside of Service Area
Taft Wastewater Treatment Facility	Adjacent agricultural fields	Land Disposal (Fodder irrigation)	No	Secondary, undisinfected	1,085	0	1,085	0

6.7.3 Recycled Water Systems

Legal Requirements:

CWC 10633(c) *(Describe) the recycled water currently being used in the supplier's service area, including, but not limited to, the type, place, and quantity of use.*

The wastewater effluent from the Taft area is currently used in the vicinity of the WWTF for irrigating non-edible fodder crops. This water currently receives secondary level treatment.

6.7.4 Recycled Water Beneficial Uses

Legal Requirements:

CWC 10633(d) *(Describe and quantify) the potential uses of recycled water, including, but not limited to, agricultural irrigation, landscape irrigation, wildlife habitat enhancement, wetlands, industrial reuse, groundwater recharge, indirect potable reuse, and other appropriate uses, and a determination with regard to the technical and economic feasibility of serving those uses .*
CWC 10633(e) *(Describe) the projected use of recycled water within the supplier's service area at the end of 5, 10, 15 and 20 years…*
CWC 10633(e)
(Describe) the projected use of recycled water within the supplier's service area at the end of 5, 10, 15, and 20 years, and a description of the actual use of recycled water in comparison to uses previously projected pursuant to this subdivision.

Currently, wastewater effluent is beneficially used to irrigate fodder crops near the wastewater treatment plant. However, this recycling does not beneficially impact the District's water supplies or demands since the District does not supply agricultural water. A 2018 Recycled Water Study by The Wallace Group that evaluated recycled water for urban uses concluded that a recycled water system was economically unfeasible.

6.7.5 Actions to Encourage and Optimize Future Recycled Water Use

Legal Requirements:

CWC 10633(f) *(Describe the) actions, including financial incentives, which may be taken to encourage the use of recycled water, and the projected results of these actions in terms of acre-feet of recycled water used per year.*
CWC 10633(g) *(Provide a) plan for optimizing the use of recycled water in the supplier's service area, including actions to facilitate the installation of dual distribution systems, to promote recirculating uses, to facilitate the increased use of treated wastewater that meets recycled water standards, and to overcome any obstacles to achieving that increased use.*

In June 2015, the City of Taft, WKWD, West Side Cemetery District (WSCD), and the West Side Recreation & Park District (WSRPD) signed a Memorandum of Understanding (MOU) to explore water recycling opportunities (see **Appendix G**). The MOU outlines their common interest in recycled water, and the terms for securing a consultant to perform a recycled water study. This MOU exemplifies the level of cooperation and local interest in recycled water in the local community. The City of Taft also supports recycled water through long-term goals and inclusion within the City's General Plan as Policy PF-10. However, the District's recycled water study showed that recycled water was economically unfeasible.

While the recycled water study showed that recycled water was not economically feasible, WKWD is still open to exploring other options in the future if economic or water supply conditions change.

While not a form of recycled municipal water, the District is also interested in reusing produced water brought to the surface in oil wells. This concept is in the early investigation phase and no details are yet available.

6.8 Desalinated Water Opportunities

Legal Requirements:

§10631(i) Describe the opportunities for development of desalinated water, including, but not limited to, ocean water, brackish water, and groundwater, as a long-term supply.

The California UWMP Act requires a discussion of potential opportunities for use of desalinated water (Water Code Section 10631[i]). WKWD has evaluated such opportunities, and they are described in the following section, including opportunities for desalination of brackish water, groundwater, oilfield produced water, and seawater.

6.8.1 Brackish Water and/or Groundwater Desalination

The sources of groundwater for WKWD include SWP and Kern River water that is recharged within the District. Neither of these supplies contains high TDS levels and therefore do not contribute significant amounts of TDS which would cause brackish groundwater.

The oil industry is prevalent in the District, and significant quantities of water are pumped from deep aquifers during oil recovery operations. This water, called 'produced water' is currently injected back into deep geologic formations through wells. The water is typically brackish and would require treatment for salinity, and possibly other constituents, before it could be reused. WKWD is exploring several opportunities for using this produced water.

6.8.2 Seawater Desalination

Because the WKWD service area is not in a coastal area, it is neither practical nor economically feasible for WKWD to implement a seawater desalination program. Therefore, WKWD has no current plans to pursue seawater desalination, and desalinated supplies are not included in the supply summaries in this Plan.

6.9 Exchanges or Transfers

Legal Requirements:

§10631(d) Describe the opportunities for exchanges or transfers of water on a short-term or long-term basis.

Important elements to enhancing the long-term reliability of water supplies are transfers and exchanges. These have been important supplies that supplement the District's SWP water. The primary transfers and exchanges for WKWD are summarized in the table below.

Table 6-5: Transfer and Exchange Opportunities

Transfer agency	Transfer or exchange	Short term or long term	Proposed Volume	Time Period
Kern Tulare Water District	2:1 Exchange	Short-Term	650 AF/year	Through 2036
Buena Vista WSD	Transfer	Long-term	6,500 AF/year	On-going
Total	-	-	7,150AF/year	-
Units : Acre-feet				

6.10 Energy Consumption

Energy intensity is defined as the amount of energy used to collectively divert, store, convey, treat, and distribute each unit volume of water and herein is reported as kilowatt hours per acre-foot (kW-hr/ac-ft). The analysis was performed using data for 2020, which had the best overall energy use records between 2016 and 2020 and is considered representative of the District's water delivery profile.

WKWD utilizes two sources of water: groundwater, and raw water from the State Water Project. Raw water from the State Water Project is delivered directly to one of the District's customers with the use of WKWD pump stations. The customer directly pays these energy costs, and the energy usage is included in the analysis

The energy intensity analysis is shown below in **Table 6-6**. The final calculated energy intensity is 6,137 kWh/AF. WKWD is different from many other retail urban water suppliers in that several facilities used for groundwater extraction, conveyance, and distribution are powered by natural gas from the SoCal Gas Company and PG&E. Natural gas wells and booster pumps operate at lower efficiencies than their electric counterparts, however, due to site location limitations, this is often the only practical power option. Natural gas use is metered and measured in units of Therms. To calculate Energy Intensity all energy units must be in the same units of kWh. The equation to convert Therms to kWh, provided by SoCal Gas, can be seen below. All other facilities are powered by electricity from PG&E or solar panels depending on location.

$$1\ Therm * \frac{100{,}000\ BTU}{Therm} * \frac{1\ kWh}{3412\ BTU}$$

Table 6-6: Energy Intensity (2020)

Description	Extract and Divert	Place into Storage	Distribution	Total Utility
Volume of Water Entering Process (AF)	19,229	1,786	15,415	15,415
Energy Consumed (kWh)	18,625,899	11,787	77,728,169	94,600,608
Energy Intensity (kWh/AF)	969	7	5,042	6,251

6.11 Future Water Projects

Legal Requirements:

CWC 10631(g) *…The urban water supplier shall include a detailed description of expected future projects and programs… that the urban water supplier may implement to increase the amount of the water supply available to the urban water supplier in average, single-dry, and multiple-dry water years. The description shall identify specific projects and include a description of the increase in water supply that is expected to be available from each project. The description shall include an estimate with regard to the implementation timeline for each project or program.*

Table 6-7 summarizes proposed actions to improve water supplies and water management in WKWD. Implementation of each project will be dependent on available funding and staff time.

Table 6-7: Future Water Supply Projects

Action	Joint Project with other agencies		Description	Planned Implementation Year	Planned for Use in Year Type	Expected Increase in Water Supply (AF)
	Y/N	Agency				
Delta Conveyance Facility	Y	State of California	Through Delta conveyance to improve supply water reliability	Unknown	Average	2,200 AF (7% of SWP contract)
Automatic Meter Reading	N		Install new automatic reading digital meters at all customer turnouts. Some have already been installed on existing customers.	In progress	All	Unknown. Some increase in efficiency with better data is expected.

6.12 Summary of Existing and Planned Sources of Water

Legal Requirements

CWC 10631
(b)Identify and quantify, to the extent practicable, the existing and planned sources of water available to the supplier over the same five-year increments described in subdivision 10631(a). (4) (Provide a) detailed description and analysis of the amount and location of groundwater that is projected to be pumped by the urban water supplier. The description and analysis shall be based on information that is reasonably available, including, but not limited to, historic use records.

WKWD is always interested in pursuing new water supplies through short and long-terms transfers, exchanges, or banking agreements. Given potential impacts from climate change, and the gradual reduction in SWP reliability, new water sources may be needed in the future. No specific sources are

currently known, but WKWD staff will stay apprised of opportunities to increase importation of water into the District.

Table 6-8 tabulates the existing and anticipated future water supplies for WKWD.

Table 6-8: Water Supplies — Current and Projected

Water Source	2020		2025	2030	2035	2040	2045
	Actual Volume	Level of Treatment of Source Water					
Purchased Water	0	-	0	0	0	0	0
Groundwater (recovered from local bank)	15,415	Disinfection	14,795	14,870	14,947	15,026	15,106
Imported Surface water	103	None	18,396	18,207	18,050	17,892	17,735
Recycled Water	0	-	0	0	0	0	0
Desalinated Water	0	-	0	0	0	0	0
Stormwater Use	0	-	0	0	0	0	0
Transfers		-					
Buena Vista WSD	5,000	None	6,500	6,500	6,500	6,500	6,500
Exchanges	-						
Santa Clarita Retun	-500		-	-	-	-	-
Rosedale-Rio Bravo WSD	0	None					
Kern Tulare WD	-2,986	None	650	650	650	-	-
Total	17,032		40,341	40,227	40,147	39,418	39,340
Estimated Demands[2]	16,338		17,356	17,448	17,542	17,637	17,735

Notes:

1. Groundwater (recovered from local bank) reflected the total treated water demands plus system losses, since the District could meet all treated water demands with banked groundwater for the foreseeable future.
2. For years 2025 to 2045, imported surface water based on the reliability in the 2019 SWP Delivery Capability Report, which varies from 58.4% in 2025 down to 56.3% in 2045.
3. Demands based on assumptions and criteria described in Section 4 – Water Uses.
4. Some transfers are recovery of groundwater.

7 Water Supply Reliability

The UWMPA requires urban water suppliers to assess water supply reliability by comparing total projected water demands with the expected water supply over the UWMP planning period. The UWMPA requires this assessment for normal (average), single-dry and multiple-dry-years. This section presents the reliability assessment for WKWD's service area.

It is the stated goal of WKWD to deliver a reliable and high-quality water supply for their customers, even during dry periods. Based on conservative water supply and demand assumptions, in combination with conservation of non-essential demand during certain dry years, the District expects to continue achieving this goal over the next 25 years.

7.1 Constraints on Water Sources

Legal Requirements:

CWC 10631(c)(2)
For any water source that may not be available at a consistent level of use, given specific legal, environmental, water quality, or climatic factors, describe plans to supplement or replace that source with alternative sources or water demand management measures, to the extent practicable.
CWC Section 10634
The plan shall include information, to the extent practicable, relating to the quality of existing sources of water available to the supplier over the same five-year increments as described in subdivision (a) of Section 10631, and the manner in which water quality affects water management strategies and supply reliability.

7.1.1 Constraints on Surface Water Supplies

Overview
The District's primary surface water supply comes from the SWP. The District has a contract amount of 31,500 AF, however SWP water deliveries are variable and typically less than the full contract amount.

The amount of SWP water allocated to contractors each year is dependent on a number of factors that can vary significantly from year to year. The primary factors affecting SWP supply include hydrologic conditions in northern California, the amount of water in SWP storage reservoirs at the beginning of the year, regulatory and operational constraints on SWP facilities, and the total amount of water requested by the contractors. On average the availability of SWP supplies to SWP contractors is generally less than their full Table A amounts in many years and can be significantly less in very dry years.

State Water Project Delivery Capability Report
DWR prepares a biennial report to assist SWP contractors and local planners in assessing the near and long-term availability of supplies from the SWP. DWR issued its most recent update, the 2019 DWR State Water Project Delivery Capability Report (DCR), in August 2020. In this report, DWR provides

SWP supply estimates for use in various planning efforts, including 2020 UWMP updates. Water availability estimates are provided for both current and future conditions.

DWR's estimates of SWP deliveries are based on a computer model that simulates monthly operations of the SWP and Central Valley Project systems. Key assumptions and inputs to the model include the system facilities, hydrologic inflows, regulatory and operational constraints on system operations, and projected contractor demands for SWP water. For example, the 2019 DCR uses the following assumptions to model current conditions: existing facilities, hydrologic inflows to the model based on 82 years of historical inflows (1922 through 2003), current regulatory and operational constraints, and contractor demands at maximum Table A amounts.

The DCR provides a reliability of about 59% for 2020, which equates to 18,600 AF/year for WKWD (31,500 AF (100% Table A amount) x 59% = 18,600 AF/year).

Delta Conveyance Project

An ongoing planning effort to increase long-term supply reliability for both the SWP and CVP is taking place through the Delta Conveyance Project. The Delta Conveyance Project facilities would allow for greater flexibility in balancing the needs of the estuary (Delta) with the reliability of water supplies. The plan would also provide other benefits, such as reducing the risk of long outages from Delta levee failures.

Public negotiations between Department of Water Resources (DWR) and Public Water Agencies (PWAs) for the Delta Conveyance Project (DCP) began in 2019 and were completed in April 2020. These negotiations led to an Agreement in Principle (AIP) for an Amendment to the State Water Contract regarding the DCP. The Parties' goal was to equitably allocate costs and benefits of a DCP and to preserve State Water Project operational flexibility. A decision by each participating PWA for approving a contract amendment with DWR would not occur until after the environmental review for the DCP is completed.

While there is widespread support for the DCP, it is early in the planning and design phase. To date, WKWD has committed considerable resources to the DCP planning effort and has committed to support the process in the future.

7.1.2 Constraints on Groundwater Supplies

Three factors affect the availability of groundwater: 1) Sufficient recovery capacity (wells and pumps), 2) Sustainability of the groundwater resource to meet pumping demand on a renewable basis, and 3) Groundwater quality including protection of groundwater resources (wells) from known contamination, and provisions for treatment/blending in the event of contamination. These topics are addressed below:

Recovery Capacity

For many years the District's groundwater supply came entirely from the South Well Field, located about 15 miles northeast of Taft. The wells were grouped in a small area, which began to impact groundwater levels and total recovery capacity. Reductions in SWP supplies also created additional stress on the groundwater levels. As a result, the District constructed the North Well Field in 2013. Located about 3 miles northwest of the South Well Field, these facilities provide the District more flexibility and reliability for operations and increases access to its water supplies. The North Well Field project increased the number of production wells from 8 to 13.

Sustainability of Groundwater Resources

Groundwater supplies in WKWD have provided a reliable buffer against drought and reduced surface water supplies. The District currently recharges the majority of its surface water supply (with the exception of about 3,000 AF/year which is delivered directly to one industrial water user). This practice helps regulate water supplies and reduce the need for water-use restrictions in dry years and even multi-year droughts. The District currently has a net positive balance of about 240,000 AF in the local aquifer, which would provide about a ten-year water supply, if necessary. The Sustainable Groundwater Management Act (SGMA) requires that WKWD manage their groundwater supplies sustainably with no net long-term overdraft or other undesirable results. More information on SGMA is provided in Section 6.4.2.

Groundwater Quality

Groundwater quality in the two well fields is generally excellent, with the exception of one well with slightly elevated arsenic concentrations. The District has enacted a blending program to address the arsenic. Refer to Section 7.2 for more details.

7.1.3 Constraints on Recycled Water Supplies

The Taft metropolitan area currently recycles wastewater effluent for non-edible crop irrigation but does not have a recycled water program to help meet domestic water demands. The District investigated a program to recycle 400 AF/year for large landscape use but it was found to be uneconomical. Refer to Section 6.7 for more information on the proposed recycled water program. If economic conditions for recycled water change, it would be a reliable supply and provide the same quantity in every hydrologic year type. While indoor water usage (and hence wastewater effluent) can go down in dry years due to conservation efforts, the recycled water program would only use about 25% of the effluent (400 AF versus 1,460 AF), so the full amount would be available every year, and thus help to reduce demands for potable water.

7.2 Water Quality Impacts on Water Reliability

The quality of the imported water and other recharge sources are not anticipated to reduce reliability. These waters come from high quality sources including the SWP and Kern River.

Overall, groundwater quality in the vicinity of the District well fields is excellent. The water quality of the District's wells represents a family of water that is typical of water recharged by high quality Kern River water. Groundwater quality in other parts of the District, especially the western portion, has high salinity and is generally unusable. Groundwater quality generally improves to the east, which

explains why the well fields are located at the far eastern end of the District. This has limited the area that can be developed for wells, but that has been partially rectified by the construction of the North Well field, which now supplements the South Well field, and provides greater pumping capacity and redundancy.

In summary, water quality issues are not anticipated to have any significant impact on water reliability for the District.

7.3 Reliability by Type of Year

Legal Requirements:

> ***CWC 10631(c) (1)***
> *Describe the reliability of the water supply and vulnerability to seasonal or climatic shortage, to the extent practicable, and provide data for each of the following: (A) an average water year, (B) a single dry water year, (C) multiple dry water years.*

The available supplies and water demands for WKWD's service area were analyzed to assess the region's ability to satisfy demands during three scenarios: a normal water year, single-dry year, and multiple-dry years. **Table 7-1** presents the base years for the development of water year data. The base years were determined from the historical SWP deliveries. The Average Water Year is simply the estimate long-term average conditions for the SWP.

Table 7-1: Bases of Water Year Data

Water Year Type	Base Year(s)	Available Supplies		
		Volume Availability	SWP Reliability	% of avg supply
Average Water Year	-	18,600	59%	100%
Single-Dry Water Year	2014	1,600	5%	8%
Multiple-Dry Water Years – 1st Year	1988	3,500	11%	19%
Multiple-Dry Water Years – 2nd Year	1989	14,500	46%	78%
Multiple-Dry Water Years - 3rd Year	1990	4,400	14%	24%
Multiple-Dry Water Years – 4th Year	1991	7,900	25%	42%
Multiple-Dry Water Years – 5th Year	1992	5,400	17%	29%

7.4 Supply and Demand Assessment

Legal Requirements:

CWC 10635(a)
Every urban water supplier shall include, as part of its urban water management plan, an assessment of the reliability of its water service to its customers during normal, dry, and multiple dry water years. This water supply and demand assessment shall compare the total water supply sources available to the water supplier with the total projected water use over the next 20 years, in five-year increments, for a normal water year, a single dry water year, and multiple dry water years. The water service reliability assessment shall be based upon the information compiled pursuant to Section 10631, including available data from state, regional or local agency population projections within the service area of the urban water supplier.

This section compares the supplies and demands for normal, single-dry year, and multiple-dry year scenarios in WKWD. Also included are tables showing the source of the waters, including surface water, transfers and exchanges, and pumping from the District's local groundwater bank. The tables show current conditions in 2020 and projections in 5-year increments through 2045. All values in these tables are rounded to the nearest 100.

Some of the tables show a water surplus in certain years. In these years, the surplus water will be banked for use in dry years. In all year types the District can meet demands; when water supplies are low due to dry conditions the balance can be made up with banked groundwater.

Normal Year

Table 7-2: Normal Year Supply and Demand Comparison

Water Use	Water Use (AFY)					
	2020	2025	2030	2035	2040	2045
Surface Water (100% of Normal)	18,600	18,600	18,600	18,600	18,600	18,600
Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
Total Supply	25,750	25,750	25,750	25,750	25,100	25,100
Total Demand	16,338	17,356	17,448	17,542	17,637	17,735
Difference (from Banked Groundwater)	0	0	0	0	0	0

Single Dry Year

Table 7-3: Single Dry Year Supply and Demand Comparison

Water Use	Water Use (AFY)					
	2020	2025	2030	2035	2040	2045
Surface Water (8% of Normal)	1,600	1,600	1,600	1,600	1,600	1,600
Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
Total Supply	8,750	8,750	8,750	8,750	8,100	8,100
Total Demand	16,338	17,356	17,448	17,542	17,637	17,735
Difference (from Banked Groundwater)	7,588	8,606	8,698	8,792	9,537	9,635

Multiple Dry Years

The Multiple Dry Year analysis assumes that Stage I of the Water Shortage Response Plan (WSRP) will be enacted in the third year of a drought (see **Section 8** – Water Shortage Contingency Planning). This results in demands that are 10% lower than demands in other years.

Table 7-4: Multiple Dry Year Supply and Demand Comparison

Year	Description	Water Use (AFY)					
		2020	2025	2030	2035	2040	2045
Year 1	Surface Water (19% of Normal)	3,500	3,500	3,500	3,500	3,500	3,500
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	10,650	10,650	10,650	10,650	10,000	10,000
	Total Demand	16,338	17,356	17,448	17,542	17,637	17,735
	Difference (from Banked Groundwater)	5,688	6,706	6,798	6,892	7,637	7,735
Year 2	Surface Water (78% of Normal)	14,500	14,500	14,500	14,500	14,500	14,500
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	21,650	21,650	21,650	21,650	21,000	21,000
	Total Demand	16,338	17,356	17,448	17,542	17,637	17,735
	Difference (from Banked Groundwater)	0	0	0	0	0	0
Year 3	Surface Water (24% of Normal)	4,400	4,400	4,400	4,400	4,400	4,400
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	11,550	11,550	11,550	11,550	10,900	10,900
	Total Demand	14,704	15,620	15,703	15,788	15,873	15,962
	Difference (from Banked Groundwater)	3,154	4,070	4,153	4,238	4,973	5,062
Year 4	Surface Water (42% of Normal)	7,900	7,900	7,900	7,900	7,900	7,900
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	15,050	15,050	15,050	15,050	14,400	14,400
	Total Demand	14,704	15,620	15,703	15,788	15,873	15,962
	Difference (from Banked Groundwater)	0	570	653	738	1,473	1,562
Year 5	Surface Water (29% of Normal)	5,400	5,400	5,400	5,400	5,400	5,400
	Surface Water Transfers/Exchanges	7,150	7,150	7,150	7,150	6,500	6,500
	Total Supply	12,550	12,550	12,550	12,550	11,900	11,900
	Total Demand	14,704	15,620	15,703	15,788	15,873	15,962
	Difference (from Banked Groundwater)	2,154	3,070	3,153	3,238	3,973	4,062

Summary of Comparisons

As shown in the analyses above, WKWD has adequate supplies to meet demands during normal, single-dry, and multiple-dry years throughout the 25-year planning period. WKWD will pump banked groundwater to meet demand when demand exceeds the surface water supply in single-dry and multiple-dry year periods. In times of excess, the water will be banked for use in the future. Currently, WKWD has about 247,545 AF in storage which represents about 10 years of full annual demands and helps to ensure reliability in dry periods. The groundwater storage often increases in wet and dry years

from recharge efforts, so the storage is expected to last for several decades. WKWD's water reliability is stable, largely due to the long history of banking groundwater for use in dry years.

7.5 Drought Risk Assessment

A drought risk assessment was completed to evaluate the District's ability to meet a 5-year drought if it occurred over the next five years. The assessment looks at current demands and effectiveness of water augmentation and water use reduction measures.

The assessment simulates the same 5-year drought (1988-1992) evaluated in **Section 7.3**. This drought is simulated using estimated water demands over the next 5 years (2021-2025). The following procedure was used in developing the Drought Risk Assessment:

1. Water demands were interpolated between current (2020) usage and anticipated 2025 demands.
2. SWP supplies are based on the values presented in **Table 7-1.**
3. Water augmentation measures included the District's wells; demand reduction of 10% is assumed to occur in the third year of drought with implementation of Stage 1 of the District's Water Shortage Response Plan.

The results of the Drought Risk Assessment are shown in **Table 7-5** below.

Table 7-5: Drought Risk Assessment (2021-2025)

Description	Water Use (AFY)				
	2021	2022	2023	2024	2025
Water Demands	16,194	16,051	14,317	12,756	15,620
SWP Allocation	11%	46%	14%	25%	17%
SWP Supplies	3,500	14,500	4,400	7,900	5,400
Shortfall	12,694	1,551	9,917	4,856	10,220
Water Conservation Measures	0	0	1,432	1,276	1,562
Recovery of Banked Groundwater	12,694	1,551	8,485	3,580	8,658
Revised Surplus/(shortfall)	0	0	0	0	0
Resulting % Use Reduction from WSCP action	0%	0%	10%	10%	10%

The Drought Risk Assessment shows that supply augmentation and water use reduction savings can adequately address water shortage in the simulated drought and allow urban water needs to be met.

7.6 Regional Supply Reliability

Legal Requirements

CWC 10620 (f)
An urban water supplier shall describe in the plan water management tools and options used by that entity that will maximize resources and minimize the need to import water from other regions.

Each water supply source has its own reliability characteristics. In any given year, the variability in weather patterns around the state may affect the availability of supplies to the Kern River Alluvial Fan and SWP. For example, from 2013 through 2015, California experienced dry conditions in all three years. WKWD was able to provide sufficient water due to agreements with local agencies and an active banking program. To ensure reliability, WKWD intends to increase their water reliability by maximizing their banking program. If one supplier reduces deliveries, then additional supply can be acquired through the banked water in drier years.

WKWD's supply is pumped from the groundwater which is recharged using SWP and Kern River waters. Water banking by the District began in 1966 in the Kern River Fan area. Long-term groundwater sustainability is ensured by a positive balance maintained in the ground. WKWD is required to maintain a positive balance according to local agreements, and the amount of banked water exceeds the annual demands. Many other agencies in the Kern Groundwater Subbasin also practice groundwater recharge and banking in an effort to stabilize groundwater levels and augment supplies.

Storm water and imported water contribute to the recharge of the Basin. Storm water recharge is affected by changes in the local hydrology and is highly limited to the dry climate of the region. The amount of SWP water allocated to contractors each year is dependent on a number of factors that can vary significantly from year to year. The primary factors affecting SWP supply availability include hydrologic conditions in northern California, the amount of water in SWP storage reservoirs at the beginning of the year, regulatory and operational constraints on SWP facilities, and the total amount of water requested by the contractors. The availability of SWP supplies to SWP contractors is generally less than their full Table A amounts in most years and can be significantly less in very dry years.

The Kern River Alluvial Fan depends on local and imported supplies located in two distinct hydrologic regions of the state. A drought in Southern California may not necessarily mean a drought in Northern California. Reliability for WKWD will be tied to droughts in Northern California and SWP deliveries since the majority of the water is from the SWP. While the surface water is unreliable, it is recharged and stored underground thus providing a reliable supply.

Table 7-6 summarizes factors resulting in inconsistent supplies for WKWD's various water supplies.

Table 7-6: Factors Resulting in Inconsistency of Supply

Water supply sources	Limitation quantification	Legal	Environmental	Water quality	Climatic	Additional information
Surface Water						
Kern County Water Agency (SWP)	X		X			Dependent on SWP deliveries and environmental pumping restrictions
Groundwater						
Kern River Alluvial Fan (WKWD Bank Extractions)	X					Dependent on SWP deliveries
Transfers / Exchanges						
Rosedale-Rio Bravo		X				Time limit on agreement
Kern-Tulare Water District		X				Time limit on agreement
Buena Vista Water Storage District		X				Time limit on agreement but not during this planning period

7.7 Climate Change Impacts on Water Demands, Supplies, and Reliability

DWR guidelines require urban water suppliers consider the potential effects related to climate change in the UWMP as it relates to water demands, water supply, and water supply reliability. These three topics are provided below after a general discussion on climate change impacts.

General Impacts from Climate Change

Climate change model projections indicate that California in general can expect to be impacted by the following:

- Increased temperatures
- Decrease in snowpack due to increasing winter temperatures
- More precipitation falling as rain and less as snow
- More winter runoff and less spring/summer runoff due to warmer temperatures
- Greater water demand for crop and landscape irrigation
- Greater extremes in flooding and droughts
- Sea level rise, which could impact Delta water quality and Delta water deliveries

The Tulare Lake Basin portion of the Kern County Integrated Regional Water Management Plan prepared a Climate Change Vulnerability Assessment in August 2014 (Kennedy/Jenks, 2014). This technical memorandum identifies the potential climate change vulnerabilities in the Kern Region and potential future actions to mitigate the vulnerabilities. The Vulnerability Assessment is an extensive document and should be referenced for more detailed information. The assessment prioritized the vulnerabilities in Kern County as follows (1 being the sector most prioritized [high risk] and 4 being the sector least prioritized [low risk] with respect to climate change vulnerability):

1. Water Supply; Water Quality
2. Water Demand; Flooding
3. Ecosystem and Habitat
4. Sea Level Rise and Hydropower

Climate Change Impact to Water Demands

One of the primary effects expected from climate change in the future is an increase in average global temperature. According to the Western Region Climate Center, California has experienced an increase of 1.1 to 2 degrees Fahrenheit (°F) in mean temperature in the past century. Both minimum and maximum annual temperatures have increased, with the minimum temperatures (+1.6 to 2.5 °F) increasing more than maximums (+0.4 to 1.6 °F). The average annual temperature of Kern County is expected to rise 3.5-6.3°F by the end of the 21st Century (DWR, June 2015). As a result, summer dryness is predicted to start earlier and last longer than it has historically. This change in temperature will increase evaporation, lengthen growing seasons, intensify evapotranspiration, and will lead to drier soils which will require more irrigation water.

Increases in temperature may be expected to impact water resources through changes to precipitation patterns, evapotranspiration rate increases, increased customer water use, increased wildfire potential, and faster snowmelt. These potential impacts are likely to impact the State Water Project supplies.

As climate change becomes noticeable and quantifiable, the WKWD response will need to include reducing demands to match possible reduction of water supplies from the SWP. At this point, impacts from possible climate change are not quantifiable. Reduction of the per capita demands in the system can help respond to climate change in two ways. Reduced water demands equate to less energy use through reduced groundwater pumping and/or movement of water supplies through the system. Further reduction of per capita water demands may be challenging to achieve, as the WKWD has already implemented many demand management or conservation methodologies.

It is anticipated climate change increase in temperatures and more hot days will impact landscape water demands by WKWD municipal/domestic customers; however, as WKWD has goals to maintain their per capita use goal, urban water demands are not anticipated to increase. Temperature rises will translate to increased evapotranspiration rates. Mitigating possible increased water demands for landscape may require less landscaping, increased use of drought tolerant plantings, or more efficient irrigation strategies with the District.

Warmer temperatures will result in a shift towards more rain and less snow, resulting in less snowpack storage. DWR (June 2015) states that most climate model precipitation projections for the state anticipate drier conditions in Southern California, with heavier and warmer winter precipitation in Northern California. On average projections indicate little change in total annual precipitation in

California (Kennedy/Jenks, August 2014). However, the distribution, timing and type of that precipitation may vary. Even modest changes in California would have a significant impact because California ecosystems are conditioned to historical precipitation levels and water resources are nearly fully utilized. In WKWD, local rainfall provides only a small contribution to landscape irrigation demands and groundwater recharge, but any reduction would be detrimental. Precipitation that impacts SWP supplies is more important to WKWD's water supplies.

Climate Change Impacts to Water Supplies

Because the Kern Region relies heavily on imported supplies, any reduction or change in the timing or availability of those supplies could have negative impacts on the water supplies of the Region. Reductions in imported water supplies would lead to increased reliance on local groundwater, recycled water, or other sources of supplies if demand was not reduced. WKWD is highly reliant on SWP contract water originating from Northern California and receives Kern River water through exchanges and transfers. As the northern Sierra's peaks are relatively lower than the southern Sierra, a warmer climate is projected to cause greater snowpack reduction in the state's northern Mountains, which provide much of the SWP water delivered from the Delta. Climate change could cause earlier runoff in the Delta, and result in water supplies being available during months when Delta pumping restrictions are more severe. The timing and availability of these supplies could be impacted by climate change.

Oil and gas drilling in the county could be impacted by decreasing water availability, particularly in times of drought by limiting the amount of water available for cooling, fuel extraction, and power generation. The effects of climate change and water availability on the oil and gas sector include a combination of potential direct and indirect impacts. Water is required in many different stages of the oil and gas value chain, from exploration to processing to transport, and the volume of water used in these activities varies, with the largest volume used in the refining process. Among exploration and production processes, the largest volume of water is used as a supplemental source. Industrial water accounts for about 75% of the water use in WKWD, so this sector could be significantly impacted.

The Kern Region is not directly subject to sea level rise. However, sea level rise would affect imported water supplies. The principal concern is the potential for sea water intrusion that would increase Delta salinity. Climate change could adversely impact Delta water quality through the following:

- Reduce surface water flows into the Delta
- Raise sea level and cause sea water intrusion into the Delta
- Require more freshwater releases from reservoirs to maintain Delta water quality, thereby reducing water available for urban uses
- Increase water temperatures in the Delta and rivers/streams flowing into the Delta
- Increase sediment loading in the Delta (because of increased wildfires and more extreme precipitation events)
- Threaten the stability of Delta levees, whose failure would impact water quality and Delta conveyance capacity

Also, changes in local hydrology could affect natural recharge to the local groundwater aquifers and the quantity of groundwater that could be pumped sustainably over the long-term. Decreased inflow from runoff, increased evaporative losses, and warmer and shorter winter seasons can alter natural recharge of groundwater. Furthermore, additional reductions in the imported water imposed by

climate change would lead to more reliance on local groundwater, resulting in reductions in base flows, reduced groundwater outflows, increased depth to groundwater, and increased land subsidence.

WKWD will need to meet these potential reductions in SWP surface water supplies by improved water efficiency measures, additional groundwater recharge or a reduction in groundwater pumping in wet years to leave water in the aquifer for drier years.

Climate Change Impact on Water Supply Reliability

The state is already experiencing decreases to natural snowpack in the Sierra Nevada, which has implications for SWP deliveries. Climate change will likely cause more precipitation to fall as rain, and warmer temperatures will cause snowpack to melt 4 to 14 days earlier in the season. DWR is predicting that the Sierra snowpack will experience a 25% to 40% reduction by 2050 based on historical modeling, with additional decreases caused by warmer storms due to climate change. At the local level, changes in the timing and intensity of precipitation could negatively affect groundwater recharge, runoff flowing to rivers and reservoirs, flooding frequency, and length of the dry season and resulting increased risk of wildfires and vegetation die off.

Average monthly runoff is a critical component of California's water supply planning. Flood protection and water supply infrastructure have been designed and optimized for historical conditions. However, the timing of peak monthly runoff in the Sacramento River between 1906-1955 and 1956-2007 has shifted nearly a month earlier indicating that this key hydrology metric is no longer stationary (DWR, June 2015). Timing is projected to continue to move earlier in the year, further constraining water management by reducing the ability to refill reservoirs after the flood season has passed.

The Sacramento–San Joaquin River Delta is the central hub of the SWP. Potential impacts to the Delta resulting from climate change include increased risk of levee failure, reduced water quality, and reduced water supply, all of which could significantly impact SWP operations, and the reliability of the supply of water delivered through the Kern County Water Agency. Sea-level rise threatens to disrupt deliveries from the SWP if saltwater advances into the Delta and increased quantities of fresh water would need to be released to protect water quality.

The agencies like WKWD who receive SWP supplies through Kern County Water Agency will need to consider adapting to reduced deliveries from the SWP as a component of climate change adaptation. Climate change and sea level rise have both been taken considered in determining the future reliability and future allocations as presented in the 2019 SWP Delivery Capability Report (DWR, 2020). The Technical Addendum to The Final State Water Project Delivery Capability Report 2019 (California Department of Water Resources, August 26,2020) incorporated climate change modeling impacts to historically hydrology based on a high emissions scenario occurring and a 1.5-foot (45 cm) sea level rise in San Francisco. The high emissions scenario is predicated to have a 1 in 200 chance or 0.5% probability. The Kern County Water Agency (KCWA) has a municipal & industrial (M&I) Table A entitlement from the State Water Project of 135,000 AF. For historical hydrology from 1922 to 2003, the average entitlement for KCWA was predicted to have been 79,000 AF (59% of Table A full entitlement) where with said climate change models, the average entitlement is estimated at 72,000 AF (53% of Table A full entitlement), about a 9% reduction in supplies. West Kern Water District portion of the KCWA Table A entitlement is 31,500 AF or about 23.3% of KCWA (31,500/135,000 = 0.233). Therefore, if high emissions modeled scenario occurs, the WKWD average entitlement would reduce a similar 9% or about 1,657 AF (79,000 x 0.233 x 0.09 = 1,657 AF). Since this situation is unlikely

(0.5%), these reductions are not included in this UWMP, but WKWD will continue to monitor climate change impacts.

WKWD plans to adapt to climate change using a variety of strategies. Most of these strategies are considered "no-regret strategies." In other words, if climate change does not occur, or the impacts are less than expected, WKWD would have no regrets from implementing the adaptation strategies, since they would still benefit overall water reliability.

Proposed strategies to adapt to climate change essentially include projects/programs that the District is already pursuing, but perhaps more aggressively as funding and staffing availability permit. These strategies include:

- Urban water conservation
- Water transfers
- Conjunctive use programs (primarily groundwater storage within WKWD)
- Support projects that could improve the reliability of imported SWP water

8 Water Shortage Contingency Planning

The Urban Water Management Planning Act requires that the UWMP include an urban water shortage contingency analysis that addresses stages of action to be undertaken by the urban water supplier in response to water supply shortages, including more than a 50 percent reduction in water supply. In addition, the District is required to develop mandatory water conservation measures to implement during each water shortage stage.

The District's Water Shortage Response Plan (WSRP), which is synonymous with a Water Shortage Contingency Plan, is an independent document from the UWMP and can be found in **Appendix H**. The previous WSCP was prepared in 2015. The WSCP has been reorganized and expanded based on new State requirements. Some of the main topics covered in the updated WSCP include:

- Procedures for evaluating water supplies
- Criteria for declaring a water shortage
- Water shortage levels
- Shortage response actions
- Seismic risk and mitigation actions
- Community outreach
- Customer compliance and enforcement
- Revenue impacts
- Monitoring and reporting requirements
- Monitoring and evaluating the WSCP

The primary change from the 2015 WSCP was the expansion of Water Shortage Stages from four levels to six levels, which was required by the State.

9 Demand Management Measures (DMM)

Legal Requirements:

CWC 10631 (f)
(A) …A narrative shall describe the water demand management measure that the supplier plans to implement to achieve its water use targets pursuant to Section 10608.20.
(B)The narrative pursuant to this paragraph shall include descriptions of the following water demand management measures:
(i) Water waste prevention ordinances.
(ii) Metering.
(iii) Conservation pricing.
(iv) Public education and outreach.
(v) Programs to assess and manage distribution system real loss.
(vi) Water conservation program coordination and staffing support.
(vii) Other demand management measures that have a significant impact on water use as measured in gallons per capita per day, including innovative measures, if implemented.
CWC 10631
(f) Provide a description of the supplier's water demand management measures. This description shall include all of the following:
(1) (A) … a narrative description that addresses the nature and extent of each water demand management measure implemented over the past five years.

9.1 DMMs

The District recognizes that conserving water is an integral component of a responsible water strategy, and is committed to providing education, tools, and incentives to help its customers reduce the amount of water they use. The following sections review compliance with the existing Demand Management Measures (DMMs) and provide an implementation plan for compliance with the UWMP Act. Implementing DMMs, however, may be dependent on available funding and staff time to execute the programs.

9.1.1 Water Waste Prevention Ordinances

The District actively pursues incidents of water waste. District supervisors, Customer Service Representative, meter readers, and the flushing and sampling crews inspect customer usage routinely for anomalies. Incidents of waste are investigated and recommendations for correction are provided. Water sources are regulated and can be disconnected in cases of excessive leakage and/or facilities failure.

Appendix H includes the District's WSRP, which was first adopted in 2010, and was readopted as part of this UWMP update. The WSRP establishes six levels of response actions to be implemented in times of shortage (Response Level 1 through Response Level 6), with increasing restrictions on water use in response to worsening drought conditions and decreasing available supplies. The policy establishes progressive response levels including regulations to be implemented during times of declared water shortages in order to attain escalating conservation goals.

Penalties for water waste are discussed in the WSRP. Customers are given a warning after their first water waste violation. Subsequent violations can include a $300 Administrative Fee, $600 Administrative Fee (third offense), and finally Discontinuance of Service (fourth offense).

9.1.2 Metering

The District boundary encompasses 300 square miles with approximately 300 miles of transmission and distribution lines. All water deliveries provided through the District's system are metered and all new water service accounts require meters which are installed, maintained and read for billing purposes by the District. Meters are calibrated on a periodic basis. Meters that are not performing adequately are replaced.

All residential and commercial customers are billed by volume. Some industrial customers are billed by volume and some, accounting for about 40 percent of deliveries, have long-term "take or pay" contracts. (See Conservation Pricing section below for more information.) The District monitors its system in a number of different ways.

Most of the large landscapes in the District's service area have dedicated irrigation meters, including greenbelts, park accounts and a golf course (which has four meters and is classified as an Industrial account). Public school accounts have mixed use meters, but District staff are currently working with the local school district to explore the possibility of installing dedicated meters on school play fields.

The District also has meters on all of their productions wells. Beginning in 2015, the District implemented a program for annual testing of the flow meters at each well (as required by the District's State Operating Permit).

Acoustic and propeller meters are used to measure deliveries from the SWP.

The District is in the process of replacing all industrial meters with Automatic Meter Reading (AMR) technology. As of April 2021, AMR meters have been installed on all industrial accounts and residential-commercial meters in outlying communities, which track daily versus monthly usage.

9.1.3 Conservation Pricing

The District has different pricing structures, depending on customer type:

1. Residential/Commercial Rate

   Residential and Commercial customers are classified as "Domestic" customers in the District's billing system and are billed at the same rate and on a bimonthly schedule. In 2009 the District started to migrate its Domestic customers from a declining block rate structure to a flat rate. The new structure is designed for compliance with the standard that 70 percent of revenue come from volumetric rates (**Table 9-1**).

Table 9-1: Residential and Commercial Volumetric Rates (per HCF)

Volume	2020
Up to 1,000 ft³	$17.30
1,000 to 3,000 ft³	$1.73
3,001 to 4,000 ft³	$1.73
Over 4,001 ft³	$1.24

2. Industrial Rate

Industrial water use accounts for about 80 percent of the District's annual water demand; customers are subject to one of two rate structures:

a. Increasing block volumetric rates: Industrial water users subjecting to an increasing block rate structure pay for water as follows:

All water up to 3,000 cu.ft.: $2.24/hcf ($975.74 per AF)
Additional water per 100 cu.ft. $2.70/hcf (1,170.53 per AF)

Meter charges are not included in the rates above.

b. Fixed Rate "Take or Pay" contracts: Most of the industrial customers have long term "Take or Pay" contracts which guarantee customers an agreed upon amount of water (Base Supply). Should the customer take less than the Base Supply, they must still pay one-half of the contract price for the water not taken. For any purchases beyond the Base Supply, the customer is required to pay for such water that is actually delivered and is billed volumetrically.

For those customers holding "Take or Pay" contracts (which do not conform to the requirements of the DMM), the District claims a legal exemption. The "Take or Pay" contracts are legally binding; some have expiration dates, others do not. Contracts with expirations expire in various stages, the latest of which is in 2036. As these contracts begin to expire the District is shifting those customers to a negotiated volumetric rate structure with no "Take or Pay" clause and a standard volumetric rate structure that does conform to the requirements.

Most Take or Pay contracts were executed in 1988, long before the DMM requirements were developed, and are legally binding. The District does not have the legal authority to change the terms and conditions of these contracts prior to their expiration.

Appendix I includes a summary of water rates and fees in WKWD.

9.1.4 Public Education and Outreach

The District promotes water conservation efforts in coordination with AWWA, ACWA, KCWA and Water Association of Kern County programs. The District distributes public information through brochures, local speaking engagements, its website (www.wkwd.org) and special events such as community and street fairs. Some of these programs, especially those involving contact with the general public, were suspended in 2020 due to the pandemic. They are expected to resume some time in 2021 depending on health and safety conditions.

WKWD's education and outreach activities support conservation programs and enhance customer awareness of conservation. WKWD offers water conservation programs and services for all residential and commercial accounts. Programs and services include general and targeted promotions, presentations, workshops, free water savings devices, incentives for installing water-saving fixtures and equipment, as well as other education and outreach programs.

A variety of educational publications/brochures that include conservation practices are utilized. Some brochures include charts for quick references relative to indoor and outdoor conservation techniques, lists of appropriate plants for weather zones and landscape design tips.

Marketing techniques used include a specific approach for individual customers and a broad approach to communities, and include the following:

- Advertisements
- Public Service Announcements
- Bill Inserts
- Door Hangers
- District Office Displays
- Newspaper and Magazine Ads
- Community Billboards
- Newsletters/Brochures/Magazines distributed around communities at other business offices
- Radio
- Demonstration gardens
- Special Events – Media
- Programs coordinated with other agencies and public interest groups
- Educational/informational sessions for commercial, industrial and landscape irrigation customers

As part of these efforts, the District General Manager provided education on water conservation, and handed out conservation items at various schools, clubs, meetings and community events. District staff attended various community events where they handed out nozzles, educational materials and spoke to the community about saving water throughout the year.

The District has been meeting the goal of at least four contacts/year with the public and four contacts/year with the media.

The budget for these conservation-related public information programs averaged $18,912 per year from 2016 to 2020, with maximum spending of $22,628 in 2020.

Quantifying water savings through education and outreach is not feasible, however these efforts make a significant contribution towards promoting conservation efforts.

9.1.5 Programs to Assess and Manage Distribution System Real Loss

The District has conducted pre-screening system audits of its distribution system and leak detection since 1990 as part of its regular operation and maintenance procedures. These audits are conducted each month and at the end of each year. The District's monthly metered units of ground water production and metered units of water deliveries are tracked and provided to DWR each year as part of our Public Water System Statistics Report. Reports covering the past five years indicate the District's system has an annual water loss of less than 4 percent of total annual production.

In the past, this loss rate fell below the threshold that required action, but that standard has been replaced by a new requirement that specifies implementation of the AWWA M36 Standard Water Audit methodology. Implementation of the M36 methodology requires a specific set of information on authorized and unauthorized consumptions, metering inaccuracies and more; most of this data are being collected through the District's current program. The District implemented the AWWA M36 Standard Water Audit methodology for Calendar Years 2016 through 2020. The District's water audit data validity score averaged 59 out of 100.

9.1.6 Water Conservation Program Coordination and Staffing Support

The District has four staff responsible for various conservation-related tasks. The General Manager, Regulatory Administrator, Administrative Assistant, and a Water Service Technician work on conservation part-time and are in charge of program planning, development and administration. There is also a position that is assigned to responding to customer issues such as high bills, leaks, and water waste.

9.1.7 Other Demand Management Measures

Following are discussions on other DMMs that WKWD implements but are not required components of an UWMP.

9.1.7.1 School Education

WKWD recognizes the importance of educational benefits and works with the Kern County Water Agency to provide local students and teachers a variety of education programs and tools. WKWD designed a water education curriculum for elementary schools in the District that meets Common Core standards. The curriculum is district specific and was created for 2nd/3rd and 5th/6th graders. A book was provided to each classroom and it will become part of the regular curriculum.

The District and Kern County Water Agency (KCWA) are now reaching students about water conservation through Links4Ed (formerly JS Strategic) for a Standards Based Curriculum.

Students were taught at five different schools from 2016 to 2020. A total of 3,739 students were reached from 2015-2020. A summary of the students reached is shown in **Table 9-2**.

Table 9-2: School Education Activities

	McKittrick Elementary No. Students		Midway School District No. Students		Taft City School District No. Students		Maricopa Unified School District No. Students		Elk Hills School District No. Students		Total Students
	2nd	5th	2nd	5th	2nd	5th	2nd	5th	2nd	5th	
2015/16	20	20	17	19	249	240	27	18	25	32	**667**
2016/17	22	22	36	15	300	270	58	29	27	27	**806**
2017/18	22	22	21	15	300	270	58	29	27	27	**791**
2018/19	18	15	14	13	300	270	24	27	25	27	**733**
2019/20	18	17	20	14	300	270	24	27	25	27	**742**
Totals	**100**	**96**	**108**	**76**	**1,449**	**1,320**	**191**	**130**	**129**	**140**	**3,739**

9.1.7.2 Indoor and Outdoor Water Surveys for Single/Multi-Family Residential Customers Residential Plumbing Retrofits

The District has combined the Residential Assistance and Landscape Water Survey programs into a single analysis because the program is implemented as a single audit program with indoor and landscape elements. This is expected to improve efficiency and result in cost savings.

Free water use surveys are offered to WKWD residential and commercial customers, designed to help customers use water more efficiently, ranging from self-evaluations to on-site consultation of usage, targeting large residential and commercial landscape irrigators. Customers are also provided with educational materials and water-saving products to improve water use efficiency. Examples include free low-flow shower heads, shower timers and aerators for inside fixtures and for outside use, and water shut-off nozzles for hose bibs. WKWD also provides Indoor Water Conservation Kits to residential users upon request and at community outreach events. The kits provide customers information to help assess current practices and how to detect leaks.

Statistics on the number of water surveys have not been tracked closely in recent years, but the District will begin tracking it in 2021. Fixture giveaways during water surveys and at special events have had estimated values of $891 in 2018 and $7,050 in 2020.

The District currently has one full-time employee who is assigned to respond to customer issues such as high bills, leaks and water waste. The position is currently focused on meter testing and utility-side meter issues as well as high bill complaints, posting door hangers, and providing information in water waste situations. The inspector also provides low-flow devices to customers as appropriate.

9.1.7.3 Residential Plumbing Codes

There is very little new development in the District's service area; it's estimated to be on the order of about 0.5 percent growth per year or less. See Section 2 for discussion of service area characteristics.

The DMM requires that the District provide incentives such as rebates, recognition programs, or reduced connection fees, or ordinances requiring residential construction meeting water sense

specifications (WSS) for single and multi-family housing until a local, state or federal regulation is passed requiring water efficient fixtures. The 2019 California Green Building Standards Code (CAL Green Code, CALGreenCode.pdf) addresses these WSS requirements.

The 2010 CAL Green Code originally set mandatory green building measures, including a 20 percent reduction in indoor water use, as well as dedicated meter requirements and regulations addressing landscape irrigation and design. The 2019 Code identifies voluntary measures that set a higher standard of efficiency. The District, in collaboration with the local planning departments is reviewing the proposed standards to determine the most appropriate direction. The District is also supporting implementation and monitoring of the Code by incorporating the new rules into its water service or "will serve" requirements.

9.1.7.4 High-Efficiency Washing Machine Rebate Programs

The District began offering High-Efficiency Clothes Washers (HECW) rebates in 2013. The District offers $200 per washing machine that is on the Consortium for Energy Efficiency (CEE) approved list. Applications are available at the main district office and on the District website.

The District has a goal of providing at 70 rebates per year, for a total savings of about 2 gpcd for each new washing machine. The cost of this program is $9,000 per year and program participation is currently tracked through the District billing system.

Washing machine rebates from 2016 to 2020 and rebate expenditures (not including staff salary costs) included:

- 2016 – 34 rebates ($6,800)
- 2017 – 68 rebates ($12,400)
- 2018 – 54 rebates ($10,800)
- 2019 – 31 rebates ($6,200)
- 2020 – 33 rebates ($6,600)

The District has set a goal of 70 rebates per year and plans to continue outreach in an effort to increase and maintain participation. The District will also look for local program partners such as Pacific Gas and Electric (PG&E) and/or the wastewater utility to combine marketing, outreach and administrative costs, and potentially increase incentive amounts.

The District would like to evaluate a tiered rebate system, based on the potential water savings from three different levels of washing machine efficiency listed by the CEE.

9.1.7.5 Residential ULFT Replacement Programs

The District began offering High Efficiency Toilet (HET) rebates in 2012. The program was initially called the 'Junk your John Kickoff' program. Rebates are $150 per toilet. The toilets must be on the EPA WaterSense approved list and replace a toilet using 3.5 gallons/flush or higher. Applications are available at the main district office and on the District website.

Based on a resale rate for the City of Taft of 4 percent[1], the program goal is a replacement of 260 units per year over 10 years. The savings would be about 3.2 gpcd for each new toilet.

Toilet rebates from 2016 to 2020 and rebate expenditures (not including staff salary costs) included:

- 2016 – 85 rebates ($11,849)
- 2017 – 37 rebates ($4,426)
- 2018 – 51 rebates ($6,752)
- 2019 – 53 rebates ($6,710)
- 2020 – 38 rebates ($5,189)

Customers have been notified of the program through several forms of media, but the program has not yet reached its annual goals of 260 units per year. WKWD will increase outreach efforts in an effort to increase participation.

The District plans to explore revisions to the toilet rebates so they are tiered for different uses. For example, hotel toilets are used less often than residential toilets since there are less users per toilet and hotel rooms are often vacant. Alternatively, toilets at restaurants and other public areas are used more often than residential toilets and offer more potential water savings.

Program participation is currently tracked through the billing system; water savings will either be estimated based on standard assumptions or through the billing system if the capacity can be developed.

In the future, the District may consider rebates for installing xeriscape or artificial turf, to supplement the toilet and washing machine rebate programs.

9.1.7.6 Conservation Programs for Commercial, Industrial and Institutional

The District offers several conservation programs to commercial and institutional customers. Current and future efforts will focus on commercial and institutional customers, since verifying industrial savings is difficult or impossible as water usage depends on the market conditions for crude oil and demands for power generation.

Commercial and Institutional

Commercial and institutional water conservation efforts will include a combination of other DMMs including large landscape conservation, education and rebates. These water users fall into the same billing category as residential customers, and water conservation will be achieved through similar measures as residential customers.

Industrial

The District set an internal goal in 2015 of reducing industrial water usage by 10% over 10 years. About 80% of water deliveries in the District go to industrial customers. Based on 2015 deliveries of 16,970 AF, the industrial sector must reduce consumption 170 AF/year for a period of ten years through 2025 to meet this goal.

[1] City of Taft, Assessor's Office. Conversation 10/22/10.

Industrial water is primarily supplied to oil development companies and power plants. Water usage typically varies with the market for crude oil and power demands across the state, so conservation efforts are difficult, if not impossible to track. However, one improvement the District has made for industrial customers is the installation of automatic meters that read daily. That data will be available to industrial customers, where they previously received the data monthly. This data will provide more detailed information that could help them better track, manage and conserve their water usage. The industrial customers are also asked to reduce water usage on landscaping to conserve water during droughts.

The primary industries represented by these industrial accounts are oil production and electrical generation; each use almost 50% of the industrial water. More information on each is provided below:

- Oil Industry. Oil producing operations have provided the majority of the District's water sales for more than forty years. Oil production in western Kern County relies heavily on the injection of steam into the oil bearing formations to enhance the recovery of oil. Steam injection is required due to the oil's low gravity, which reduces its ability to flow or to be pumped to the surface. Once the steam is injected into the formation the steam condenses and forms an oil/water emulsion, which can be pumped or lifted back to the earth's surface. After the oil/water emulsion is recovered the oil and water must be separated to a maximum of 3 percent residual water and sediment in the oil. The oil leaves the facility via pipelines to be further refined and the water remains on site and is recycled back to steam. The water recycling process has a water loss from water staying with the oil (at a rate of about 3 percent) and because not all of the steam is recovered from the geologic formation.
- Electrical Generation. The electrical generation industry utilizes steam or natural gas, which power turbines to generate electricity. Both systems require a large amount of water for cooling tower operations. Where steam is used to turn the turbine, the steam will pass through the turbines up to seven times before the steam degrades to a quality which it can no longer be used. Once the steam becomes unsuitable, it is necessary to purchase additional water to produce new steam. When the process permits, the steam can turn the electrical turbine and then be utilized for steam injection for the oil-producing industry. This process is limited to the co-located geographic sites of the electrical generation facility and the oil-producing facility.
- Golf Courses. Golf courses are also classified as "industrial" use in the District's billing system, but as required by DWR, that water usage is reported in the Residential/Commercial category in this UWMP. Golf course water conservation is discussed in the DMM for Large Landscape Conservation (see following below).

To achieve the ten percent industrial water savings, the District will outreach directly to its largest customers. Most of these customers are relatively large and already have a relationship with the District. Both the oil and electrical generation industries employ technical personnel with a high level of expertise who are dedicated to exploring methods to enhance production and reduce operational costs. The District is somewhat limited in the added value it can provide in terms of providing technical assistance to these industries for reducing water consumption, however it is actively exploring new opportunities. Recent discussions have addressed using "produced water" to offset potable supplies.

Produced water is a term used in the oil industry to describe water that is produced along with the oil and gas. Oil reservoirs have a natural water layer (formation water) that lies under the hydrocarbons and frequently contains large volumes of water. To achieve maximum oil recovery, additional water is often injected into the reservoirs to help force the oil to the surface. Both the formation water and the injected water are eventually produced along with the oil, and, therefore, as the field becomes depleted the produced water content of the oil increases.

Historically, produced water was disposed of in large evaporation ponds, however there is increasing focus on beneficial re-uses for produced water. Some options that have been discussed are using produced water for landscape and/or dust control. Produced water is considered an industrial waste and therefore there are numerous water quality related issues to consider. Currently, the oil companies are not permitted to use the water for dust control, but they are exploring this option further. Understanding customer water quality needs and outputs could help the District evaluate whether alternative supplies would be feasible and/or whether customer produced water can be utilized to offset potable supplies elsewhere in the service area, or in other parts of Kern County. The District will continue to explore measures directly related to the process, resource and water quality needs of its largest customers in the power and oil industries.

9.1.7.7 Large Landscape Conservation Programs and Incentives

About one-third of Domestic use goes to large landscape irrigation. The District has dedicated meters on all of its parks accounts and four for the golf course while the 11 schools are on mixed use meters. Consumption information is available for all of these users.

The District plans to develop an ETo based water budget for its irrigation accounts at a rate of four per year starting in 2021. The District will include the budget information with the customer's bills and provide technical support as required.

The District and Taft Unified School District have on-going conversations about opportunities to install dedicated meters for the large fields. This metering project is estimated to cost about $18,000 and started with the high school in January 2011. The City of Maricopa High School, in the City of Maricopa, has also expressed a willingness to work with the District to split its meters. Both these projects will allow the District and the schools to gather the information required to understand the landscape uses and then do a proper assessment of potential efficiency improvements.

The Jr. College, High School, Grammar Schools, and Park District each employ individuals trained in landscape water efficiency. The District will work with staff from those entities to explore further opportunities to promote efficient water use at the schools as well.

The District has also been working with one major golf course in the service area to explore conservation options. To conserve water, the golf course has allowed fairways to go fallow, and installed ground moisture sensors. As a result, the golf course has seen an overall average water savings of 11% per year when compared to 2015 volumes.

Future goals also include:

1. Irrigation water use surveys for 1.5% of mixed use meter commercial accounts/year.

2. Implement and maintain a customer incentive program for irrigation equipment retrofits.

Increasing water use efficiency on large landscapes is a high priority for the District. The District is already in direct contact with most of its landscape customers. The District will continue to work with these customers, identify efficiency opportunities and support implementation through upgrades, rebates, metering or in other ways that are determined to be most effective. Consumption patterns will be more closely tracked and communicated with the customer, and water savings will be measured through the billing system.

9.1.7.8 Wholesale Agency Assistance Programs

The District does not provide wholesale water and this DMM therefore does not apply.

9.2 Planned Implementation to Achieve Water Use Targets

Legal Requirements

> ***CWC 10631***
> *(f) Provide a description of the supplier's water demand management measures. This description shall include all of the following:*
> *(1) (A) …The narrative shall describe the water demand management measures that the supplier plans to implement to achieve its water use targets pursuant to Section 10608.20.*

The District recognizes the need to expand conservation programs and efforts in order to continue to maintain its future water conservation goals. The District plans to implement all of the aforementioned DMMs in an effort to conserve as much water as feasible, and provide a full portfolio of water conservation measures and opportunities.

The District is in the process of identifying programs and preparing implementation plans. In addition to the activities identified for DMM implementation, the District is considering implementation of the following programs:

1. Landscape: The District will work with the School District to install dedicated irrigation meters and identify appropriate efficiency options. The District will also work with the Parks to identify opportunities to improve their irrigation efficiency. The District will provide the School District and Parks with financial and technical support as needed.

2. The District will continue to work with the golf course to identify and implement water saving opportunities.

3. The District will offer rebates for smart irrigation controllers.

10 Bibliography/References

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5. California Department of Water Resources, *The State Water Project Draft Delivery Capability Report 2019*, August 2020.
6. Kenned/Jenks Consultants, *Vulnerability to Climate Change Technical Memorandum – Kern IRWMP*, August 2014.
7. State of California*, 20x2020 Water Conservation Plan*, February 2010.
8. California Energy Commission, Public Interest Energy Research Program, *The Future Is Now: An Update on Climate Change Science Impacts and Response Options for California*, May 2009.
9. West Kern Water District, *2019 Consumer Confidence Report*.
10. West Kern Water District Groundwater Sustainability Agency, *Chapter Groundwater Sustainability Plan*, December 2019.

Appendices

APPENDIX A – UWMP CHECKLIST

Appendix A: UWMP Checklist

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Chapter 1	10615	A plan shall describe and evaluate sources of supply, reasonable and practical efficient uses, reclamation and demand management activities.	Introduction and Overview	Section
x	x	Chapter 1	10630.5	Each plan shall include a simple description of the supplier's plan including water availability, future requirements, a strategy for meeting needs, and other pertinent information. Additionally, a supplier may also choose to include a simple description at the beginning of each chapter.	Summary	Lay Description at beginning of UWMP
x	x	Section 2.2	10620(b)	Every agency that becomes an urban water supplier shall adopt an urban water management plan within one year after it has become an urban water supplier.	Plan Preparation	N/A

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 2.6	10620(d)(2)	Coordinate the preparation of its plan with other appropriate agencies in the area, including other water suppliers that share a common source, water management agencies, and relevant public agencies, to the extent practicable.	Plan Preparation	Section 2.2.3
x	x	Section 2.6.2	10642	Provide supporting documentation that the water supplier has encouraged active involvement of diverse social, cultural, and economic elements of the population within the service area prior to and during the preparation of the plan and contingency plan.	Plan Preparation	Section 2.2
x		Section 2.6, Section 6.1	10631(h)	Retail suppliers will include documentation that they have provided their wholesale supplier(s) - if any - with water use projections from that source.	System Supplies	Section 2.2.2

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
	x	Section 2.6	10631(h)	Wholesale suppliers will include documentation that they have provided their urban water suppliers with identification and quantification of the existing and planned sources of water available from the wholesale to the urban supplier during various water year types.	System Supplies	N/A
x	x	Section 3.1	10631(a)	Describe the water supplier service area.	System Description	Section 3.1
x	x	Section 3.3	10631(a)	Describe the climate of the service area of the supplier.	System Description	Section 3.1.4
x	x	Section 3.4	10631(a)	Provide population projections for 2025, 2030, 2035, 2040 and optionally 2045.	System Description	Section 3.2
x	x	Section 3.4.2	10631(a)	Describe other social, economic, and demographic factors affecting the supplier's water management planning.	System Description	Section 3.2
x	x	Sections 3.4 and 5.4	10631(a)	Indicate the current population of the service area.	System Description and Baselines and Targets	Section 3.2
x	x	Section 3.5	10631(a)	Describe the land uses within the service area.	System Description	Section 3.1.2

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 4.2	10631(d)(1)	Quantify past, current, and projected water use, identifying the uses among water use sectors.	System Water Use	Section 4.1-4.2
x	x	Section 4.2.4	10631(d)(3)(C)	Retail suppliers shall provide data to show the distribution loss standards were met.	System Water Use	Section 4.3
x	x	Section 4.2.6	10631(d)(4)(A)	In projected water use, include estimates of water savings from adopted codes, plans, and other policies or laws.	System Water Use	Section 4.4
x	x	Section 4.2.6	10631(d)(4)(B)	Provide citations of codes, standards, ordinances, or plans used to make water use projections.	System Water Use	Section 4.4
x	optional	Section 4.3.2.4	10631(d)(3)(A)	Report the distribution system water loss for each of the 5 years preceding the plan update.	System Water Use	Section 4.3
x	optional	Section 4.4	10631.1(a)	Include projected water use needed for lower income housing projected in the service area of the supplier.	System Water Use	Section 4.5
x	x	Section 4.5	10635(b)	Demands under climate change considerations must be included as part of the drought risk assessment.	System Water Use	Section 7.7

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x		Chapter 5	10608.20(e)	Retail suppliers shall provide baseline daily per capita water use, urban water use target, interim urban water use target, and compliance daily per capita water use, along with the bases for determining those estimates, including references to supporting data.	Baselines and Targets	Section 5
x		Chapter 5	10608.24(a)	Retail suppliers shall meet their water use target by December 31, 2020.	Baselines and Targets	Section 5.2
	x	Section 5.1	10608.36	Wholesale suppliers shall include an assessment of present and proposed future measures, programs, and policies to help their retail water suppliers achieve targeted water use reductions.	Baselines and Targets	N/A
x		Section 5.2	10608.24(d)(2)	If the retail supplier adjusts its compliance GPCD using weather normalization, economic adjustment, or extraordinary events, it shall provide the basis for, and data supporting the adjustment.	Baselines and Targets	Section 5.2

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x		Section 5.5	10608.22	Retail suppliers' per capita daily water use reduction shall be no less than 5 percent of base daily per capita water use of the 5-year baseline. This does not apply if the suppliers base GPCD is at or below 100.	Baselines and Targets	Section 5.1
x		Section 5.5 and Appendix E	10608.4	Retail suppliers shall report on their compliance in meeting their water use targets. The data shall be reported using a standardized form in the SBX7-7 2020 Compliance Form.	Baselines and Targets	Appendix C
x	x	Sections 6.1 and 6.2	10631(b)(1)	Provide a discussion of anticipated supply availability under a normal, single dry year, and a drought lasting five years, as well as more frequent and severe periods of drought.	System Supplies	Section 7.3
x	x	Sections 6.1	10631(b)(1)	Provide a discussion of anticipated supply availability under a normal, single dry year, and a drought lasting five years, as well as more frequent and severe periods of drought, *including changes in supply due to climate change.*	System Supplies	Section 7.7

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 6.1	10631(b)(2)	When multiple sources of water supply are identified, describe the management of each supply in relationship to other identified supplies.	System Supplies	Section 6.2-6.5
x	x	Section 6.1.1	10631(b)(3)	Describe measures taken to acquire and develop planned sources of water.	System Supplies	Section 6.1.2
x	x	Section 6.2.8	10631(b)	Identify and quantify the existing and planned sources of water available for 2020, 2025, 2030, 2035, 2040 and optionally 2045.	System Supplies	Section 6.1.2
x	x	Section 6.2	10631(b)	Indicate whether groundwater is an existing or planned source of water available to the supplier.	System Supplies	Section 6.4, 6.1.2
x	x	Section 6.2.2	10631(b)(4)(A)	Indicate whether a groundwater sustainability plan or groundwater management plan has been adopted by the water supplier or if there is any other specific authorization for groundwater management. Include a copy of the plan or authorization.	System Supplies	Section 6.4.2
x	x	Section 6.2.2	10631(b)(4)(B)	Describe the groundwater basin.	System Supplies	Section 6.4.1

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 6.2.2	10631(b)(4)(B)	Indicate if the basin has been adjudicated and include a copy of the court order or decree and a description of the amount of water the supplier has the legal right to pump.	System Supplies	Section 6.4.1
x	x	Section 6.2.2.1	10631(b)(4)(B)	For unadjudicated basins, indicate whether or not the department has identified the basin as a high or medium priority. Describe efforts by the supplier to coordinate with sustainability or groundwater agencies to achieve sustainable groundwater conditions.	System Supplies	Section 6.4.1
x	x	Section 6.2.2.4	10631(b)(4)(C)	Provide a detailed description and analysis of the location, amount, and sufficiency of groundwater pumped by the urban water supplier for the past five years	System Supplies	Section 6.4.4
x	x	Section 6.2.2	10631(b)(4)(D)	Provide a detailed description and analysis of the amount and location of groundwater that is projected to be pumped.	System Supplies	Section 6.1.2
x	x	Section 6.2.7	10631(c)	Describe the opportunities for exchanges or transfers of water on a short-term or long- term basis.	System Supplies	Section 6.9

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 6.2.5	10633(b)	Describe the quantity of treated wastewater that meets recycled water standards, is being discharged, and is otherwise available for use in a recycled water project.	System Supplies (Recycled Water)	Section 6.7
x	x	Section 6.2.5	10633(c)	Describe the recycled water currently being used in the supplier's service area.	System Supplies (Recycled Water)	Section 6.7.1
x	x	Section 6.2.5	10633(d)	Describe and quantify the potential uses of recycled water and provide a determination of the technical and economic feasibility of those uses.	System Supplies (Recycled Water)	Section 6.7.1
x	x	Section 6.2.5	10633(e)	Describe the projected use of recycled water within the supplier's service area at the end of 5, 10, 15, and 20 years, and a description of the actual use of recycled water in comparison to uses previously projected.	System Supplies (Recycled Water)	Section 6.7.1
x	x	Section 6.2.5	10633(f)	Describe the actions which may be taken to encourage the use of recycled water and the projected results of these actions in terms of acre-feet of recycled water used per year.	System Supplies (Recycled Water)	Section 6.7.5

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 6.2.5	10633(g)	Provide a plan for optimizing the use of recycled water in the supplier's service area.	System Supplies (Recycled Water)	Section 6.7.5
x	x	Section 6.2.6	10631(g)	Describe desalinated water project opportunities for long-term supply.	System Supplies	Section 6.8
x	x	Section 6.2.5	10633(a)	Describe the wastewater collection and treatment systems in the supplier's service area with quantified amount of collection and treatment and the disposal methods.	System Supplies (Recycled Water)	Section 6.7.2
x	x	Section 6.2.8, Section 6.3.7	10631(f)	Describe the expected future water supply projects and programs that may be undertaken by the water supplier to address water supply reliability in average, single-dry, and for a period of drought lasting 5 consecutive water years.	System Supplies	Section 6.11
x	x	Section 6.4 and Appendix O	10631.2(a)	The UWMP must include energy information, as stated in the code, that a supplier can readily obtain.	System Suppliers, Energy Intensity	Section 6.10

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 7.2	10634	Provide information on the quality of existing sources of water available to the supplier and the manner in which water quality affects water management strategies and supply reliability	Water Supply Reliability Assessment	Section 7.3
x	x	Section 7.2.4	10620(f)	Describe water management tools and options to maximize resources and minimize the need to import water from other regions.	Water Supply Reliability Assessment	Section 7.1.1
x	x	Section 7.3	10635(a)	Service Reliability Assessment: Assess the water supply reliability during normal, dry, and a drought lasting five consecutive water years by comparing the total water supply sources available to the water supplier with the total projected water use over the next 20 years.	Water Supply Reliability Assessment	Section 7.4
x	x	Section 7.3	10635(b)	Provide a drought risk assessment as part of information considered in developing the demand management measures and water supply projects.	Water Supply Reliability Assessment	Section 7.5

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 7.3	10635(b)(1)	Include a description of the data, methodology, and basis for one or more supply shortage conditions that are necessary to conduct a drought risk assessment for a drought period that lasts 5 consecutive years.	Water Supply Reliability Assessment	Section 7.5
x	x	Section 7.3	10635(b)(2)	Include a determination of the reliability of each source of supply under a variety of water shortage conditions.	Water Supply Reliability Assessment	Section 7.3
x	x	Section 7.3	10635(b)(3)	Include a comparison of the total water supply sources available to the water supplier with the total projected water use for the drought period.	Water Supply Reliability Assessment	Section 7.4
x	x	Section 7.3	10635(b)(4)	Include considerations of the historical drought hydrology, plausible changes on projected supplies and demands under climate change conditions, anticipated regulatory changes, and other locally applicable criteria.	Water Supply Reliability Assessment	Section 7.7
x	x	Chapter 8	10632(a)	Provide a water shortage contingency plan (WSCP) with specified elements below.	Water Shortage Contingency Planning	Section 8, Appendix H

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Chapter 8	10632(a)(1)	Provide the analysis of water supply reliability (from Chapter 7 of Guidebook) in the WSCP	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.10	10632(a)(10)	Describe reevaluation and improvement procedures for monitoring and evaluation the water shortage contingency plan to ensure risk tolerance is adequate and appropriate water shortage mitigation strategies are implemented.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.2	10632(a)(2)(A)	Provide the written decision-making process and other methods that the supplier will use each year to determine its water reliability.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.2	10632(a)(2)(B)	Provide data and methodology to evaluate the supplier's water reliability for the current year and one dry year pursuant to factors in the code.	Water Shortage Contingency Planning	Appendix H

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 8.3	10632(a)(3)(A)	Define six standard water shortage levels of 10, 20, 30, 40, 50 percent shortage and greater than 50 percent shortage. These levels shall be based on supply conditions, including percent reductions in supply, changes in groundwater levels, changes in surface elevation, or other conditions. The shortage levels shall also apply to a catastrophic interruption of supply.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.3	10632(a)(3)(B)	Suppliers with an existing water shortage contingency plan that uses different water shortage levels must cross reference their categories with the six standard categories.	Water Shortage Contingency Planning	N/A
x	x	Section 8.4	10632(a)(4)(A)	Suppliers with water shortage contingency plans that align with the defined shortage levels must specify locally appropriate supply augmentation actions.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.4	10632(a)(4)(B)	Specify locally appropriate demand reduction actions to adequately respond to shortages.	Water Shortage Contingency Planning	Appendix H

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 8.4	10632(a)(4)(C)	Specify locally appropriate operational changes.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.4	10632(a)(4)(D)	Specify additional mandatory prohibitions against specific water use practices that are in addition to state-mandated prohibitions are appropriate to local conditions.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.4	10632(a)(4)(E)	Estimate the extent to which the gap between supplies and demand will be reduced by implementation of the action.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.4.6	10632.5	The plan shall include a seismic risk assessment and mitigation plan.	Water Shortage Contingency Plan	Appendix H
x	x	Section 8.5	10632(a)(5)(A)	Suppliers must describe that they will inform customers, the public and others regarding any current or predicted water shortages.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.5 and 8.6	10632(a)(5)(B) 10632(a)(5)(C)	Suppliers must describe that they will inform customers, the public and others regarding any shortage response actions triggered or anticipated to be triggered and other relevant communications.	Water Shortage Contingency Planning	Appendix H

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x		Section 8.6	10632(a)(6)	Retail supplier must describe how it will ensure compliance with and enforce provisions of the WSCP.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.7	10632(a)(7)(A)	Describe the legal authority that empowers the supplier to enforce shortage response actions.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.7	10632(a)(7)(B)	Provide a statement that the supplier will declare a water shortage emergency Water Code Chapter 3.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.7	10632(a)(7)(C)	Provide a statement that the supplier will coordinate with any city or county within which it provides water for the possible proclamation of a local emergency.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.8	10632(a)(8)(A)	Describe the potential revenue reductions and expense increases associated with activated shortage response actions.	Water Shortage Contingency Planning	Appendix H
x	x	Section 8.8	10632(a)(8)(B)	Provide a description of mitigation actions needed to address revenue reductions and expense increases associated with activated shortage response actions.	Water Shortage Contingency Planning	Appendix H

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x		Section 8.8	10632(a)(8)(C)	Retail suppliers must describe the cost of compliance with Water Code Chapter 3.3: Excessive Residential Water Use During Drought	Water Shortage Contingency Planning	Appendix H
x		Section 8.9	10632(a)(9)	Retail suppliers must describe the monitoring and reporting requirements and procedures that ensure appropriate data is collected, tracked, and analyzed for purposes of monitoring customer compliance.	Water Shortage Contingency Planning	Appendix H
x		Section 8.11	10632(b)	Analyze and define water features that are artificially supplied with water, including ponds, lakes, waterfalls, and fountains, separately from swimming pools and spas.	Water Shortage Contingency Planning	Appendix H
x	x	Sections 8.12 and 10.4	10635(c)	Provide supporting documentation that Water Shortage Contingency Plan has been, or will be, provided to any city or county within which it provides water, no later than 30 days after the submission of the plan to DWR.	Plan Adoption, Submittal, and Implementation	Section 2.3.4

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 8.14	10632(c)	Make available the Water Shortage Contingency Plan to customers and any city or county where it provides water within 30 after adopted the plan.	Water Shortage Contingency Planning	Section 2.3.4
	x	Sections 9.1 and 9.3	10631(e)(2)	Wholesale suppliers shall describe specific demand management measures listed in code, their distribution system asset management program, and supplier assistance program.	Demand Management Measures	N/A
x		Sections 9.2 and 9.3	10631(e)(1)	Retail suppliers shall provide a description of the nature and extent of each demand management measure implemented over the past five years. The description will address specific measures listed in code.	Demand Management Measures	Section 9
x		Chapter 10	10608.26(a)	Retail suppliers shall conduct a public hearing to discuss adoption, implementation, and economic impact of water use targets (recommended to discuss compliance).	Plan Adoption, Submittal, and Implementation	Section 2.3.2

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 10.2.1	10621(b)	Notify, at least 60 days prior to the public hearing, any city or county within which the supplier provides water that the urban water supplier will be reviewing the plan and considering amendments or changes to the plan. Reported in Table 10-1.	Plan Adoption, Submittal, and Implementation	Appendix B
x	x	Section 10.4	10621(f)	Each urban water supplier shall update and submit its 2020 plan to the department by July 1, 2021.	Plan Adoption, Submittal, and Implementation	Section 2.3.3
x	x	Sections 10.2.2, 10.3, and 10.5	10642	Provide supporting documentation that the urban water supplier made the plan and contingency plan available for public inspection, published notice of the public hearing, and held a public hearing about the plan and contingency plan.	Plan Adoption, Submittal, and Implementation	Section 2.3, Appendix B
x	x	Section 10.2.2	10642	The water supplier is to provide the time and place of the hearing to any city or county within which the supplier provides water.	Plan Adoption, Submittal, and Implementation	Appendix B
x	x	Section 10.3.2	10642	Provide supporting documentation that the plan and contingency plan has been adopted as prepared or modified.	Plan Adoption, Submittal, and Implementation	Section 2.3.2

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 10.4	10644(a)	Provide supporting documentation that the urban water supplier has submitted this UWMP to the California State Library.	Plan Adoption, Submittal, and Implementation	Section 2.3.3
x	x	Section 10.4	10644(a)(1)	Provide supporting documentation that the urban water supplier has submitted this UWMP to any city or county within which the supplier provides water no later than 30 days after adoption.	Plan Adoption, Submittal, and Implementation	Section 2.3.3
x	x	Sections 10.4.1 and 10.4.2	10644(a)(2)	The plan, or amendments to the plan, submitted to the department shall be submitted electronically.	Plan Adoption, Submittal, and Implementation	Section 2.3.3
x	x	Section 10.5	10645(a)	Provide supporting documentation that, not later than 30 days after filing a copy of its plan with the department, the supplier has or will make the plan available for public review during normal business hours.	Plan Adoption, Submittal, and Implementation	Section 2.3.4
x	x	Section 10.5	10645(b)	Provide supporting documentation that, not later than 30 days after filing a copy of its water shortage contingency plan with the department, the supplier has or will make the plan available for public review during normal business hours.	Plan Adoption, Submittal, and Implementation	Section 2.3.4

Retail	Wholesale	2020 Guidebook Location	Water Code Section	Summary as Applies to UWMP	Subject	2020 UWMP Location
x	x	Section 10.6	10621(c)	If supplier is regulated by the Public Utilities Commission, include its plan and contingency plan as part of its general rate case filings.	Plan Adoption, Submittal, and Implementation	NA
x	x	Section 10.7.2	10644(b)	If revised, submit a copy of the water shortage contingency plan to DWR within 30 days of adoption.	Plan Adoption, Submittal, and Implementation	Section 2.3.4

WEST KERN WATER DISTRICT
URBAN WATER MANAGEMENT PLAN

APPENDIX B – ADOPTION RESOLUTION

RESOLUTION 21-04
RESOLUTION OF THE GOVERNING BOARD OF
WEST KERN WATER DISTRICT
ADOPTING THE URBAN WATER
MANAGEMENT PLAN 2020 UPDATE
RESCINDING RESOLUTION NO. 16-02

WHEREAS, the California Urban Water Management Planning Act, Water Code section 10610 et seq. (the Act) mandates that every urban water supplier providing water for municipal purposes to more than 3,000 customers or supplying more than 3,000 acre feet of water annually, prepare and adopt an updated Urban Water Management Plan (UWMP) at least once every five years.

WHEREAS, the West Kern Water District (WKWD) is an urban water supplier for purposes of the Act, and approved and adopted its most recent 2015 UWMP and submitted that UWMP to the California Department of Water Resources (DWR); and

WHEREAS, the Water Conservation Act of 2009, Water Code section 10608 et seq. (SBX7-7), established requirements for urban retail water suppliers to prepare urban water use targets in accordance with the goals of SBX7-7 to reduce statewide daily per capita water use by 20 percent by the year 2020; and

WHEREAS, the West Kern Water District is an "urban retail water supplier" for purposes of SBX7-7 because it directly provides potable municipal water to more than 3,000 end users; and

WHEREAS, in accordance with applicable law, including the requirements of the Act and SBX7-7, the West Kern Water District has prepared its UWMP 2020 Update and has undertaken certain agency coordination, public notice, public involvement and outreach, public comment, and other procedures in relation to its UWMP 2020 Update; and

WHEREAS, the District updated it's Water Shortage Response Plan (WSRP) as part of this UWMP 2020 Update, and adoption of the UWMP will include adoption of the revised WSRP. The WSRP was revised to provide better guidance on how decisions are made to declare water shortage Response Levels, and greater flexibility in selecting which water conservation measures will be required; and

WHEREAS, as authorized by Section 10620(e) of the Act, the West Kern Water District has prepared its UWMP 2020 Update with its own staff, with the assistance of consulting professionals, and in cooperation with other governmental agencies, and has utilized and relied upon industry standards and the expertise of industry professionals in preparing its UWMP, and has also in part utilized and relied upon the DWR Urban Water Management Plans - Guidebook for Urban Water Suppliers (March 2021) in preparing its UWMP 2020 Update; and

WHEREAS, in accordance with applicable law, including Water Code sections 10608.26 and 10642, and Government Code section 6066, the West Kern Water District made its Draft UWMP 2020 Update available for public inspection, and caused to be published within the jurisdiction of the West Kern Water District at least two notices of public hearing regarding the WKWD's UWMP 2020 Update; and

WHEREAS, the West Kern Water District held its public hearing on June 22, 2021 in the Board Room of the West Kern Water District, located at 800 Kern Street, Taft CA, regarding its UWMP 2020 Update, wherein, among other things, members of the public and other interested entities were provided with the opportunity to be heard in connection with the District's UWMP 2020 Update and the proposed adoption thereof; and

WHEREAS, pursuant to said June 22, 2021 public hearing on the UWMP 2020 Update, the West Kern Water District encouraged the active involvement of diverse social, cultural, and economic elements of the population within the West Kern Water District's service area with regard to the preparation and adoption of the 2020 UWMP Update, allowed input by members of the public and any other interested party regarding all aspects of the 2020 UWMP Update, allowed community input regarding the District's implementation plan for complying with SBX7-7, and considered the economic impacts of the District's implementation plan for complying with SBX7-7; and

WHEREAS, the Board of Directors of the West Kern Water District has reviewed and considered the purposes and requirements and of the Urban Water Management Planning Act and SBX7-7, the contents of the UWMP 2020 Update, the documentation contained in the administrative record in support of the UWMP 2020 Update, and all public and agency input received with regard to the UWMP 2020 Update, and has determined that the factual analyses and conclusions set forth in the UWMP 2020 Update are supported by substantial evidence.

NOW, THEREFORE, be it resolved, determined, and ordered by the board of directors of the West Kern Water District as follows:

1. The General Manager of the West Kern Water District is hereby authorized and directed to include a copy of this Resolution in the West Kern Water District's Urban Water Management Plan 2020 Update and, in accordance with Water Code section 10644(a), to file the Urban Water Management Plan 2020 Update with the California Department of Water Resources, the California State Library, and any city or county within which the District provides water supplies within thirty (30) days of this adoption date.
2. The General Manager is hereby authorized and directed, in accordance with Water Code section 10645, to make the Urban Water Management Plan 2020 Update available for public review during normal business hours not later than thirty (30) days after

filing a copy thereof with the California Department of Water Resources.

3. The General Manager is hereby authorized and directed, in accordance with Water Code section 10635(b), to provide that portion of the Urban Water Management 2020 Plan Update prepared pursuant to Water Code section 10635(a) to any city or county within which the District provides water supplies not later than sixty (60) days after filing a copy thereof with the California Department of Water Resources.
4. The General Manager is hereby authorized and directed to implement the components of the Urban Water Management Plan 2020 Update in accordance with the Urban Water Management Planning Act and SBX7-7, including, but not limited to, the West Kern Water District's Water Conservation Programs and its Water Shortage Response Plan.
5. The General Manager is hereby authorized and directed to recommend to the Board of Directors additional steps necessary or appropriate to effectively carry out the implementation of the Urban Water Management 2020 Plan Update, the Urban Water Management Planning Act and SBX7-7.

All the foregoing being upon the motion of Director Niblett, seconded by Director Morris, carried by the following vote:

AYES:	President David A. Wells Vice President Barry Jameson Director Gary Morris Director Scott Niblett Director Bo Bravo
NOES:	None
ABSENT:	None
ABSTAIN:	None

ADOPTED, SIGNED AND APPROVED this 22ND day of June, 2021.

DAVID A. WELLS,
President of the Board of Directors
WEST KERN WATER DISTRICT

SECRETARY'S CERTIFICATE

I, Greg A. Hammett, being the appointed secretary of the **West Kern Water District,** do hereby certify that the above and foregoing **Resolution No. 21-04** was duly adopted by the Board of Directors of said District at a legally convened meeting of said Board held on the **22nd day of June, 2021,** that the above and foregoing is a full, true, and correct copy of **Resolution 21-04**, and that the same has not been amended or repealed.

ATTEST:

GREG A. HAMMETT
Secretary of the Board of Directors
WEST KERN WATER DISTRICT

(SEAL)



APPENDIX C – STANDARDIZED DWR TABLES

Submittal Table 2-1 Retail Only: Public Water Systems			
Public Water System Number	Public Water System Name	Number of Municipal Connections 2020	Volume of Water Supplied 2020 *
Add additional rows as needed			
1510222	West Kern Water District	7,379	16,338
	TOTAL	7,379	16,338
NOTES: Unit of volume in acre-feet			

Submittal Table 2-2: Plan Identification			
Select Only One	**Type of Plan**		**Name of RUWMP or Regional Alliance** *if applicable* (select from drop down list)
☑	**Individual UWMP**		
	☐	Water Supplier is also a member of a RUWMP	
	☐	Water Supplier is also a member of a Regional Alliance	
☐	**Regional Urban Water Management Plan (RUWMP)**		
NOTES:			

Submittal Table 2-3: Supplier Identification	
Type of Supplier (select one or both)	
☐	Supplier is a wholesaler
☑	Supplier is a retailer
Fiscal or Calendar Year (select one)	
☑	UWMP Tables are in calendar years
☐	UWMP Tables are in fiscal years
Unit	AF
NOTES:	

Submittal Table 2-4 Retail: Water Supplier Information Exchange
The retail Supplier has informed the following wholesale supplier(s) of projected water use in accordance with Water Code Section 10631.
Wholesale Water Supplier Name
Add additional rows as needed
Kern County Water Agency
NOTES:

Submittal Table 3-1 Retail: Population - Current and Projected						
Population Served	2020	2025	2030	2035	2040	2045*(opt)*
	22,172	22,097	22,542	22,997	23,460	23,933
NOTES:						

Submittal Table 4-1 Retail: Demands for Potable and Non-Potable[1] Water - Actual			
Use Type	2020 Actual		
Drop down list May select each use multiple times These are the only Use Types that will be recognized by the WUEdata online submittal tool	Additional Description (as needed)	Level of Treatment When Delivered Drop down list	Volume[2]
Add additional rows as needed			
Single Family	Residential	Drinking Water	2,594
Industrial	Treated	Drinking Water	9,867
Industrial	La Paloma deliveries	Raw Water	1,571
Commercial		Drinking Water	1,839
Losses		Drinking Water	467
		TOTAL	16,338
NOTES:			

Submittal Table 4-2 Retail: Use for Potable and Non-Potable[1] Water - Projected						
Use Type	Additional Description (as needed)	Projected Water Use[2] *Report To the Extent that Records are Available*				
Drop down list May select each use multiple times These are the only Use Types that will be recognized by the WUEdata online submittal tool		2025	2030	2035	2040	2045 (opt)
Add additional rows as needed						
Single Family	Residential	2,585	2,637	2,690	2,744	2,800
Commercial		1,833	1,870	1,908	1,946	1,985
Industrial	Treated	9,400	9,400	9,400	9,400	9,400
Industrial	Raw water	3,000	3,000	3,000	3,000	3,000
Losses		538	541	544	547	550
	TOTAL	17,356	17,448	17,542	17,637	17,735
NOTES:						

Submittal Table 4-3 Retail: Total Water Use (Potable and Non-Potable)						
	2020	2025	2030	2035	2040	2045 (opt)
Potable Water, Raw, Other Non-potable *From Tables 4-1R and 4-2 R*	16,338	17,356	17,448	17,542	17,637	17,735
Recycled Water Demand[1] *From Table 6-4*	0	0	0	0	0	0
Optional Deduction of Recycled Water Put Into Long-Term Storage[2]	0	0	0	0	0	0
TOTAL WATER USE	16,338	17,356	17,448	17,542	17,637	17,735
NOTES:						

Submittal Table 4-4 Retail: Last Five Years of Water Loss Audit Reporting	
Reporting Period Start Date (mm/yyyy)	Volume of Water Loss [1,2]
01/2016	2325
01/2017	2,485
01/2018	2,474
01/2019	481
01/2020	467
NOTES: The more recent numbers are considered more accurate due to issues with data management. Refer to UWMP for more details.	

Submittal Table 4-5 Retail Only: Inclusion in Water Use Projections	
Are Future Water Savings Included in Projections? (Refer to Appendix K of UWMP Guidebook) *Drop down list (y/n)*	No
If "Yes" to above, state the section or page number, in the cell to the right, where citations of the codes, ordinances, or otherwise are utilized in demand projections are found.	
Are Lower Income Residential Demands Included In Projections? *Drop down list (y/n)*	Yes
NOTES:	

Submittal Table 5-2: 2020 Compliance				**From**
SB X7-7 2020 Compliance Form				
Retail Supplier or Regional Alliance Only				
2020 GPCD			2020 Confirmed Target GPCD*	Did Supplier Achieve Targeted Reduction for 2020? Y/N
Actual 2020 GPCD*	2020 TOTAL Adjustments*	Adjusted 2020 GPCD* *(Adjusted if applicable)*		
185	*0*	*185*	*189*	*Yes*
**All cells in this table should be populated manually from the supplier's SBX7-7 2020 Compliance Form and reported in Gallons per Capita per Day (GPCD)*				
NOTES:				

Submittal Table 6-1 Retail: Groundwater Volume Pumped						
☐	Supplier does not pump groundwater. The supplier will not complete the table below.					
☐	All or part of the groundwater described below is desalinated.					
Groundwater Type ***Drop Down List*** *May use each category multiple times*	Location or Basin Name	2016*	2017*	2018*	2019*	2020*
Add additional rows as needed						
Alluvial Basin	Kern County Subbasin	16300	15392	15765	15487	14767
	TOTAL	16,300	15,392	15,765	15,487	14,767
NOTES:						

Submittal Table 6-2 Retail: Wastewater Collected Within Service Area in 2020						
☐	Percentage of 2020 service area covered by wastewater collection system *(optional)*					
	Percentage of 2020 service area population covered by wastewater collection system *(optional)*					
Wastewater Collection			**Recipient of Collected Wastewater**			
Name of Wastewater Collection Agency	Wastewater Volume Metered or Estimated? *Drop Down List*	Volume of Wastewater Collected from UWMP Service Area 2020 *	Name of Wastewater Treatment Agency Receiving Collected Wastewater	Treatment Plant Name	Is WWTP Located Within UWMP Area? *Drop Down List*	Is WWTP Operation Contracted to a Third Party? *(optional)* *Drop Down List*
City of Taft and Ford City /Taft Heights Sanitation District	Metered	1,085	City of Taft and Ford City /Taft Heights Sanitation District	Taft Wastewater Treatment Facility	Yes	Yes
Total Wastewater Collected from Service Area in 2020:		1,085				
NOTES:						

☑	**No wastewater is treated or disposed of within the UWMP service area.** The supplier will not complete the table below.										
Wastewater Treatment Plant Name	Discharge Location Name or Identifier	Discharge Location Description	Wastewater Discharge ID Number *(optional)* [2]	Method of Disposal ***Drop down list***	Does This Plant Treat Wastewater Generated Outside the Service Area? ***Drop down list***	Treatment Level ***Drop down list***	**2020 volumes** [1]				
							Wastewater Treated	Discharged Treated Wastewater	Recycled Within Service Area	Recycled Outside of Service Area	Instream Flow Permit Requirement
Taft WWTF	Agricualtural Fields	Adjacent Agricualtural lands		Land disposal	No	Secondary, Undisinfected	1,085	1,085	1,085		
						Total	1,085	1,085	1,085	0	0

NOTES:

Submittal Table 6-4 Retail: Recycled Water Direct Beneficial Uses Within Service Area

☑	Recycled water is not used and is not planned for use within the service area of the supplier. The supplier will not complete the table below.

Name of Supplier Producing (Treating) the Recycled Water:	
Name of Supplier Operating the Recycled Water Distribution System:	
Supplemental Water Added in 2020 (volume) *Include units*	
Source of 2020 Supplemental Water	

Beneficial Use Type *Insert additional rows if needed.*	**Potential** Beneficial Uses of Recycled Water (Describe)	Amount of **Potential** Uses of Recycled Water (Quantity) *Include volume units* [1]	General Description of 2020 Uses	Level of Treatment *Drop down list*	2020 [1]	2025 [1]	2030 [1]	2035 [1]	2040 [1]	2045 [1] (opt)
Agricultural irrigation										
Landscape irrigation (exc golf courses)										
Golf course irrigation										
Commercial use										
Industrial use										
Geothermal and other energy production										
Seawater intrusion barrier										
Recreational impoundment										
Wetlands or wildlife habitat										
Groundwater recharge (IPR)										
Reservoir water augmentation (IPR)										
Direct potable reuse										
Other (Description Required)										
				Total:	0	0	0	0	0	0
				2020 Internal Reuse						

NOTES:

☑	Recycled water was not used in 2015 nor projected for use in 2020. The supplier will not complete the table below. If recycled water was not used in 2020, and was not predicted to be in 2015, then check the box and do not complete the table.

Beneficial Use Type	2015 Projection for 2020 [1]	2020 Actual Use[1]
Insert additional rows as needed.		
Agricultural irrigation		
Landscape irrigation (exc golf courses)		
Golf course irrigation		
Commercial use		
Industrial use		
Geothermal and other energy production		
Seawater intrusion barrier		
Recreational impoundment		
Wetlands or wildlife habitat		
Groundwater recharge (IPR)		
Reservoir water augmentation (IPR)		
Direct potable reuse		
Other (Description Required)		
Total	0	0

NOTE:

Submittal Table 6-6 Retail: Methods to Expand Future Recycled Water Use			
☑	Supplier does not plan to expand recycled water use in the future. Supplier will not complete the table below but will provide narrative explanation.		
	Provide page location of narrative in UWMP		
Name of Action	Description	Planned Implementation Year	Expected Increase in Recycled Water Use *
Add additional rows as needed			
		Total	0
NOTES:			

Submittal Table 6-7 Retail: Expected Future Water Supply Projects or Programs						
☐	No expected future water supply projects or programs that provide a quantifiable increase to the agency's water supply. Supplier will not complete the table below.					
☐	Some or all of the supplier's future water supply projects or programs are not compatible with this table and are described in a narrative format.					
	Provide page location of narrative in the UWMP					
Name of Future Projects or Programs	Joint Project with other suppliers?		Description (if needed)	Planned Implementation Year	Planned for Use in Year Type *Drop Down List*	Expected Increase in Water Supply to Supplier* *This may be a range*
	Drop Down List (y/n)	*If Yes, Supplier Name*				
Add additional rows as needed						
California Water Fix	Yes	State of California	Improvements to Delta to improve water reliability	Unknown	Average Year	2,200 AF (7% of SWP contract)
Autmoatic Meter Reading	No		Install new AMR meters. Some have already been installed.	In progress	All Year Types	Unknown, some increase in efficiency expected
NOTES:						

Submittal Table 6-8 Retail: Water Supplies — Actual

Water Supply	Additional Detail on Water Supply	2020		
Drop down list May use each category multiple times.These are the only water supply categories that will be recognized by the WUEdata online submittal tool		Actual Volume*	Water Quality Drop Down List	Total Right or Safe Yield* (optional)
Add additional rows as needed				
Groundwater (not desalinated)	Banked groundwater	14,767	Drinking Water	
	Total	14,767		0
NOTES:				

OPTIONAL Table 6-8 Retail: Water Supplies — Actual *Potable*

Water Supply	Additional Detail on Water Supply	2020		
Drop down list May use each category multiple times.These are the only water supply categories that will be recognized by the WUEdata online submittal tool		Actual Volume*	Water Quality Drop Down List	Total Right or Safe Yield* (optional)
Add additional rows as needed				
Purchased or Imported Water	Raw SWP water	1,571	Other Non-Potable Water	
	Total	1,571		0
NOTES:				

Submittal Table 6-9 Retail: Water Supplies — Projected											
Water Supply		Projected Water Supply * Report To the Extent Practicable									
Drop down list May use each category multiple times. These are the only water supply categories that will be recognized by the WUEdata online submittal tool	Additional Detail on Water Supply	**2025**		**2030**		**2035**		**2040**		**2045** (opt)	
		Reasonably Available Volume	Total Right or Safe Yield (optional)	Reasonably Available Volume	Total Right or Safe Yield (optional)	Reasonably Available Volume	Total Right or Safe Yield (optional)	Reasonably Available Volume	Total Right or Safe Yield (optional)	Reasonably Available Volume	Total Right or Safe Yield (optional)
Add additional rows as needed											
		40,341		40,227		40,147		39,418		39,340	
	Total	40,341	0	40,227	0	40,147	0	39,418	0	39,340	0
NOTES:											

Submittal Table 7-1 Retail: Basis of Water Year Data (Reliability Assessment)			
Year Type	**Base Year** If not using a calendar year, type in the last year of the fiscal, water year, or range of years, for example, water year 2019-2020, use 2020	**Available Supplies if Year Type Repeats**	
		☐	Quantification of available supplies is not compatible with this table and is provided elsewhere in the UWMP. Location _____
		☑	Quantification of available supplies is provided in this table as either volume only, percent only, or both.
		Volume Available *	**% of Average Supply**
Average Year	Long-Term Avg	18600	100%
Single-Dry Year	2014	1600	8%
Consecutive Dry Years 1st Year	1988	3500	19%
Consecutive Dry Years 2nd Year	1989	14500	78%
Consecutive Dry Years 3rd Year	1990	4400	24%
Consecutive Dry Years 4th Year	1991	7900	42%
Consecutive Dry Years 5th Year	1992	5400	29%
NOTES:			

Submittal Table 7-2 Retail: Normal Year Supply and Demand Comparison					
	2025	2030	2035	2040	2045 *(Opt)*
Supply totals (*autofill from Table 6-9)*	40,341	40,227	40,147	39,418	39,340
Demand totals *(autofill from Table 4-3)*	17,356	17,448	17,542	17,637	17,735
Difference	22,985	22,779	22,605	21,781	21,605
NOTES:					

Submittal Table 7-3 Retail: Single Dry Year Supply and Demand Comparison					
	2025	2030	2035	2040	2045 (Opt)
Supply totals*	17,356	17,448	17,542	17,637	17,735
Demand totals*	17,356	17448	17,542	17,637	17,735
Difference	0	0	0	0	0
NOTES: No shortages will occur since banked groundwater will be used to meet demands not met by current year water supplies					

Submittal Table 7-4 Retail: Multiple Dry Years Supply and Demand Comparison						
		2025*	2030*	2035*	2040*	2045* (Opt)
First year	Supply totals	17,356	17,448	17,542	17,637	17,735
	Demand totals	17,356	17,448	17,542	17,637	17,735
	Difference	0	0	0	0	0
Second year	Supply totals	17,356	17,448	17,542	17,637	17,735
	Demand totals	17,356	17,448	17,542	17,637	17,735
	Difference	0	0	0	0	0
Third year	Supply totals	15,620	15,703	15,788	15,873	15,962
	Demand totals	15,620	15,703	15,788	15,873	15,962
	Difference	0	0	0	0	0
Fourth year	Supply totals	15,620	15,703	15,788	15,873	15,962
	Demand totals	15,620	15,703	15,788	15,873	15,962
	Difference	0	0	0	0	0
Fifth year	Supply totals	15,620	15,703	15,788	15,873	15,962
	Demand totals	15,620	15,703	15,788	15,873	15,962
	Difference	0	0	0	0	0
Sixth year *(optional)*	Supply totals					
	Demand totals					
	Difference	0	0	0	0	0
NOTES: No shortages will occur since banked groundwater will be used to meet demands not met by current year water supplies. 10% conservation measures implemented in year 3.						

Submittal Table 7-5: Five-Year Drought Risk Assessment Tables to address Water Code Section 10635(b)

2021	Total
Total Water Use	16,194
Total Supplies	3,500
Surplus/Shortfall w/o WSCP Action	(12,694)
Planned WSCP Actions (use reduction and supply augmentation)	
WSCP - supply augmentation benefit	12694
WSCP - use reduction savings benefit	0
Revised Surplus/(shortfall)	0
Resulting % Use Reduction from WSCP action	0%

2022	Total
Total Water Use	16,051
Total Supplies	14,500
Surplus/Shortfall w/o WSCP Action	(1,551)
Planned WSCP Actions (use reduction and supply augmentation)	
WSCP - supply augmentation benefit	1551
WSCP - use reduction savings benefit	0
Revised Surplus/(shortfall)	0
Resulting % Use Reduction from WSCP action	0%

2023	Total
Total Water Use	14,317
Total Supplies	4,400
Surplus/Shortfall w/o WSCP Action	(9,917)
Planned WSCP Actions (use reduction and supply augmentation)	
WSCP - supply augmentation benefit	8485
WSCP - use reduction savings benefit	1,432
Revised Surplus/(shortfall)	0
Resulting % Use Reduction from WSCP action	10%

2024	Total
Total Water Use	12,756
Total Supplies	7,900
Surplus/Shortfall w/o WSCP Action	(4,856)
Planned WSCP Actions (use reduction and supply augmentation)	
WSCP - supply augmentation benefit	3580
WSCP - use reduction savings benefit	1,276
Revised Surplus/(shortfall)	0
Resulting % Use Reduction from WSCP action	10%

2025	Total
Total Water Use	15,620
Total Supplies	5,400
Surplus/Shortfall w/o WSCP Action	(10,220)
Planned WSCP Actions (use reduction and supply augmentation)	
WSCP - supply augmentation benefit	8658
WSCP - use reduction savings benefit	1,562
Revised Surplus/(shortfall)	0
Resulting % Use Reduction from WSCP action	10%

Submittal Table 8-1
Water Shortage Contingency Plan Levels

Shortage Level	Percent Shortage Range	Shortage Response Actions (*Narrative description*)
1	Up to 10%	Reduce water use by up to 10%
2	Up to 20%	Reduce water use by up to 20%
3	Up to 30%	Reduce water use by up to 30%
4	Up to 40%	Reduce water use by up to 40%
5	Up to 50%	Reduce water use by up to 50%
6	>50%	Reduce water use by over 50%

NOTES:

Submittal Table 8-2: Demand Reduction Actions

Shortage Level	Demand Reduction Actions ***Drop down list*** *These are the only categories that will be accepted by the WUEdata online submittal tool. Select those that apply.*	How much is this going to reduce the shortage gap? *Include units used (volume type or percentage)*	Additional Explanation or Reference *(optional)*	Penalty, Charge, or Other Enforcement? ***For Retail Suppliers Only*** *Drop Down List*
Add additional rows as needed				
1-6	Expand Public Information Campaign			

NOTES:

Submittal Table 8-3: Supply Augmentation and Other Actions			
Shortage Level	Supply Augmentation Methods and Other Actions by Water Supplier ***Drop down list*** *These are the only categories that will be accepted by the WUEdata online submittal tool*	How much is this going to reduce the shortage gap? *Include units used (volume type or percentage)*	Additional Explanation or Reference *(optional)*
Add additional rows as needed			
1-6	Stored Emergency Supply	Retrieve banked groundwater	
NOTES:			

Submittal Table 10-1 Retail: Notification to Cities and Counties		
City Name	60 Day Notice	Notice of Public Hearing
Add additional rows as needed		
Taft	Yes	Yes
Maricopa	Yes	Yes
County Name *Drop Down List*	60 Day Notice	Notice of Public Hearing
Add additional rows as needed		
Kern County	Yes	Yes
NOTES:		

SB X7-7 Table 0: Units of Measure Used in 2020 UWMP* *(select one from the drop down list)*
Acre Feet
NOTES: None

SB X7-7 Table 2: Method for 2020 Population Estimate	
Method Used to Determine 2020 Population (may check more than one)	
☐	**1. Department of Finance** (DOF) or **American Community Survey** (ACS)
☑	**2. Persons-per-Connection Method**
☐	**3. DWR Population Tool**
☐	**4. Other** DWR recommends pre-review
NOTES:	

SB X7-7 Table 3: 2020 Service Area Population	
2020 Compliance Year Population	
2020	22,172
NOTES: None	

SB X7-7 Table 4: 2020 Gross Water Use							
		2020 Deductions					
Compliance Year 2020	**2020 Volume Into Distribution System** *This column will remain blank until SB X7-7 Table 4-A is completed.*	**Exported Water ***	**Change in Dist. System Storage*** (+/-)	**Indirect Recycled Water** *This column will remain blank until SB X7-7 Table 4-B is completed.*	**Water Delivered for Agricultural Use***	**Process Water** *This column will remain blank until SB X7-7 Table 4-D is completed.*	**2020 Gross Water Use**
	16,338			-	-	11,738	**4,600**
NOTES:							

SB X7-7 Table 4-A: 2020 Volume Entering the Distribution System(s), Meter Error Adjustment

Complete one table for each source.

Name of Source	Groundwater and Raw Water
This water source is *(check one)* **:**	
☑	The supplier's own water source
☐	A purchased or imported source

Compliance Year 2020	Volume Entering Distribution System [1]	Meter Error Adjustment [2] *Optional (+/-)*	Corrected Volume Entering Distribution System
	16,338	-	16,338

NOTES

SB X7-7 Table 4-A: 2020 Volume Entering the Distribution System(s) Meter Error Adjustment

Complete one table for each source.

Name of Source	State Water Allocation
This water source is *(check one)* **:**	
☐	The supplier's own water source
☑	A purchased or imported source

Compliance Year 2020	Volume Entering Distribution System [1]	Meter Error Adjustment [2] *Optional (+/-)*	Corrected Volume Entering Distribution System
			0

NOTES:

Data from this table will not be entered into WUEdata.
Instead, the entire table will be uploaded to WUEdata as a separate upload in Excel format.

SB X7-7 Table 4-C: 2020 Process Water Deduction Eligibility **(For use only by agencies that are deducting process water) Choose Only One**	
☑	**Criteria 1**- Industrial water use is equal to or greater than 12% of gross water use. Complete SB X7-7 Table 4-C.1
☐	**Criteria 2** - Industrial water use is equal to or greater than 15 GPCD. Complete SB X7-7 Table 4-C.2
☐	**Criteria 3** - Non-industrial use is equal to or less than 120 GPCD. Complete SB X7-7 Table 4-C.3
☐	**Criteria 4** - Disadvantaged Community. Complete SB x7-7 Table 4-C.4
NOTES:	

Data from this table will not be entered into WUEdata.
Instead, the entire table will be uploaded to WUEdata as a separate upload in Excel format.

SB X7-7 Table 4-C.1: 2020 Process Water Deduction Eligibility *(For use only by agencies that are deducting process water using Criteria 1)*

Criteria 1
Industrial water use is equal to or greater than 12% of gross water use

2020 Compliance Year	2020 Gross Water Use Without Process Water Deduction	2020 Industrial Water Use	Percent Industrial Water	**Eligible for Exclusion Y/N**
	16,338	11,753	72%	YES

NOTES: Industrial water = Treated water deliveries + 3.2% losses + La Paloma deliveries - Industrial water deliveries moved to the commercial category.

Data from this table will not be entered into WUEdata.
Instead, the entire table will be uploaded to WUEdata as a separate upload in Excel format.

SB X7-7 Table 4-C.3: 2020 Process Water Deduction Eligibility *(For use only*
by agencies that are deducting process water using Criteria 3)

Criteria 3
Non-industrial use is equal to or less than 120 GPCD

2020 Compliance Year	2020 Gross Water Use Without Process Water Deduction *Fm SB X7-7 Table 4*	2020 Industrial Water Use	2020 Non-industrial Water Use	2020 Population *Fm SB X7-7 Table 3*	Non-Industrial GPCD	**Eligible for Exclusion Y/N**
	16,338		16,338	22,172	658	NO

NOTES:

Data from these tables will not be entered into WUEdata. Instead, the entire tables will be uploaded to WUEdata as a separate upload in Excel format.

This table(s) is only for Suppliers that deduct process water from their 2020 gross water use.

SB X7-7 Table 4-D: 2020 Process Water Deduction - Volume *Complete a separate table for each industrial customer with a process water exclusion*

Name of Industrial Customer	*La Paloma*				
Compliance Year 2020	Industrial Customer's Total Water Use *	Total Volume Provided by Supplier*	% of Water Provided by Supplier	Customer's Total Process Water Use*	Volume of Process Water Eligible for Exclusion for this Customer
	1,571	1,571	100%	1,571	1,571

*** Units of measure (AF, MG , or CCF)** must remain consistent throughout the UWMP, as reported in SB X7-7 Table 0 and Submittal Table 2-3.

NOTES: La Poloma received raw untreated water

SB X7-7 Table 4-D: 2020 Process Water Deduction - Volume *Complete a separate table for each industrial customer with a process water exclusion*

Name of Industrial Customer	*Numerous other power and oil companies*				
Compliance Year 2020	Industrial Customer's Total Water Use *	Total Volume Provided by Supplier*	% of Water Provided by Supplier	Customer's Total Process Water Use*	Volume of Process Water Eligible for Exclusion for this Customer
	10,167	10,167	100%	10,167	10,167

*** Units of measure (AF, MG , or CCF)** must remain consistent throughout the UWMP, as reported in SB X7-7 Table 0 and Submittal Table 2-3.

NOTES: There are too many industrial customers to list. These customers received treated potable water. Volume includes industrial deliveries plus 3.2% for losses

SB X7-7 Table 5: 2020 Gallons Per Capita Per Day (GPCD)		
2020 Gross Water *Fm SB X7-7 Table 4*	**2020 Population** *Fm SB X7-7 Table 3*	**2020 GPCD**
4,600	22,172	**185**
NOTES:		

SB X7-7 Table 9: 2020 Compliance

Actual 2020 GPCD[1]	Optional Adjustments to 2020 GPCD (Enter "0" if Adjustment Not Used)			TOTAL Adjustments[1]	Adjusted 2020 GPCD [1] *(Adjusted if applicable)*	2020 Confirmed Target GPCD [1, 2]	**Did Supplier Achieve Targeted Reduction for 2020?**
	Extraordinary Events[1]	Weather Normalization[1]	Economic Adjustment[1]				
185	-	-	-	-	185	189	**YES**

[1] *All values are reported in GPCD*

[2] ***2020 Confirmed Target GPCD*** *is taken from the Supplier's SB X7-7 Verification Form Table SB X7-7, 7-F.*

NOTES:

WUEdata Entry Exceptions

The data from the tables below will not be entered into WUEdata tables (the tabs for these tables' worksheets are colored **purple**). These tables will be submitted as separate uploads, in Excel, to WUEdata.

Process Water Deduction

SB X7-7 tables 4-C, 4-C.1, 4-C.2, 4-C.3, 4-C.4 and 4-D A supplier that will use the process water deduction will complete the appropriate tables in Excel, submit them as a separate upload to the WUE data tool, and include them in its UWMP.

Target Method 2

SB X7-7 tables 7-B, 7-C, and 7-D

A supplier that selects Target Method 2 will contact DWR (gwen.huff@water.ca.gov) for SB X7-7 tables 7-B, 7-C, and 7-D.

Target Method 4

These tables are only available online at http://www.dwr.water.ca.gov/wateruseefficiency/sb7/committees/urban/u4/ptm4.cfm A supplier that selects Target Method 4 will save the tables from the website listed above, complete the tables, submit as a separate upload to WUE data, and include them with its UWMP.

SB X7-7 Table 0: Units of Measure Used in UWMP* *(select one from the drop down list)*
Acre Feet
**The unit of measure must be consistent with Table 2-3*
NOTES:

SB X7-7 Table-1: Baseline Period Ranges			
Baseline	**Parameter**	**Value**	**Units**
10- to 15-year baseline period	2008 total water deliveries	21,788	Acre Feet
	2008 total volume of delivered recycled water	-	Acre Feet
	2008 recycled water as a percent of total deliveries	0.00%	Percent
	Number of years in baseline period[1, 2]	10	Years
	Year beginning baseline period range	2000	
	Year ending baseline period range[3]	2009	
5-year baseline period	Number of years in baseline period	5	Years
	Year beginning baseline period range	2005	
	Year ending baseline period range[4]	2009	

[1] If the 2008 recycled water percent is less than 10 percent, then the first baseline period is a continuous 10-year period. If the amount of recycled water delivered in 2008 is 10 percent or greater, the first baseline period is a continuous 10- to 15-year period. *[2] The Water Code requires that the baseline period is between 10 and 15 years. However, DWR recognizes that some water suppliers may not have the minimum 10 years of baseline data.*

[3] The ending year must be between December 31, 2004 and December 31, 2010.

[4] The ending year must be between December 31, 2007 and December 31, 2010.

NOTES:

SB X7-7 Table 2: Method for Population Estimates	
Method Used to Determine Population (may check more than one)	
☐	**1. Department of Finance** (DOF) DOF Table E-8 (1990 - 2000) and (2000-2010) and DOF Table E-5 (2011 - 2015) when available
☑	**2. Persons-per-Connection Method**
☐	**3. DWR Population Tool**
☑	**4. Other** DWR recommends pre-review
NOTES:	

SB X7-7 Table 3: Service Area Population		
Year		**Population**
10 to 15 Year Baseline Population		
Year 1	2000	16,778
Year 2	2001	17,176
Year 3	2002	17,574
Year 4	2003	17,973
Year 5	2004	18,371
Year 6	2005	18,769
Year 7	2006	19,167
Year 8	2007	19,565
Year 9	2008	19,964
Year 10	2009	20,362
Year 11		
Year 12		
Year 13		
Year 14		
Year 15		
5 Year Baseline Population		
Year 1	2005	18,769
Year 2	2006	19,167
Year 3	2007	19,565
Year 4	2008	19,964
Year 5	2009	20,362
2015 Compliance Year Population		
2015		20,591
NOTES:		

SB X7-7 Table 4: Annual Gross Water Use *								
Baseline Year *Fm SB X7-7 Table 3*		**Volume Into Distribution System** *This column will remain blank until SB X7-7 Table 4-A is completed.*	**Deductions**					**Annual Gross Water Use**
			Exported Water	**Change in Dist. System Storage** (+/-)	**Indirect Recycled Water** *This column will remain blank until SB X7-7 Table 4-B is completed.*	**Water Delivered for Agricultural Use**	**Process Water** *This column will remain blank until SB X7-7 Table 4-D is completed.*	
10 to 15 Year Baseline - Gross Water Use								
Year 1	2000	15,906			-		12,233	3,673
Year 2	2001	16,236			-		12,073	4,163
Year 3	2002	17,574			-		13,011	4,563
Year 4	2003	18,911			-		14,262	4,649
Year 5	2004	20,883			-		15,692	5,191
Year 6	2005	21,239			-		15,914	5,325
Year 7	2006	22,457			-		16,907	5,550
Year 8	2007	22,612			-		16,941	5,671
Year 9	2008	21,788			-		16,351	5,437
Year 10	2009	21,740			-		16,567	5,173
Year 11	0	-			-		-	-
Year 12	0	-			-		-	-
Year 13	0	-			-		-	-
Year 14	0	-			-		-	-
Year 15	0	-			-		-	-
10 - 15 year baseline average gross water use								**4,939**
5 Year Baseline - Gross Water Use								
Year 1	2005	21,239			-		15,914	5,325
Year 2	2006	22,457			-		16,907	5,550
Year 3	2007	22,612			-		16,941	5,671
Year 4	2008	21,788			-		16,351	5,437
Year 5	2009	21,740			-		16,567	5,173
5 year baseline average gross water use								**5,431**
2015 Compliance Year - Gross Water Use								
2015		16,542	-		-		12,508	**4,034**

* NOTE that the units of measure must remain consistent throughout the UWMP, as reported in Table 2-3

NOTES: Exludes direct raw water deliveries to La Paloma Powerplant

SB X7-7 Table 4-A: Volume Entering the Distribution System(s)

Complete one table for each source.

Name of Source	District wells and banked groundwater
This water source is:	
☑	The supplier's own water source
☐	A purchased or imported source

Baseline Year *Fm SB X7-7 Table 3*		Volume Entering Distribution System	Meter Error Adjustment* *Optional (+/-)*	Corrected Volume Entering Distribution System
10 to 15 Year Baseline - Water into Distribution System				
Year 1	2000	15,906		15,906
Year 2	2001	16,236		16,236
Year 3	2002	17,574		17,574
Year 4	2003	18,911		18,911
Year 5	2004	20,883		20,883
Year 6	2005	21,239		21,239
Year 7	2006	22,457		22,457
Year 8	2007	22,612		22,612
Year 9	2008	21,788		21,788
Year 10	2009	21,740		21,740
Year 11	0			-
Year 12	0			-
Year 13	0			-
Year 14	0			-
Year 15	0			-
5 Year Baseline - Water into Distribution System				
Year 1	2005	21,239		21,239
Year 2	2006	22,457		22,457
Year 3	2007	22,612		22,612
Year 4	2008	21,788		21,788
Year 5	2009	21,740		21,740
2015 Compliance Year - Water into Distribution System				
2015		16,542		16,542

** Meter Error Adjustment - See guidance in Methodology 1, Step 3 of Methodologies Document*

NOTES: Excludes raw water deliveries to La Paloma Powerplant

SB X7-7 Table 4-B: Indirect Recycled Water Use Deduction *(For use only by agencies that are deducting indirect recycled water)*

Baseline Year *Fm SB X7-7 Table 3*		**Surface Reservoir Augmentation**					**Groundwater Recharge**			**Total Deductible Volume of Indirect Recycled Water Entering the Distribution System**
		Volume Discharged from Reservoir for Distribution System Delivery	Percent Recycled Water	Recycled Water Delivered to Treatment Plant	Transmission/ Treatment Loss	Recycled Volume Entering Distribution System from Surface Reservoir Augmentation	Recycled Water Pumped by Utility*	Transmission/ Treatment Losses	Recycled Volume Entering Distribution System from Groundwater Recharge	
10-15 Year Baseline - Indirect Recycled Water Use										
Year 1	2000			-		-			-	-
Year 2	2001			-		-			-	-
Year 3	2002			-		-			-	-
Year 4	2003			-		-			-	-
Year 5	2004			-		-			-	-
Year 6	2005			-		-			-	-
Year 7	2006			-		-			-	-
Year 8	2007			-		-			-	-
Year 9	2008			-		-			-	-
Year 10	2009			-		-			-	-
Year 11	0			-		-			-	-
Year 12	0			-		-			-	-
Year 13	0			-		-			-	-
Year 14	0			-		-			-	-
Year 15	0			-		-			-	-
5 Year Baseline - Indirect Recycled Water Use										
Year 1	2005			-		-			-	-
Year 2	2006			-		-			-	-
Year 3	2007			-		-			-	-
Year 4	2008			-		-			-	-
Year 5	2009			-		-			-	-
2015 Compliance - Indirect Recycled Water Use										
2015				-		-			-	-

**Suppliers will provide supplemental sheets to document the calculation for their input into "Recycled Water Pumped by Utility". The volume reported in this cell must be less than total groundwater pumped - See Methodology 1, Step 8, section 2.c.*

NOTES:

SB X7-7 Table 4-C: Process Water Deduction Eligibility *(For use only by agencies that are deducting process water) Choose Only One*	
☑	**Criteria 1**- Industrial water use is equal to or greater than 12% of gross water use. Complete SB X7-7 Table 4-C.1
☐	**Criteria 2** - Industrial water use is equal to or greater than 15 GPCD. Complete SB X7-7 Table 4-C.2
☐	**Criteria 3** - Non-industrial use is equal to or less than 120 GPCD. Complete SB X7-7 Table 4-C.3
☐	**Criteria 4** - Disadvantaged Community. Complete SB x7-7 Table 4-C.4
NOTES:	

SB X7-7 Table 4-C.1: Process Water Deduction Eligibility

Criteria 1
Industrial water use is equal to or greater than 12% of gross water use

Baseline Year *Fm SB X7-7 Table 3*		Gross Water Use Without Process Water Deduction	Industrial Water Use	Percent Industrial Water	**Eligible for Exclusion Y/N**
10 to 15 Year Baseline - Process Water Deduction Eligibility					
Year 1	2000	15,906	12,233	77%	YES
Year 2	2001	16,236	12,073	74%	YES
Year 3	2002	17,574	13,011	74%	YES
Year 4	2003	18,911	14,262	75%	YES
Year 5	2004	20,883	15,692	75%	YES
Year 6	2005	21,239	15,914	75%	YES
Year 7	2006	22,457	16,907	75%	YES
Year 8	2007	22,612	16,941	75%	YES
Year 9	2008	21,788	16,351	75%	YES
Year 10	2009	21,740	16,567	76%	YES
Year 11	0	-			NO
Year 12	0	-			NO
Year 13	0	-			NO
Year 14	0	-			NO
Year 15	0	-			NO
5 Year Baseline - Process Water Deduction Eligibility					
Year 1	2005	21,239	15,914	75%	YES
Year 2	2006	22,457	16,907	75%	YES
Year 3	2007	22,612	16,941	75%	YES
Year 4	2008	21,788	16,351	75%	YES
Year 5	2009	21,740	16,567	76%	YES
2015 Compliance Year - Process Water Deduction Eligiblity					
2015		16,542	12,508	76%	YES

NOTES:

SB X7-7 Table 4-C.2: Process Water Deduction Eligibility

Criteria 2

Industrial water use is equal to or greater than 15 GPCD

Baseline Year *Fm SB X7-7 Table 3*		Industrial Water Use	Population	Industrial GPCD	**Eligible for Exclusion Y/N**
10 to 15 Year Baseline - Process Water Deduction Eligibility					
Year 1	2000		16,778	-	NO
Year 2	2001		17,176	-	NO
Year 3	2002		17,574	-	NO
Year 4	2003		17,973	-	NO
Year 5	2004		18,371	-	NO
Year 6	2005		18,769	-	NO
Year 7	2006		19,167	-	NO
Year 8	2007		19,565	-	NO
Year 9	2008		19,964	-	NO
Year 10	2009		20,362	-	NO
Year 11	0		-		NO
Year 12	0		-		NO
Year 13	0		-		NO
Year 14	0		-		NO
Year 15	0		-		NO
5 Year Baseline - Process Water Deduction Eligibility					
Year 1	2005		18,769	-	NO
Year 2	2006		19,167	-	NO
Year 3	2007		19,565	-	NO
Year 4	2008		19,964	-	NO
Year 5	2009		20,362	-	NO
2015 Compliance Year - Process Water Deduction Eligibility					
2015			20,591	-	NO

NOTES:

SB X7-7 Table 4-C.3: Process Water Deduction Eligibility

Criteria 3

Non-industrial use is equal to or less than 120 GPCD

Baseline Year *Fm SB X7-7 Table 3*		Gross Water Use Without Process Water Deduction *Fm SB X7-7 Table 4*	Industrial Water Use	Non-industrial Water Use	Population *Fm SB X7-7 Table 3*	Non-Industrial GPCD	**Eligible for Exclusion Y/N**
10 to 15 Year Baseline - Process Water Deduction Eligibility							
Year 1	2000	15,906		15,906	16,778	846	NO
Year 2	2001	16,236		16,236	17,176	844	NO
Year 3	2002	17,574		17,574	17,574	893	NO
Year 4	2003	18,911		18,911	17,973	939	NO
Year 5	2004	20,883		20,883	18,371	1,015	NO
Year 6	2005	21,239		21,239	18,769	1,010	NO
Year 7	2006	22,457		22,457	19,167	1,046	NO
Year 8	2007	22,612		22,612	19,565	1,032	NO
Year 9	2008	21,788		21,788	19,964	974	NO
Year 10	2009	21,740		21,740	20,362	953	NO
Year 11	0	-		-	-		NO
Year 12	0	-		-	-		NO
Year 13	0	-		-	-		NO
Year 14	0	-		-	-		NO
Year 15	0	-		-	-		NO
5 Year Baseline - Process Water Deduction Eligibility							
Year 1	2005	21,239		21,239	18,769	1,010	NO
Year 2	2006	22,457		22,457	19,167	1,046	NO
Year 3	2007	22,612		22,612	19,565	1,032	NO
Year 4	2008	21,788		21,788	19,964	974	NO
Year 5	2009	21,740		21,740	20,362	953	NO
2015 Compliance Year - Process Water Deduction Eligiblity							
2015		16,542		16,542	20,591	717	NO

NOTES:

SB X7-7 Table 4-C.4: Process Water Deduction Eligibility

Criteria 4
Disadvantaged Community
Use IRWM DAC Mapping tool http://www.water.ca.gov/irwm/grants/resources_dac.cfm

	California Median Household Income	Service Area Median Household Income	Percentage of Statewide Average	**Eligible for Exclusion? Y/N**
2015 Compliance Year - Process Water Deduction Eligibility				
2010	$53,046		0%	YES

A "Disadvantaged Community" is a community with a median household income less than 80 percent of the statewide average.

NOTES:

SB X7-7 Table 4-D: Process Water Deduction - Volume *Complete a separate table for each industrial customer with a process water exclusion*						
Name of Industrial Customer		*Total for 283 industrial meters*				
Baseline Year *Fm SB X7-7 Table 3*		Industrial Customer's Total Water Use	Total Volume Supplied by Water Agency	% of Water Supplied by Water Agency	Customer's Total Process Water Use	Volume of Process Water Eligible for Exclusion for this Customer
10 to 15 Year Baseline - Process Water Deduction						
Year 1	2000	12,233	12,233	100%	12,233	12,233
Year 2	2001	12,073	12,073	100%	12,073	12,073
Year 3	2002	13,011	13,011	100%	13,011	13,011
Year 4	2003	14,262	14,262	100%	14,262	14,262
Year 5	2004	15,692	15,692	100%	15,692	15,692
Year 6	2005	15,914	15,914	100%	15,914	15,914
Year 7	2006	16,907	16,907	100%	16,907	16,907
Year 8	2007	16,941	16,941	100%	16,941	16,941
Year 9	2008	16,351	16,351	100%	16,351	16,351
Year 10	2009	16,567	16,567	100%	16,567	16,567
Year 11	0					-
Year 12	0					-
Year 13	0					-
Year 14	0					-
Year 15	0					-
5 Year Baseline - Process Water Deduction						
Year 1	2005	15,914	15,914	100%	15,914	15,914
Year 2	2006	16,907	16,907	100%	16,907	16,907
Year 3	2007	16,941	16,941	100%	16,941	16,941
Year 4	2008	16,351	16,351	100%	16,351	16,351
Year 5	2009	16,567	16,567	100%	16,567	16,567
2015 Compliance Year - Process Water Deduction						
2015		12,508	12,508	100%	12,508	12,508
NOTES:						

SB X7-7 Table 5: Gallons Per Capita Per Day (GPCD)				
Baseline Year *Fm SB X7-7 Table 3*		Service Area Population *Fm SB X7-7 Table 3*	Annual Gross Water Use *Fm SB X7-7 Table 4*	Daily Per Capita Water Use (GPCD)
10 to 15 Year Baseline GPCD				
Year 1	2000	16,778	3,673	195
Year 2	2001	17,176	4,163	216
Year 3	2002	17,574	4,563	232
Year 4	2003	17,973	4,649	231
Year 5	2004	18,371	5,191	252
Year 6	2005	18,769	5,325	253
Year 7	2006	19,167	5,550	259
Year 8	2007	19,565	5,671	259
Year 9	2008	19,964	5,437	243
Year 10	2009	20,362	5,173	227
Year 11	0	-	-	
Year 12	0	-	-	
Year 13	0	-	-	
Year 14	0	-	-	
Year 15	0	-	-	
10-15 Year Average Baseline GPCD				**237**
5 Year Baseline GPCD				
Baseline Year *Fm SB X7-7 Table 3*		Service Area Population *Fm SB X7-7 Table 3*	Gross Water Use *Fm SB X7-7 Table 4*	Daily Per Capita Water Use
Year 1	2005	18,769	5,325	253
Year 2	2006	19,167	5,550	259
Year 3	2007	19,565	5,671	259
Year 4	2008	19,964	5,437	243
Year 5	2009	20,362	5,173	227
5 Year Average Baseline GPCD				**248**
2015 Compliance Year GPCD				
2015		20,591	4,034	**175**
NOTES:				

SB X7-7 Table 6: Gallons per Capita per Day *Summary From Table SB X7-7 Table 5*	
10-15 Year Baseline GPCD	237
5 Year Baseline GPCD	248
2015 Compliance Year GPCD	175
NOTES:	

SB X7-7 Table 7: 2020 Target Method *Select Only One*		
Target Method		Supporting Documentation
☑	Method 1	SB X7-7 Table 7A
☐	Method 2	SB X7-7 Tables 7B, 7C, and 7D *Contact DWR for these tables*
☐	Method 3	SB X7-7 Table 7-E
☐	Method 4	Method 4 Calculator
NOTES:		

SB X7-7 Table 7-A: Target Method 1 20% Reduction	
10-15 Year Baseline GPCD	**2020 Target GPCD**
237	**189**
NOTES:	

SB X7-7 Table 7-B: Target Method 2	Target
Landscape Water Use	

Tables for Target Method 2 (SB X7-7 Tables 7-B, 7-C, and 7-D) are not included in the SB X7-7 Verification Form, but are still required for water suppliers using Target Method 2. These water suppliers should contact Gwen Huff at (916) 651-9672 or gwen.huff@water.ca.gov

SB X7-7 Table 7-C: Target Method 2

Target CII Water Use

Tables for Target Method 2 (SB X7-7 Tables 7-B, 7-C, and 7-D) are not included in the SB X7-7 Verification Form, but are still required for water suppliers using Target Method 2. These water suppliers should contact Gwen Huff at (916) 651-9672 or gwen.huff@water.ca.gov

SB X7-7 Table 7-D: Target Method 2 Summary

Tables for Target Method 2 (SB X7-7 Tables 7-B, 7-C, and 7-D) are not included in the SB X7-7 Verification Form, but are still required for water suppliers using Target Method 2. These water suppliers should contact Gwen Huff at (916) 651-9672 or gwen.huff@water.ca.gov

SB X7-7 Table 7-E: Target Method 3				
Agency May Select More Than One as Applicable	Percentage of Service Area in This Hydrological Region	Hydrologic Region	"2020 Plan" Regional Targets	Method 3 Regional Targets (95%)
☐		North Coast	137	130
☐		North Lahontan	173	164
☐		Sacramento River	176	167
☐		San Francisco Bay	131	124
☐		San Joaquin River	174	165
☐		Central Coast	123	117
☐		Tulare Lake	188	179
☐		South Lahontan	170	162
☐		South Coast	149	142
☐		Colorado River	211	200
Target *(If more than one region is selected, this value is calculated.)*				**0**
NOTES:				

SB X7-7 Table 7-F: Confirm Minimum Reduction for 2020 Target			
5 Year Baseline GPCD *From SB X7-7 Table 5*	Maximum 2020 Target[1]	Calculated 2020 Target[2]	**Confirmed 2020 Target**
248	236	189	**189**

[1] Maximum 2020 Target is 95% of the 5 Year Baseline GPCD *[2] 2020 Target is calculated based on the selected Target Method, see SB X7-7 Table 7 and corresponding tables for agency's calculated target.*

NOTES:

SB X7-7 Table 8: 2015 Interim Target GPCD		
Confirmed 2020 Target *Fm SB X7-7 Table 7-F*	10-15 year Baseline GPCD *Fm SB X7-7 Table 5*	**2015 Interim Target GPCD**
189	237	**213**
NOTES:		

SB X7-7 Table 9: 2015 Compliance								
Actual 2015 GPCD	2015 Interim Target GPCD	Optional Adjustments *(in GPCD)* Enter "0" if Adjustment Not Used: Extraordinary Events	Weather Normalization	Economic Adjustment	TOTAL Adjustments	Adjusted 2015 GPCD	2015 GPCD *(Adjusted if applicable)*	**Did Supplier Achieve Targeted Reduction for 2015?**
175	213	*From Methodology 8 (Optional)*	*From Methodology 8 (Optional)*	*From Methodology 8 (Optional)*	-	175	175	**YES**
NOTES:								

APPENDIX D - NOTICE OF PUBLIC HEARINGS & NOTIFICATION LETTERS

NOTICE OF DIVIDED PUBLICATION

Pursuant to Sections 3381 through 3385, Revenue and Taxation Code, the Notice of Power to Sell Tax-Defaulted Property in and for County of Kern, State of California, has been divided and distributed to various newspapers of general circulation published in said county, for publication of a portion thereof in each of said newspapers.

NOTICE OF IMPENDING POWER TO SELL TAX-DEFAULTED PROPERTY

Notice is hereby given that real property taxes and assessments on the parcels described below will have been defaulted for five or more years. By law on July 1, 2021, at the hour of 12:01a.m. the herein described real property will become subject to the Treasurer-Tax Collector's power to sell for failure to pay said duly assessed and legally levied taxes against said property, unless the property is redeemed or an installment redemption plan is initiated prior to 5:00 p.m. on June 30, 2021. If the property is not redeemed the right of redemption will terminate upon any subsequent sale by the Treasurer-Tax Collector. All information concerning redemption, or the initiation of an installment plan of redemption will upon request be furnished by Jordan Kaufman, County of Kern Treasurer-Tax Collector, Bakersfield, California, (661) 868-3490 or E-Mail: ttc@kerncounty.com.

The amount to redeem, in dollar and cents, is set forth opposite its parcel number. This amount includes all defaulted taxes, penalties, and fees that have accrued from the date of tax-default to the date of this publication.

I certify (or declare) under penalty of perjury that the foregoing is true and correct.

JORDAN KAUFMAN, TREASURER-TAX COLLECTOR, COUNTY OF KERN Executed at Bakersfield, Kern County on May 25, 2021.

PARCEL NUMBERING SYSTEM EXPLANATION

A parcel numbering system is a numerical system for referring to each parcel or property within Kern County. The standard parcel numbering system consists of, first; the map book number; secondly, the page number within the map book, and block number if one exists; and the parcel number within the block. By this system a county is divided into geographical areas called map books, each map book into geographical areas called pages, each page into blocks, and each block into parcels as owned and used. The maps referred to are available for inspection in the office of the Kern County Assessor.

EXAMPLE: Parcel number: 052-623-13-01-1

052-Book 52 of the Assessor's Maps

623-Map Page 62 and Block 3

13-Parcel 13 within Block 3

01-Indicates partial ownership when not 00

1-Check digit for numerical processing integrity

The real property that is the subject of this Notice is situated in the County of Kern, State of California, and is described as follows:

PROPERTY TAX-DEFAULTED IN THE YEAR 2016, FOR TAXES, ASSESSMENTS AND OTHER CHARGES FOR THE FISCAL YEAR 2015 - 2016

067-113-02-00-6 $7,752.21
433 FAIRVIEW ST RIDGECREST
ANGLE MELBA J

067-174-14-00-6 $8,150.11
209 FLORENCE ST RIDGECREST
MC BRIDE TAMARA L

081-072-53-00-0 $1,281.27
ONG FRANCISCO C & YORK SIN

081-081-47-00-9 $6,341.98
1445 FARRAGUT ST RIDGECREST
LONGO PETER A & GLORIA R FMLY LTD PTP

081-104-08-00-2 $285.06
CHRISTIAN HERITAGE COLLEGE

081-232-17-00-2 $874.64
WONG TONY

081-241-27-00-7 $1,341.41
FRUKTOW NICHOLAS N

081-292-23-00-7 $1,437.21
ARCADIA UNLTD LLC

081-331-38-00-5 $1,236.47
FRUKTOW NICHOLAS N

081-332-29-00-6 $420.33
MARIANI MONICA MARIE

081-333-29-00-3 $1,276.35
MONTADRATH LLC

097-040-30-00-5 $901.32
LARA CARL

153-294-23-00-5 $829.57
NEWSOM TRUST

154-150-08-00-0 $295.02
FRUKTOW NICHOLAS

154-250-43-00-0 $157.52
MC INTYRE LIV TR

155-020-05-00-0 $192.80
DRESSELHAUS CARL D

155-050-16-00-1 $175.41
HIGHLAND AV RANDSBURG
YODER KEITH

155-071-23-00-4 $3,661.07
129 BUTTE AV RANDSBURG
DAGER FAMILY TRUST

155-121-08-00-5 $162.01
SNOWDEN C L ET AL

155-190-24-00-5 $433.99
NORMAN WARREN

155-210-06-00-8 $162.01
FABER SANDY

155-225-06-00-6 $319.11
AMERICAN LEGION RAND POST 298

155-236-09-00-5 $2,879.55
27804 GOLER AV JOHANNESBURG
CLARK MAGGIE L

155-251-01-00-2 $282.12
FABER SANDY

155-284-08-00-3 $3,435.22
WINCHESTER WALTER R ET AL

155-293-01-00-8 $310.51
LYNN ROBERT & ANNA

155-312-03-00-2 $387.17
TRUESDELL DONALD

155-335-15-00-4 $567.79
RODRIGUEZ REYNALDO S

155-380-12-00-5 $3,983.59
145 BUTTE AV RANDSBURG
DAGER FAMILY TRUST

341-101-18-00-5 $123.54
CUOMO MICHAEL ANTHONY

341-300-16-00-0 $618.38
GOBOURNE LLOYD G JR & WANDA M

343-031-14-00-7 $303.11
WHITELEY BETTYE JOANA

343-032-07-00-4 $879.04
FAIRCHILD FLOYD F & CORRAINE M

343-032-08-00-7 $879.04
FAIRCHILD FLOYD F & CORRAINE M

343-032-09-00-0 $879.04
FAIRCHILD FLOYD F & CORRAINE M

343-032-10-00-2 $634.15
FAIRCHILD FLOYD F & CORRINE M

343-082-30-00-5 $4,650.17
724 WASP AV RIDGECREST
MELLO RANNA J

343-190-40-00-2 $682.03
GREENLAWN ST RIDGECREST
WELCH LISA KAY

343-190-41-00-5 $6,520.93
1162 GREENLAWN ST RIDGECREST
WELCH LISA KAY

343-221-05-00-6 $2,228.89
225 LILAC ST RIDGECREST
LUTU FAASUKA P & KAREN ALISHAVAH M

352-132-08-00-2 $631.03
1445 CALVERT BL RIDGECREST
MC DANELL DAVID E & PRISCILLA

352-141-05-00-9 $1,041.02
JAEGER MICHAEL V & VANESSA R

352-143-31-00-8 $1,884.33
3956 WARD AV RIDGECREST
MAR CAT 6 REVOCABLE LIVING TRUST

352-143-32-00-1 $1,884.33
3950 WARD AV RIDGECREST
MAR CAT 6 REVOCABLE LIVING TRUST

352-152-38-00-5 $2,919.14
1151 THORN ST RIDGECREST
PERRY DEAN J

352-161-11-00-2 $1,043.83
ANDRUS MARK AARON & BELEN TORRES

352-243-08-00-1 $113.06
SIERRA BREEZE MUTUAL WATER CO

352-243-09-00-4 $157.61
SIERRA BREEZE MUTL WATER CO INC

352-243-10-00-6 $1,230.64
1618 CHAPARRAL DR RIDGECREST
SIERRA BREEZE SUN & SWIM CLUB

352-261-30-00-6 $1,673.57
POWERS GAYLORD D

352-273-18-00-9 $502.19
SMITH LESLIE F & LYNDA D

352-273-40-00-2 $2,521.46
3604 WARD AV RIDGECREST
RODRIGUEZ JOSE & PENA CLAUDIA

352-300-44-00-1 $1,761.94
907 CLIFFORD ST RIDGECREST
NEWMAN ARTHUR

352-310-37-00-4 $851.76
FALLGATTER JAMES C

396-053-01-00-5 $7,911.51
120 PURPLE SAGE LN RIDGECREST
MOSES MARIA M

396-100-08-00-9 $3,896.22
SANCHEZ EDWARD A &
RODRIGUEZ LUZ MARIA

419-042-17-00-8 $3,350.90
321 MOYER AV RIDGECREST
MEZA MARIA F

419-042-36-00-3 $12,849.58
404 WARD AV RIDGECREST
ZELENY HOWARD S

456-052-03-00-1 $110.45
WHITE GARY A & NANCY L

477-060-18-00-7 $12,170.63
455 NORMA ST RIDGECREST
WEBB DARYL

477-070-20-00-5 $955.04
136 SUNSET ST RIDGECREST
HENDERSON BETTYE M

478-063-12-00-7 $11,186.48
318 WILSON AV RIDGECREST
STORRUSTE MILREE D

508-041-23-00-7 $2,484.78
GIFFORD WILLIAM J ET AL

508-120-18-00-9 $424.34
STANTON FAMILY TRUST

508-152-21-00-0 $9,045.00
1164 GUAM ST RIDGECREST
CARRASCO ALFRED & MONICA L

511-052-23-00-1 $515.28
EUKEL BRONSON

DATED THIS 25th DAY OF MAY 2021

Total Records: 66

PUB: June 3, 10, 2021
PUB: MIDWAY DRILLER

Notice of Public Hearing

Notice is hereby given that a public hearing will be held to consider the adoption of the West Kern Water District's Urban Water Management Plan (UWMP) 2020 Update and Water Shortage Response Plan (WSRP) 2020 Update, which have been prepared according to March 2021 State Guidelines. A copy of the Draft UWMP and WSRP are available to the public for inspection at 800 Kern Street in Taft or on the District's website https://www.wkwd.org/. A public hearing will be conducted on the adoption of both Plans on June 22, 2021, at 5:30 pm at 800 Kern Street in Taft. Public comments are invited.

PUB: June 10, 17, 2021
PUB: Midway Driller

ORDER TO SHOW CAUSE FOR CHANGE OF NAME
Case Number BCV-21-100444 TO ALL INTERESTED PERSONS:

1. Petitioner Celeste Kimberly Selnick filed a petition with this court for a decree changing names as follows:

Celeste Kimberly Selnick to Celeste Kimberly Webb

2. THE COURT ORDERS that all persons interested in this matter shall appear before this court at the hearing indicated below to show cause, if any, why the petition for change of name should not be granted. Any person objecting to the name changes described above must file a written objection that includes the reasons for the objection at least two days before the matter is scheduled to be heard and must appear at the hearing to show cause why the petition should not be granted. If no written objection is timely filed, the court may grant the petition without a hearing.

NOTICE OF HEARING on 07/19/21 at 8:30 a.m. in Dept. 12, Superior Court, County of Kern, Metropolitan Division, 1415 Truxtun Ave., Bakersfield, CA 93301

3. A Copy of this Order to Show Cause shall be published at least once each week for four successive weeks prior to the date set for hearing on the petition in the following newspaper of general circulation, printed in this county: Midway Driller, 800 Center Street, Taft, CA 93268.

Dated: 05/17/2021
Court Commissioner
PUB: May 20, 27, June 3, 10, 2021
PUB: MIDWAY DRILLER

T.S. No. 2020-20628 Loan No. OGORMAN APN: 017-130-046 NOTICE OF TRUSTEE'S SALE YOU ARE IN DEFAULT UNDER A DEED OF TRUST DATED 6/1/2010. UNLESS YOU TAKE ACTION TO PROTECT YOUR PROPERTY, IT MAY BE SOLD AT A PUBLIC SALE. IF YOU NEED AN EXPLANATION OF THE NATURE OF THE PROCEEDING AGAINST YOU, YOU SHOULD CONTACT A LAWYER. A public auction sale to the highest bidder for cash, cashier's check drawn on a state or national bank, check drawn by a state or federal credit union, or a check, MUST BE MADE PAYABLE TO: CALIFORNIA TRUSTEE SERVICES, INC., drawn by a state or federal savings and loan association, or savings association, or savings bank specified in Section 5102 of the Financial Code and authorized to do business in this state will be held by the duly appointed trustee as shown below, of all right, title, and interest conveyed to and now held by the trustee in the hereinafter described property under and pursuant to a Deed of Trust described below. The sale will be made, but without covenant or warranty, expressed or implied, regarding title, possession, or encumbrances, to pay the remaining principal sum of the note(s) secured by the Deed of Trust, with interest and late charges thereon, as provided in the note(s), advances, under the terms of the Deed of Trust, interest thereon, fees, charges and expenses of the Trustee for the total amount (at the time of the initial publication of the Notice of Sale) reasonably estimated to be set forth below. The amount may be greater on the day of sale. PLEASE NOTE ALL CASHIER CHECKS MUST BE MADE PAYABLE TO: CALIFORNIA TRUSTEE SERVICES, INC. Trustor: Debbie Reid O'Gorman Duly Appointed Trustee: California Trustee Services, Inc. Recorded 6/25/2010 as Instrument No. 2010-0014311 in book XX, page XX of Official Records in the office of the Recorder of Napa County, California, Date of Sale:7/7/2021 at 1:30 PM Place of Sale: At the fountain to the right of the Napa County Superior Court, 1111 Third Street, Napa, CA 94559 Amount of unpaid balance and other charges: $1,493,198.00 Street Address or other common designation of real property: 3225 Lake County Highway Calistoga, CA 94515 A.P.N.: 017-130-046 The undersigned Trustee disclaims any liability for any incorrectness of the street address or other common designation, if any, shown above. If no street address or other common designation is shown, directions to the location of the property may be obtained by sending a written request to the beneficiary within 10 days of the date of first publication of this Notice of Sale. If the Trustee is unable to convey title for any reason, the successful bidder's sole and exclusive remedy shall be the return of monies paid to the Trustee, and the successful bidder shall have no further recourse. NOTICE TO POTENTIAL BIDDERS: If you are considering bidding on this property lien, you should understand that there are risks involved in bidding at a trustee auction. You will be bidding on a lien, not on the property itself. Placing the highest bid at a trustee auction does not automatically entitle you to free and clear ownership of the property. You should also be aware that the lien being auctioned off may be a junior lien. If you are the highest bidder at the auction, you are or may be responsible for paying off all liens senior to the lien being auctioned off, before you can receive clear title to the property. You are encouraged to investigate the existence, priority, and size of outstanding liens that may exist on this property by contacting the county recorder's office or a title insurance company, either of which may charge you a fee for this information. If you consult either of these resources, you should be aware that the same lender may hold more than one mortgage or deed of trust on the property. NOTICE TO PROPERTY OWNER: The sale date shown on this notice of sale may be postponed one or more times by the mortgagee, beneficiary, trustee, or a court, pursuant to Section 2924g of the California Civil Code. The law requires that information about trustee sale postponements be made available to you and to the public, as a courtesy to those not present at the sale. If you wish to learn whether your sale date has been postponed, and, if applicable, the rescheduled time and date for the sale of this property, you may call 916-939-0772 or visit this Internet Website http://www.nationwideposting.com on the home page and click sale list to get the most updated sale information, using the file number assigned to this case 2020-20628. Information about postponements that are very short in duration or that occur close in time to the scheduled sale may not immediately be reflected in the telephone information or on the Internet Website. The best way to verify postponement information is to attend the scheduled sale. NOTICE TO TENANT: You may have a right to purchase this property after the trustee auction pursuant to Section 2924m of the California Civil Code. If you are an "eligible tenant buyer," you can purchase the property if you match the last and highest bid placed at the trustee auction. If you are an "eligible bidder," you may be able to purchase the property if you exceed the last and highest bid placed at the trustee auction. There are three steps to exercising this right of purchase. First, 48 hours after the date of the trustee sale, you can call 916-939-0772, or visit this internet website http://www.nationwideposting.com, using the file number assigned to this case 2020-20628 to find the date on which the trustee's sale was held, the amount of the last and highest bid, and the address of the trustee. Second, you must send a written notice of intent to place a bid so that the trustee receives it no more than 15 days after the trustee's sale. Third, you must submit a bid so that the trustee receives it no more than 45 days after the trustee's sale. If you think you may qualify as an "eligible tenant buyer" or "eligible bidder," you should consider contacting an attorney or appropriate real estate professional immediately for advice regarding this potential right to purchase. DATE: 5/21/2021 California Trustee Services, Inc. 3639 Midway Drive, Suite B232 San Diego, California 92110 Sale Info Line 916-939-0772 Or Login to: http://www.nationwideposting.com All Other Info: 1-619-630-0631 Thomas Dandrea, Trustee's Sale Officer NPP0374096 To: DAILY MIDWAY DRILLER 06/03/2021, 06/10/2021, 06/17/2021
PUB: June 3, 10, 17, 2021
PUB: MIDWAY DRILLER

NOTICE OF PETITION TO ADMINISTER ESTATE OF Virva Hedland, AKA Virva Eliisa Hedland. Case No. BPB-21-002523

To all heirs, beneficiaries, creditors, and contingent creditors, and persons who may otherwise be interested in the will or estate, or both, of Virva Hedland, AKA Virva Eliisa Hedland

A Petition for Probate has been filed by Curtis Hedland in the Superior Court of California, County of Kern. The Petition for Probate requests that Curtis Hedland be appointed as personal representative to administer the estate of the decedent. The Petition requests the decedent's will and codicils, if any, be admitted to probate. The will and any codicils are available for examination in the file kept by the court. The petition requests authority to administer the estate under the Independent Administration of Estates Act. (This authority will allow the personal representative to take many actions without obtaining court approval. Before taking certain very important actions, however, the personal representative will be required to give notice to interested persons unless they have waived notice or consented to the proposed action.) The independent administration authority will be granted unless an interested person files an objection to the petition and shows good cause why the court should not grant the authority.

A hearing on the petition will be held in this court as follows originally set for 07/09/2021 at 8:30 a.m. in Div. P located at SUPERIOR COURT OF CALIFORNIA, COUNTY OF KERN, METROPOLITAN DIVISION, 1215 TRUXTUN AVENUE, BAKERSFIELD, CA 93301. If you object to the granting of the petition, you should appear at the hearing and state your objections or file written objections with the court before the hearing. Your appearance may be in person or by your attorney. If you are a creditor or a contingent creditor of the decedent, you must file your claim with the court and mail a copy to the personal representative appointed by the court within the later of either (1) four months from the date of first issuance of letters to a general personal representative, as defined in section 58(b) of the California Probate Code, or (2) 60 days from the date of mailing or personal delivery to you of a notice under section 9052 of the California Probate Code. Other California statutes and legal authority may affect your rights as a creditor.

You may want to consult with an attorney knowledgeable in California Law. You may examine the file kept by the court. If you are a person interested in the estate, you may file with the court a Request for Special Notice (form DE154) of the filing of an inventory and appraisal of estate assets or of any petition or account as provided in Probate Code section 1250. A Request for Special Notice form is available from the court clerk. Attorney for petitioner (name) Bill Wright (Address) 1800 Westwind Dr. Suite 401 Bakersfield, CA 93301 (Telephone) 661-325-5719.

PUB: June 10, 17, 24, 2021
PUB: Midway Driller

Now hiring

ELK HILLS ELEMENTARY SCHOOL DISTRICT:
Position: Small Group Teacher (SGT) Grade: K-2 Location: Tupman, CA
Reports to: Literacy and Assessment TOSA School Year: 2021-2022 (Non-permanent)
Under the supervision of the Literacy Intervention and Assessment Teacher on Special Assignment (TOSA), the small group teacher has two major responsibilities: working closely with lower elementary teachers in order to ensure 100% of students are reading on grade level by the end of 3rd grade. The SGT collaborates with all K-8 teachers, TOSA, and the school site superintendent/principal to develop, oversee, and monitor response to reading instruction, and helps build student and family capacity by developing a deeper understanding of foundational reading skills and works to foster evidence-based best practices. The SGT works with students identified with highest priority literacy needs. The SGT is a one year (21-22 SY) position 100% grant funded.

Board of Directors
David A. Wells
President

Barry M. Jameson
Vice President

Gary J. Morris
Scott D. Niblett
Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Mr. Mark Staples
Planning & Development Services Director
City of Taft
209 E. Kern
Taft, CA 93268
mstaples@cityoftaft.org

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Mr. Staples:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

We anticipate completing the UWMP update in May or June of 2021. We will formally notify you when a draft UWMP update is available. The public and all interested agencies will have 14 days to provide comments before the Draft is considered for adoption by the WKWD Board of Directors.

Please feel free to contact me at (661) 763-3151 or ghammett@wkwd.org if you would like to provide input or participate in the UWMP development.

Sincerely,

Greg A. Hammett
General Manager

Board of Directors
David A. Wells
President

Barry M. Jameson
Vice President

Gary J. Morris
Scott D. Niblett
Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Ms. Rochelle Invina
Regional Planner
Kern Council of Governments
1401 19th St., Ste 300
Bakersfield, CA 93301
rinvina@kerncog.org

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Ms. Invina:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

We anticipate completing the UWMP update in May or June of 2021. We will formally notify you when a draft UWMP update is available. The public and all interested agencies will have 14 days to provide comments before the Draft is considered for adoption by the WKWD Board of Directors.

Please feel free to contact me at (661) 763-3151 or ghammett@wkwd.org if you would like to provide input or participate in the UWMP development.

Sincerely,

Greg A. Hammett
General Manager

Board of Directors
David A. Wells
President

Barry M. Jameson
Vice President

Gary J. Morris
Scott D. Niblett
Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Mr. Tim Ashlock
Engineer-Manager
Buena Vista Water Storage District
PO Box 756
Buttonwillow, CA 93206
tim@bvh2o.com

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Mr. Ashlock:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

We anticipate completing the UWMP update in May or June of 2021. We will formally notify you when a draft UWMP update is available. The public and all interested agencies will have 14 days to provide comments before the Draft is considered for adoption by the WKWD Board of Directors.

Please feel free to contact me at (661) 763-3151 or ghammett@wkwd.org if you would like to provide input or participate in the UWMP development.

Sincerely,

Greg A. Hammett
General Manager

Board of Directors
David A. Wells
President

Barry M. Jameson
Vice President

Gary J. Morris
Scott D. Niblett
Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Mr. Tom McCarthy
General Manager
Kern County Water Agency
3200 Rio Mirada Dr.
Bakersfield, CA 93308-4944
tmccarthy@kcwa.com

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Mr. McCarthy:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

We anticipate completing the UWMP update in May or June of 2021. We will formally notify you when a draft UWMP update is available. The public and all interested agencies will have 14 days to provide comments before the Draft is considered for adoption by the WKWD Board of Directors.

Please feel free to contact me at (661) 763-3151 or ghammett@wkwd.org if you would like to provide input or participate in the UWMP development.

Sincerely,

Greg A. Hammett
General Manager

Board of Directors
David A. Wells
President

Barry M. Jameson
Vice President

Gary J. Morris
Scott D. Niblett
Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Mr. Eric Averett
General Manager
Rosedale-Rio Bravo Water Storage District
PO Box 20820
Bakersfield, C A 93390-0820
eaverett@rrbwsd.com

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Mr. Averett:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

We anticipate completing the UWMP update in May or June of 2021. We will formally notify you when a draft UWMP update is available. The public and all interested agencies will have 14 days to provide comments before the Draft is considered for adoption by the WKWD Board of Directors.

Please feel free to contact me at (661) 763-3151 or ghammett@wkwd.org if you would like to provide input or participate in the UWMP development.

Sincerely,

Greg A. Hammett
General Manager

Board of Directors
David A. Wells
President

Barry M. Jameson
Vice President

Gary J. Morris
Scott D. Niblett
Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Mr. Eric Ziegler
City Administrator
City of Maricopa
PO Box 550
Maricopa, CA 93252
lrobison_com@bak.rr.com

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Mr. Ziegler:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

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Sincerely,

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General Manager

Board of Directors
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Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Mr. Jon Parker
General Manager
Kern Water Bank Authority
1620 Mill Rock Way, Ste 500
Bakersfield, CA 93311
jparker@kwb.org

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Mr. Parker:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

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Please feel free to contact me at (661) 763-3151 or ghammett@wkwd.org if you would like to provide input or participate in the UWMP development.

Sincerely,

Greg A. Hammett
General Manager

Board of Directors
David A. Wells
President

Barry M. Jameson
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Gary J. Morris
Scott D. Niblett
Bo J. Bravo

Greg A. Hammett
General Manager

J.D. Bramlet
Director of Operations

Sanjay "Sunny" Kapoor
Director of Finance

February 15, 2021

Ms. Lorelei Oviatt
Director, Planning & Community Development
County of Kern
2700 M Street, Ste 250
Bakersfield, CA 93301-2370
kerncd@kerncounty.com

Subject: West Kern Water District – Notification of Urban Water Management Plan Update

Dear Ms. Oviatt:

West Kern Water District (WKWD) wishes to inform you that we are updating our Urban Water Management Plan (UWMP) to comply with 2020 guidelines in accordance with the Urban Water Management Planning Act (California Water Code Sections 10610 to 10656). The UWMP update will evaluate existing water conservation measures, as well as water supply, water demand and water supply reliability over the next 25 years.

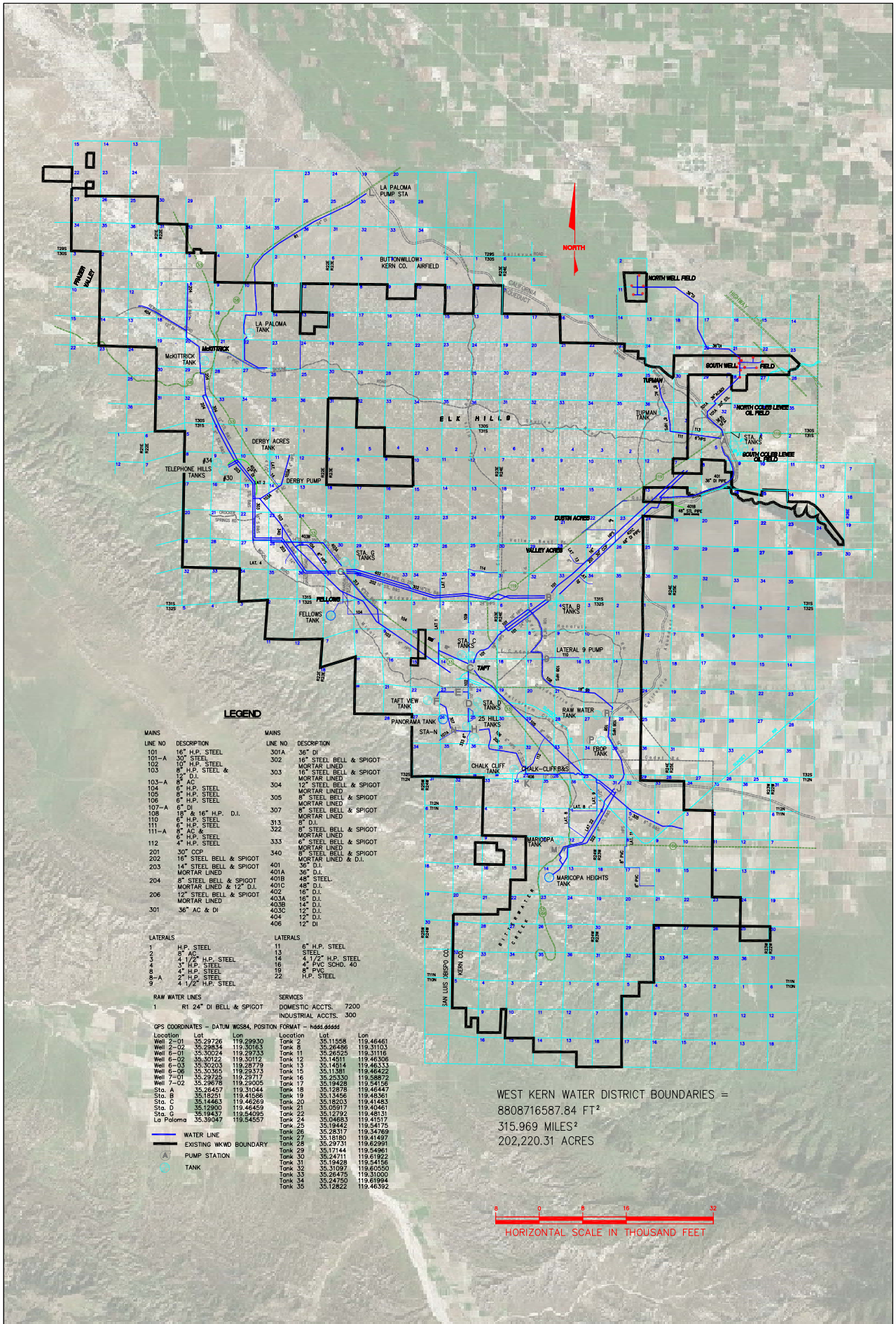
We anticipate completing the UWMP update in May or June of 2021. We will formally notify you when a draft UWMP update is available. The public and all interested agencies will have 14 days to provide comments before the Draft is considered for adoption by the WKWD Board of Directors.

Please feel free to contact me at (661) 763-3151 or ghammett@wkwd.org if you would like to provide input or participate in the UWMP development.

Sincerely,

Greg A. Hammett
General Manager

APPENDIX E – DISTRIBUTION SYSTEM MAP



LEGEND

MAINS

LINE NO	DESCRIPTION
101	16" H.P. STEEL
101-A	30" STEEL
102	10" H.P. STEEL
103	8" H.P. STEEL & 12" D.I.
103-A	8" AC
104	6" H.P. STEEL
105	8" H.P. STEEL
106	6" H.P. STEEL
107-A	6" DI
108	18" & 16" H.P. D.I.
110	6" H.P. STEEL
111	6" H.P. STEEL
111-A	8" AC & 6" H.P. STEEL
112	4" H.P. STEEL
201	30" CCP
202	16" STEEL BELL & SPIGOT
203	14" STEEL BELL & SPIGOT MORTAR LINED
204	8" STEEL BELL & SPIGOT MORTAR LINED & 12" D.I.
206	12" STEEL BELL & SPIGOT MORTAR LINED
301	36" AC & DI

MAINS

LINE NO	DESCRIPTION
301A	36" DI
302	16" STEEL BELL & SPIGOT MORTAR LINED
303	16" STEEL BELL & SPIGOT MORTAR LINED
304	12" STEEL BELL & SPIGOT MORTAR LINED
305	8" STEEL BELL & SPIGOT MORTAR LINED
307	8" STEEL BELL & SPIGOT MORTAR LINED
313	8" D.I.
322	8" STEEL BELL & SPIGOT MORTAR LINED
333	6" STEEL BELL & SPIGOT MORTAR LINED
340	8" STEEL BELL & SPIGOT MORTAR LINED & D.I.
401	36" D.I.
401A	36" D.I.
401B	48" STEEL
401C	48" D.I.
402	16" D.I.
403A	16" D.I.
403B	14" D.I.
403C	12" D.I.
404	12" D.I.
406	12" DI

LATERALS

1	H.P. STEEL
2	8" AC
3	4-1/2" H.P. STEEL
4	3" H.P. STEEL
5	4" H.P. STEEL
5-A	2" H.P. STEEL
9	4 1/2" H.P. STEEL

LATERALS

11	6" H.P. STEEL
13	STEEL
14	4.1/2" H.P. STEEL
16	4" PVC SCHD. 40
19	8" PVC
22	H.P. STEEL

RAW WATER LINES

1	R1 24" DI BELL & SPIGOT

SERVICES

DOMESTIC ACCTS.	7200
INDUSTRIAL ACCTS.	300

GPS COORDINATES - DATUM WGS84, POSITION FORMAT - hddd.ddddd

Location	Lat	Lon
Well 2-01	35.29726	119.29930
Well 2-02	35.29834	119.30163
Well 6-01	35.30024	119.29733
Well 6-02	35.30122	119.30112
Well 6-03	35.30203	119.29779
Well 6-06	35.30365	119.29373
Well 7-01	35.29725	119.29717
Well 7-02	35.29678	119.29005
Sta. A	35.26457	119.31044
Sta. B	35.18251	119.41586
Sta. C	35.14463	119.46269
Sta. D	35.12900	119.46459
Sta. G	35.19437	119.54095
La Paloma	35.39047	119.54557

Location	Lat	Lon
Tank 2	35.11558	119.46461
Tank 8	35.26486	119.31103
Tank 11	35.26525	119.31116
Tank 12	35.14511	119.46306
Tank 13	35.14514	119.46333
Tank 15	35.11381	119.46422
Tank 16	35.25330	119.58872
Tank 17	35.19428	119.54156
Tank 18	35.12878	119.46447
Tank 19	35.13456	119.48361
Tank 20	35.18203	119.41483
Tank 21	35.05917	119.40461
Tank 22	35.12792	119.48131
Tank 24	35.04683	119.41517
Tank 25	35.19442	119.54175
Tank 26	35.28317	119.34769
Tank 27	35.18180	119.41497
Tank 28	35.29731	119.62991
Tank 29	35.17144	119.54961
Tank 30	35.24711	119.61922
Tank 31	35.19428	119.54156
Tank 32	35.31097	119.60550
Tank 33	35.26475	119.31000
Tank 34	35.24750	119.61994
Tank 35	35.12822	119.46392

WATER LINE
EXISTING WKWD BOUNDARY
PUMP STATION
TANK

WEST KERN WATER DISTRICT BOUNDARIES =
8808716587.84 FT²
315.969 MILES²
202,220.31 ACRES

8 0 8 16 32
HORIZONTAL SCALE IN THOUSAND FEET

SHEET 1 OF 1
JOB NO.: N/A

D. JAMESON | H. O. STARKEY
T. TURLEY | JD. BRAMLET

WEST KERN WATER DISTRICT FACILITIES MAP

CAD FILENAME:	DRAWN BY:	DATE:	SCALE:
FACILITIES	WLB	6/8/99	1"=8000'

westkern water district
P.O. Box 1105 • Taft, CA 93268
661 763-3151 • FAX 661 765-5435

REV. NO.	DATE	DESCRIPTION	DRAWN BY	CHK'D BY
2	10/18/99	DISTRIBUTION SYSTEM	WLB	TTT
3	9/12/00	DISTRIBUTION SYSTEM	ZCC	FJ
4	1/7/02	LA PALOMA	ZCC	TTT
5	7/15/02	ELK HILLS ANNEXATION	DCJ	TTT
6	1/21/08	ANNEXATION #14	DCJ	JDB
7	7/24/12	NWF/TANK GIS/LAYOUT UPDATE	DCJ	

APPENDIX F - ESTIMATED DISTRIBUTION SYSTEM WATER LOSSES

AWWA Free Water Audit Software:
Reporting Worksheet

WAS v5.0
American Water Works Association

? Click to access definition
+ Click to add a comment

Water Audit Report for: West Kern Water District (1510022)
Reporting Year: 2016 (1/2016 - 12/2016)

Please enter data in the white cells below. Where available, metered values should be used; if metered values are unavailable please estimate a value. Indicate your confidence in the accuracy of the input data by grading each component (n/a or 1-10) using the drop-down list to the left of the input cell. Hover the mouse over the cell to obtain a description of the grades

All volumes to be entered as: ACRE-FEET PER YEAR

To select the correct data grading for each input, determine the highest grade where the utility meets or exceeds all criteria for that grade and all grades below it.

<---------- Enter grading in column 'E' and 'J' ---------->

Master Meter and Supply Error Adjustments

WATER SUPPLIED

				Pcnt:	Value:	
Volume from own sources:	4	20,196.370	acre-ft/yr			acre-ft/yr
Water imported:			acre-ft/yr			acre-ft/yr
Water exported:	4	3,895.860	acre-ft/yr	7		acre-ft/yr

Enter negative % or value for under-registration
Enter positive % or value for over-registration

WATER SUPPLIED: 16,300.510 acre-ft/yr

AUTHORIZED CONSUMPTION

Click here: ? for help using option buttons below

				Pcnt:	Value:	
Billed metered:	5	14,186.070	acre-ft/yr			
Billed unmetered:			acre-ft/yr			
Unbilled metered:	5	5.409	acre-ft/yr			
Unbilled unmetered:	5	40.751	acre-ft/yr		40.751	acre-ft/yr

Use buttons to select percentage of water supplied **OR** value

AUTHORIZED CONSUMPTION: 14,232.231 acre-ft/yr

WATER LOSSES (Water Supplied - Authorized Consumption) 2,068.279 acre-ft/yr

Apparent Losses

				Pcnt:	Value:	
Unauthorized consumption:		40.751	acre-ft/yr	0.25%		acre-ft/yr

Default option selected for unauthorized consumption - a grading of 5 is applied but not displayed

Customer metering inaccuracies:	3	289.622	acre-ft/yr	2.00%		acre-ft/yr
Systematic data handling errors:	5	35.465	acre-ft/yr	0.25%		acre-ft/yr

Default option selected for Systematic data handling errors - a grading of 5 is applied but not displayed

Apparent Losses: 365.838 acre-ft/yr

Real Losses (Current Annual Real Losses or CARL)

Real Losses = Water Losses - Apparent Losses: 1,702.441 acre-ft/yr

WATER LOSSES: 2,068.279 acre-ft/yr

NON-REVENUE WATER

NON-REVENUE WATER: 2,114.440 acre-ft/yr

= Water Losses + Unbilled Metered + Unbilled Unmetered

SYSTEM DATA

Length of mains:	8	318.0	miles
Number of active AND inactive service connections:	6	7,704	
Service connection density:		24	conn./mile main

Are customer meters typically located at the curbstop or property line? Yes

Average length of customer service line: (length of service line, beyond the property boundary, that is the responsibility of the utility)

Average length of customer service line has been set to zero and a data grading score of 10 has been applied

Average operating pressure: 5 60.0 psi

COST DATA

Total annual cost of operating water system:	10	$19,381,158	$/Year	
Customer retail unit cost (applied to Apparent Losses):	5	$2.50	$/100 cubic feet (ccf)	
Variable production cost (applied to Real Losses):	5	$237.67	$/acre-ft	☐ Use Customer Retail Unit Cost to value real losses

WATER AUDIT DATA VALIDITY SCORE:

***** YOUR SCORE IS: 50 out of 100 *****

A weighted scale for the components of consumption and water loss is included in the calculation of the Water Audit Data Validity Score

PRIORITY AREAS FOR ATTENTION:

Based on the information provided, audit accuracy can be improved by addressing the following components:

1: Volume from own sources
2: Customer metering inaccuracies
3: Billed metered

AWWA Free Water Audit Software:
Reporting Worksheet

WAS v5.0
American Water Works Association.
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? Click to access definition
+ Click to add a comment

Water Audit Report for: West Kern Water District (1510022)
Reporting Year: 2017 1/2017 - 12/2017

Please enter data in the white cells below. Where available, metered values should be used; if metered values are unavailable please estimate a value. Indicate your confidence in the accuracy of the input data by grading each component (n/a or 1-10) using the drop-down list to the left of the input cell. Hover the mouse over the cell to obtain a description of the grades

All volumes to be entered as: ACRE-FEET PER YEAR

To select the correct data grading for each input, determine the highest grade where the utility meets or exceeds all criteria for that grade and all grades below it.

Master Meter and Supply Error Adjustments

WATER SUPPLIED

<---------- Enter grading in column 'E' and 'J' ---------->

					Pcnt:	Value:	
Volume from own sources:	5	15,592.440	acre-ft/yr				acre-ft/yr
Water imported:	n/a	0.000	acre-ft/yr				acre-ft/yr
Water exported:	n/a	0.000	acre-ft/yr				acre-ft/yr

Enter negative % or value for under-registration
Enter positive % or value for over-registration

WATER SUPPLIED: 15,592.440 acre-ft/yr

AUTHORIZED CONSUMPTION

Click here: ? for help using option buttons below

				Pcnt:	Value:	
Billed metered:	6	12,906.500	acre-ft/yr			
Billed unmetered:	n/a		acre-ft/yr			
Unbilled metered:	5	4.995	acre-ft/yr			
Unbilled unmetered:		194.906	acre-ft/yr	1.25%		acre-ft/yr

Default option selected for Unbilled unmetered - a grading of 5 is applied but not displayed

AUTHORIZED CONSUMPTION: 13,106.401 acre-ft/yr

Use buttons to select percentage of water supplied **OR** value

WATER LOSSES (Water Supplied - Authorized Consumption)

2,486.040 acre-ft/yr

Apparent Losses

				Pcnt:	Value:	
Unauthorized consumption:		38.981	acre-ft/yr	0.25%		acre-ft/yr

Default option selected for unauthorized consumption - a grading of 5 is applied but not displayed

Customer metering inaccuracies:	5	476.617	acre-ft/yr	3.56%		acre-ft/yr
Systematic data handling errors:		32.266	acre-ft/yr	0.25%		acre-ft/yr

Default option selected for Systematic data handling errors - a grading of 5 is applied but not displayed

Apparent Losses: 547.864 acre-ft/yr

Real Losses (Current Annual Real Losses or CARL)

Real Losses = Water Losses - Apparent Losses: 1,938.175 acre-ft/yr

WATER LOSSES: 2,486.040 acre-ft/yr

NON-REVENUE WATER

NON-REVENUE WATER: 2,685.940 acre-ft/yr

= Water Losses + Unbilled Metered + Unbilled Unmetered

SYSTEM DATA

Length of mains:	8	318.0	miles
Number of active AND inactive service connections:	6	7,712	
Service connection density:		24	conn./mile main

Are customer meters typically located at the curbstop or property line? Yes

Average length of customer service line:

(length of service line, beyond the property boundary, that is the responsibility of the utility)

Average length of customer service line has been set to zero and a data grading score of 10 has been applied

Average operating pressure:	5	60.0	psi

COST DATA

Total annual cost of operating water system:	10	$18,503,251	$/Year	
Customer retail unit cost (applied to Apparent Losses):	8	$2.70	$/100 cubic feet (ccf)	
Variable production cost (applied to Real Losses):	5	$86.12	$/acre-ft	☐ Use Customer Retail Unit Cost to value real losses

WATER AUDIT DATA VALIDITY SCORE:

***** YOUR SCORE IS: 58 out of 100 *****

A weighted scale for the components of consumption and water loss is included in the calculation of the Water Audit Data Validity Score

PRIORITY AREAS FOR ATTENTION:

Based on the information provided, audit accuracy can be improved by addressing the following components:

1: Volume from own sources
2: Billed metered
3: Unbilled metered

AWWA Free Water Audit Software:
Reporting Worksheet

WAS v5.0
American Water Works Association.
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? Click to access definition
+ Click to add a comment

Water Audit Report for: West Kern Water District (1510022)
Reporting Year: 2018 1/2018 - 12/2018

Please enter data in the white cells below. Where available, metered values should be used; if metered values are unavailable please estimate a value. Indicate your confidence in the accuracy of the input data by grading each component (n/a or 1-10) using the drop-down list to the left of the input cell. Hover the mouse over the cell to obtain a description of the grades

All volumes to be entered as: ACRE-FEET PER YEAR

To select the correct data grading for each input, determine the highest grade where the utility meets or exceeds all criteria for that grade and all grades below it.

Master Meter and Supply Error Adjustments

WATER SUPPLIED

<---------- Enter grading in column 'E' and 'J' ---------->

					Pcnt:	Value:	
Volume from own sources:	6	17,086.620	acre-ft/yr	3			acre-ft/yr
Water imported:	n/a	0.000	acre-ft/yr				acre-ft/yr
Water exported:	5	1,435.520	acre-ft/yr	3			acre-ft/yr

Enter negative % or value for under-registration
Enter positive % or value for over-registration

WATER SUPPLIED: 15,651.100 acre-ft/yr

AUTHORIZED CONSUMPTION

Click here: ? for help using option buttons below

				Pcnt:	Value:	
Billed metered:	6	15,249.800	acre-ft/yr			
Billed unmetered:	n/a	0.000	acre-ft/yr			
Unbilled metered:	6	4.450	acre-ft/yr			
Unbilled unmetered:	5	39.128	acre-ft/yr		39.128	acre-ft/yr

Use buttons to select percentage of water supplied **OR** value

AUTHORIZED CONSUMPTION: 15,293.378 acre-ft/yr

WATER LOSSES (Water Supplied - Authorized Consumption) 357.722 acre-ft/yr

Apparent Losses

				Pcnt:	Value:	
Unauthorized consumption:		39.128	acre-ft/yr	0.25%		acre-ft/yr

Default option selected for unauthorized consumption - a grading of 5 is applied but not displayed

Customer metering inaccuracies:	4	311.311	acre-ft/yr	2.00%		acre-ft/yr
Systematic data handling errors:		38.125	acre-ft/yr	0.25%		acre-ft/yr

Default option selected for Systematic data handling errors - a grading of 5 is applied but not displayed

Apparent Losses: 388.563 acre-ft/yr

Check input values; APPARENT LOSSES should be less than WATER LOSSES

Real Losses (Current Annual Real Losses or CARL)

Real Losses = Water Losses - Apparent Losses: -30.841 acre-ft/yr

WATER LOSSES: 357.722 acre-ft/yr

NON-REVENUE WATER

NON-REVENUE WATER: 401.300 acre-ft/yr

= Water Losses + Unbilled Metered + Unbilled Unmetered

SYSTEM DATA

Length of mains:	8	318.0	miles
Number of active AND inactive service connections:	8	7,784	
Service connection density:		24	conn./mile main

Are customer meters typically located at the curbstop or property line? Yes

Average length of customer service line: (length of service line, beyond the property boundary, that is the responsibility of the utility)

Average length of customer service line has been set to zero and a data grading score of 10 has been applied

Average operating pressure:	5	60.0	psi

COST DATA

Total annual cost of operating water system:	10	$18,149,172	$/Year	
Customer retail unit cost (applied to Apparent Losses):	8	$2.40	$/100 cubic feet (ccf)	
Variable production cost (applied to Real Losses):	5	$144.45	$/acre-ft	☐ Use Customer Retail Unit Cost to value real losses

WATER AUDIT DATA VALIDITY SCORE:

***** YOUR SCORE IS: 62 out of 100 *****

A weighted scale for the components of consumption and water loss is included in the calculation of the Water Audit Data Validity Score

PRIORITY AREAS FOR ATTENTION:

Based on the information provided, audit accuracy can be improved by addressing the following components:

1: Volume from own sources
2: Customer metering inaccuracies
3: Billed metered

AWWA Free Water Audit Software:
Reporting Worksheet

WAS v5.0

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Water Audit Report for: West Kern Water District (1510022)
Reporting Year: 2019 | 1/2019 - 12/2019

Please enter data in the white cells below. Where available, metered values should be used; if metered values are unavailable please estimate a value. Indicate your confidence in the accuracy of the input data by grading each component (n/a or 1-10) using the drop-down list to the left of the input cell. Hover the mouse over the cell to obtain a description of the grades

All volumes to be entered as: ACRE-FEET PER YEAR

To select the correct data grading for each input, determine the highest grade where the utility meets or exceeds all criteria for that grade and all grades below it.

Master Meter and Supply Error Adjustments

WATER SUPPLIED

<---------- Enter grading in column 'E' and 'J' ---------->

					Pcnt:	Value:	
Volume from own sources:	7	15,206.000	acre-ft/yr	3		-1,114.080	acre-ft/yr
Water imported:	n/a		acre-ft/yr				acre-ft/yr
Water exported:	6	0.000	acre-ft/yr				acre-ft/yr

Enter negative % or value for under-registration
Enter positive % or value for over-registration

WATER SUPPLIED: 16,320.080 acre-ft/yr

AUTHORIZED CONSUMPTION

Click here: ? for help using option buttons below

				Pcnt:	Value:	
Billed metered:	8	14,947.000	acre-ft/yr			
Billed unmetered:	n/a		acre-ft/yr			
Unbilled metered:	6	22.000	acre-ft/yr			
Unbilled unmetered:	5	40.800	acre-ft/yr		40.800	acre-ft/yr

Use buttons to select percentage of water supplied **OR** value

AUTHORIZED CONSUMPTION: 15,009.800 acre-ft/yr

WATER LOSSES (Water Supplied - Authorized Consumption)

1,310.280 acre-ft/yr

Apparent Losses

			Pcnt:	Value:	
Unauthorized consumption:	40.800	acre-ft/yr	0.25%		acre-ft/yr

Default option selected for unauthorized consumption - a grading of 5 is applied but not displayed

Customer metering inaccuracies:	4	151.202	acre-ft/yr	1.00%	acre-ft/yr
Systematic data handling errors:	5	37.368	acre-ft/yr	0.25%	acre-ft/yr

Default option selected for Systematic data handling errors - a grading of 5 is applied but not displayed

Apparent Losses: 229.370 acre-ft/yr

Real Losses (Current Annual Real Losses or CARL)

Real Losses = Water Losses - Apparent Losses: 1,080.910 acre-ft/yr

WATER LOSSES: 1,310.280 acre-ft/yr

NON-REVENUE WATER

NON-REVENUE WATER: 1,373.080 acre-ft/yr

= Water Losses + Unbilled Metered + Unbilled Unmetered

SYSTEM DATA

Length of mains:	8	318.0	miles
Number of active AND inactive service connections:	8	7,521	
Service connection density:		24	conn./mile main

Are customer meters typically located at the curbstop or property line? Yes

Average length of customer service line: (length of service line, beyond the property boundary, that is the responsibility of the utility)

Average length of customer service line has been set to zero and a data grading score of 10 has been applied

Average operating pressure: 5 | 60.0 psi

COST DATA

Total annual cost of operating water system:	10	$18,668,470	$/Year	
Customer retail unit cost (applied to Apparent Losses):	8	$2.07	$/100 cubic feet (ccf)	
Variable production cost (applied to Real Losses):	5	$120.26	$/acre-ft	☐ Use Customer Retail Unit Cost to value real losses

WATER AUDIT DATA VALIDITY SCORE:

***** YOUR SCORE IS: 67 out of 100 *****

A weighted scale for the components of consumption and water loss is included in the calculation of the Water Audit Data Validity Score

PRIORITY AREAS FOR ATTENTION:

Based on the information provided, audit accuracy can be improved by addressing the following components:

1: Volume from own sources
2: Customer metering inaccuracies
3: Variable production cost (applied to Real Losses)

APPENDIX G – MEMORANDUM OF UNDERSTANDING ON WATER RECYCLING

MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding ("MOU") is executed as of June 16, 2015, by and among **City of Taft** ("Taft"), **West Side Recreation & Park District** ("WSRPD"), **West Side Cemetery District** ("WSCD"), and **West Kern Water District** ("WKWD").

RECITALS

A. California is in the middle of an historic drought and state officials have mandated that Californians conserve water and develop new water use patterns that will reduce total demand over the medium and long terms.

B. Taft owns and operates a sewage treatment plant east of Taft. WSRPD operates parks and recreational facilities and WSCD operates a cemetery, all of which facilities consume a total of approximately 200 acre feet of water per year for watering lawns and landscaping. WKWD provides potable water service to the facilities operated by WSRPD and WSCD, as well as nearly all other urban consumers in the Taft area.

C. WSRPD and WSCD do not need potable water for landscape irrigation. If non-potable water from a source other than WKWD's existing supplies could be substituted for the potable water now used by WSRPD and WSCD for irrigation, it would be equivalent to reducing consumption of potable water within the WKWD service area. Water from the treatment plant treated to tertiary standards would likely be usable for irrigation, but the parties do not currently know if that idea is practical. Therefore, they have agreed to study the concept.

UNDERSTANDINGS AND AGREEMENTS

1. WKWD will retain a qualified consultant to study and produce a report on the issues, cost and practicality of treating effluent at the Taft Municipal Wastewater Treatment Plant to tertiary standards and then delivering the treated water to WSRPD and WSCD for use in irrigating their parks, recreational facilities and cemetery. Issues to be considered by the consultant will include:

(a) the practicality of providing tertiary treatment of a specified quantity of effluent at the treatment plant and required improvements to do so,

(b) regulatory and safety issues that might be raised by using tertiary treated gray water at the specified facilities,

(c) how gray water would be delivered from the treatment plant to end use facilities,

(d) work that would be required to segregate new gray water from existing potable water at those facilities, and

(e) the capital and operating costs of such a project.

WKWD shall advise the other parties of the consultant that WKWD intends to retain and solicit their comments on the appropriateness of the particular consultant. WKWD shall then provide the other parties with the agreement retaining the consultant and will provide a reasonable opportunity for them to comment or object to the consultant or the agreement. WKWD will not proceed to enter into an agreement with a consultant if a party objects. WKWD will not agree to any amendment of the consultant's agreement without first obtaining the approval of the other parties. If the parties cannot reach agreement on the consultant or the consultant's agreement, including the cost, then this Memorandum of Understanding will terminate.

2. District and Taft will cooperate with the consultant retained by WKWD in conducting this study, including providing the consultant with reasonable access to (a) the treatment plant, (b) existing delivery systems, (c) plant personnel, and (d) records of treatment plant operations such as quantities of effluent treated, test results, equipment specifications, and maintenance and repair records.

3. WSRPD and WSCD will cooperate with the consultant retained by WKWD in conducting this study, including providing the consultant with reasonable access to (a) plans for irrigation systems, (b) water use records and (c) operational personnel.

4. WKWD will (a) provide its consultant with any records in its possession requested by the consultant, access to district personnel, and information on its existing water delivery system, (b) provide supervision and oversight of the consultant, and (c) administer the consultant's contract for services and pay the consultant.

5. All parties agree to provide such other reasonable assistance or agreements as may be needed for the proper conduct of the study, at no material cost to such party.

6. The parties agree to provide the following contributions toward the cost of the consulting contract as finally approved by all of the parties:

WKWD: Remaining Balance TBD
Taft: $2,000
WSRPD: $1,000
WSCD: $1,000

The parties other than WKWD will pay their share of the study cost to WKWD within thirty (30) days of WKWD executing the agreement to retain the consultant. WKWD shall apply all funds received toward the cost of the consulting contract. Each party will bear its own incidental out of pocket costs and staff time associated with providing the

consultant with requested information and documents. A party's share of the cost may not be increased without the written consent of that party.

7. WKWD will provide the other parties with a working draft of the consultant's report for their review and correction of factual errors before it is finalized. Each party will receive several copies of the final report.

8. Any party may withdraw its cooperation from the conduct of this study on thirty (30) days' prior written notice to the other parties. No governing body of a party shall be required to accept or otherwise acknowledge the report prepared by the consultant. No party is agreeing to participate in or pay for any recommendations that may be contained in the report, and specifically, no party is agreeing to undertake a project for the tertiary treatment of effluent and use of gray water.

9. The memorandum of understanding will terminate upon the consultant rendering its final report. The parties will not be obligated to enter into any future agreements.

[Signatures on next page]

The parties have executed this Memorandum of Understanding as of the date first above written.

City of Taft

By: _____
Name: Randy Miller
Title: Mayor

West Side Recreation and Park District

By: _____
Name: Donald F Koenig
Title: District Administrator

West Side Cemetery District

By: _____
Name: Joel Bauer
Title: District Manager

West Kern Water District

By: _____
Name: HARRY O. STARKEY
Title: GENERAL MANAGER

APPENDIX H - WATER SHORTAGE RESPONSE PLAN

WATER SHORTAGE RESPONSE PLAN

FOR

WEST KERN WATER DISTRICT

May 2021

Prepared By:

Provost & Pritchard Consulting Group

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1 – Matrix of Water Use Restrictions by Water Shortage Stage
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Definitions

The following words and phrases whenever used in the Water Shortage Response Plan will have the meaning defined in this Section:

"Customer" means any person, business, corporation, public or private entity, public or private association, public or private agency, government agency or institution, school district, college, or any other user of water provided by West Kern Water District.

"Days" are defined as calendar days, unless otherwise indicated.

"District" means the West Kern Water District.

"Drought" will mean any shortage in water supply based upon expected demands that are caused by hydrological, environmental, legislative, judicial actions, or by infrastructure failure.

"Reasonable Probability" refers to potential reductions due to shortages due to drought conditions, regulatory restriction enacted upon imported supplies, catastrophic emergencies, and other factors.

"Waste/Unreasonable Use" means among other things, violations of the restrictions set forth in this policy at each specific response level.

"Water Conservation" means the efficient management of water resources for beneficial uses, preventing waste, or accomplishing additional benefits with the same amount of water.

"Water" will refer to potable water, unless otherwise specified.

"WSRP" refers to West Kern Water District's Water Shortage Response Plan in existence on the effective date of this ordinance and as readopted or amended from time to time, or an equivalent plan of the District to manage or allocate supplies during shortages. The Water Shortage Response Plan is the same as a Water Shortage Contingency Plan.

1 - PURPOSES AND PRINCIPLES OF PLAN

The purpose of the West Kern Water District (WKWD or District) Water Shortage Response Plan (WSRP) is to provide a methodology for analyzing water supply reliability, establish water shortage levels, identify appropriate response actions, and document protocols for enforcing the WSRP. This WSRP was prepared according to requirements in Sections 10632 & 10635 of the California Water Code. **Table 1** below shows the required components of a WSRP, the relevant water code section, and where they are found in this document.

Table 1: Water Shortage Response Plan Requirements

Topic	CA Water Code Section	WSRP Section
Water Supply Reliability Analysis	WC 10632 (a.1)	Section 2
Annual Assessment Procedures	WC 10632 (a.2)	Section 2
Water Shortage Levels	WC 10632 (a.3)	Section 3 Table 2
Shortage Response Actions	WC 10632 (a.4) WC 10632 (b)	Section 4
Communication Protocols	WC 10632 (a.5)	Section 5
Compliance and Enforcement	WC 10632 (a.6)	Section 6
Legal Authority	WC 10632 (a.7)	Section 7
Financial Consequences of WSRP	WC 10632 (a.8)	Section 8
Monitoring and Reporting	WC 10632 (a.9)	Section 9
WSRP Refinement Procedures	WC 10632 (a.10)	Section 10

2 - PROCEDURES FOR CONDUCTING ASSESSMENT

2.1 Decision Making Process

Regulatory Requirement

§10632(a.2.A) The written decision-making process that an urban water supplier will use each year to determine its water supply reliability.
§10632 (a.2.B) (iv) A defined set of locally applicable evaluation criteria that are consistently relied upon for each annual water supply and demand assessment.

The District's Operations Staff and Regulatory Administrator are responsible for collecting and analyzing various hydrologic datasets, assessing water demands, and assessing system capacities versus anticipated supplies. The General Manager will be updated regularly, and the District Board of Directors will also be provided informative briefings at monthly Board meetings. Please be advised that the levels below correspond to the required Water Shortage Levels outlined in WC 10632.

Response Level 1
The existence of a Water Shortage Response Level 1 shall be ongoing when declared by Board action. Declaration of Level 1 may be implemented upon reaching:

1. Three-years of consecutive state-wide drought; and
2. Significant reduction in groundwater levels, as deemed by the Board of Directors; and
3. Significant reduction in groundwater storage, as deemed by the Board of Directors.

Response Level 1 can also be declared if there are facility or infrastructure issues (such as well failure, pipeline failure, aqueduct breach, etc.) that reduce water supplies.

Response Levels 2 to 6 & 6a
Response Levels 2 to 6 & 6a shall be enacted only after situations occur that are more severe than those needed to enact Response Level 1 & 1a. These Response Levels can only be declared after the Board of Directors has first declared a 'Water Shortage Emergency'.

WKWD recharges most of their surface water, creating a storage buffer to help deal with droughts and other water supply interruptions. These reserves have proven to be very effective and have historically eliminated the need for water use restrictions in WKWD for many years. Current groundwater storage can meet demands for approximately ten years.

As a result, hard triggers for implementing Response Levels 2 to 6 & 6a are not considered practical. Instead, these levels will be enacted by the Board of Directors based on a subjective evaluation of the following factors:

1. Assessing three years of unconstrained supply to the District
2. Local drought conditions
3. General Statewide drought conditions
4. Groundwater depths, including recent changes
5. Total banked groundwater storage, including recent changes
6. Changes in well capacity due to groundwater level declines
7. Recent allocation of surface water

8. Short-term ability to purchase water from other sources
9. Water quality issues impacting the water supply
10. Infrastructure issues (such as well failure, pipeline failure, aqueduct breach, etc.) that could significantly reduce water supplies

The existence of Water Shortage Response Level 2 or Level 3 conditions may be declared by resolution of the WKWD Board of Directors and adopted at a regular or special public meeting held in accordance with state law. The mandatory conservation measures applicable to Response Level 2 or Level 3 conditions shall take effect on the tenth (10) day after the date the response level is declared. Within five (5) days following the declaration of the response level, the District shall publish a summary of the resolution in one or more newspapers. The District may also post notice of the condition on its website. Lastly, the District does currently maintain an automated robocalling system that may be utilized to alert all water users within the District's service area.

Water Shortage Response Levels 4 through Level 6 may be declared as deemed necessary by the Board of Directors. The mandatory conservation measures applicable to Response Levels 4 through 6 shall take effect on the tenth (10) day after the date the response level is declared. Within five (5) days following the declaration of the response level, the District shall publish a summary of the resolution in one or more newspapers. The District may also post notice of the condition on its website. The most restrictive Water Shortage Response Level 6a is only to be implemented in very extreme conditions. This Level is designed to be implemented on a short-term basis no longer than 45 days. These extreme conditions could call for a complete prohibition on all water use throughout the District and would require water tanks to be brought into the District for emergency situations of health and safety. Both Levels 6 and 6a will be implemented in accordance with the procedures specified in California Water Code Sections 351 and 352. These sections indicate the protocol for publicly noticing the public hearing that is needed when implementing or declaring a water shortage emergency.

The District's Board of Directors may declare an end to a Water Shortage Response Level 2 or higher by the adoption of a resolution at any regular or special meeting held in accordance with state law.

2.2 Data Inputs and Assessment Methodology

Current Year Demand

Regulatory Requirement

§10632 (a.2.B) (i) Current year unconstrained demand, considering weather, growth, and other influencing factors, such as policies to manage current supplies to meet demand objectives in future years, as applicable.

The District currently delivers disinfected groundwater to residential, commercial, and industrial customers. In addition, Raw water from the State Water Project (SWP) is delivered to one industrial customer in the District, the La Paloma Power Co. LLC (La Paloma). The District provides water to the local wastewater treatment facility but does not oversee sewage collection or treatment. The recycled water from this facility is used to irrigate fodder crops on adjacent agricultural land The District's current and projected water demand is broken down into three categories: Potable Water, Raw Water, and Recycled Demand. This demand summary can be found in **Table 2** below.

Table 2: Total Water Demands

Description	2015	2020
Potable Water	16,542	14,767
Raw Water	4,461	1,571
Recycled Water Demand	0	0
TOTALWATER DEMAND	21,003	16,338

Future water demand estimates will typically be based on the following criteria and assumptions:

1. Future population growth is 0.4% per year, which is consistent with the population growth rate that was assumed in the 2010 UWMP.
2. In 2020 and beyond, residential, and commercial demands are based on the District meeting its 2020 per capita goal of 189 gallons/capita/day.
3. Raw water demands to La Paloma have fluctuated over the years with an average usage of 3000 AF/yr. their total contract supply is 5,500 AF/year).
4. Treated industrial demands after 2020 are based on the average water use from 2016 to 2020, which is 10,400 AF/year.

Several other factors can affect demand projections, which are not included in the estimate above, including:

- Land use revisions
- New regulations
- Consumer choice
- Economic conditions
- Oil prices and oil demand
- Transportation needs
- Highway construction
- Environmental factors
- Conservation programs
- Plumbing codes

The foregoing factors affect the amount of water needed, as well as the timing of when it is needed. Past experiences have indicated that the economy is the biggest factor in determining water demand projections. During an economic recession, there is a major downturn in development and a subsequent slowing of the projected demand for water. The projections in this Plan do not attempt to forecast recessions or droughts. Likewise, no speculation is made about future plumbing codes or other regulatory changes. Also, much of the industrial water demand is used by oil exploration companies. Predicting the oil economy and subsequent demand for water in the oil fields is not feasible.

Quantification of Water Supply

Regulatory Requirement

§10632 (a.2.B) The key data inputs and assessment methodology used to evaluate the urban water supplier's water supply reliability for the current year and one dry year.
§10632 (a.2.B) (iii) Current year available supply, considering hydrological and regulatory conditions in the current year and one dry year. The annual supply and demand assessment may consider more than one dry year solely at the discretion of the urban water supplier.
§10632 (a.2.B) (v) A description and quantification of each source of water supply.

Water supply facilities in the District include 13 wells (5 in the North Well Field and 8 in the South Well Field), 26 water tanks, and approximately 346 miles of pipelines. The facilities are spread out over the entire district, which covers over 300 square miles.

Imported Water Supply
The District maintains a contract for surface water from the State Water Project (SWP) in conjunction with the Kern County Water Authority (WKWA) of an annual amount of 31,500 acre-feet per year (AFY). The 2020 UWMP analysis estimated that the long-term reliability of this SWP supply is estimated to be approximately 60%

During wet years when high-flow water is available, an additional 10,000 AFY is available to WKWD. Historically, this high-flow water has been purchased or exchanged by WKWD to increase the water banking program. The surface water indirectly available to WKWD consists of in-lieu surface water delivered to Buena Vista Water Storage District (BVWSD) and credited to WKWD for recharge. This water is either SWP water or high-flow Kern River water. The surface water is not currently used as a direct domestic water supply source.

WKWD also has two turnouts along the California Aqueduct that have been used to deliver untreated water directly to industrial customers. Currently only one of the turnouts is operated by the District, which supplies untreated water to La Paloma. An agreement was established in 2001 between WKWD and La Paloma for a maximum delivery of 6,500 AFY, with the Agreement being amended in 2018 for an annual delivery of 5,500 AF.. Historically La Paloma has taken less than their contract amount and WKWD utilizes the balance of the water for recharge to its water banking program or exchanges with other entities.

Delta Conveyance Facility Supply
The District plans to participate in the Delta Conveyance Facility project and is hopeful that this will drastically improve and sustain their long-term water reliability. However, this project is not scheduled to be implemented for several years.

Groundwater Supplies
The District has two well fields that primarily pump groundwater that has been banked over several decades. The pumping capacity is capable of meeting the District's peak summertime demands. The amount of groundwater in storage fluctuates based on hydrologic conditions, but currently represent about a 10-year supply. This is the source directly used to meet most District demands.

Existing Infrastructure Constraints

Regulatory Requirement

§10632 (a.2.B) (iii) Existing infrastructure capabilities and plausible constraints.

The District maintains an existing distribution system. The primary facilities in the District include the following:

- 13 active groundwater wells (1 inactive well)
- 26 above ground water storage tanks
- 15 booster pump stations
- 346 miles of distribution pipelines
- Recharge basins of approximately 415 acres
- Recharge basins in project vicinity of approximately 6,862 acres
- Recharge basins in Tule Elk reserve of approximately 729 acres
- 2 Aqueduct Turnouts (1 active)

Possible infrastructure constraints include problems with State Water Project facilities or internal well and conveyance facilities. If there are problems with the Delta, California Aqueduct, or Aqueduct Turnouts, then the District could rely on the large volume of groundwater banked to meet demands. The District currently has excess capacity in their wellfields and conveyance facilities; however, any number of conditions could constrain capacity of existing infrastructure in a manner than would require the District to declare a water shortage and enforce water conservation measures.

3 - WATER SHORTAGE LEVELS

Regulatory Requirement

§10632 (a.3.A) Six standard water shortage levels corresponding to progressive ranges of up to 10, 20, 30, 40, and 50 percent shortages and greater than 50 percent shortage. Urban water suppliers shall define these shortage levels based on the suppliers' water supply conditions, including percentage reductions in water supply, changes in groundwater levels, changes in surface elevation or level of subsidence, or other changes in hydrological or other local conditions indicative of the water supply available for use. Shortage levels shall also apply to catastrophic interruption of water supplies, including, but not limited to, a regional power outage, an earthquake, and other potential emergency events.

As outlined in the new Water Code requirements (10632 a & b.), Water Shortage Contingency Plans must include or be adapted to the six standard water shortage levels, which correspond to the progressive conservation ranges of <10%, 10-20%, 20-30%, 30-40%, 40-50% and 50+%. These six levels are described in **Table 2.** The various Response Actions that correspond with these levels are addressed in **Section 4** of this plan.

Table 2: Updated Levels of Water Shortage

RESPONSE LEVELS	DESCRIPTION	RESTRICTIONS	CONSERVATION TARGET[2]
Level 1	Water Awareness	Voluntary	0 to 10%
Level 2	Moderate Water Shortage	Mandatory	10% - 20%
Level 3	Severe Water Shortage	Mandatory	20% - 30%
Level 4	Extreme Water Shortage	Mandatory	30% - 40%
Level 5	Critical Water Shortage	Mandatory	40% - 50%
Level 6	Emergency Water Shortage	Mandatory	Greater than 50%
Level 6a Short Term[2]	Short-Term Water Emergency	Mandatory	Greater than 50%

Notes:
1 – Short term conditions occur for 45 days or less and may be attributed to infrastructure, water quality or power issues, as well as hydrologic conditions.
2 – 'Normal Water Production' refers to the average water production during the last 3 years with unconstrained supplies.

These water shortage stages each include specific water use restrictions that will be adopted and enforced. The following should also be noted regarding these water shortage stages:

- This policy establishes water management requirements necessary to conserve water, enable effective water supply planning, assure reasonable and beneficial use of water, prevent waste of water, prevent unreasonable use of water within the District in order to assure adequate supplies of water to meet the needs of the public, and further the public's health, safety, and welfare, recognizing that water is a limited natural resource that requires careful management not only in times of drought but at all times.

- This policy establishes progressive response levels including regulations to be implemented during times of declared water shortages or declared water shortage emergencies. It establishes six levels of response actions to be implemented in times of shortage, with increasing restrictions on water use in response to worsening drought conditions and decreasing available supplies.

- Level 1 shortage response measures are voluntary and will be reinforced through local and regional public education and awareness measures that may be funded in part by the District. During response condition Levels 1 through 6 & 6a, the District Board of Directors will determine the necessity for each conservation measures and water-use restriction, which become increasingly restrictive to attain escalating conservation goals.

  Detailed descriptions of each water shortage stage and their associated water use restrictions are provided in the following section.

4 - SHORTAGE RESPONSE ACTIONS

4.1 Response Actions by Water Shortage Level

Regulatory Requirement

§10632 (a.4) Shortage response actions that align with the defined shortage levels

While there are six different water shortage levels with varying response actions, there are several response actions that are considered permanent and are always implemented. Each Water Shortage Level must adhere to these response actions as well as any additional actions that are pertinent to that level.

Permanent Response Actions

- All hoses shall be equipped with a shut-off nozzle. Hosing down driveways, streets, parking lots, sidewalks or buildings is prohibited unless required for health and safety.
- Excessive watering or over-saturation causing water to run off onto sidewalks, streets, or gutters is prohibited.
- Residential and commercial landscape irrigation shall not take place between the hours of 10am and 6pm. (Consider adjusting the landscape irrigation run time)
- Washing of motor vehicles, trailers, boats and other types of equipment shall only be done using a bucket and/or a hand-held hose that has a shut-off nozzle, a high pressure/low volume wash system, or be conducted at a commercial site that recirculates water on-site. Washing during hot weather conditions shall be avoided as additional water then becomes required due to evaporation.
- Eating or drinking establishments, including but not limited to: Restaurants, cafes, cafeterias, bars or other public places where food or drink are served and/or purchased, shall serve water only upon request.
- Operators of hotels and motels shall offer patrons the option of not having their towels and linens washed daily.
- Pools, spas, and ornamental fountains/ponds should have recirculation and be leak proof. Draining and refilling is only permitted for health, maintenance, or structural reasons.
- Stop use of potable water for compaction or dust control where non-potable or recycled water is available.
- Repair all leaks within twenty-four (24) hours of notification by the District unless other arrangements are made with the General Manager.
- Users of construction meters and fire hydrant meters will be monitored for efficient water use.

Water Shortage Response Levels

Following are response actions for each of the six water shortage stages that can be declared by the District. These response actions are also illustrated in a matrix included as **Attachment 1**. The District has the authority to be flexible when selecting which response actions to require, but the following are recommended guidelines for each stage.

When the State mandates specific response actions during a Water Shortage Emergency they will be added to the lists below.

Level 1. Water Awareness (90% to 100% of Normal Water Production)

Level 1. Below Normal Water Supply is categorized with a possible reduction percentage of up to 10%. A Level 1 condition applies when there is reasonable probability that there will be supply reduction but is considered a voluntary level. Existence of a Response Level 1 condition is considered on-going, and the District shall take action to implement the Level 1 conservation practices identified in this Plan. These actions may include:

- Increased public education and outreach efforts to emphasize public awareness of the need to implement voluntary water conservation practices.

Level 2. Moderate Water Shortage (80% to 90% of Normal Water Production)

Level 2. Moderate Water Shortage is categorized with a possible reduction percentage of 10-20%. A Level 2 condition applies when the District notifies its customers to reduce water usage due to drought or other reduction supplies. The WKWD Board of Directors shall declare the existence of a Response Level 2 condition and implement selected mandatory Level 2 conservation measures identified in this Plan. These actions may include:

- Reduce large & significant landscape watering by 25%
- Eliminate all over-use of water by contracted industrial customers
- Reduce non-contracted industrial water use by 15%

Level 3. Severe Water Shortage (70% to 80% of Normal Water Production)

Level 3. Severe Water Shortage is categorized with a possible reduction percentage of 20-30%. A Level 3 condition applies when increasing cutbacks are necessary due to continued drought or disaster. The WKWD Board of Directors shall declare the existence of a Response Level 3 condition and shall implement selected actions from Levels 1 & 2 as well as additional actions outlined below pursuant to this Plan. These actions may include:

- Reduce non-contracted industrial water use by 60%
- Lawn watering and landscape irrigation shall be limited to no more than 10 minutes per water station per assigned day as follows: Residents with even street number addresses water on Wednesday, Friday, and Sunday. Residents with odd number addresses may water on Tuesday, Thursday, and Saturday. NO watering is allowed on Monday. (These restrictions apply to manual and automatic watering.) Irrigation run time shall be adjusted to avoid runoff.

Upon declaration of a Response Level 3 condition, no new potable water service shall be provided, no new temporary meters or permanent meters shall be provided, and no statement of immediate ability to serve or provide potable water service such as will serve letters shall be issued, except under the following circumstances:

- A valid, unexpired building permit has been issued for the project;
  or
- The Project is necessary to protect the public's health, safety, and welfare; or
- The applicant provides substantial evidence to the District, of an enforceable commitment that water demands for the project will be offset prior to the provision of a new water meter(s) to the satisfaction of the District.

Level 4 Extreme Water Shortage (60% to 70% of Normal Water Production)

Level 4. Extreme Water Shortage is categorized with a possible reduction percentage of 30-40%. A Level 4 condition applies when the District's Board of Director's declares a water shortage emergency pursuant to this Plan and notifies its customers that Level 4 requires a demand reduction in order for the District to have supplies available to meet basic needs. The WKWD Board of Directors shall declare the existence of a Response Level 4 condition and implement selected actions from Levels 1 through 3 as well as additional actions outlined below. These actions may include:
All the Response Actions in Level 3 plus the following new Response Actions:

- Reduce large and significant landscape watering by 35%
- Eliminate all over-use of water by contracted industrial customers
- Eliminate non-contracted industrial water use
- Reduce contracted industrial customers, excluding large landscape watering by 10%
- Reduce California Resources Corporation water use by 10%
- Reduce Elk Hills Power water use by 10%
- Limit residential and commercial landscape irrigation to no more than once per week. Residents and commercial businesses with odd street number addresses water on Tuesdays. Residents and commercial businesses with even street number addresses water on Wednesdays. No watering is allowed on Monday, Thursday, Friday, Saturday or Sunday. (These restrictions apply to manual and automatic watering.) Irrigation run time shall be adjusted to avoid runoff.
- Washing of motor vehicles, trailers, boats, and other types of equipment is prohibited unless required for health and safety.
- The application of potable water to driveways and sidewalks is prohibited.
- The installation of new turf or landscaping is prohibited.
- No irrigation with potable water of ornamental turf on public street medians
- New connections to the District's water distribution system will be allowed but their water use shall be restricted to the minimum requirements for personal health and safety.

Level 5 Critical Water Shortage (50% to 60% of Normal Water Production)

Level 5 Critical Water Shortage is categorized with a possible reduction percentage of 40-50%. A Level 5 condition applies when the District's Board of Director's declares a water shortage emergency pursuant to this Plan and notifies its customers that Level 5 requires a demand reduction in order for the District to have supplies available to meet basic needs. All the Response Actions in Levels 1 through 4 are required plus the following new Response Actions:

- Reduce large and significant landscape watering by 50%
- Reduce contracted industrial customers, excluding large landscape watering by 20%
- Reduce California Resources Corporation water use by 20%
- Reduce Elk Hills Power water use by 20%
- Water use for ornamental ponds and fountains is prohibited.

The following Response Actions replace previous less stringent actions:

- Water for flow testing and construction purposes from water agency fire hydrants and blow-offs is prohibited.

- Water use exceedance tiered pricing and/or excessive water use fines will be implemented.

Level 6 Emergency Water Shortage (>50% of Normal Water Production)

Level 6 Critical Water Shortage is categorized with a possible reduction percentage of 40-50%. All the Response Actions in Level 5 are required plus the following and those that replace previous less stringent actions:

- Motor vehicles and equipment shall be washed only at commercial establishments that use recycled or reclaimed water.
- Import water tanks into the District's service area to provide potable water
- Reduce large and significant landscape watering by 75%
- Reduce contracted industrial customers, excluding large landscape watering by 40%
- Reduce potable water deliveries for power generation by 40%
- Reduce Elk Hills Power water use by 40%

The following Response Actions replace previous less stringent actions:

- Water use exceedance tiered pricing and/or excessive water use fines will be increased.
- No commitments ("will serves") will be made to provide service for new water service connections.

Level 6a Emergency Water Shortage Short-Term (>50% of Normal Water Production)

Level 6 Critical Water Shortage is categorized with a possible reduction percentage of >50%+. A short-term declaration is for water shortage conditions expected for a duration of less than 45 days. Level 6a is the most critical and restrictive Water Shortage Level and is considered an Emergency Shortage. All the Response Actions through Level 6 are required plus the following:

- Motor vehicles and equipment shall not be washed under any circumstances
- Eliminate all landscape watering
-
- Reduce contracted industrial customers, excluding large landscape watering by 80%
- Reduce California Resources Corporation water use by 50%
- Reduce Elk Hills Power water use by 50%

The following Response Actions replace previous less stringent actions:

- All non-emergency or water use not defined in this Plan will be prohibited

4.2 Locally Appropriate Supply Augmentation Actions

Regulatory Requirement

§10632 (a.4.A) Locally appropriate supply augmentation actions.

If surface water supplies are limited, there may be other options through transfer, exchanges or open-market water purchases to secure additional surface water from the State Water Project of Kern River

In the event of a water shortage, the District has significant reserves of groundwater that can be used if surface water supplies are low. The current reserves can provide ten years of the District's annual water demands.

4.3 Locally Appropriate Demand Reductions

Regulatory Requirement

§10632 (a.4.B) Locally appropriate demand reduction actions to adequately respond to shortages.

The demand reductions in this plan address the unique water use characteristics in the District where about 80% of the water is used for industrial purposes, including oil field operations and power plants. The demand reductions also focus on the priorities of the water supplies. Some industrial water users are not contracted, and they have lower priority over contracted industrial water users. Municipal use is a higher priority than industrial use, but outdoor watering is considered lower priority than indoor use.

4.4 Locally Appropriate Operational Changes

Regulatory Requirement

§10632 (a.4.C) Locally appropriate operational changes.

During a water shortage operational changes are generally not needed, unless there is a catastrophic interruption in supply. This may require modifying the wells typically used or redirecting through different routes if a pipeline is non-operational.

4.5 Gap Between Supply and Demand

Regulatory Requirement

§10632 (a.4.E) For each action, an estimate of the extent to which the gap between supplies and demand will be reduced by implementation of the action.

Each Water Shortage Level includes response actions that are estimated to provide the needed water savings required. These response actions have also been refined over time and proven to generally provide the reductions needed. If prohibitions at any level do not result in the required water savings, the District can simply go to the next level. The District also has flexibility to enforce only some of the response actions in a level, providing the opportunity to make small adjustments when needed.

5 - COMMUNITY OUTREACH

5.1 Current and Predicted Shortages

Regulatory Requirement

§10632 (a.5) Communication protocols and procedures to inform customers, the public, interested parties, and local, regional, and state governments, regarding, at a minimum, all the following:
(A) Any current or predicted shortages as determined by the annual water supply and demand assessment described pursuant to Section 10632.1.

The WKWD has identified the four following categories as significant points of discussion, regarding current and predicted drought shortages.

- Various causes of drought in the area
- Regulatory impacts on water supplies
- Drought impacts on water supplies
- Constraints on deliveries, transfers and exchanges

Should a potential shortage be anticipated, the public and WKWD customers will be notified of the potential for a drought declaration and water conservation measures via public notices, announcements on the District's web page, (www.wkwd.org) and in their billing statements.

5.2 Shortage Response Actions

Regulatory Requirement

§10632 (a.5.B) Any shortage Response Actions triggered or anticipated to be triggered by the annual water supply and demand assessment described pursuant to Section 10632.1.
Any other relevant communications.

The District's Board of Directors will be kept informed of water shortage conditions to enable them to make timely and appropriate decisions on the following actions:

- Coordination with customers on the development and implementation of plans
- Frequent assessment of water shortage status
- Adoption of resolutions to change water shortage levels
- Declaration of a water shortage emergency
- Adoption of an Emergency Water Reduction Plan

These actions may be communicated to District customers by way of billing inserts, newspaper advertising, on the District's webpage (www.wkwd.org) and by verbal communication with District personnel

6 - CUSTOMER COMPLIANCE AND ENFORCEMENT

Regulatory Requirement

§10632 (a.6) For an urban retail water supplier, customer compliance, enforcement, appeal, and exemption procedures for triggered shortage Response Actions as determined pursuant to Section 10632.2.

Any person, who uses, causes to be used, or permits the use of water in violation of this policy is guilty of an offense punishable as provided herein. Each day that a violation of this policy occurs is a separate offense.

Violation of a provision of this policy may be subject to enforcement through installation of a flow-restricting device in the service meter. If a flow-restrictor is placed in the service, the violator shall pay the cost of the material and labor for device installation and removal.

Willful violations of the mandatory conservation measures and water use restrictions as set forth in this policy may be enforced by discontinuing service to the property at which the violation occurs as provided by Water Code Section 356. Violations may also be subject to criminal, civil, and administrative penalties and remedies specified in this policy. If water service is disconnected, restoration shall be according to the District's Rules and Regulations. All remedies provided for herein shall be cumulative and not exclusive for the duration of the declared water shortage emergency.

First Violation

Upon notification or observation of waste or misuse of water, the District shall:

a. Make a photographic and written record of the violation; and
b. Provide notice to the customer in writing and/or by means of a door tag; and
c. Log the warning in the customer's account record.

Second Violation - $300.00 Administrative Fee

In the event a second violation occurs, the District shall:

a. Make a photographic and written record of the violation; and
b. Assess an administrative fee of $300.00 upon the customer for the second offense; and
c. Give notice to the customer in writing that if such waste or misuse continues or subsequent violation occurs, the consumer will be subjected to escalating administrative fees and potential discontinuance of service; and
d. Log the warning in the customer's account record.

Third Violation - $600.00 Administrative Fee

Upon a third offense the District shall:

a. Make a photographic and written record of the violation; and
b. Assess an administrative fee of $600.00 upon the customer for the third offense; and
c. Give notice to the customer in writing that if such waste or misuse continues or subsequent violation occurs, the consumer will be subject to discontinuance of service; and
d. Log the warning in the customer's account record; and
e. Report violation to appropriate law enforcement for possible criminal prosecution.

Fourth Violation – Discontinuance of Service

Upon a fourth offense the District shall:

a. Make a photographic and written record of the violation;
b. Give written notice to the customer that disconnection of the service will occur within five (5) working days of the date of the notice;
c. Disconnect the customer's service; and
d. Restoration and reconnection fees will be charged in accordance with the District's Rules and Regulations. Service will be restored only when the customer has provided satisfactory evidence to the District indicating waste and unreasonable use of water will no longer occur.

Appeals

The District recognizes there may be mitigating or intervening circumstances bearing upon a customer's apparent misuse of water. Upon receipt of any notice regarding purported misuse or waste of water, the customer shall have five (5) working days within which to file a written request for reconsideration with the General Manager. If the customer is not satisfied with the General Manager's decision, the customer shall have fifteen (15) days after the General Manager's decision within which to file a written appeal to the Board of Directors. The Board shall conduct a hearing on the appeal at the next regularly scheduled Board meeting immediately following the appeal. The Board's decision following such hearing shall be final and conclusive.

7 - LEGAL AUTHORITY OF THE PLAN

Regulatory Requirement

§10632 (a.7.A) A description of the legal authorities that empower the urban water supplier to implement and enforce its shortage Response Actions specified in paragraph (4) that may include, but are not limited to, statutory authorities, ordinances, resolutions, and contract provisions.

This WSRP adheres with the California Water Code 10632. This document is also required by State law as outlined in the Water Code, which states that, "Every urban water supplier shall prepare and adopt a water shortage contingency plan as part of its urban water management plan…" (WC 10632). As an established California Water District, WKWD has the authority to implement the WSRP, declare water shortages, and implement shortage response actions including statutory authorities, ordinances, resolutions, and contract provisions.

This Policy shall be known as the West Kern Water District Water Shortage Response Plan ("WSRP" or "Policy"). Article 10, Section 2 of the California Constitution declares that waters of the state are to be put to beneficial use, that waste, unreasonable use, or unreasonable method of use of water be prevented, and that water be conserved for public welfare.

West Kern Water District may experience shortages due to drought conditions, regulatory restriction enacted upon imported supplies, catastrophic emergencies, and other factors. Conservation of current water supplies and minimization of the effects of water supply shortages that are the result of drought are essential to the public health, safety, and welfare. Regulation of the time of certain water use, manner of certain water use, design of rates, method of application of water for certain uses, and installation and use of water-saving devices provide an effective means of conserving water.

In addition, California Water Code Sections 375 et seq. authorizes a water supplier to adopt and enforce a comprehensive water conservation program. Adoption and enforcement of a comprehensive water conservation program will allow the District to delay or avoid implementing measures such as water rationing or more restrictive water use regulations pursuant to a declared water shortage emergency as authorized by California Water Code Sections 350 et seq.

The District has adopted an Urban Water Management Plan that includes water conservation as a necessary and effective component of its programs to provide a reliable supply of water to meet the needs of the public within its service territory. The District's Urban Water Management Plan also includes a contingency analysis of actions to be taken in response to water supply shortages. This WSRP is consistent with the Urban Water Management Plan adopted by the District.

7.1 Declaring a Water Shortage Emergency

Regulatory Requirement

§10632 (a.7.B) A statement that an urban water supplier shall declare a water shortage emergency in accordance with Chapter 3 (commencing with Section 350) of Division 1.

The WKWD will follow the protocols outlined in this Plan should it become necessary to declare a water shortage emergency. The process will follow the pertinent sections of the California Water Code and be noticed for a public hearing, typically at a Board of Directors meeting.

7.2 Supplier Coordination

Regulatory Requirement

§10632 (a.7.C) A statement that an urban water supplier shall coordinate with any city or county within which it provides water supply services for the possible proclamation of a local emergency, as defined in Section 8558 of the Government Code.

The General Manager or designated staff will be available and responsible for coordinating with City and County officials within the District's service area should there be a necessary proclamation for a local water emergency.

8 - REVENUE REDUCTIONS AND EXPENSE INCREASES

The various revenue sources available to the District during droughts include, but are not limited to water sales, system connection fees, interest income, special assessments, reserves, and other non-operating revenues such as grant funding when available. In addition, there may be special outside funding sources made available to water agencies during a water emergency (e.g., Levels 4 through 6a). Following are discussions on potential revenue reductions during droughts and how they will be addressed.

8.1 Potential Revenue Reductions and Expense Increases

Regulatory Requirement

§10632 (a.8) A description of the financial consequences of, and responses for, drought conditions, including, but not limited to, all of the following:
(A) A description of potential revenue reductions and expense increases associated with activated shortage Response Action described in paragraph (4)

Potential revenue reductions include lost water sales to any of the customer categories served by WKWD including oil companies, power companies, golf courses, agriculture, domestic, commercial and industrial water users. All water users are billed volumetrically, so a drought or water shortage could cause a revenue reduction in the District.

Potential expense increases may include, but are not limited to:

- Higher SWP water costs due to reduced water deliveries
- Due to the proximity of the active well field, increased demand could exacerbate existing pumping depressions, resulting in increased lifts and increased pumping costs
- Purchases of higher priced transfer water

Attachment 2 includes tables estimating the potential revenue impacts from implementing the six water shortage stages.

8.2 Mitigation Actions

Regulatory Requirement

§10632 (a.8.B) A description of mitigation actions needed to address revenue reductions and expense increases associated with activated shortage Response Actions described in paragraph (4).

Currently, WKWD has sufficient funds in their operating reserves to supplement deficiencies in revenue caused from a water shortage. Additionally, water shortages will require additional pumping of groundwater, which is the most cost effective water sources for WKWD. WKWD has substantial groundwater reserves that can meet District's water needs for about ten years.

8.3 Cost Compliance

Regulatory Requirement

§10632 (a.8.C) A description of the cost of compliance with Chapter 3.3 (commencing with Section 365) of Division 1.

The District Rules and Regulations address penalties for wasteful use of water. Declaring a water shortage and enforcing response actions can be performed by existing staff with no significant increases in operating cost.

9 - MONITORING AND REPORTING REQUIREMENTS

Regulatory Requirement

§10632 (a.9) For an urban retail water supplier, monitoring and reporting requirements and procedures that ensure appropriate data is collected, tracked, and analyzed for purposes of monitoring customer compliance and to meet state reporting requirements.

WKWD has and will continue to comply with State reporting requirements. The District meters all water deliveries to its customers, which assists in assuring customer compliance. Additionally, the District maintains a protocol for receiving and addressing complaints of non-compliance and misuse.

Production

Under normal water supply conditions, potable water production figures are recorded daily. An accounting sheet of water owed to WKWD, carryover from the previous year, and totals in the ground that have been banked are also reviewed daily and tallied monthly.

Disaster Shortage

During emergency shortages, production figures are reported to the Supervisor hourly and to the Manager and the Water Shortage Response Team daily. Daily reports will also be provided to the Board of Directors.

10 - MONITORING AND EVALUATING THE PLAN

Regulatory Requirement

§10632 (a.10) Reevaluation and improvement procedures for systematically monitoring and evaluating the functionality of the water shortage contingency plan in order to ensure shortage risk tolerance is adequate and appropriate water shortage mitigation strategies are implemented as needed.

This WSRP is in update to a previous 2016 WSRP. This update satisfies new State requirements for WSRPs, and reflects the refinements and improvements deemed necessary to adequately address the District's needs. In addition, this WSRP incorporates important lessons learned during the historic drought of 2013-2015. The WSRP will be re-evaluated at least every five years and at the end of each major drought period to assess its performance. If deemed necessary, it will be modified and improved based on lessons learned. The Plan may also be updated in the middle of a drought year if needed.

ATTACHMENT 1

West Kern Water District - Water Use Restrictions by Water Shortage Stage

Water Supply Reduction %	Permanent Response Actions	Stage 1 < 10%	Stage 2 Up To 20%	Stage 3 Up To 30%	Stage 4 Up To 40%	Stage 5 Up To 50%	Stage 6 >50%	Stage 6A* >50% short term
Hoses equipped with a shut-off nozzle	●	●	●	●	●	●	●	●
Excessive watering on streets & sidewalks prohibited	●	●	●	●	●	●	●	●
Residential & commercial landscape irrigation restrictions	●	●	●	●	●	●	●	●
Restrictions for washing outdoor vehicles, trucks or boats	●	●	●	●	●	●	●	●
Restaurants shall serve water only upon request	●	●	●	●	●	●	●	●
Hotels shall have opt-out linen service	●	●	●	●	●	●	●	●
Restrictions for spas, pools & fountains	●	●	●	●	●	●	●	●
Use of potable water for compaction or dust control	●	●	●	●	●	●	●	●
Repair all leaks within 24 hours	●	●	●	●	●	●	●	●
Monitor users of construction meters or fire hydrant meters	●	●	●	●	●	●	●	●
Increased public education		●	●	●	●	●	●	●
Reduce large & significant landscape watering			25%	25%	35%	50%	75%	100%
Eliminate industrial water use above contracted amounts			●	●	●	●	●	●
Reduction of non-contracted industrial water			15%	60%	100%	100%	100%	100%
Stop use of potable water for sewer system maintenance or fire protection				●	●	●	●	●
Restrictions on new connections				●	●	●	●	●
Reductions for contracted industrial customers					10%	20%	40%	80%
Reduce California Resources Corporation & Elk Hills Power water use					10%	20%	40%	50%
No irrigation with potable water of ornamental turf or public street medians					●	●	●	●
Water flow testing of fire hydrants or blow offs is prohibited						●	●	●
Water exceedance tiered pricing and fines						●	●	●
All non-emergency water use not defined in the WSCP is prohibited								●
Import water tanks to provide potable water								●

* Level 6a is a short term declaration less than 45 days.

Note: At any time the District may choose to increase these efforts to promote water savings, based on the current implemented Stage. Additionally, all regulations associated with a State Drought Emergency Declaration may become mandatory at any given Stage.

ATTACHMENT 2

WEST KERN WATER DISTRICT - WATER SHORTAGE RESPONSE PLAN

TABLE 1 - ENTITLEMENT / BANKED WATER OVERVIEW

(all units in AF)

RESPONSE LEVEL	% REDUCTION	DISTRICT DEMAND Historical High 2007 (1)	DEMAND MINUS REDUCTION	REDUCTION	CUSTOMER REDUCTION[2]	DISTRICT FROM BANKED WATER	DISTRICT BANKED WATER ACCOUNT IN 2020	YEARS UNTIL CURRENT BANK IS DEPLETED
I	10%	27,700	24,900	2,800	-	2,800	180,000	64
II	20%	27,700	22,200	5,500	2,750	2,750	180,000	65
III	30%	27,700	19,400	8,300	4,150	4,150	180,000	43
IV	40%	27,700	16,600	11,100	5,550	5,550	180,000	32
V	50%	27,700	13,900	13,800	6,900	6,900	180,000	26
VI	60%	27,700	11,100	16,600	8,300	8,300	180,000	22

(1) Based on 2007 (which was a high water use year) plus supplying La Paloma 4,500 AF/year

(2) Stage 1 requests a 10% voluntary customer reduction, and the District will supply any shortfall from the banked water account. In Stages 2 through 4 the shortfall will be split 50% with customer reduction and 50% from District banked water

WEST KERN WATER DISTRICT
WATER SHORTAGE RESPONSE PLAN
TABLE 2 - WATER SHORTAGE ACTIONS

ATTACHMENT 2

ACTION	
1	BOD determines which stage to implement based on consideration of climate, surface water deliveries, overall drought conditions, groundwater levels, and volume of groundwater banked.
2	BOD adopts conservation measures of "Water Shortage Response Plan"
3	In order to enact Stage 2 or higher, the BOD will need to adopt Resolution declaring a Water Shortage Emergency
4	Reduce by 25% or 35% large landscape watering (parks, schools, ball fields, golf course, cemetery, green belt)
5	Eliminate all over-use of water to industrial customers
6	Eliminate water deliveries by 15%, 60% or 100% to non-contracted industrial customers
7	Reduce by 10%, contracted industrial customers, excluding large landscape watering

RESPONSE LEVEL	
I	Public conservation education program/request customer voluntary reduction
II	Public conservation education program/request customer voluntary reduction
II	Enforce Residential/Commercial conservation measures of Water Shortage Response Plan
II	Reduce by 25% large landscape watering
II	Eliminate all over-use of water by industrial customers
II	Reduce by 15% non-contracted industrial water use
III	Public conservation education program/request customer voluntary reduction
III	Enforce Residential/Commercial conservation measures of Water Shortage Response Plan
III	Reduce by 25% large landscape watering
III	Eliminate all over-use of water by industrial customers
III	Reduce by 60% non-contracted industrial water use
IV	Public conservation education program/request customer voluntary reduction
IV	Enforce Residential/Commercial conservation measures of Water Shortage Response Plan
IV	Reduce by 35% large landscape watering
IV	Eliminate all over-use of water by industrial customers
IV	Eliminate non contracted industrial water use
IV	Reduce by 10% contracted industrial customers, excluding large landscape watering
IV	Reduce by 10% California Resources Corporation
IV	Reduce by 10% Elk Hills Power

WEST KERN WATER DISTRICT
WATER SHORTAGE RESPONSE PLAN
TABLE 3 - 2007 WATER USAGE

Description	2007 Water Demand (AF)
Residential / Commercial	4,200
Large Landscape	800
Contracted Industrial	5,100
Overuse of Industrial Supplies	1,200
Non-Contracted Industrial	3,300
California Resources Corporation	2,200
Elk Hills	3,000

Note: 2007 water usage data is used in evaluating total water usage and conservation requirements. 2007 was selected since it was a high water use year.

WEST KERN WATER DISTRICT - WATER SHORTAGE RESPONSE PLAN **ATTACHMENT 2**

TABLE 4 - WATER SAVINGS AND REVENUE IMPACTS

(all units in acre-feet)

RESPONSE LEVEL I 0-10%	District Can Meet Current Demands	REDUCTION %	ESTIMATED ACRE FEET	ESTIMATED REDUCED REVENUE $ Annual Revenue[1]	Reduction
Public conservation education program		-	-	$11,000	$11,000
RESPONSE LEVEL II 20%	**2,750 Customer Reduction Required**				
Public conservation education program		-	-	$11,000	$11,000
Enforce conservation measures on Residential/Commercial customers		20%	840	$4,200,000	$840,000
Reduce large landscape watering		25%	200	$800,000	$200,000
Eliminate over-use of water by industrial customers		100%	1,200	$1,200,000	$1,200,000
Reduce non-contracted industrial water use		15%	495	$3,300,000	$495,000
			2,735		$2,746,000
RESPONSE LEVEL III 30%	**4,150 Customer Reduction Required**				
Public conservation education program		-	-	$11,000	$11,000
Enforce conservation measures on Residential/Commercial customers		20%	840	$4,200,000	$840,000
Reduce large landscape watering		25%	200	$800,000	$200,000
Eliminate over-use of water by industrial customers		100%	1,200	$1,200,000	$1,200,000
Reduce non-contracted industrial water use		60%	1,980	$3,300,000	$1,980,000
			4,220		$4,231,000
RESPONSE LEVEL IV 40%	**6,900 Customer Reduction Needed**				
Public conservation education program		-	-	$11,000	$11,000
Enforce conservation measures on Residential/Commercial customers		25%	1,050	$4,200,000	$1,050,000
Reduce large landscape watering		35%	280	$800,000	$280,000
Eliminate over-use of water by industrial customers		100%	1,200	$1,200,000	$1,200,000
Eliminate non-contracted industrial water use		100%	3,300	$3,300,000	$3,300,000
Reduce contracted industrial water use		10%	510	$5,100,000	$510,000
Reduce California Resources Corporation water use		10%	220	$2,200,000	$220,000
Reduce Elk Hills Power water use		10%	300	$3,000,000	$300,000
			6,860		$6,871,000
RESPONSE LEVEL V 50%	**6,900 Customer Reduction Needed**				
Public conservation education program		-	-	$11,000	$11,000
Enforce conservation measures on Residential/Commercial customers		25%	1,050	$4,200,000	$1,050,000
Reduce large landscape watering		50%	400	$800,000	$400,000
Eliminate over-use of water by industrial customers		100%	1,200	$1,200,000	$1,200,000
Eliminate non-contracted industrial water use		100%	3,300	$3,300,000	$3,300,000
Reduce contracted industrial water use		20%	1,020	$5,100,000	$1,020,000
Reduce California Resources Corporation water use		20%	440	$2,200,000	$440,000
Reduce Elk Hills Power water use		20%	600	$3,000,000	$600,000
			8,010		$8,021,000
RESPONSE LEVEL VI 60%	**6,900 Customer Reduction Needed**				
Public conservation education program		-	-	$11,000.00	$11,000.00
Enforce conservation measures on Residential/Commercial customers		25%	1050	$4,200,000	$1,050,000.00
Reduce large landscape watering		75%	600	$800,000	$600,000.00
Eliminate over-use of water by industrial customers		100%	1200	$1,200,000	$1,200,000.00
Eliminate non-contracted industrial water use		100%	3300	$3,300,000	$3,300,000.00
Reduce contracted industrial water use		40%	2040	$5,100,000	$2,040,000.00
Reduce California Resources Corporation water use		40%	880	$2,200,000	$880,000.00
Reduce Elk Hills Power water use		40%	1200	$3,000,000	$1,200,000.00
			10270		$10,281,000.00

1 - Water costs assumed to be $1,000/AF

WEST KERN WATER DISTRICT
WATER SHORTAGE RESPONSE PLAN
TABLE 5 - ACTIONS TO OVERCOME REVENUE IMPACTS

RESPONSE LEVEL I	**District Can Meet Current Demands**	
REPSONSE LEVEL II	Water Use Reduction (AF)	2,750
	Impacts to Revenue	$2,746,000
Miscellaneous expenditure reduction		$650,000
Capital and equipment reduction		$800,000
Power costs will reduce		$900,000
SWP costs/miscellaneous water purchases will reduce		$450,000
	Total	$2,800,000
RESPONSE LEVEL III	Water Use Reduction (AF)	4,150
	Impacts to Revenue	$4,231,000
District will require monetary adjustments		
Miscellaneous expenditure reduction		$800,000
Capital and equipment reduction		$1,200,000
Power costs will reduce		$1,350,000
SWP costs/miscellaneous water purchases will reduce		$900,000
	Total	$4,250,000
RESPONSE LEVEL IV	Water Use Reduction (AF)	5,550
	Impacts to Revenue	$6,871,000
District will require monetary adjustments		
Miscellaneous expenditure reduction		$1,400,000
Capital and equipment reduction		$1,700,000
Power costs will reduce		$2,400,000
SWP costs/miscellaneous water purchases will reduce		$1,400,000
	Total	$6,900,000
RESPONSE LEVEL V	Water Use Reduction (AF)	6,900
	Impacts to Revenue	$8,021,000
District will require monetary adjustments		
Miscellaneous expenditure reduction		$2,100,000
Capital and equipment reduction		$2,400,000
Power costs will reduce		$3,000,000
SWP costs/miscellaneous water purchases will reduce		$2,100,000
	Total	$9,600,000
RESPONSE LEVEL VI	Water Use Reduction (AF)	8,300
	Impacts to Revenue	$1,200,000
District will require monetary adjustments		
Miscellaneous expenditure reduction		$2,800,000
Capital and equipment reduction		$3,100,000
Power costs will reduce		$4,000,000
SWP costs/miscellaneous water purchases will reduce		$2,800,000
	Total	$12,700,000

APPENDIX I - WATER RATE SCHEDULE

Exhibit A
DISTRICT'S FEES AND CHARGES
For Year 2021

(Public) ***(Reviewed Annually)*** ***Effective 2/1/2021***

DEPOSITS

Residential/Commercial/Public Entity - Existing

3/4" or 5/8" Meter	$50
1" Meter	$100
Collection Acct.	$50 (Re-establish credit with balance due to District)

Industrial

Up to 1" Meter	$100
2" Meter	$300
3" Meter	$400
4" Meter	$500

Temporary Hydrant Meter

Cost of Replacement (as listed in Rules & Regs)

Current Charge	$900

METER INSTALLATION FEE

1" Meter	$176
2" Meter	$663
Larger than 2"	Actual Cost

Automatic Meter Reading Installation Fees

Cell Card	$210
Register	$90

SERVICE CONNECTION FEE

1" Meter	**$2,888** + Water Supply Fee *
2" Meter	**$3,970** + Water Supply Fee *
Larger than 2"	Actual Cost

THEFT OF WATER- PENALTY CHARGES

(Includes Jumper)	Residential	Industrial
Service Fee (minimum)	$200	$500
Deposit	$100	$500

If damages and water loss are more, customer will be charged accordingly.

METER LOCKING SYSTEM - $100

Replace Angle Valve - **$700** Minimum. If repair is more, customer is charged accordingly.

RECONNECT FEE - $50

RETURN CHECK FEE - $35

***CALLOUT FEE - $150** - restore service outside of regular business hours*

***METER TEST - $50** - test within 6 months after last test or more than once a year*

INDUSTRIAL SHORT TERM (3 yrs. or less) WATER RATE - $750/AF

CAPACITY PURCHASE SURCHARGES (buy into the infrastructure system):

RESIDENTIAL - $510.31 - $2,071.48 (varies by location)

INDUSTRIAL - $272.17/bpd

WATER SUPPLY FEE – $6,000/AF

SERVICE / FINANCE CHARGES

INDUSTRIAL - 1 ½ % per month on past due accounts

Residential / Commercial / Public Entity -

Delinquent Notice - $10 Flat Fee

Relocation of Hydrant Meters - $50.00

WEST KERN WATER DISTRICT
WATER RATES (Public)

RESIDENTIAL/COMMERCIAL/PUBLIC ENTITY (Schedule No. R) Effective 6/11 Billing

Applicable to all metered water service other than for industrial purposes.

Rates

	Per Meter - Bimonthly
Quantity Rates	
First 1000 cu.ft. or less	$ 17.30
Over 1000 cu.ft. per 100 cu.ft	$ 1.73
Over 4000 cu.ft. per 100 cu.ft.	$ 1.24
Minimum Charge	
For 5/8 x 3/4 meter	$ 17.30
For 1 inch meter	$ 21.53
For 2 inch meter	$ 46.62
For 3 inch meter	$ 86.14
For 4 inch meter	$119.07
For 6 inch meter	$190.22

INDUSTRIAL (Schedule No. IW-1) Effective 6/11 Billing

Applicable to all metered water service furnished for industrial purposes except water furnished to NPR No. 1, Elk Hills, Buena Vista Golf Course, Federal Prison, La Paloma Generating, Sunrise, and Occidental of Elk Hills Cogen Plants and raw water.

Rates

Quantity Rates	
All water up to 3000 cu.ft.	$ 2.24 per meter $975.74 per AF
Add'l water per 100 cu.ft.	$ 2.70/hcf

All industrial customers will be charged $68 per meter per month.
6" meters will be charged a minimum of $111 per meter per month.

APPENDIX J – REDUCED DELTA RELIANCE ANALYSIS

West Kern Water District
Reduced Delta Reliance Analysis

The Sacramento-San Joaquin Delta Reform Act of 2009 established a new state agency, the Delta Stewardship Council (DSC), to develop a Delta Plan that ensures coordinated action at the state, federal and local levels in meeting ecosystem health and water supply reliability needs in the Sacramento-San Joaquin Delta. The Delta Plan, adopted by the DSC in 2013, includes a policy (WR-P1) to Reduce Reliance on the Delta Through Improved Regional Water Self Reliance. Projects that are "covered actions" affecting the Delta (e.g., transfers of water from North of the Delta) must demonstrate that they are consistent with the policies in the Delta Plan, including WR-P1.

WR-P1 subsection (a) states that:

a) *Water shall not be exported from, transferred through, or used in the Delta if all of the following apply:*
    1) *One or more water suppliers that would receive water as a result of the export, transfer or use have failed to adequately contribute to reduced reliance on the Delta and improved regional self-reliance consistent with all of the requirements listed in paragraph (1) of subsection (c);*
    2) *That failure has significantly caused the need for the export, transfer, or use; and*
    3) *The export, transfer, or use would have a significant adverse environmental impact in the Delta.*

WR P1 subsection (c)(1) defines what adequately contributing to reduced reliance on the Delta means in terms of (a)(1) above as:

c) *Water suppliers that have done all the following are contributing to reduced reliance on the Delta and improved regional self-reliance and are therefore consistent with this policy:*

    A. *Completed a current Urban or Agricultural Water Management Plan (Plan) which has been reviewed by the California Department of Water Resources for compliance with the applicable requirements of Water Code Division 6, Parts 2.55, 2.6 and 2.8;*
    B. *Identified, evaluated and commenced implementation, consistent with the implementation schedule set forth in the plan, of all programs and projects included in the Plan that are locally cost effective and technical feasible which reduced reliance on the Delta; and*
    C. *Included in the Plan, commencing in 2015, the expected outcome for measurable reduction in Delta reliance and improvement in regional self-reliance shall be reported in the Plan as the reduction in the amount of water used, or in the percentage of water used, from the Delta watershed. For purposes of reporting, water efficiency is considered a new source of supply, consistent with Water Code section 1011(a).*

West Kern Water District
Reduced Delta Reliance Analysis

The analysis provided here provides documentation related to compliance with WR-P1 for the West Kern Water District (WKWD). The approach taken is somewhat simplified from the detailed analysis identified in Appendix C of DWR's Urban Water Management Plan Guidebook (Guidebook Appendix C). The analysis uses the following steps:

1. Identify Delta Water Supply Baseline;
2. Qualitatively identify water management measures and increased regional self-reliance within WKWD;
3. Indicate projected use of Delta water supplies within WKWD for projection periods; and
4. Quantify the reduction in reliance on the Delta for projection periods.

Delta Water Supply Baseline

The Sacramento-San Joaquin Delta Reform Act went into effect in 2010, which is proposed for use as the baseline. The most representative analysis of the Delta supply available to Kern County Water Agency (KCWA) as of 2010 is DWR's State Water Project (SWP) 2009 Delivery Reliability Report (DRR). The 2009 SWP DRR identified a SWP average reliability of 60% of SWP contractors' Table A amounts (Table 6.3). Based on WKWD's Table A Allocation through the KCWA contract with DWR, the estimated baseline supply available for WKWD through the KCWA contract is 18,900 acre-feet. This 18,900 acre-feet Delta water supply baseline will be maintained for purposes of both the 2015 UWMP and the 2020 UWMP.

Water Management Measures and Increased Regional Self Reliance

As described in Chapter 9 of the 2020 UWMP, WKWD has implemented significant demand reduction measures. The demand reduction These measures include the following:

- Water Waste Prevention ordinances
- Metering
- Conservation Pricing
- Public Education and Outreach
- Programs to Assess and Manage Distribution System Real loss
- Water Conservation Program Coordination and Staffing Support
- School Education
- Indoor and Outdoor Water Surveys for Single/Multi-Family Residential Customers Residential Plumbing Retrofits
- Residential Plumbing Codes
- High-Efficiency Washing Machine Rebate Programs
- Residential ULFT Replacement Programs
- Conservation Programs for Commercial, Industrial and Institutional Customers
- Large Landscape Conservation Programs and Incentives
- Wholesale Agency Assistance Programs

These measures will be implemented and supplemented with additional demand reduction measures as those measured are demonstrated to be technologically feasible. Currently WKWD is considering implementing the following programs:

- Work with Park and School Districts to install dedicated Irrigation meters and identify appropriate efficiency options
- Continue to work with golf courses to identify and implement water saving opportunities
- Offer rebates for smart irrigation controllers.

Projected use of Delta Water Supplies by West Kern Water District

Based on projected WKWD water use and the availability of other resources, average WKWD use of imported water from KCWA is projected to remain below the 2019 SWP DCR supply level of 18,400 acre-feet. This projected water use reflects the water conservation and water management actions implemented by WKWD water conservation program measures. With its projected use of imported water remaining below its 2010 water supply baseline of 18,900 acre-feet, WKWD is maintaining a net reduction in reliance on Delta water supplies of 500 acre-feet per year.

APPENDIX D

CRC CARBON TERRAVAULT 1 WSA – CONSISTENCY WITH DWR GUIDELINES

CRC Carbon Terravault 1 WSA – Consistency with DWR Guidelines

Guidelines Section Number and Title (DWR, 2003)	Guidelines Direction	Relevant WSA Section and Response
Section 1 (page 2). Does SB 610 or SB221 apply to the proposed project?	Is the project subject to SB 610? Is the project subject to CEQA (Water Code §10910(a)? If yes, continue.	WSA Section 1.1. Yes, the project is subject to SB610 and CEQA.
	Is it a "Project" as defined by Water Code §10912(a) or (b)? If yes, to comply with SB 610 go to Section 2.0, page 4.	WSA Section 1.1. Yes, the Project is considered to meet the definition of "project" per Water Code §10912(a) or (b).
	Is the project subject to SB 221? Does the tentative map include a "subdivision" as defined by Government Code §66473.7(a)(1)? If no, stop.	No, the Project does not include a "subdivision", SB 221 does not apply to the Project, and no further action relevant to SB 221 is required.
Section 2.0 (page 4). Who will prepare the SB 610 analysis?	Is there a public water system ("water supplier") for the project (Water Code §10910(b)? If no, go to Section 3.0, page 6.	WSA Section 2.1. No, the project site is not connected to a public water system.
Section 3.0 (page 6). Has an assessment already been prepared that includes this project?	Has this project already been the subject of an assessment (Water Code §10910(h)? If no, go to Section 4.0, page 8.	No, the Project has not been the subject of an assessment.
Section 4.0 (page 8). Is there a current Urban Water Management Plan?	Is there an adopted urban water management Plan (Water Code §10910(c)? If yes, continue. If yes, the information from the UWMP related to the proposed water demand for the project may also be used for carrying out Section 5.0, Steps 1 and 2, Section 7; proceed to Section 5, page 10 of the Guidelines.	WSA Section 3.2. Yes, there is an adopted UWMP in the Project area.
	Is the project water demand for the project accounted for in the most recent UWMP (Water Code §10910(c)(2)? If no, go to Section 5.0, page 10.	No
Section 5.0 (page 10). What information should be included in an assessment?	Step One (page 13). Documenting wholesale water supplies.	The Project is not a retail water supplier and would not include the use of wholesale water supplies.
	Step Two (page 17). Documenting Supply if Groundwater is a Source.	The Tulare Lake Basin – Kern County Subbasin is the proposed water supply. WSA Sections 1.3, 2.3 and 2.43.

Guidelines Section Number and Title (DWR, 2003)	Guidelines Direction	Relevant WSA Section and Response
	Specify if a groundwater management plan or any other specific authorization for groundwater management for the basin has been adopted and how it affects the water supplier's use of the basin.	WSA Section 3.3 Yes, the Kern County Groundwater Authority Groundwater Sustainability Plan was published in 2022.
	Description and analysis of the amount and location of groundwater pumped by the water supplier for the past five years. Include information on proposed pumping locations and quantities. The description and analysis is to be based on information that is reasonably available, including, but not limited to, historic use records from DWR.	Site-specific historic records are not available. WSA Section 1.3 provides a description of the Project's water requirements.
	Analysis of the location, amount, and sufficiency of groundwater that is projected to be pumped by the water supplier.	WSA Section 3.2. The quantity of water available in the Kern County Subbasin is sufficient for the Project.
	Step 3 (page 21). Documenting project demand (Project Demand Analysis).	WSA Section 1.3. Construction of the Project will require 75-acre feet; operation, 19.49-acre feet per year.
	Step 4 (page 26). Documenting dry year(s) supply.	WSA Section 3.2. Addresses water supply availability including during dry years.
	Step 5 (page 31). Documenting dry year(s) demand.	WSA Section 3.2 addresses annual demands, including dry years and multiple dry years conditions including during dry year scenarios.
Section 6.0 (page 33). Is the projected water supply sufficient or insufficient for the proposed project		WSA Section 4.0 summarizes how the identified water supply/supplies are considered sufficient for the Project.
Section 7.0 (page 35). If the projected supply is determined to be insufficient. Section 8.0 (page 38). Final SB 610 assessment actions by lead agencies.	Does the assessment conclude that supply is "sufficient"? If no, continue. The lead agency shall review the WSA and must decide whether additional water supply information is needed for its consideration of the proposed project. The lead	WSA Section 4.0 concludes that sufficient water supplies are available for the Project. The WSA for the Project must be approved prior to or in concurrence with the EIR.

Guidelines Section Number and Title (DWR, 2003)	Guidelines Direction	Relevant WSA Section and Response
	agency "shall determine, based on the entire record, whether projected water supplies will be sufficient to satisfy the demands of the project, in addition to existing and planned future uses."	
	The description of the groundwater basin may be excerpted from the groundwater management plan, from DWR Bulleting 118, California's Ground Water, or from some other document that has been published and that discusses the basin boundaries, type of rock that constitutes the aquifer, variability of the aquifer material, and total groundwater in storage (average specific yield times the volume of the aquifer).	WSA Section 2.2 provides a description of the groundwater basin characteristics using all available resources, including DWR Bulletin 118.
	In an adjudicated basin the amount of water the urban supplier has the legal right to pump should be enumerated in the court decision.	The Project is not in an adjudicated basin.
	Bulletin 160, California Water Plan Update. Estimates at the basin or subbasin level will be projected for some basins in Bulletin 118. If the basin has not been evaluated by DWR, data that indicate groundwater level trends over a period of time should be collected and evaluated.	
	If the evaluation indicates an overdraft due to existing groundwater extraction, or projected increases in groundwater extraction, describe actions and/or program designed to eliminate the long term overdraft condition.	WSA Section 3.2. The referenced and Appendicized GSP, UWMP and IRWMP describes in detail the subject actions and programs.

Appendix H

Noise Assessment

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ENVIRONMENTAL NOISE ASSESSMENT

CRC CARBON TERRAVAULT 1 PROJECT
KERN COUNTY CALIFORNIA

WJVA Report No. 22-44

PREPARED FOR

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SEPTEMBER 27, 2023

1. INTRODUCTION

Project Description

The Carbon TerraVault 1 (CTV-1) Project, is being proposed by Carbon TerraVault, LLC (CTV) a wholly owned subsidiary of California Resources Corporation (CRC). The Project would establish a carbon dioxide (CO_2) capture and storage network in the Elk Hills Oil Field in Western Kern County which will remove CO_2 from natural gas produced from the Greater Elk Hills Area (GEHA) prior to processing at CRC's Cryogenic Gas Plant One (CGP-1). The captured CO_2 would then be transported through a network of onsite pipelines to CO_2 injection wells into geologically distinct depleted oil and gas reservoirs for permanent storage. The network will eventually take CO_2 from other onsite projects to maximize the full extent and capacity of the world class storage reservoirs within the field.

The proposed Project would include two identical capture, compression and pumping facilities located adjacent to the CGP-1, as well as the construction and modifications of a combination of new and existing injection and monitoring wells, and installation of approximately 15 miles of associated pipelines to complete the permanent storage network. The extensive existing oilfield infrastructure will be utilized to the maximum extent possible during the full life cycle of this project.

The proposed storage network would include six injection wells into two separate reservoirs and associated infrastructure, capable of storing a combined approximately 48 million metric tons of CO_2. The two reservoirs known as "26R" and "A1/A2" are geologically distinct depleted oil and gas reservoirs. These reservoirs have confining qualities that make them ideal for permanent carbon dioxide storage including no connection or proximity to underground sources of drinking water (USDW). As proposed, the Project would inject up to 200,000 metric tons of concentrated CO2 per year (MMtpa) captured from natural gas produced at Elk Hills through dedicated Class VI injection wells, into identified geographically confined reservoirs for storage in perpetuity.

The Project also includes establishing and utilizing a temporary construction corridor and temporary storage and laydown areas. The temporary construction corridor right-of-way (ROW), of up to approximately 50 feet in width, will be established along areas of the pipeline route not accessible via established roads or other existing cleared areas to allow for off-road construction equipment and a travel path. Temporary storage and laydown areas outside of the ROW will be used to store equipment, pipe, and materials and to stage construction activities. Laydown areas are designed to minimize new disturbance by utilizing existing, cleared areas such as fields, parking lots, or other developed areas. After completion of construction, all laydown areas will be returned to pre-Project contours and revegetated to native habitat conditions where applicable.

The two CO_2 compression and pumping facilities will be constructed in two consecutive phases over 18 months. Phase 1 is located within the CGP-1 facility and Phase 2 will be located within a fenced area measuring approximately 120 feet by 210 feet, an area of 0.55 acres. The facilities will be accessed via Skyline Drive within the Elk Hills Oil Field, west of Gate 4.

During construction, water will be used for dust suppression, fire protection, and pipeline hydrotesting. Construction activities will generally occur during daylight hours, but limited night work could potentially include, but are not limited to, pipeline tie-in connections, refuelling equipment, staging equipment and material for the following day's construction activities, quality assurance/control, and commissioning. All lighting utilized during night work will be situated to avoid lighting impacts on the surrounding area by directing lights down to the work area and only for durations necessary to complete the task safely. Traffic control will be provided for street encroachments and crossings as necessary.

Project construction will result in temporary disturbance associated with the pipeline construction corridor and temporary construction storage and laydown areas and limited permanent disturbance associated with new pipeline sleeper installation sites and the CO_2 compression and pumping facility.

Environmental Noise Assessment

This environmental noise assessment has been prepared to determine if significant noise impacts would be produced by the project and to describe mitigation measures for noise if significant impacts are determined. The environmental noise assessment, prepared by WJV Acoustics, Inc. (WJVA), is based upon the project site plan dated 11-3-22, project-related traffic data provided by Ruettgers & Schuler Civil Engineers, and ambient noise level measurements conducted on January 26 & 27, 2023. Revisions to the site plan, project-related traffic data or other project-related information available to WJVA at the time the analysis was prepared may require a reevaluation of the findings and/or recommendations of the report.

Appendix A provides definitions of the acoustical terminology used in this report. Unless otherwise stated, all sound levels reported in this analysis are A-weighted sound pressure levels in decibels (dB). A-weighting de-emphasizes the very low and very high frequencies of sound in a manner similar to the human ear. Most community noise standards utilize A-weighted sound levels, as they correlate well with public reaction to noise. Appendix B provides typical A-weighted sound levels for common noise sources.

In terms of human perception, a 5 dB increase or decrease is considered to be a noticeable change in noise levels. Additionally, a 10 dB increase or decrease is perceived by the human ear as half as loud or twice as loud. In terms of perception, generally speaking the human ear cannot perceive an increase (or decrease) in noise levels less than 3 dB.

2. THRESHOLDS OF SIGNIFICANCE

The CEQA Guidelines apply the following questions for the assessment of significant noise impacts for a project:

a. Would the project result in generation of a substantial temporary or permanent increase in ambient noise levels in the vicinity of the project in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?

b. Would the project result in generation of excessive groundborne vibration or groundborne noise levels?

c. For a project located within the vicinity of a private airstrip or an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project expose people residing or working in the project area to excessive noise levels?

a. Noise Level Standards

Kern County

The Kern County Noise Element of General Plan[1] establishes noise level criteria in terms of the Day-Night Average Level (L_{dn}) metric. The L_{dn} is the time-weighted energy average noise level for a 24-hour day, with a 10 dB penalty added to noise levels occurring during the nighttime hours (10:00 p.m.-7:00 a.m.). The L_{dn} represents cumulative exposure to noise over an extended period of time and is therefore calculated based upon annual average conditions.

The Noise Element establishes a land use compatibility criterion of 65 dB L_{dn} for exterior noise levels in outdoor activity areas of residential uses. Outdoor activity areas generally include backyards of single-family residences and individual patios or decks of multi-family developments. The intent of the exterior noise level requirement is to provide an acceptable noise environment for outdoor activities and recreation.

The Noise Element also requires that interior noise levels attributable to exterior noise sources not exceed 45 dB L_{dn}. The intent of the interior noise level standard is to provide an acceptable noise environment for indoor communication and sleep. Excerpts from the Kern County General Plan Noise Element relevant to the project are provided below.

The following noise sensitive land uses have been identified in the County:

- Residential areas
- Schools
- Convalescent and acute care hospitals
- Parks and recreational areas
- Churches

Goals

1) Ensure that residents of Kern County are protected from excessive noise and that moderate levels of noise are maintained.

2) Protect the economic base of Kern County by preventing the encroachment of incompatible land uses near known noise producing roadways, industries, railroads, airports, oil and gas extraction, and other sources.

Policies

1) Review discretionary industrial, commercial, or other noise-generating land use projects for compatibility with nearby noise-sensitive land uses.

2) Require noise level criteria applied to all categories of land uses to be consistent with the recommendations of the California Division of Occupational Safety and Health (DOSH).

3) Encourage vegetation and landscaping along roadways and adjacent to other noise sources in order to increase absorption of noise.

4) Utilize good land use planning principles to reduce conflicts related to noise emissions.

5) Prohibit new noise-sensitive land uses in noise-impacted areas unless effective mitigation measures are incorporated into the project design. Such mitigation shall be designed to reduce noise to the following levels: a) 65 dB L_{dn} or less in outdoor activity areas; b) 45 dB L_{dn} or less within interior living spaces or other noise sensitive interior spaces.

6) Ensure that new development in the vicinity of airports will be compatible with existing and projected airport noise levels as set forth in the ALUCP.

7) Employ the best available methods of noise control.

8) Enforce the State Noise Insulation Standards (California Administrative Code, Title 24) and Chapter 35 of the Uniform Building Code concerning the construction of new multiple-occupancy dwellings such as hotels, apartments, and condominiums.

Implementation Measures

The following are programs to be carried out by the Kern County to implement the goals and policies of the Noise Element.

A) Utilize zoning regulations to assist in achieving noise-compatible land use patterns.

B) Require proper acoustical treatment of transportation facilities, including highways, airports, and railroads.

C) Review discretionary development plans, programs and proposals, including those initiated by both the public and private sectors, to ascertain and ensure their conformance to the policies outlined in this element.

D) Review discretionary development plans for proposed residential or other noise sensitive land uses in noise-impacted areas to ensure their conformance with the noise standards of 65 dB L_{dn} or less in outdoor activity areas and 45 dB L_{dn} or less within interior living spaces.

E) Review discretionary development plans to ensure compatibility with adopted Airport Land Use Compatibility Plans.

F) Require proposed commercial and industrial uses or operations to be designed or arranged so that they will not subject residential or other noise sensitive land uses to exterior noise levels in excess of 65 dB L_{dn} and interior noise levels in excess of 45 dB L_{dn}.

G) At the time of any discretionary approval, such as a request for a General Plan Amendment, zone change or subdivision, the developer may be required to submit an acoustical report indicating the means by which the developer proposes to comply with the noise standards. The acoustical report shall:

a) Be the responsibility of the applicant.

b) Be prepared by a qualified acoustical consultant experienced in the fields of environmental noise assessment and architectural acoustics.

c) Be subject to the review and approval of the Kern County Planning Department and the Environmental Health Services Department. All recommendations therein shall be complied with prior to final approval of the project.

H) Encourage cooperation between the County and the incorporated cities within the County to control noise.

I) Noise analyses shall include recommended mitigation, if required, and shall:

a) Include representative noise level measurements with sufficient sampling periods and locations to adequately describe local conditions.

b) Include estimated noise levels, in terms of CNEL, for existing and projected future (10-20 years hence) conditions, with a comparison made to the adopted policies of the Noise Element.

c) Include recommendations for appropriate mitigation to achieve compliance with the adopted policies and standards of the Noise Element.

d) Include estimates of noise exposure after the prescribed mitigation measures have

been implemented. If compliance with the adopted standards and policies of the Noise Element will not be achieved, a rationale for acceptance of the project must be provided.

J) Develop implementation procedures to ensure that requirements imposed pursuant to the findings of an acoustical analysis are conducted as part of the project permitting process.

State of California

There are no state noise standards that are applicable to the project.

Federal Noise Standards

There are no federal noise standards that are applicable to the project.

b. Construction Noise and Vibration

Section 8.36 (Noise Control) of the Kern County Code of Ordinances[2] limits construction to the hours of 6:00 a.m. to 9:00 p.m. on weekdays, and between 8:00 a.m. and 9:00 p.m. on weekends, when construction is within 1,000 feet of a residence. Certain exceptions to these hours are specified in the code.

Kern County does not have regulations that define acceptable levels of vibration. One of the most recent references suggesting vibration guidelines is the California Department of Transportation (Caltrans) Transportation and Construction Vibration Guidance Manual[3]. The Manual provides guidance for determining annoyance potential criteria and damage potential threshold criteria. These criteria are provided below in Table I and Table II, and are presented in terms of peak particle velocity (PPV) in inches per second (in/sec).

TABLE I

GUIDELINE VIBRATION ANNOYANCE POTENTIAL CRITERIA

Human Response	Maximum PPV (in/sec)	
	Transient Sources	Continuous/Frequent Intermittent Sources
Barely Perceptible	0.04	0.01
Distinctly Perceptible	0.25	0.04
Strongly Perceptible	0.9	0.1
Severe	2.0	0.4

Source: Caltrans

TABLE II GUIDELINE VIBRATION DAMAGE POTENTIAL THRESHOLD CRITERIA		
Structure and Condition	Maximum PPV (in/sec)	
	Transient Sources	Continuous/Frequent Intermittent Sources
Extremely fragile, historic buildings, ancient monuments	0.12	0.08
Fragile buildings	0.2	0.1
Historic and some old buildings	0.5	0.25
Older residential structures	0.5	0.3
New residential structures	1.0	0.5
Modern industrial/commercial buildings	2.0	0.5

Source: Caltrans

3. SETTING

The Project area is located generally within western Kern County, California. It is entirely within the boundary of the Elk Hills Oil Field, an approximately 75-square-mile complex with surface and mineral rights privately held by CRC in the San Joaquin Valley of unincorporated Kern County. The Project area extends east of the intersection of Skyline Road and Elk Hills Road, approximately 0.50 miles, and west of the intersection, approximately 5.5 miles. The majority of the Project area follows existing and maintained pipeline rights-of-way. The Project area is approximately 12.75 miles west of Interstate 5 and five miles south of State Route 58. It can be accessed via CRC's gated and guarded entrance to the oil field located at the western intersection of Skyline Road and Elk Hills Road (Figure 1).

The Project area is bordered on all sides by existing oil and gas exploration and production. Existing land use outside of the Project area generally includes agricultural lands, current, past, and abandoned oil and gas exploration and production land, and undeveloped land owned by CRC and other oil and gas operators. The City of McKittrick is approximately four miles west of the Project area, and the City of Taft is approximately nine miles to the south. The Project area is located within two U.S. Geological Survey (USGS) 7.5-minute topographic quadrangles. All the Sections, Townships, and Ranges are in the Mount Diablo Base Meridian.

a. Background Noise Level Measurements

As described above, the project site is located entirely within the boundary of the Elk Hills Oil Field. As such, there are no noise sensitive land uses located in the greater project area. The closest sensitive receptors (residential land uses) are located at distances of five (5) miles or greater from project site areas.

WJVA conducted long-term (24-hour) ambient noise measurement in the vicinity of the closest sensitive receptors to the greater project areas. Measurements of existing ambient noise levels in the project vicinity were conducted on February 27, 2023 and. Long-term (24-hour) ambient noise level measurements were conducted at four (4) locations (sites LT-1, LT-2, LT-3 and LT-4). Long-term ambient noise measurement site LT-1 was located within the community of Tupman, near the corner of Emmons Boulevard (Tupman Road) and Grace Boulevard. Ambient noise measurement site LT-2 was located in the vicinity of residential land uses along Taft Highway. Ambient noise measurement site LT-3 was located in the vicinity of residential land uses in the community of Dustin Acres, near the intersection of Taft Highway and Tank Farm Road. Ambient noise measurement site LT-4 was located within the community of McKittrick, near the corner of Reward Road and 2nd Street.

Noise monitoring equipment consisted of Larson-Davis Laboratories Model LDL-820 sound level analyzers equipped with B&K Type 4176 1/2" microphones. The equipment complies with the specifications of the American National Standards Institute (ANSI) for Type I (Precision) sound level meters. The meters were calibrated with a B&K Type 4230 acoustic calibrator to ensure the accuracy of the measurements.

Measured hourly energy average noise levels (L_{eq}) at site LT-1 ranged from a low of 39.8 dB between 2:00 a.m. and 3:00 a.m. to a high of 63.1 dB between 2:00 p.m. and 3:00 p.m. Hourly maximum (L_{max}) noise levels at site LT-1 ranged from 56.4 to 86.6 dB. Residual noise levels at the monitoring site, as defined by the L_{90} statistical descriptor ranged from 32.1 to 47.6 dB. The L_{90} is a statistical descriptor that defines the noise level exceeded 90% of the time during each hour of the sample period. The L_{90} is generally considered to represent the residual (or background) noise level in the absence of identifiable single noise events from traffic, aircraft and other local noise sources. The measured L_{dn} value at site LT-1 during the 24-hour noise measurement period was 60.8 dB. Figure 3 graphically depicts hourly variations in ambient noise levels at the LT-1 long-term monitoring site as well as a site photograph.

Measured hourly energy average noise levels (L_{eq}) at site LT-2 ranged from a low of 58.1 dB between 11:00 p.m. and midnight to a high of 74.3 dBA between 1:00 p.m. and 2:00 p.m. Hourly maximum (L_{max}) noise levels at site LT-2 ranged from 77.8 to 88.4 dB. Residual noise levels at the monitoring site, as defined by the L_{90}, ranged from 46.1 to 54.2 dB. The measured L_{dn} value at site LT-2 during the 24-hour noise measurement period was 74.1 dB. Figure 4 graphically depicts hourly variations in ambient noise levels at the LT-2 long-term monitoring site as well as a site photograph.

Measured hourly energy average noise levels (L_{eq}) at site LT-3 ranged from a low of 55.9 dB between 2:00 a.m. and 3:00 a.m. to a high of 70.6 dBA between 4:00 p.m. and 5:00 p.m. Hourly maximum (L_{max}) noise levels at site LT-3 ranged from 77.7 to 87.5 dB. Residual noise levels at the monitoring site, as defined by the L_{90}, ranged from 43.1 to 51.4 dB. The measured L_{dn} value at site LT-3 during the 24-hour noise measurement period was 71.4 dB. Figure 4 graphically depicts hourly variations in ambient noise levels at the LT-3 long-term monitoring site as well as a site photograph.

Measured hourly energy average noise levels (L_{eq}) at site LT-4 ranged from a low of 38.0 dB between 1:00 a.m. and 2:00 a.m. to a high of 55.7 dBA between 5:00 a.m. and 6:00 a.m. Hourly maximum (L_{max}) noise levels at site LT-4 ranged from 55.8 to 76.0 dB. Residual noise levels at the monitoring site, as defined by the L_{90}, ranged from 31.3 to 49.1 dB. The measured L_{dn} value at site LT-4 during the 24-hour noise measurement period was 56.7 dB. Figure 5 graphically depicts hourly variations in ambient noise levels at the LT-4 long-term monitoring site.

4. PROJECT NOISE IMPACTS

Noise associated with the project is discussed below for both the construction phase as well as the Operation and Maintenance (O&M) phase.

a. Project Traffic Noise Impacts on Noise-Sensitive Land Uses (Less Than Significant)

The project would result in a temporary increase in vehicle trips during the construction phases (pipeline construction phase and CO2 Compression and Pumping Facility Construction Phase) and a permanent increase in vehicle trips during the CO2 Compression and Pumping Facility Operation and Maintenance Phase.

WJVA reviewed the project trip generation analysis prepared for the project by Ruetgers & Schuler Civil Engineers (dated March 8, 2023). The analysis provides the anticipated project-related daily trips for each of the above-described three project phases but does not provide the distribution of these trips among nearby roadways. In order to assess potential project-related increases in traffic noise, WJVA prepared an analysis which applied all anticipated project-related trips to each roadway in the project vicinity, individually. This results in a worst-case assessment of project-related traffic noise increases as it assumes all project trips are applied to each roadway individually

The above-described trip generation analysis provided anticipated daily project-related traffic volumes during project construction (Pipeline and Construction phase as well CO2 Compression and Pumping Facility Construction Phase) and during ongoing Operation and Maintenance. The traffic analysis provided the following associated project-related daily trips:

- Pipeline Construction Phase: 52 trucks
- CO_2 Compression and Pumping Facility Construction Phase: 160 vehicles (employee cars)
- CO_2 Compression and Pumping Facility Operation and Maintenance Phase: 20 vehicles (employee cars)

The project construction schedule indicates that the Pipeline Construction Phase and the CO_2 Compression and Pumping Facility Construction Phase would generally occur simultaneously. As such, the project-related traffic volumes for these phases were combined to provide a worst-case assessment of project-related increases in traffic noise.

WJVA analyzed traffic noise levels for both existing and 2046 traffic conditions, along six (6) roadway segments in the project vicinity. These roadway segments represent the roadways which border the project area, and which would likely be utilized to access the overall project site. It is anticipated that project-related traffic would generally access the site via Elk Hills Road and Gate 4 (Skyline Drive). Most project-related traffic would access Elk Hills Road via State Route 119 (SR 119) to Valley West Road. However, some project-related traffic could access the project site from the north, via Stockdale Highway, Wasco Way and Brite Road. For the purpose of this analysis, all project-related traffic was applied to each roadway segment individually.

WJVA modeled the increased daily traffic trips to provide a generalized understanding of overall increases in traffic noise associated with the project. WJVA utilized the FHWA Traffic Noise Model[4] to quantify generalized increases in traffic noise. The FHWA Model is a standard analytical method used for roadway traffic noise calculations. The model is based upon reference energy emission levels for automobiles, medium trucks (2 axles) and heavy trucks (3 or more axles), with consideration given to vehicle volume, speed, roadway configuration, distance to the receiver, and the acoustical characteristics of the site. The FHWA Model was developed to predict hourly L_{eq} values for free-flowing traffic conditions, and is generally considered to be accurate within ±1.5 dB. To predict L_{dn} values, it is necessary to determine the hourly distribution of traffic for a typical day and adjust the traffic volume input data to yield an equivalent hourly traffic volume. The noise modeling assumptions used to calculate project traffic noise are provided as Appendix C.

As stated above, the distribution of the project-related trips over the local roadways was not provided as part of the traffic study. For a generalized (and worst-case analysis), WJVA modeled anticipated noise levels that would occur if all project-generated trips were applied to each individual roadway segment. Truck percentages along Taft Highway and Stockdale Highway were provided by Caltrans. Truck percentages along the remaining roadway segments as well as the day/night distribution of traffic were estimated by WJVA based upon previous noise studies conducted along similar roadways.

Construction Phase-

Table III provides traffic noise exposure levels for existing conditions as well as existing conditions plus construction traffic (Pipeline Construction Phase and the CO2 Compression and Pumping Facility Construction Phase combined). Noise levels provided in Table III represent those that would occur at a reference setback distance of 150 feet from the centerline of each roadway segment.

TABLE III

MODELED TRAFFIC NOISE LEVELS, dB, L_{dn}
CRC CARBON TERRAVAULT 1 – EXISTING CONDTIONS
CONSTRUCTION PHASE

Roadway Segment	Existing	Existing Plus Project	Change	Impact Yes/No?
Elk Hills Road (n/o Skyline Drive)	59	59	0	No
Elk Hills Road (s/o Skyline Drive)	59	59	0	No
Taft Hwy/SR 119 (near Dustin Acres)	67	67	0	No
Elk Hills Road (n/o Taft Hwy)	60	60	0	No
Stockdale Hwy (e/o Wasco Way)	56	57	+1	No
Brite Road (w/o Wasco Way)	62	63	+1	No

Source: WJV Acoustics
Kern COG
Caltrans

Table IV provides traffic noise exposure levels for 2046 conditions as well as 2046 conditions plus construction traffic (Pipeline Construction Phase and the CO2 Compression and Pumping Facility Construction Phase combined). Noise levels provided in Table IV represent those that would occur at a reference setback distance of 150 feet from the centerline of each roadway segment.

TABLE IV

MODELED TRAFFIC NOISE LEVELS, dB, L_{dn}
CRC CARBON TERRAVAULT 1 – 2046 CONDITIONS
CONSTRUCTION PHASE

Roadway Segment	Existing	Existing Plus Project	Change	Impact Yes/No?
Elk Hills Road (n/o Skyline Drive)	59	59	0	No
Elk Hills Road (s/o Skyline Drive)	59	59	0	No
Taft Hwy/SR 119 (near Dustin Acres)	67	67	0	No
Elk Hills Road (n/o Taft Hwy)	60	60	0	No
Stockdale Hwy (e/o Wasco Way)	56	57	+1	No
Brite Road (w/o Wasco Way)	63	63	0	No

Source: WJV Acoustics
Kern COG
Caltrans

Reference to Table III and Table IV indicate the project-related traffic noise associated with the construction phases would generally not result in any increase in traffic noise exposure levels along roadways in the project vicinity. Noise levels along Stockdale Highway and Brite Road could increase by up to 1 dB. However, as described above the calculations applied all project-related traffic volumes to each roadway segment and should therefore be considered a worst-case assessment of project-related increases in traffic noise.

Operation and Maintenance Phase-

Table V provides traffic noise exposure levels for existing conditions as well as existing conditions plus traffic associated with CO2 Compression and Pumping Facility Operation and Maintenance Phase. Noise levels provided in Table V represent those that would occur at a reference setback distance of 150 feet from the centerline of each roadway segment.

TABLE V

MODELED TRAFFIC NOISE LEVELS, dB, L_{dn}
CRC CARBON TERRAVAULT 1 – EXISTING CONDTIONS
OPERATIONS & MAINTENANCE PHASE

Roadway Segment	Existing	Existing Plus Project	Change	Impact Yes/No?
Elk Hills Road (n/o Skyline Drive)	59	59	0	No
Elk Hills Road (s/o Skyline Drive)	59	59	0	No
Taft Hwy/SR 119 (near Dustin Acres)	67	67	0	No
Elk Hills Road (n/o Taft Hwy)	60	60	0	No
Stockdale Hwy (e/o Wasco Way)	56	56	0	No
Brite Road (w/o Wasco Way)	62	62	0	No

Source: WJV Acoustics
Kern COG
Caltrans

Table VI provides traffic noise exposure levels for 2046 conditions as well as 2046 conditions plus traffic associated with CO2 Compression and Pumping Facility Operation and Maintenance Phase. Noise levels provided in Table VI represent those that would occur at a reference setback distance of 150 feet from the centerline of each roadway segment.

TABLE VI

MODELED TRAFFIC NOISE LEVELS, dB, L_{dn}
CRC CARBON TERRAVAULT 1 – 2046 CONDITIONS
OPERATIONS & MAINTENANCE PHASE

Roadway Segment	Existing	Existing Plus Project	Change	Impact Yes/No?
Elk Hills Road (n/o Skyline Drive)	59	59	0	No
Elk Hills Road (s/o Skyline Drive)	59	59	0	No
Taft Hwy/SR 119 (near Dustin Acres)	67	67	0	No
Elk Hills Road (n/o Taft Hwy)	60	60	0	No
Stockdale Hwy (e/o Wasco Way)	56	56	0	No
Brite Road (w/o Wasco Way)	63	63	0	No

Source: WJV Acoustics
Kern COG
Caltrans

Reference to Table V and Table VI indicate the project-related traffic noise associated with the construction phases would generally not result in any increase in traffic noise exposure levels along roadways in the project vicinity.

b. Noise From Operations and Maintenance (Less Than Significant)

Once operational, project-related noise would generally be limited to noise associated with the usage of two (2) compressors; one each associated with the injection wells and the gas plant. The exact make and model of these compressors was not known at the time this analysis was prepared. However, according the project applicant, the compressor selection would likely be as follows (or similar).

- Manufacturer: Dresser-Rand
- Type: Reciprocating
- Frame: 7HOSS6
- 4000HP Electric Motor 13200V @ 720 rpm
- Max Rod Load (lb.): 75,000
- Rated BHP: 7,800
- Rated RPM: 1,000
- Stages: Five (5)
- Noise level: 85 dBA @ 3ft

According to the project applicant, noise levels associated with the proposed equipment would be approximately 85 dBA at a distance of three (3) feet from the units. One compressor would be located in section 35R, just south of the Elk Hills Power plant and one in section 14Z at the northwest most portion of the project. Figure 1 (site plan) provides the general locations for reference. The closest sensitive receptors to these two areas are located at distance of approximately five (5) miles or greater from the proposed compressor locations.

At a distance of five miles from the compressor units, noise levels were calculated to be approximately 20 dB. Such noise levels would not be audible at any sensitive receptor location.

c. Noise From Construction (Less Than Significant)

Project construction is expected to take up to 18-months. Well activities, infrastructure work and facilities work may be conducted simultaneously as these activities are mostly geographically separated from each other. Construction duration may vary based on factors such as weather, seasonal environmental constraints, resource availability, or various site-specific conditions.

Overall project construction has been broken down into two (2) individual components (or phases), 1). Pipeline Construction Activities, and 2). Compression and Pumping Facility Construction Activities. Each of these two phases will include its own schedule and equipment types required to complete the construction activities. The closest sensitive receptors (residential, schools, etc.) to the proposed construction activities are located at setback distances of approximately five (5) miles or greater (communities of McKittrick and Valley Acres).

Well Drilling Activities-
The construction phase of the project would include the drilling of approximately three (3) new injection wells and two (2) new monitoring wells, within the project areas. Additionally, some existing production wells would be converted to injection wells. All new well drilling activities as well as well conversion and workover activities would occur within the two project areas, Section 35R and Section 14Z. All well drilling activities would occur at distances of approximately five (5) miles or greater from existing sensitive receptor locations.

The exact drill rig or rigs to be used for these activities was not known at the time of this analysis. WJVA has conducted extensive noise levels measurements as well as extensive noise modelling relating to noise levels associated with well drilling activities. During the preparation of the Kern County Oil and Gas EIR, WJVA conducted noise level measurements of numerous drill rigs, in December 2014 and January 2015. These noise level measurements were used as inputs into the SoundPLAN noise model, to calculate noise exposure levels in terms of the Day-Night Level (L_{dn}), the noise metric applicable to the Kern County noise level standards. The largest (and loudest) of these measured drill rigs was the large-scale exploratory rig, Kenai #7. As the noise levels associated with this rig represent a worst-case assessment of drilling noise levels, they are applied for the purpose of this analysis. Additionally, the analysis applied the loudest measured noise levels, as measured from various positions around the rig, while in operation, and assumed that these noise levels would be constant, over a 24-hour period. As such, modelled noise levels should be considered a worst-case assessment of project-related well drilling activities.

The Kern County noise level standard applicable to the project is 65 dB L_{dn}, at the location of sensitive receptors. WJVA used the SoundPLAN noise model to calculated setback distances to various noise contours, for the above-described Kenai #7 Rig. The modelled distance from the rig to the 65 dB L_{dn} noise level contour was 3,270 feet (approximately 0.6 miles). As described above, the closest sensitive receptors to the project areas are at setback distances of five miles or greater. At a setback distance of five miles, noise levels associated with the large-scale exploratory rig would be approximately 47 dB L_{dn}. Such levels do not take into account any acoustical shielding that would occur from intervening topography and do not take into account any atmospheric or ground absorption, and should therefore be considered a worst-case assessment of noise levels associated with drilling activities at nearby sensitive receptor locations.

Pipeline Construction Activities-
New pipe will be installed above ground and sub-subsurface using primarily traditional cut and cover (trenching) techniques with short bores used for road crossings if necessary. The Project also includes establishing a temporary construction corridor, temporary storage and laydown areas, and hydrostatic testing. It is anticipated a total of up to 15 miles of up to 16-inch pipeline will be constructed as a result of this project.

Project construction is anticipated to occur over a period of up to 8 months. Pipeline construction is likely to occur on multiple sections of the pipeline at once. Other work related to the facilities may also overlap with the pipeline construction work. Idling and purging will occur after the new pipeline for each phase of construction is operational.

Construction duration may vary based on factors such as weather, seasonal environmental constraints, resource availability, number of contractor spreads, permit acquisition, and other issues encountered in the field. Pipeline installation rates are dependent on terrain and other site-specific conditions, and number of welds required in the trench. An estimated rate of installation is approximately 400 feet of pipe per day is expected.

Compression and Pumping Facility Construction Activities-

The construction period for the proposed project from site preparation through construction and testing is expected to commence in 2023 beginning with the Arco Substation expansion by PG&E. Work on the project site would commence in 2024 and would extend for approximately 12 months.

Construction of the proposed project would include the following activities:

- Site preparation
- Construction of access and site internal roads
- Grading and earthwork
- Dust control
- Concrete foundations
- Major equipment installation
- Structural steel work
- Electrical/instrumentation work
- Storm water management facilities
- Architecture and landscaping

WJVA staff reviewed the anticipated construction schedule and proposed equipment list associated with various components of project construction. These components and associated equipment lists are summarized below:

Pipeline Construction:

Noise levels associated with pipeline construction activities are described below in two individual components, 1). Excavate and backfill, and 2). Pipe install. Each of these two components will entail a different timeline and equipment list. These details are summarized below in Table VIII and Table IX:

- **Excavation and Backfill:**

TABLE VIII

CONTRUCTION EQUIPMENT
PIPELINE EXCAVATION AND BACKFILL
CRC CARBON TERRAVAULT 1, KERN COUNTY

EQUIPMENT TYPE	QUANTIY	FULL-TIME	PART-TIME
1-Ton Work Truck	12	x	
5-Ton Utility Flat Bed Truck	4		x
12-Yard Dump Truck	12	x	
Soft Dig Truck 350 CFM	2	x	
Hydro Vac trucks	2		x
2500-Gallon Water truck	4		x
185 CFM Air compressor	4		x
Backhoe	4	x	
2-Yard Loader	3	x	
45k LB Excavator	2	x	
36" Ride on Compactor	4	x	

Source: CRC

- **Pipe Installation:**

TABLE IX

CONTRUCTION EQUIPMENT
PIPELINE INSTALLATION
CRC CARBON TERRAVAULT 1, KERN COUNTY

EQUIPMENT TYPE	QUANTIY	FULL-TIME	PART-TIME
1-Ton Work truck	16	x	
5-Ton Utility Flat Bed Truck	6		x
2500-Gallon Water truck	4		x
25-Ton Stinger Crane	3	x	
15-Ton Boom Truck	3	x	
25T RT Crane	3		x
D6 Side Boom	6	x	
Bending Machine	1		x
185 CFM Air Compressor	4	x	
400 CFM Air Compressor	1		x
250 amp Welding Machine	8	x	
4000W Generator	4		x
DitchWitch HDD Machine	1		x
Vacuum Truck	2		x

Source: CRC

According to the project applicant, certain pieces of equipment would typically be utilized on a full-time basis (approximately 10 hours per day) and others would be utilized on a part-time basis. For the purpose of this analysis, noise levels associated with various phases and components of construction activities were analyzed based upon the worst-case assumption that all pieces of equipment were operable simultaneously.

WJVA used the Federal Highway Administration (FHWA) Roadway Construction Noise Model (RCNM)[5] to estimate project-related construction noise levels at nearby sensitive receptor locations. Construction noise levels were modeled at a setback distance of five (5) miles, the approximate distance of the closest sensitive receptors to the proposed construction activities. Construction noise levels were modeled using the RCNM for the two above-described pipeline construction phases are modeled noise levels are provided below, at a setback distance of five miles from the construction activities:

- Excavation and Backfill: 34 dB L_{eq}
- Pipe Install: 36 dB L_{eq}

Compression and Pumping Facility Construction:
Noise levels associated with compression and pumping facility construction activities are described below in two individual components, 1). Booster Station, and 2). Substation. Each of

these two components will entail a different timeline and equipment list. These details are summarized below in Table X and Table XI:

- **Booster Station:**

TABLE IX

CONTRUCTION EQUIPMENT
COMPRESSION AND PUMPING FACILITY CONSTRUCTION-BOOSTER STATION
CRC CARBON TERRAVAULT 1, KERN COUNTY

EQUIPMENT TYPE	QUANTIY	FULL-TIME	PART-TIME
Hydro-Crane	3	X	
Reach Lift	1	X	
Backhoe	3	X	
120-200 Ton Crane	1		X
20-40 Ton Crane	1		X
Grader	2		X
Scraper	1		X
Front Loader and Truck	1		X

Source: CRC

- **Substation:**

TABLE IX

CONTRUCTION EQUIPMENT
COMPRESSION AND PUMPING FACILITY CONSTRUCTION-SUBSTATION
CRC CARBON TERRAVAULT 1, KERN COUNTY

EQUIPMENT TYPE	QUANTIY	FULL-TIME	PART-TIME
Crane	1		X
Backhoe	2		X
Grader	2	X	
Scraper	1		X
Front Loader and Truck	1		X

Source: CRC

According to the project applicant, certain pieces of equipment would typically be utilized on a full-time basis (approximately 10 hours per day) and others would be utilized on a part-time basis. For the purpose of this analysis, noise levels associated with various phases and components of construction activities were analyzed based upon the worst-case assumption that all pieces of equipment were operable simultaneously.

WJVA used the Federal Highway Administration (FHWA) Roadway Construction Noise Model (RCNM) to estimate project-related construction noise levels at nearby sensitive receptor locations. Construction noise levels were modeled at a setback distance of five (5) miles, the approximate distance of the closest sensitive receptors to the proposed construction activities. Construction noise levels modeled using the RCNM for the two above-described pipeline construction phases are provided below, at a setback distance of five miles from the construction activities:

- Booster Station: 33 dB L_{eq}
- Substation: 32 dB L_{eq}

As stated above, these modeled construction noise levels assume every piece of construction equipment are in simultaneous operation. Additionally, these modeled construction noise levels do not take into account atmospheric absorption or acoustical shielding provided by intervening terrain and topography between the construction areas and the sensitive receptor locations. As such, the noise levels described above should be considered a worst-case assessment of construction noise levels. **Noise levels from project construction activities would not be audible over existing ambient noise levels at any sensitive receptor location.**

d. Vibration Impacts (Less Than Significant)

The dominant sources of man-made vibration are sonic booms, blasting, pile driving, pavement breaking, demolition, diesel locomotives, and rail-car coupling. None of these activities are anticipated to occur with construction or operation of the proposed project. Typical vibration levels at distances of 100 feet and 300 feet are summarized by Table X. As stated above, construction activities would occur at distance of five miles or greater from any existing sensitive receptor locations. As such, construction-related vibration would not result in any impacts to sensitive receptors.

TABLE X

TYPICAL VIBRATION LEVELS DURING CONSTRUCTION

	PPV (in/sec)	
Equipment	**@ 100´**	**@ 300´**
Bulldozer (Large)	0.011	0.006
Bulldozer (Small)	0.0004	0.00019
Loaded Truck	0.01	0.005
Jackhammer	0.005	0.002
Vibratory Roller	.03	0.013
Caisson Drilling	.01	0.006

Source: *Caltrans*

After full project build out, it is not expected that ongoing operational activities will result in any vibration impacts at nearby sensitive uses.

e. Noise Impacts from Nearby Airports or Airstrips (No Impact)

The Project site is not located within two miles of a public airport or private airstrip. The Elk Hills Buttonwillow Airport is located approximately 4 miles northeast of the project site.

5. IMPACT SUMMARY

The project is not expected to result in any significant noise impacts during either the Construction Phases or the Operation and Maintenance Phase. All sensitive receptors (residential, schools, hospitals, parks, churches, etc.) are located at distances of five miles or greater from the proposed project areas. At these distances, noise associated with all project-related activities would not be audible over existing (without project) noise levels. Therefore, the inclusion of mitigation measures is not required for project noise compliance.

6. SOURCES CONSULTED

1. *Kern County, Noise Element of the General Plan, adopted June 15, 2004.*

2. Kern County Code of Ordinances, Section 8.36 (Noise Control). 2007.

3. California Department of Transportation, *Transportation and Construction Vibration Guidance Manual,* September 2013.

4. Federal Highway Administration, *Traffic Noise Model, Version 2.5,* April 14, 2004.

5. California Department of Transportation, *Roadway Construction Noise Model,* 2006.

FIGURE 1: PROJECT SITE PLAN

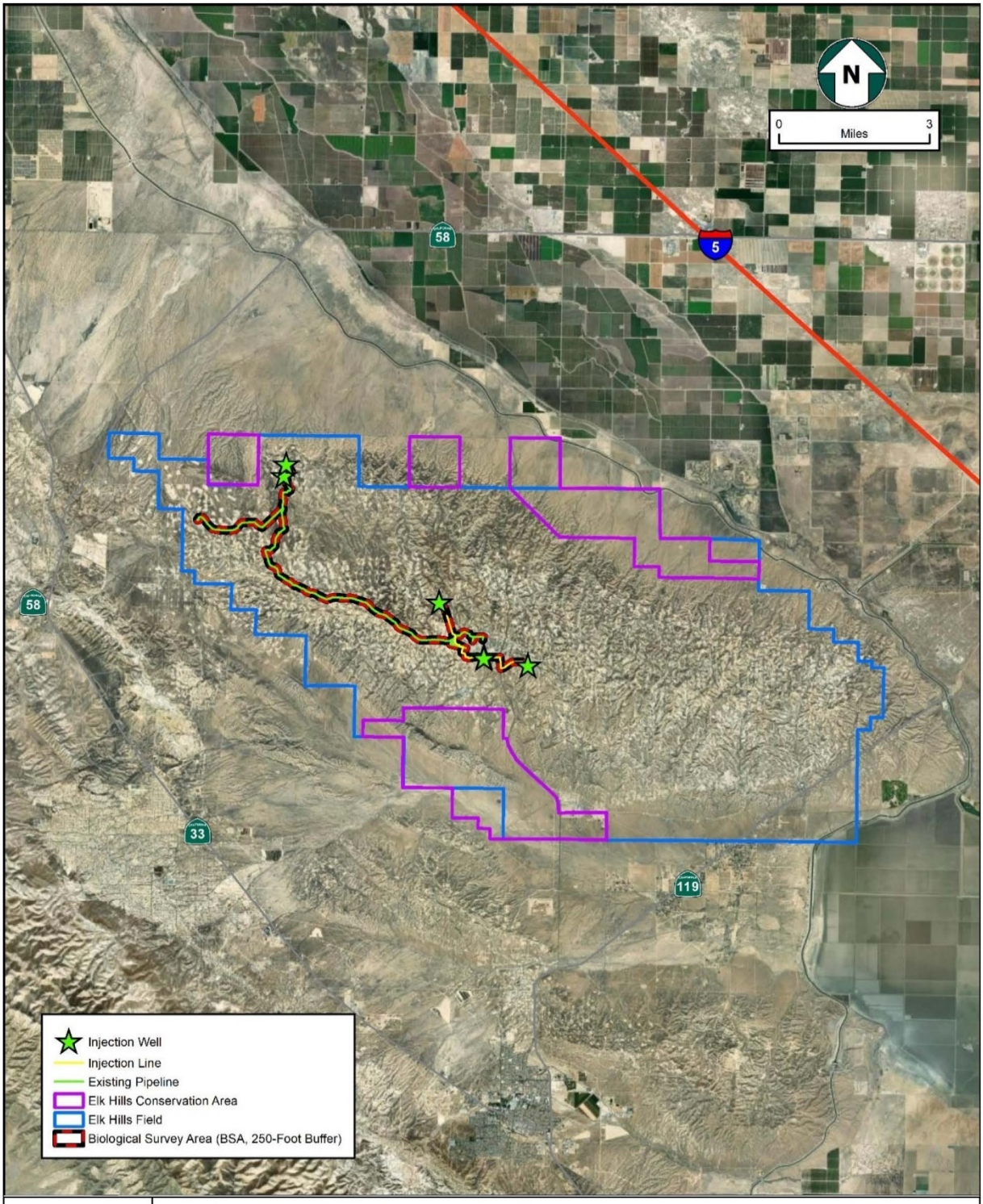


Figure 1-2
Project Area
Carbon TerraVault 1 Project, Kern County, California

FIGURE 2: PROJECT VICINITY AND AMBIENT NOISE MONITORING SITES

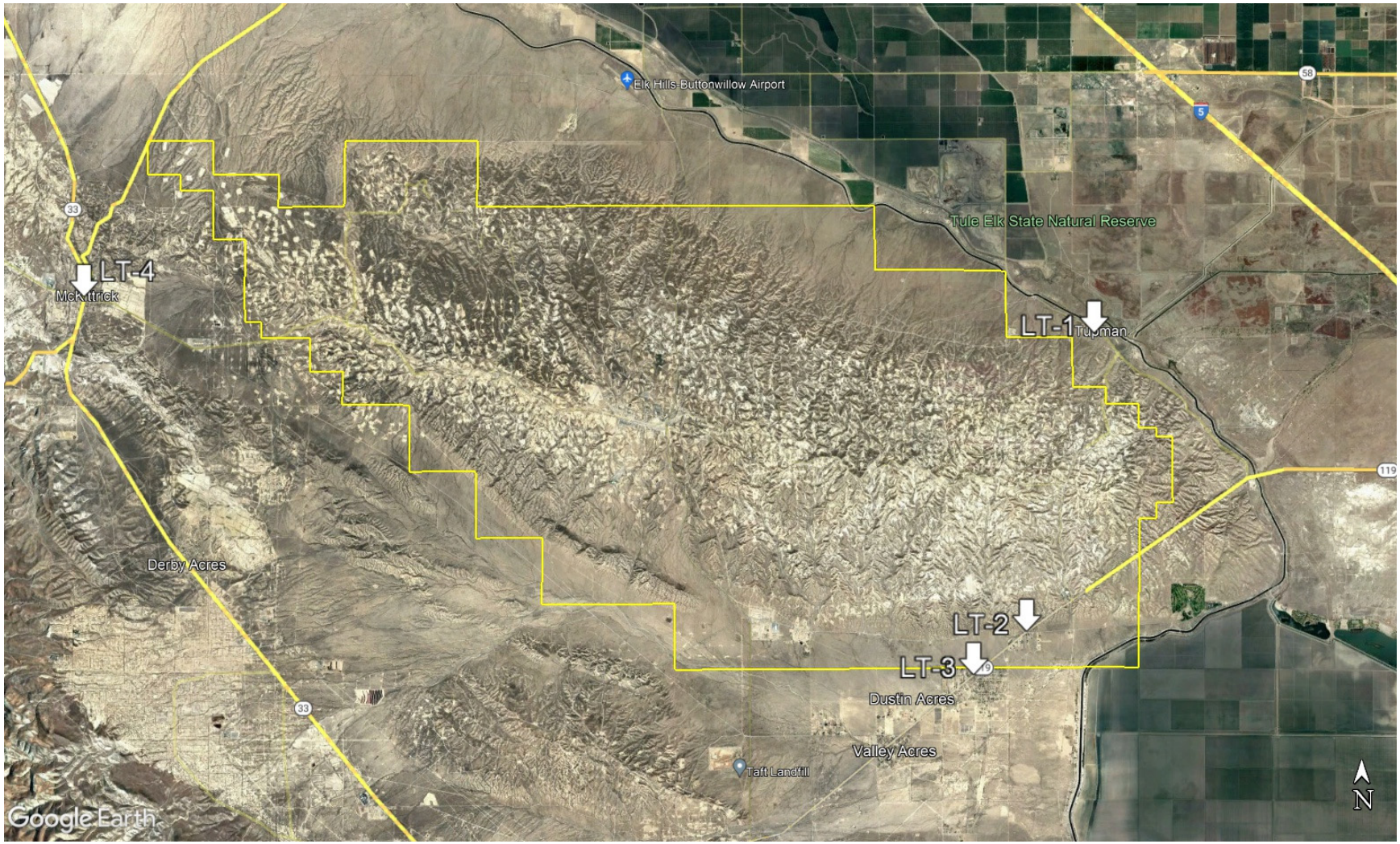


FIGURE 3: HOURLY NOISE LEVELS AT LONG-TERM MONITORING SITE LT-1

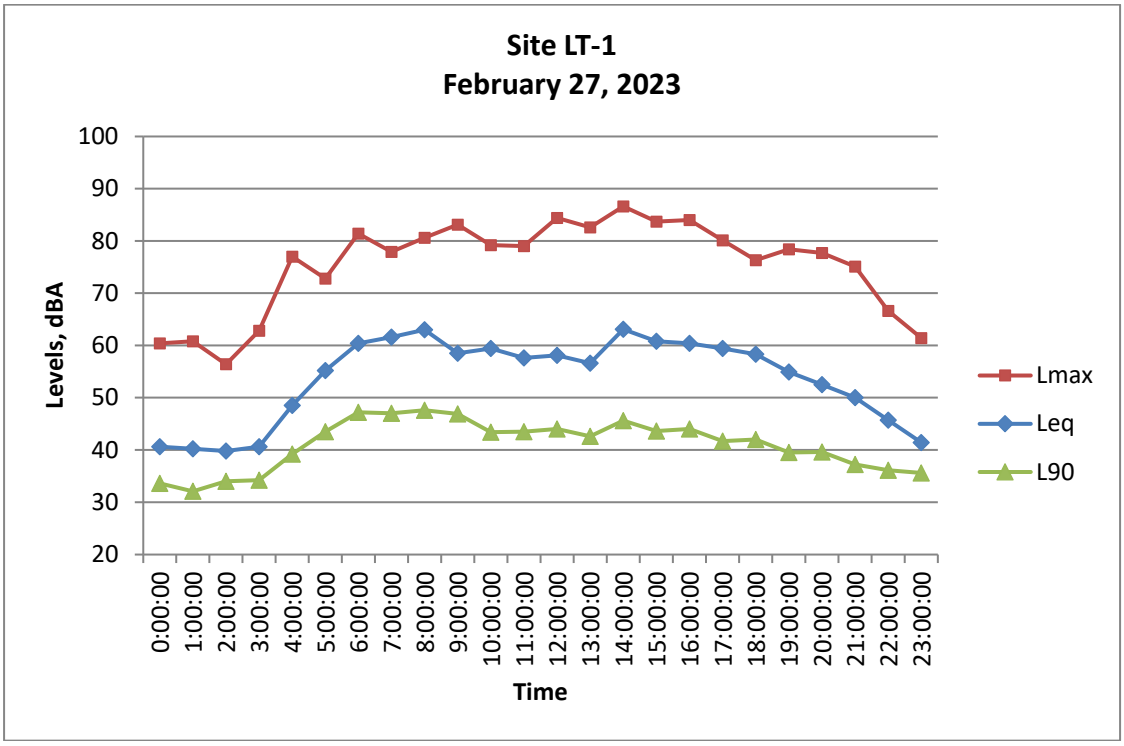




FIGURE 4: HOURLY NOISE LEVELS AT LONG-TERM MONITORING SITE LT-2

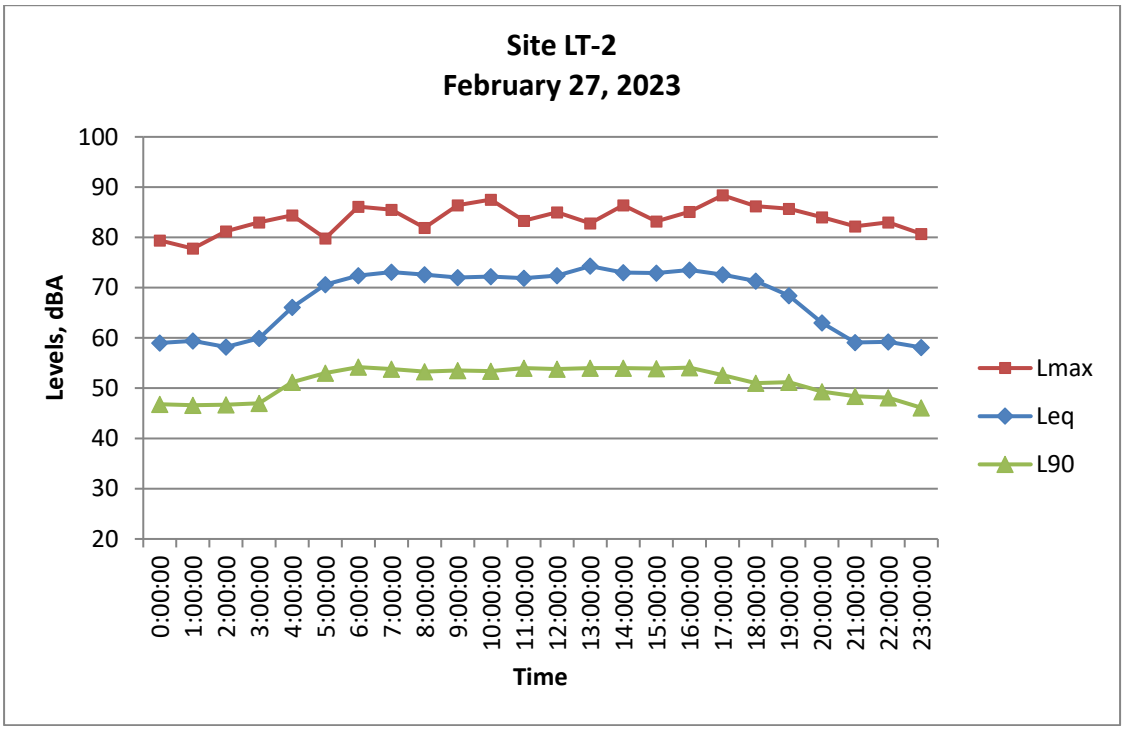




FIGURE 5: HOURLY NOISE LEVELS AT LONG-TERM MONITORING SITE LT-3

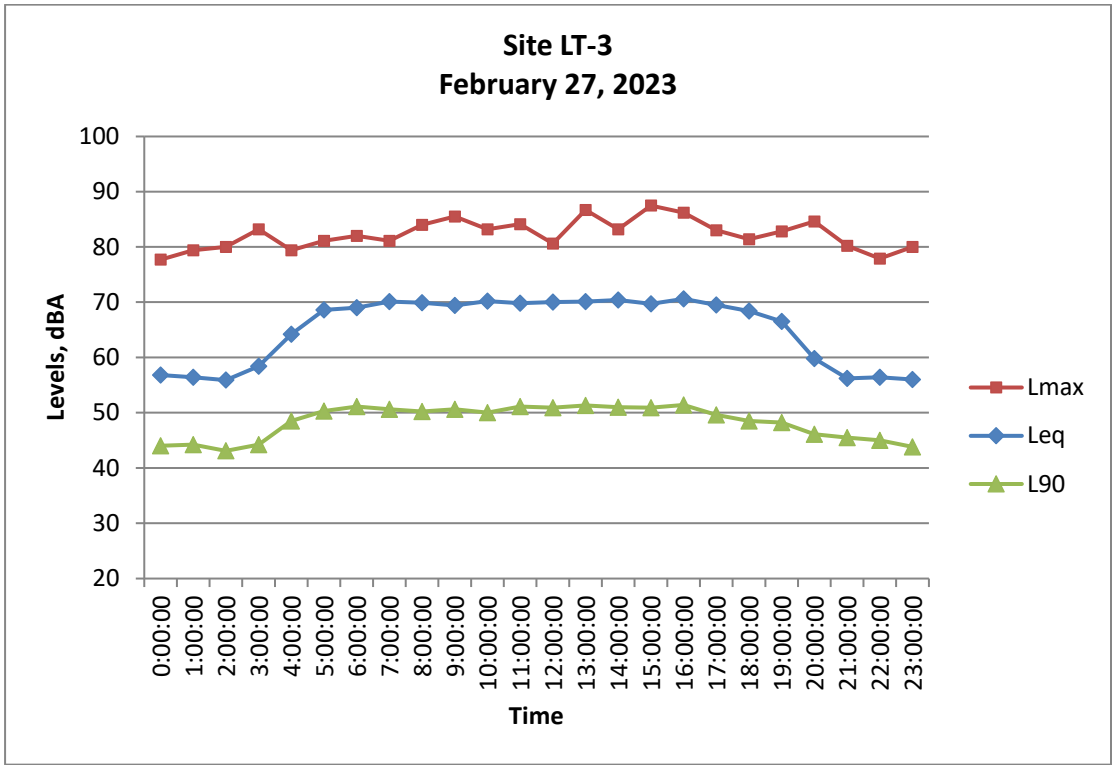
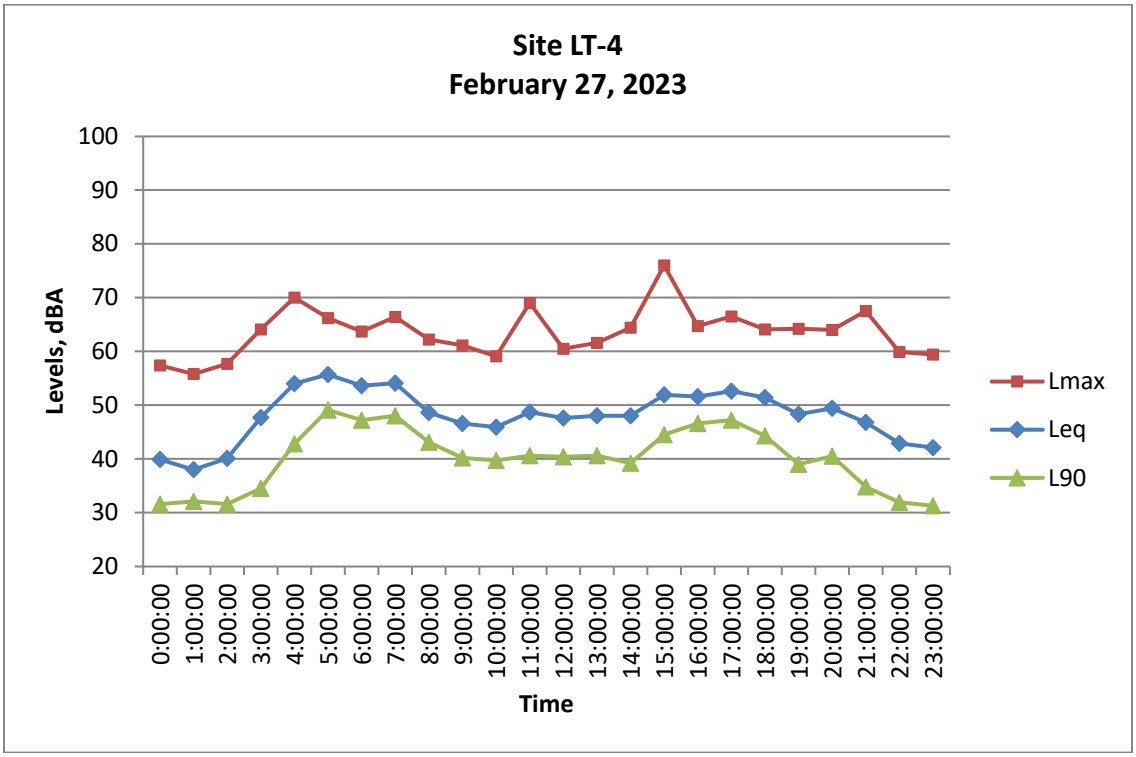




FIGURE 6: HOURLY NOISE LEVELS AT LONG-TERM MONITORING SITE LT-4





APPENDIX A-1

ACOUSTICAL TERMINOLOGY

AMBIENT NOISE LEVEL: The composite of noise from all sources near and far. In this context, the ambient noise level constitutes the normal or existing level of environmental noise at a given location.

CNEL: Community Noise Equivalent Level. The average equivalent sound level during a 24-hour day, obtained after addition of approximately five decibels to sound levels in the evening from 7:00 p.m. to 10:00 p.m. and ten decibels to sound levels in the night before 7:00 a.m. and after 10:00 p.m.

DECIBEL, dB: A unit for describing the amplitude of sound, equal to 20 times the logarithm to the base 10 of the ratio of the pressure of the sound measured to the reference pressure, which is 20 micropascals (20 micronewtons per square meter).

DNL/L_{dn}: Day/Night Average Sound Level. The average equivalent sound level during a 24-hour day, obtained after addition of ten decibels to sound levels in the night after 10:00 p.m. and before 7:00 a.m.

L_{eq}: Equivalent Sound Level. The sound level containing the same total energy as a time varying signal over a given sample period. L_{eq} is typically computed over 1, 8 and 24-hour sample periods.

NOTE: The CNEL and DNL represent daily levels of noise exposure averaged on an annual basis, while L_{eq} represents the average noise exposure for a shorter time period, typically one hour.

L_{max}: The maximum noise level recorded during a noise event.

L_n: The sound level exceeded "n" percent of the time during a sample interval (L_{90}, L_{50}, L_{10}, etc.). For example, L_{10} equals the level exceeded 10 percent of the time.

A-2

ACOUSTICAL TERMINOLOGY

NOISE EXPOSURE CONTOURS: Lines drawn about a noise source indicating constant levels of noise exposure. CNEL and DNL contours are frequently utilized to describe community exposure to noise.

NOISE LEVEL REDUCTION (NLR): The noise reduction between indoor and outdoor environments or between two rooms that is the numerical difference, in decibels, of the average sound pressure levels in those areas or rooms. A measurement of Anoise level reduction" combines the effect of the transmission loss performance of the structure plus the effect of acoustic absorption present in the receiving room.

SEL or SENEL: Sound Exposure Level or Single Event Noise Exposure Level. The level of noise accumulated during a single noise event, such as an aircraft overflight, with reference to a duration of one second. More specifically, it is the time-integrated A-weighted squared sound pressure for a stated time interval or event, based on a reference pressure of 20 micropascals and a reference duration of one second.

SOUND LEVEL: The sound pressure level in decibels as measured on a sound level meter using the A-weighting filter network. The A-weighting filter de-emphasizes the very low and very high frequency components of the sound in a manner similar to the response of the human ear and gives good correlation with subjective reactions to noise.

SOUND TRANSMISSION CLASS (STC): The single-number rating of sound transmission loss for a construction element (window, door, etc.) over a frequency range where speech intelligibility largely occurs.

APPENDIX C

TRAFFIC NOISE MODELING CALCULATIONS

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Appendix I

Transportation Technical Documentation

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1800 30th Street, Suite 260
Bakersfield, CA 93301

October 12, 2023

257-74
Electronic Mail

Chris Mynk
QK Inc.
5080 California Ave Suite 220
Bakersfield, CA 93309

REF: Trip Generation and Vehicle Miles Traveled Analysis for Proposed CRC TerraVault Project in Elk Hills

Mr. Mynk:

This letter is in response to your request for a trip generation and vehicle miles traveled analysis (VMT), for construction and operation and maintenance (O&M) phases of the proposed pipeline and carbon capture facility located within CRC Elk Hills field boundary. Operating hours will be seven days a week, 24 hours a day, compressing and pumping CO_2.

The following components of the project were analyzed for trip generation and VMT:

- Pipeline Construction phase
- CO_2 Injection Well construction phase
- CO_2 Compression and Pumping Facility construction and O&M phase

PROJECT TRIP GENERATION AND DISTRIBUTION

Pipeline Construction Phase

Traffic generated during the pipeline construction phase will include personnel vehicles and water trucks. Proposed pipeline routes are shown on the attached site plan. These vehicles will access the pipeline along the route under construction at the time. Trip generation estimates for pipeline construction traffic is presented in Table 1. Construction operations are anticipated to occur between 6:00 AM and 5:00 PM.

Trip generation calculations were based on the following peak construction period assumptions:

Vehicles

- 1 Ton Work Trucks: It is anticipated there will be approximately 16 - 1 Ton Work Trucks which will make a trip to the work site and one trip out of the work site daily. It is

assumed that 75 percent of the 1 Ton Work Trucks will arrive and depart the work site within the peak hour of adjacent street traffic.

- 5 Ton Work Trucks: It is anticipated there will be approximately 6 - 5 Ton Work Trucks which will make a trip to the work site and one trip out of the work site daily. 5 Ton Work Trucks will be on site periodically as needed. It is assumed that 75 percent of the 1 Ton Work Trucks will arrive and depart the work site within the peak hour of adjacent street traffic.
- Water Trucks: It is anticipated there will be approximately 4 water trucks that will make a trip into the work site and one trip out of the work site periodically as needed. It is assumed that one of the Water Trucks will arrive and depart the work site within the peak hour of adjacent street traffic.

The table below summarizes the trips generated by the project using the above assumptions.

Table 1
Pipeline Construction Phase Trip Generation

			AM Peak Hour Trips		PM Peak Hour Trips	
Traffic Type	Variable	ADT	In Trips	Out Trips	In Trips	Out Trips
1 Ton Work Truck	16 (per day)	32	100% 13	0% 0	0% 0	100% 13
5 Ton Utility Flat Bed Truck	6 (per day)	12	100% 5	0% 0	0% 0	100% 5
Water Truck	4 (per day)	8	100% 1	0% 0	0% 0	100% 1
	Total Trips	52	19	0	0	19

As shown in Table 1, the construction of the pipeline will generate approximately 52 daily trips, with 19 trips during the PM peak hour and 19 trips during the AM peak hour of a typical weekday.

CO_2 Compression and Pumping Facility Construction Phase

The CO_2 Compression and Pumping Facility construction phase will generally include personnel vehicles. Anticipated deliveries of materials and equipment will occur on off peak periods and sporadically. Deliveries were not included in the trip generation as they will generally be very low volumes and not a daily occurrence. The proposed facility location is shown on the attached site plan. These vehicles will access the pipeline along the route under construction at the time. Trip generation estimates for pipeline construction traffic is presented in Table 2. Construction operations are anticipated to occur between 6:00 AM and 5:00 PM.

Trip generation calculations were based on the following peak construction period assumptions:

Passenger Vehicles:

- There will be approximately 80 construction personnel that will be on site daily. The following assumptions were made regarding carpool and peak hour travel:
    - A carpool factor of 1.25 was used, as a conservative assumption of personnel per vehicle.
    - With construction hours between 6:00 AM and 5:00 PM, tt is assumed that 75 percent of the personnel vehicles will arrive and depart the work site within the peak hour of adjacent street traffic.

Table 2
CO_2 Compression and Pumping Facility Construction Phase Trip Generation

			AM Peak Hour Trips		PM Peak Hour Trips	
Traffic Type	Variable	ADT	In Trips	Out Trips	In Trips	Out Trips
Worker Vehicle	80 (per day)	160	100% 48	0% 0	0% 0	100% 48

As shown in Table 2, the construction of the CO_2 Compression and Pumping Facility will generate approximately 48 daily trips, with 48 trips during the PM peak hour and 48 trips during the AM peak hour of a typical weekday.

CO_2 Compression and Pumping Facility Operation and Maintenance Phase

The CO_2 Compression and Pumping Facility will include 5 full time employees which will operate the facility seven days a week, 24 hours a day. An additional 5 full time employees could be on-site at any time if repairs or other maintenance work is required.

Trip generation calculations for the operation and maintenance phase were based on the following assumptions:

Passenger Vehicles:

- There will be approximately 5 full time staff with an additional 5 employees which may be on site during maintenance or repair times on-site daily. The following assumptions were made regarding peak hour travel:
    - One full time staff employee will enter and exit the facility during the peak hour of adjacent street traffic in both the AM and PM hours.
    - 5 maintenance/repair employees will enter and exit the site during the peak hour of adjacent street traffic in both the AM and PM hours.
    - Each employee will make one inbound trip, and one outbound trip daily.

Table 3
CO_2 Compression and Pumping Facility
Operation and Maintenance Phase Trip Generation

			AM Peak Hour Trips		PM Peak Hour Trips	
Traffic Type	Variable	ADT	In Trips	Out Trips	In Trips	Out Trips
Worker Vehicle	10 (per day)	20	86% 6	14% 1	14% 1	86% 6

As shown in Table 3, the operation and maintenance phase of the CO_2 Compression and Pumping Facility will generate approximately 20 daily trips, with 7 trips during the PM peak hour and 7 trips during the AM peak hour of a typical weekday. It is noted that the maintenance or repair work will occur periodically and there will generally only be one trip in the peak hour.

CO_2 Injection Well Construction

There are planned to be a total of six CO2 injections wells constructed as part of the project. Construction activities are estimated to take approximately 18 days for each well.

Trip generation calculations for the operation and maintenance phase were based on the following assumptions:

Passenger Vehicles:

- Passenger Car/Pickup Truck: It is anticipated there will be approximately 6 Passenger Car/Pickup Trucks which will make a trip to the work site and one trip out of the work site daily.
- Heavy Duty Truck: It is anticipated there will be approximately 2 Heavy Duty Trucks which will make a trip to the work site and one trip out of the work site daily.

Table 4
CO_2 Injection Well Construction Phase

			AM Peak Hour Trips		PM Peak Hour Trips	
Traffic Type	Variable	ADT	In Trips	Out Trips	In Trips	Out Trips
Passenger Car/ Pickup Truck	6 (per day)	12	100% 6	0% 0	0% 0	100% 6
Heavy Trucks	2 (per day)	4	100% 2	0% 0	0% 0	100% 2
	Total Trips	16	8	0	0	8

As shown in Table 4, the construction of the injection wells will generate approximately 16 daily trips, with 8 trips during the PM and PM peak hours of a typical weekday.

Findings

Based on thresholds established by the Caltrans Guide for the Preparation of Traffic Impact Studies, a project must generate 50 or more trips in the peak hour to warrant the analysis of a roadway facility. As is shown in the trip generation tables above, the various components of the project are not anticipated to generate more than 48 trips in either the AM or PM peak hour during the construction phase, and no more than 7 in the operation and maintenance phase. There may be periodic overlap of the construction phases, but only for a limited time, and the construction activities are limited to within the existing Elk Hills facility boundaries. Therefore, due to the amount of peak hour trips being generally less than 50 trips in the peak hour, further level of service analysis is not warranted, and the construction and O&M phases of the project are not expected to cause any operational issues of the adjacent roadway facilities.

Vehicle Miles Traveled Analysis.

At the time of this analysis, Kern County has not developed a Vehicle Miles Traveled (VMT) policy. Therefore, the guidelines outlined in OPR's *SB 743: Technical Advisory on Evaluating Transportation Impacts in CEQA*, dated December 2018 were used in evaluating the project for VMT impacts.

The advisory provides "screening thresholds" for identifying whether a land use project should be expected to result in a less than significant transportation impact under CEQA. Projects meeting one or more of these criteria would not be required to undergo a detailed VMT analysis. One such screening threshold pertains to the project generated daily traffic. According to the advisory, if the project generates fewer than 110 average daily trips, the project is presumed to create a less than significant impact.

As shown on Table 3, the project is anticipated to generate no more than 20 daily trips once the facility is fully operational. During construction, daily trips are anticipated to exceed the 110 daily trip threshold by approximately 50 trips, however, it is for a limited time during construction, and will not create any lasting impacts due to the temporary nature of the trips. Therefore, with the facility generating less than 110 daily trips during the operational phase, the project is presumed to have a less than significant traffic impact.

Please contact me should you have any questions.

Very truly yours,

Ian J. Parks
R.C.E. 58155



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Appendix J

Tribal Cultural AB-52 Outreach

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Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
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Web Address: http://kernplanning.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

Certified Mail <7017 1450 0001 9937 8307>

February 25, 2022

FILE: ZCC 5, Map 119; CUP 5, Map 119

San Manuel Band of Mission Indians
Attn: Cultural Resources Analyst
26569 Community Center Drive
Highland, CA 92346

RE: AB 52 Tribal Consultation – Zone Classification Change and Conditional Use Permit for carbon capture and sequestration. (PP22405)

Dear Ladies and Gentlemen,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for proposed carbon capture and sequestration. The proposed project, the Carbon TerraVault 1 (CTV 1) Project, would allow for the capture and sequestration of carbon dioxide (CO_2) within identified geographically confined reservoirs for storage in perpetuity.

Specifically, the project proponent is requesting the following applications: (a) Zone Change Case (ZCC) #5, Map #119; and (b) Conditional Use Permit (CUP) #5, Map #119 to allow for a 5,745.44 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells and related improvements for storage of CO_2.

The project site is located within the Central Valley portion of unincorporated Kern County, west of Elk Hills Road and north of Skyline Road, within the Elk Hills Oil Field, approximately 26 miles from the City of Bakersfield, approximately 8.5 miles from the City of Taft and approximately 4 miles from the unincorporated community of Buttonwillow, also being located within Sections 7, 8, 9, 10, 13, 15, 16, 17, 18, and 26 of Township 30 South, Range 23 East, Mount Diablo Base and Meridian (MDBM).

In compliance with California Assembly Bill No. 52 (AB 52), this Department is requesting your review and comments on the potential impacts on cultural places associated with your tribe by this proposal. Your participation is important at this early stage of processing to ensure that cultural places important to your tribe are identified, and the potential impacts associated with implementation of the project are mitigated.

If you have not responded by **Monday, March 28, 2022**, this Department will assume your tribe has declined consultation as per Public Resources Code (PRC) 21080.3.1.

If you have any questions, comments or wish to request a consultation regarding this proposal please contact me at (661) 862-8629 or by email at hooverc@kerncounty.com.

Sincerely,

Cindi Hoover, Supervising Planner
Advanced Planning

Enclosure: Vicinity Map

Lorelei H. Oviatt, AICP, Director
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PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
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Administrative Operations

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February 25, 2022

FILE: ZCC 5, Map 119; CUP 5, Map 119

Tejon Indian Tribe
Attn: Collin Rambo, Cultural Resource Management Technician
1731 Hasti Acres Dr., Suite 108
Bakersfield, CA 93309

RE: AB 52 Tribal Consultation – Zone Classification Change and Conditional Use Permit for carbon capture and sequestration. (PP22405)

Dear Mr. Rambo,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for proposed carbon capture and sequestration. The proposed project, the Carbon TerraVault 1 (CTV 1) Project, would allow for the capture and sequestration of carbon dioxide (CO_2) within identified geographically confined reservoirs for storage in perpetuity.

Specifically, the project proponent is requesting the following applications: (a) Zone Change Case (ZCC) #5, Map #119; and (b) Conditional Use Permit (CUP) #5, Map #119 to allow for a 5,745.44 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells and related improvements for storage of CO_2.

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Sincerely,

Cindi Hoover, Supervising Planner
Advanced Planning

Enclosure: Vicinity Map

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Web Address: http://kernplanning.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
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February 25, 2022

FILE: ZCC 5, Map 119; CUP 5, Map 119

Torres Martinez Desert Cahuilla Indians
Attn: Michael Mirelez, Cultural
Resources Coordinator
P.O. Box 1160
Thermal, CA 92274

RE: AB 52 Tribal Consultation – Zone Classification Change and Conditional Use Permit for carbon capture and sequestration. (PP22405)

Dear Mr. Mirelez,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for proposed carbon capture and sequestration. The proposed project, the Carbon TerraVault 1 (CTV 1) Project, would allow for the capture and sequestration of carbon dioxide (CO_2) within identified geographically confined reservoirs for storage in perpetuity.

Specifically, the project proponent is requesting the following applications: (a) Zone Change Case (ZCC) #5, Map #119; and (b) Conditional Use Permit (CUP) #5, Map #119 to allow for a 5,745.44 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells and related improvements for storage of CO_2.

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If you have any questions, comments or wish to request a consultation regarding this proposal please contact me at (661) 862-8629 or by email at hooverc@kerncounty.com.

Sincerely,

Cindi Hoover, Supervising Planner
Advanced Planning

Enclosure: Vicinity Map

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PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

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February 25, 2022

FILE: ZCC 5, Map 119; CUP 5, Map 119

Twenty-Nine Palms Band of Mission Indians
Attn: Anthony Madrigal Jr., Tribal Grants Administrator
46-200 Harrison Place
Coachella, CA 92236

RE: AB 52 Tribal Consultation – Zone Classification Change and Conditional Use Permit for carbon capture and sequestration. (PP22405)

Dear Mr. Madrigal, Jr.,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for proposed carbon capture and sequestration. The proposed project, the Carbon TerraVault 1 (CTV 1) Project, would allow for the capture and sequestration of carbon dioxide (CO_2) within identified geographically confined reservoirs for storage in perpetuity.

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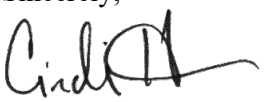
If you have any questions, comments or wish to request a consultation regarding this proposal please contact me at (661) 862-8629 or by email at hooverc@kerncounty.com.

Sincerely,



Cindi Hoover, Supervising Planner
Advanced Planning

Enclosure: Vicinity Map

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PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

Certified Mail <7017 1450 0001 9937 8321>

February 25, 2022

FILE: ZCC 5, Map 119; CUP 5, Map 119

Twenty-Nine Palms Band of Mission Indians
Attn: Darrell Mike, Tribal Chairman
46-200 Harrison Place
Coachella, CA 92236

RE: AB 52 Tribal Consultation – Zone Classification Change and Conditional Use Permit for carbon capture and sequestration. (PP22405)

Dear Mr. Mike,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for proposed carbon capture and sequestration. The proposed project, the Carbon TerraVault 1 (CTV 1) Project, would allow for the capture and sequestration of carbon dioxide (CO_2) within identified geographically confined reservoirs for storage in perpetuity.

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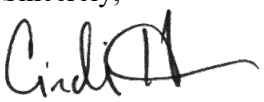
If you have not responded by **Monday, March 28, 2022**, this Department will assume your tribe has declined consultation as per Public Resources Code (PRC) 21080.3.1.

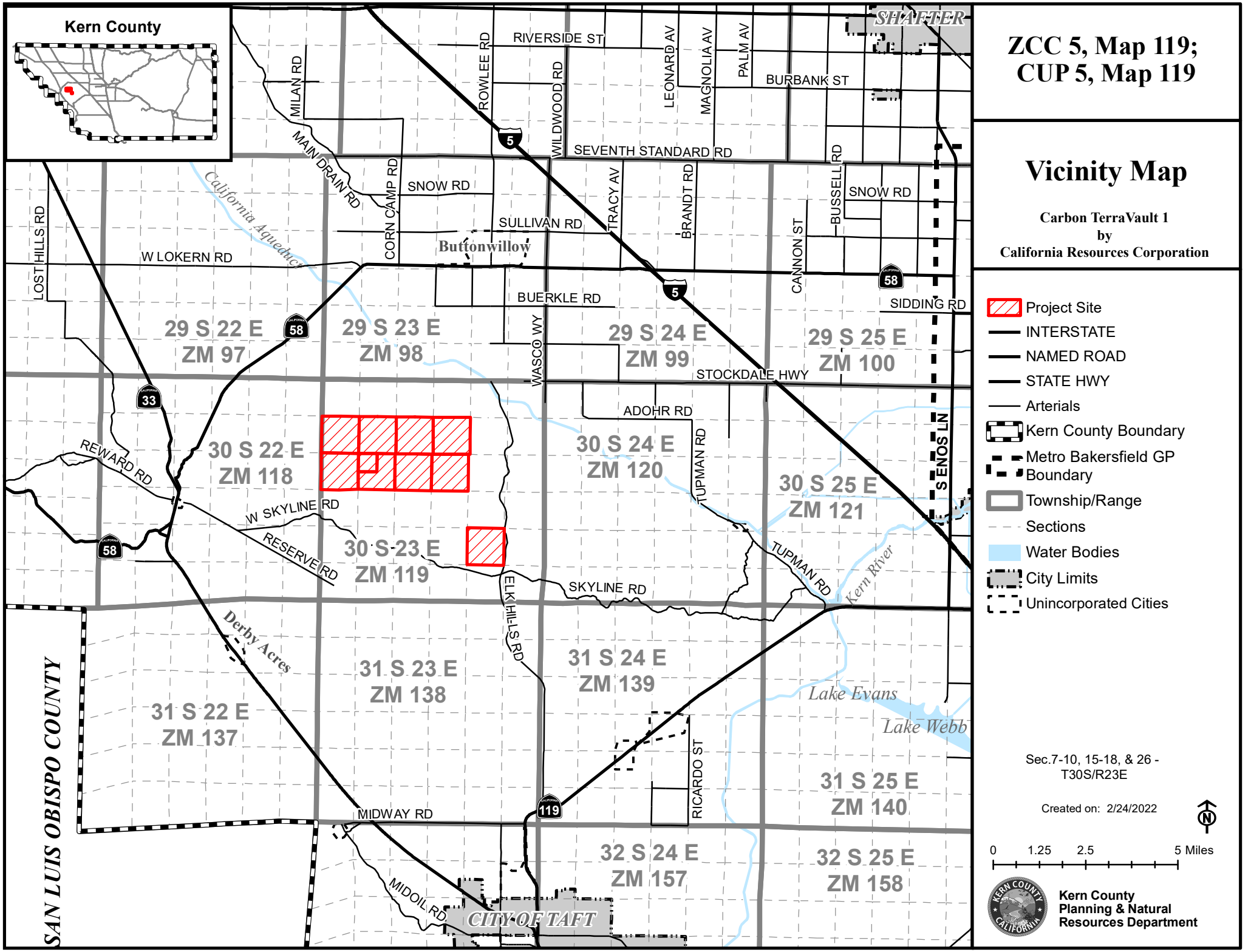
If you have any questions, comments or wish to request a consultation regarding this proposal please contact me at (661) 862-8629 or by email at hooverc@kerncounty.com.

Sincerely,



Cindi Hoover, Supervising Planner
Advanced Planning

Enclosure: Vicinity Map



ZCC 5, Map 119; CUP 5, Map 119

Vicinity Map

Carbon TerraVault 1
by
California Resources Corporation

- Project Site
- INTERSTATE
- NAMED ROAD
- STATE HWY
- Arterials
- Kern County Boundary
- Metro Bakersfield GP Boundary
- Township/Range
- Sections
- Water Bodies
- City Limits
- Unincorporated Cities

Sec.7-10, 15-18, & 26 - T30S/R23E

Created on: 2/24/2022

0 1.25 2.5 5 Miles

Kern County Planning & Natural Resources Department

Cindi Hoover

From: Ryan Nordness <Ryan.Nordness@sanmanuel-nsn.gov>
Sent: Wednesday, March 9, 2022 4:44 PM
To: Cindi Hoover
Subject: RE: AB52 notice for Carbon Capture and Sequestration PP22405
Attachments: COU-Kern-2022-PP22405.pdf

CAUTION: This email originated from outside of the organization. Do not click links, open attachments, or provide information unless you recognize the sender and know the content is safe.

Hello Cindi,
Thank you for contacting the San Manuel Band of Mission Indians (SMBMI) regarding the above-referenced project. SMBMI appreciates the opportunity to review the project documentation, which was received by the Cultural Resources Management Department on March 2nd. The proposed project is located outside of Serrano ancestral territory and, as such, SMBMI will not be requesting to receive consulting party status with the lead agency or to participate in the scoping, development, or review of documents created pursuant to legal and regulatory mandates.

Kind regards,
Ryan Nordness
Cultural Resource Analyst
San Manuel Band of Mission Indians

Appendix K

Other References

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K.1 Energy CTV Fuel Usage Calculations

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CTV Fuel Usage Calculations for Energy Chapter
onsite equipment - nonroad diesel construction equipment
offsite equipment - gasoline worker commute trips

		CO2 Emissions (ton/year)[a]		Total Project CO2 emissions (tons/project)	Carbon Itensity of Fuel (pounds of CO2/gallon)[b]	Gallons of Fuel[c]	Total Gallons of fuel
		2024	2025	Total			
FAcilities Construction							
building	onsite	679.2	676.6	1355.8	22.45	133,139	
	offsite	477.86	459.9	937.76	17.86	115,754	248,894
pipelines Construction							
construction	onsite	1005.3		1005.3	22.45	98,720	
	offsite	95.57		95.57	17.86	11,797	
const1	onsite	0		0	22.45	0	
	offsite	1.07		1.07	17.86	132	110,649
well construction							
construction-2(	onsite		668.25	668.25	22.45	65,622	
	offsite		198.47	198.47	17.86	24,499	90,121
Well Pads Construction							
Construction-2	onsite		102.88	102.88	22.45	10,103	
	offsite		53.91	53.91	17.86	6,654	16,757
Project Operations							
Worker commu	offsite			85	17.86	10,492	10,492

a CO2 Emissions from Appendix B of Air Quality Impact Analysis (Trinity 2023)
b Carbon Intensity factors from US Energy Information Administration (EIA 2023), assuming all onsite fuel use is diesel, and all offsite fuel use is finished gasoline
c Convert MT/year to pounds per year: MT * 1,000,000 g/MT / 453.6 g/lb

EIA 2023. U. S. Energy Information Administration. Carbon Dioxide Coefficients. Accessed 11/17/2023.
https://www.eia.gov/environment/emissions/co2_vol_mass.php

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K.2 Carbon Management Business Park 2023 Report

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Envisioning a Carbon Management Business Park

An exploration of carbon management and clean energy industries, and their potential benefits and impacts if developed within a Carbon Management Business Park sited in Kern County.

Technical Report | June 2023

PREPARED BY BLUE ENGINE
FOR THE Kern County Planning and Natural Resources Department



ENVISIONING A CARBON MANAGEMENT BUSINESS PARK

This technical report supplements the informational website

cmbp.kernplanning.com

Technical report and website prepared for the
Kern County Planning and Natural Resources Department

by Blue Engine
and with Technical Assistance from the
U.S. Department of Energy Communities-Local Energy Action Program (C-LEAP)

JUNE 2023

Preface

What is a carbon management business park?

Carbon management industries are those that capture carbon dioxide (CO_2) for the purpose of removing it from the atmosphere or preventing its release to the atmosphere. The capture of CO_2 can be either the primary purpose of the industry – where a facility is built exclusively to capture gaseous CO_2 from the atmosphere, or a secondary goal – where CO_2 that is a byproduct of a primary industry process is captured. The Kern County Planning and Natural Resources Department has envisioned a conceptual Carbon Management Business Park, which could be developed as a large industrial park where one or several carbon management industries are located, with the aim of capturing CO_2 at the scale of millions of tons per year. Clean energy industries that support carbon management could be co-located within the park.

About Kern County Planning and Natural Resources Department

The Planning and Natural Resources Department (the Department) provides consolidated land use planning and community development programs for Kern County's residents, landowners and businesses. The Department's mission is to balance the county's economic vitality and resource conservation with the diverse needs of Kern County at large by preparing and implementing programs that are aligned with the county's General Plan. In 2021, with approval from the Kern County Board of Supervisors, the Planning and Natural Resource Department applied for the U.S. Department of Energy's (U.S. DOE) Communities Local Energy Action Plan (C-LEAP) Pilot Initiative. The Department's aim was

to secure expert technical assistance in order to better understand the nascent carbon management sector – what industries are involved, how they work, what they look like, and the potential benefits and impacts those industries could have if developed at a large scale in Kern County. The proposal was successful, and in 2022 Kern County became one of the 24 communities nationwide to be awarded a C-LEAP grant.

About the U.S. DOE Communities-Local Energy Action Program

C-LEAP is a pilot program developed by the U.S. Department of Energy (U.S. DOE) that is designed to facilitate community-driven clean energy transitions by providing supportive services valued at up to $16 million USD. The program partners specifically with communities that are experiencing either direct environmental justice impacts, or direct economic impacts from a shift away from historical reliance on fossil fuels. Kern County faces both of these challenges. C-LEAP recipients are awarded up to 18 months of high-quality technical assistance from a network of national experts in order to help build community clean-energy related economic development action plans.

About Blue Engine

Blue Engine provides advisory services to local governments, communities, and companies or other organizations seeking to develop decarbonization strategies, with particular focus on identifying opportunities and mitigating impacts of the ongoing energy transformation. The team at Blue Engine works closely with its sister company, Climate Now, a multimedia educational resource that produces accessible, expert-driven content – including a weekly podcast, videos, and events across the United States – about how and why the climate is changing, the clean energy technologies available to address and mitigate climate change, and the role of policies, markets, and stakeholder communities in driving the transition to a net-zero emissions global economy. The combined capabilities of Climate Now and Blue Engine allow the team to manage projects that are highly interdisciplinary in nature, and to act as a communication bridge between project experts and stakeholder communities.

About this report

Kern County Planning and Natural Resources Department, in partnership with an executive committee of community leaders who represent the diverse stakeholders of Kern County, was awarded the C-LEAP grant to perform a pre-feasibility analysis for a conceptual carbon management industrial park that could serve as a Clean Energy and Carbon Management Hub for all of California. The envisioned park would comprise 30 million square feet of development on 4,000 acres, and could be supported by over 30,000 acres of solar power. The goal of the pre-feasibility analysis was to understand how much carbon could be

captured in such a facility, what kinds of industries would locate there, and how such a park might impact the surrounding community and environment of Kern County. This report, in conjunction with the website cmbp.kernplanning.com, addresses each of those questions. The website serves as an executive summary of this report, which is meant to provide a comprehensive review of the state of the art of carbon management technologies, and of the clean energy technologies most likely to support them in an industrial park situated in Kern County.

Disclaimer

This document was prepared by Blue Engine for the Kern County Planning and Natural Resources Department, and with support from the U.S. DOE Technical Assistance Team and other academic and industry experts. The purpose of the report is not to endorse or advise a specific strategy of development of a carbon management business park, but to provide a sufficient summary of publicly available information on these industries to allow area property owners, private investors, and the broader community to make their own well-informed strategic development plans. Any content or opinions expressed herein do not reflect the views of the U.S. Department of Energy or members of the U.S. DOE Technical Assistance Team, nor any of the other subject matter and industry experts who so generously contributed their time and knowledge.

Additionally, the research summarized within this report includes results that are experimental in nature, and neither Blue Engine, the Kern County Planning and Natural Resources Department, or any employees of either entity make any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information herein. Reference to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not constitute or imply an endorsement or recommendation by Blue Engine or the Kern County Planning and Natural Resources Department.

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Suggested citation:

E. Pope, S. Colbourn, V. Farid, S. Dasgupta, J. Lawler. Envisioning a Carbon Management Business Park. Technical Report, Blue Engine. June 2023.

Kern County Planning and Natural Resources Department Team Members

Lorelei H. Oviatt, AICP, Department Director

Cindi Hoover, AICP, Division Chief of Plan Development and Special Projects

Mark Tolentino, Staff Planner, Plan Development and Special Projects

Julie Williams, Supervising Planner, GIS, Map Updates and Addressing

Blue Engine Team Members

Emily Pope, Project Manager and Lead Author

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1. Introduction

It is not an overstatement to say that Kern County is integral to feeding and fueling the state of California, and by extension, the United States. Since the discovery of oil in the Kern River Field in 1899, Kern County has led California in oil and gas production.[1] Currently, it produces about 70% of the state's oil,[2] and is host to four of the top seven producing oil fields in the nation.[3] As the southernmost county of California's Central Valley, which produces a quarter of the nation's food,[4] Kern also leads California in the agricultural sector, producing over $8 billion USD in goods from livestock and crops annually.[5]

These industries are important not only for what they export to the rest of the state and the nation, but for what they provide to the residents of Kern County. Nearly 1 in 5 county jobs are directly tied to the agriculture sector.[6] Oil and gas also provides about 2% of jobs in the region,[7] but more significantly, the sector is an important source of county tax revenue. The top ten property tax payers of Kern County are associated with either the extractive or energy sectors,[8] and in total, the oil and gas industry accounts for about a quarter of the county's annual tax revenue.[9] However, as policies are implemented to address climate

[1] Takahashi,K., D.L. Gautier (2007) A brief history of oil and gas in San Joaquin Valley. [12]
[2] Karlamangla (2022) If oil drilling ends in California, what happens to oil country? [7]
[3] U.S. Bureau of Land Management (no date) California Oil and Gas. [1]
[4] U.S. Geological Survey (no date) California's Central Valley. [17]
[5] California Department of Food and Agriculture (no date) County crop reports. [2]
[6] State of California Employment Development Department (no date) Kern County, California Labor Market Information Resources and Data. [11]
[7] State of California Employment Development Department (no date) Kern County, California Labor Market Information Resources and Data. [11]
[8] U.S. Department of the Interior (no date) Natural Resources Revenue Data: Kern County. [10]
[9] Karlamangla (2022) If oil drilling ends in California, what happens to oil country? [7]

change, regional water supplies and global energy use patterns are evolving. As a result, the agriculture and oil and gas sectors of Kern County are also anticipating an evolution.

Decades of drought in the southwestern United States have led to increasing dependence on groundwater resources for irrigation of agricultural lands, resulting in over-depletion of subsurface aquifers and subsidence of the land in the Central Valley. It is anticipated that by 2040, average annual water supplies in the San Joaquin Valley (the southern portion of the Central Valley, where Kern is located) may need to decline by as much as 20%, as climate change drives increasing aridity and as policies such as the Sustainable Groundwater Management Act mandate reduced consumption of water from aquifers.[10] The Public Policy Institute of California estimates that as much as 900,000 acres of farmland could be fallowed in the San Joaquin Valley in the next two decades. Landowners will need viable economic alternatives for creating revenue from their lands, and communities will need new industries that can provide alternative jobs and tax revenue.

The oil and gas industry is also experiencing a shift, as solar and wind become increasingly competitive energy markets,[11] and as focus grows among global, national and regional institutions to reduce the emission of greenhouse gases like carbon dioxide (CO_2). But the oil and gas industry, and in particular, the oil and gas industry *in Kern County*, is uniquely equipped to take the lead in a new market that has incredible growth potential: carbon dioxide removal.

The National Academy of Sciences, Engineering and Medicine estimates that by mid-century it will be necessary to remove 10 billion metric tons of CO_2 from the atmosphere every year to prevent global average temperatures from rising above 2°C.[12] Carbon dioxide removal can be accomplished in a variety of ways – such as through significant re-forestation efforts, through changing agricultural practices to enhance the drawdown and storage of CO_2 in soils, or through restoring wetlands and mangroves along coastal habitats, to name a few.[13] Among the most effective methods of CO_2 removal however, is carbon capture and sequestration (CCS), or the process of trapping CO_2 from the atmosphere and from point sources of CO_2 emissions (like chimney stacks of large industrial facilities) and then pumping the CO_2 deep underground, into geologic layers in the subsurface that trap and hold the CO_2, much like it trapped and held the fossil fuels from which that CO_2 was derived. This technique is effective for two reasons: first, it is much easier to account for how much CO_2 is captured and sequestered via CCS than to estimate CO_2 drawdown from nature-based solutions like reforestation or soil re-generation, because gas pressures and flow rates of the CO_2 being pumped underground can be measured. Second, CO_2 that is pumped into well-characterized geologic layers of

[10] Escriva-Bou, *et al.* (2023) The future of agriculture in the San Joaquin Valley. [6]
[11] Lazard (2021) Levelized cost of energy. [8]
[12] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 9. [9]
[13] Climate Now (2021) Carbon Dioxide Removal (CDR). [3]

the subsurface is effectively trapped there indefinitely – it will be hundreds or thousands of years, at least, before that CO_2 returns to the atmosphere.[14]

CCS is a nascent industry – less than 100 million metric tons of CO_2 is injected in the subsurface globally, and almost all of that injection is for the purpose of enhanced oil recovery (in which injected CO_2 pressurizes oil-filled cracks and pore spaces, helping push oil out of the ground) rather than permanent underground storage.[15] But new federal and state policies are incentivizing growth in CCS for the purpose of permanent CO_2 storage in the United States, and Kern County is extremely well positioned to benefit from those incentives. The geologic layers beneath Kern County that have allowed it to be such a prolific producer of oil and gas are the same kinds of layers that are perfectly suited for CO_2 storage. In fact, sediments underlying California's Central Valley have been identified as having among the highest CO_2 storage capacity in the nation, with storage potential of billions of tons of CO_2.[16] Additionally, companies and employees within the oil and gas industry who have been established in Kern County for decades have the requisite knowledge to safely and effectively drill injection wells, transport CO_2 from sources of capture to injection sites, and sequester CO_2 underground. Kern County is home to more than 7,000 direct employees of the oil and gas sector,[17] who already have the skillsets needed for carbon capture and storage. As of this report's publication, three companies in Kern County have begun the permitting process through the U.S. Environmental Protection Agency to develop the types of wells needed (called EPA Class VI wells) for CO_2 injection and permanent geologic storage.[18] For those wells to be cost effective, there will need to be a significant source of CO_2 – on the scale of millions of metric tons annually – available for injection. Where all that CO_2 could come from has yet to be determined, but one possibility is a dedicated carbon management park, which would locate existing and new industries that capture or produce CO_2 in close proximity to the injection sites.

1.1 What is a carbon management park?

In Spring 2022, Kern County was among the inaugural group of recipients for the Communities LEAP (Local Energy Action Program, or C-LEAP) technical assistance grant from the U.S. Department of Energy.[19] The Kern County Planning and Natural Resources Department's goal in obtaining this C-LEAP grant was to answer a question: could repurposing challenged agricultural lands with the development of one or several large-scale industrial parks designed for the express purpose of capturing CO_2 be an economically viable source of new jobs and revenue to Kern County over the coming

[14] Climate Now (2021) Carbon Dioxide Removal: Carbon Capture and Storage, Part II. [5]
[15] Climate Now (2021) Carbon Dioxide Removal: Carbon Capture and Storage, Part I. [4]
[16] Teletzke, G. (2018) Evaluation of Practicable Subsurface CO2 Storage. [13]
[17] U.S. Department of the Interior (no date) Natural Resources Revenue Data: Kern County. [10]
[18] EPA (last updated May 19, 2023) Class VI wells permitted by EPA. [16]
[19] U.S. Department of Energy (no date) Communities LEAP Pilot. [15]

decades? If so, what types of industries would be best suited for such a park, and what considerations should be taken in whether, where and how much to develop?

With technical assistance from the C-LEAP program, these questions are addressed through a Carbon Management Business Park pre-feasibility analysis, presented in the form of an interactive website hosted by the Kern County Planning and Natural Resources Department, and accompanied by this report. The analysis is designed to clarify the costs and benefits of a variety of emerging carbon management and clean energy industries, and based on these costs and benefits, to provide the necessary information for local residents and decision-makers to determine which carbon management technologies might be best suited for the region.

As principal investigator for the C-LEAP award, the Kern County Planning and Natural Resources Department developed a hypothetical framework for the carbon management park, envisioning a 30 million square foot park on 4,000 acres, with another 30,000 acres dedicated to solar power, that would be sited far from urban areas, in fallowed farmlands that are no longer viable for agriculture. The park would be closely situated to areas where EPA Class VI well permits for deep CO_2 storage are already being processed,[20] allowing regional infrastructure to work together. A variety of carbon management and clean energy technologies could be co-located within the park, and proximity to rail and interstate highways would provide connections with nearby transportation hubs like Los Angeles and Stockton that would expand the potential feedstock supply chains for the industrial park and potential end users for clean energy production.

Blue Engine Strategies was contracted by the Kern County Planning and Natural Resources Department to complete the pre-feasibility analysis, by gathering and synthesizing information about a suite of industries that could potentially be co-located on such a park. Each industry type was examined through a set of 4 lenses: technological, societal, environmental and economic. Information was collected through the following methods:

- Continuous research support and technical assistance from a team of experts from the U.S. Department of Energy through the C-LEAP Program
- Interviews with research experts at universities and national research laboratories, and with industry representatives
- Consultation with an Executive Committee of regional leaders, organized by the Planning and Natural Resources Department
- Independent scholarship of the latest published research, policies and regional data relevant to these technologies

This report provides a detailed summary of the pre-feasibility analysis. In addition, Blue Engine constructed a website, cmbp.kernplanning.com, that serves as an Executive Summary for this report. The website provides an interactive site map that can help users envision what such a park might look like, and explores a variety of the technologies that

[20] EPA (last updated May 19, 2023) Class VI wells permitted by EPA. [16]

could feasibly be incorporated into a carbon management and clean energy business park. The website provides an overview of how each technology investigated in this report works, how it might benefit from co-location with other technologies in a shared industrial space, and what impacts and benefits such a technology would have on the regional community and environment.

Please note, the purpose of this analysis is not to endorse any carbon management technology or specific business park configuration for development in Kern County. The purpose of the website and report is to provide a useful synthesis of relevant information about carbon management and clean energy to stakeholders, developers and planners in the Kern County community, to ensure that they have a holistic understanding of these novel industries. With such a resource, private investors and local stakeholders will be better equipped to plan how the region's energy economy should grow in a well-informed and transparent manner.

Any development of a carbon management business park in Kern County would be facilitated by private investors. Those investors would be required to submit a proposal to the Kern Planning and Natural Resources Department that would include a specified location and a Specific Plan designating the industries and land uses to be built. An Environmental Impact Report (EIR) would be required and the EIR and Specific Plan would go through a full public process.

1.2 How to read this report

This report is laid out in ten sections subsequent to this introduction. The first section (Section 2) provides a summary of the federal and state policy landscape that is relevant to all the carbon management industries examined here, and is intended as a general resource that is referred to in subsequent sections. Sections 3 through 5 examine industries whose primary or secondary purpose is to capture CO_2 for permanent underground storage, and Sections 6 through 10 examine industries that could support carbon management industries (e.g. energy storage or water treatment), could benefit from co-location with carbon management industries (e.g. hydrogen via electrolysis), and/or are tangential to carbon management industries (e.g. CO_2 transport and CO_2 utilization). The use of CO_2 for enhanced oil recovery is not examined in this report. Finally, Section 11 provides a brief examination of how carbon management industries might take advantage of partnerships with (and be a benefit for) the dominant regional industry of agriculture.

This report represents a synthesis of information derived from academic literature, publicly available data and subject matter and industry expertise. For each factor of analysis, the aim is to provide as quantitative an assessment of the state of the industry as possible. Where specific estimates of a variable were available (such as land use, energy or water use requirements) a specific value or range of values is given, with the range encompassing all published estimates that could be verified as reasonable based on corroborating reports or expert discussions. Because carbon management industries are novel and in a phase of

rapid growth and innovation, it is expected that all systems will become more efficient, smaller and less expensive in the coming decades than the technologies described here.

All costs listed in this report are given in U.S. dollars, and are reported as the dollar value used in the source material, unless explicitly noted otherwise in the text. That is, except for references in which cost estimates were older than 10 years or reported in a non-U.S. currency (noted in text), the dollar amount reported is the same as that reported in the referenced material and is not adjusted for inflation since the year of reference publication. This approach was taken for three reasons: (1) To maximize transparency with regards to how all calculations in this report were made and from where all information was obtained, and thus we avoided inflation corrections to reduce the possibility of confusion or miscalculation; (2) Most cost estimates are derived from references published within the last 5 years, which means inflation would increase the cost estimates by less than 20%.[21] Nearly all technologies examined in this report have cost uncertainties much greater than 20%, and we report the full range of cost estimates aggregated from multiple sources; (3) Given the rapidity with which carbon management industries are growing, cost reductions that have likely occurred in the last 1-5 years from "learning by doing" may partially or completely offset the cost increases resulting from inflation.

A detailed techno-economic analysis of potential fiscal and economic benefits of the carbon management industry to Kern County was completed in parallel to the construction of this report by the Natelson Dale Group, Inc., and is appended at the end of the report.

[21] U.S. Bureau of Labor Statistics (no date) CPI Inflation Calculator. [14]

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17. U.S. Geological Survey. California's Central Valley. Published online (no date). Accessed March 4, 2023 from https://ca.water.usgs.gov/projects/central-valley/about-central-valley.html.

2. Policy Brief

International pressure to address climate change is spurring significant public and private interest in the development of carbon management technologies, and a variety national and state policies that enhance the benefits of deploying these technologies are making them particularly viable for development in Kern County. However, the building and operating of these technologies still must adhere to environmental, land use, and other existing policies if deployed.

In this report section, we endeavor to outline the topline general policy items that would impact carbon management implementation within Kern County. Thus, this section does not adhere to the lenses of analysis used throughout the rest of this report—this is intended as an informational addendum to the report at large.

- The first section explores the international case for limiting greenhouse gas concentrations in the atmosphere, as well as the natural and technological pathways available to remove carbon dioxide (CO_2) from the atmosphere.
- The second section outlines the United States' federal climate goals and California's state climate goals.
- The third section outlines the permitting and environmental requirements that projects looking to site in Kern County would need to adhere to in designing and constructing a carbon management facility, like the hypothetical carbon management business park.
- The fourth and final section outlines the subsidies and incentives available for implementing carbon management practices and related monetary benefits for emissions reduction.

2.1 International goals and the case for CCS

According to the IPCC, limiting global warming to 1.5°C is imperative to preserving the well-being of people and natural ecosystems.[1] It is considered a crucial target by the international community because climatic and environmental changes past that point become more drastic and unpredictable.[2] For example, limiting warming to 1.5°C is expected to lead to declines in coral reefs of 70-90% globally; however, warming of 2°C would lead to a near-total loss of coral reefs.[3]

Based upon the potential future pathways seen in Figure 2.1, meeting the future on the best possible terms relies upon not only rapidly lowering global emissions, but also removing more CO_2 from the atmosphere that we generate. The gray band at the bottom of the illustration demonstrates scenarios of net CO_2 removal. There are both natural and technological pathways to remove CO_2 from the atmosphere.

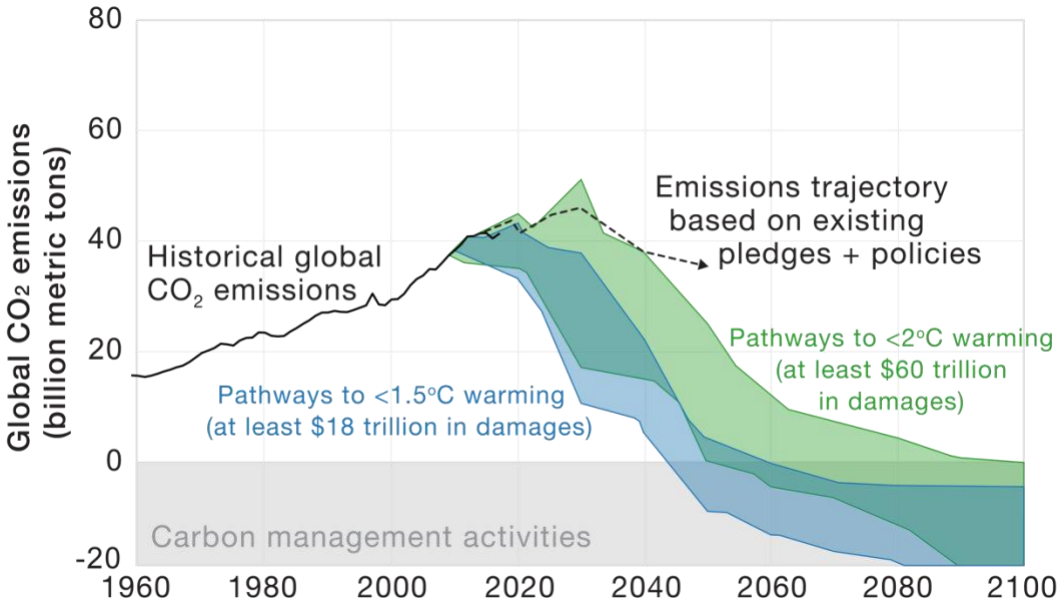

Figure 2.1. Illustration of CO_2 emissions pathways that could be employed to ensure global average temperatures remain below 2°C (green shaded region) or 1.5°C (blue shaded region). As temperatures rise, the cost of mitigating damages from extreme weather events like heat waves, floods and droughts will rise at a disproportionately higher rate.[4] Each region represents an aggregate of multiple modeled pathways that could maintain the desired temperature limits. Nearly all pathways require global CO_2 emissions to become net-negative by mid- or end-century, which will require the employment of carbon management activities to remove CO_2 from the atmosphere.[5] Adapted from Wikimedia commons: Mitigation Pathways.

[1] IPCC (October 8, 2018) Summary for Policymakers. [26]
[2] Nandi (August 9, 2021) World fails to meet key climate goal: IPCC. [32]
[3] IPCC (October 8, 2018) Summary for Policymakers. [26]
[4] Nuccitelli (September 19, 2021) Can the economy afford NOT to fight climate change? [34]
[5] Rogelj, *et al.* (2018) Scenarios limiting global mean temperature increase below 1.5°C. [41]

Natural processes, such as plant growth in forests and wetlands or ocean acidification, serve to sequester atmospheric carbon, but can also have undesirable effects once they pass natural thresholds.[6] For example, ocean acidification impacts the biodiversity of the ocean as it makes it difficult for coral and oysters to form their robust shells.[7] Plant-based solutions—like afforestation and wetland restoration—are promising because they are not only beneficial for sequestering CO_2, but also serve to support climate resilience and ecosystem health in the region.[8] However, these natural solutions – even when environmentally beneficial – can be problematic from a carbon management perspective, because it is difficult to assess how much CO_2 is being removed from the atmosphere from such interventions, and how long it will remain trapped in these organic reservoirs.[9]

Technological processes can also assist in removing CO_2 from the atmosphere and are generally termed carbon capture and storage (CCS). Many of the technological options available for capture—including DAC, BiCRS/BECCS, and point-source capture (with steel as an example industry)—are explored within this report at large, in Sections 3, 4, and 5, respectively. The primary value of these technologies is that they can prevent CO_2 from entering the atmosphere or remove it directly from the air.[10] Furthermore, if scaled adequately, these systems have the potential to remove CO_2 at much faster rates than natural processes.[11] They also can remove CO_2 with a smaller land footprint than natural solutions like reforestation, though the costs are generally higher per ton of CO_2 removed for technological solutions.[12] Given the time-sensitive nature of climate change, technological processes may be necessary to slow the rise in atmospheric CO_2 before we reach critical tipping points.[13] Achieving a global warming of under 2°C likely requires the use of carbon removal technologies *in addition to* substantial reductions in standard greenhouse gas emissions.[14]

2.2 Federal and state climate goals

The U.S. federal government has set ambitious targets for climate action in the coming decades. By 2030, the goal is to reduce greenhouse gas emissions to 50% of 2005 levels—by 2050, the target is to reach net-zero emissions.[15]

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[6] Sustainability for All – Acciona (no date) What are carbon sinks? [44]

[7] NOAA (April 1, 2020) Ocean Acidification. [33]

[8] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[9] Climate Now (October 5, 2021) Carbon Dioxide Removal: Forests. [14]

[10] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[11] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[12] Lebling, Leslie-Bole, *et al*. (May 2, 2022) 6 Things to Know About Direct Air Capture. [30]

[13] Mayewski, Beal (September 29, 2022) We miscalculated our climate tipping points. [31]

[14] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[15] The White House (no date) National Climate Task Force. [47]

In recent years, federal action on climate change has been supported by the Bipartisan Infrastructure Law (BIL) and the Inflation Reduction Act (IRA).[16] The BIL package awarded funding for over 20,000 projects and supports efforts to modernize the electric grid, expand rail and other public transportation, as well as maintaining other key infrastructure like roads, bridges, and water treatment facilities.[17] The IRA tackles climate more directly, with consumer rebates to install energy efficient appliances, tax credits for solar or electric vehicle purchases, and measures to directly reduce pollution and implement community-scale clean energy solutions.[18] A full exploration of the IRA's climate-related provisions is included in the Subsidies & Incentives section below.

As a state, California has set goals that are more ambitious than federal goals. By 2045, California is aiming to be carbon neutral.[19] This includes a goal to reduce natural gas consumption by 94% and greenhouse gas emissions by 85%.[20] These goals also rely upon ramping up carbon capture and sequestration efforts within California. In the most recent scoping plan announced by the California Air Resources Board (CARB), California targets to remove "20 million metric tons CO_2 equivalent ($MMTCO_2e$) by 2030 and 100 $MMTCO_2e$ by 2045" from the atmosphere to meet its climate targets.[21] This is aligned with the findings of other recent California-specific reports on reaching carbon neutrality, like Lawrence Livermore National Laboratory's Getting to Neutral.

2.3 Permits

2.3.1 Local land use

- Applicable for facilities with CO_2 capture, transport, or storage that takes physical place within, or in certain parts, of city or county boundaries.
- Agency level: local government
- Turnaround timeline: more than 18 months

The authorization of land use encompasses the physical footprint of the facility, from the types of activities allowed in certain areas, to the detailed aspects of facilities such as building height, traffic, noise, and other environmental impacts. Any planned CCS facilities must follow the city or county's zoning and land-use ordinance.

Carbon management projects on sites previously developed for similar purposes (like establishing a BiCRS facility by retrofitting a retired bioenergy plant, see Section 4) might

[16] The White House (no date) National Climate Task Force. [47]
[17] The White House (no date) Building a Better America. [45]
[18] The White House (August 15, 2022) The Inflation Reduction Act. [46]
[19] Office of Governor Newsom (November 16, 2022) California Releases World's First Plan. [36]
[20] Office of Governor Newsom (November 16, 2022) California Releases World's First Plan. [36]
[21] Office of Governor Newsom (November 16, 2022) California Releases World's First Plan. [36]

face fewer hurdles, since some uses might have been allowed already for existing facilities—however, this is not always the case. For instance, the installation of tall columns for carbon capture solvent or a gas flare may face minimal review when placed at an existing refinery that would have been permitted for much taller distillation columns, but could face higher scrutiny at a former power plant site, where they might exceed specified height limits for the site.

Transportation via pipeline will likely face a high level of scrutiny and review, regardless of the existing right-of-ways (ROW) in place. One way to reach compliance is to seek amendment of a county's zoning map to allow uses or activities commonly related to carbon capture and storage.[22] Such a measure would likely only be appropriate if it is in the county's long-term interests and economic plan, as opposed to authorizing a single project.

2.3.2 CO_2 Pipelines — Easements and ROWs

- Applicable for CO_2 transport.
- More than one agency could be involved and projects would generally involve private parties (including the pipeline owner and landowners)
- Timeline: more than 18 months

Permitting pipelines is often difficult and time consuming because most pipelines are sited across land held by a variety of owners. Thus, it is more attractive to route pipelines in such a way that it crosses large land holdings in the hands of fewer owners. Surface ownership of a pipeline might cross private, local government, state, federal, and tribal, as well as existing third-party easements. Under an easement—a legal agreement conferring to the pipeline owner the right to site, construct and operate the pipeline on a landowner's property—the holder is granted the right to travel over another's property.[23]

Areas with existing pipelines run may offer potentially easier pathways to siting. Depending on the contract language, opportunities for new development may already exist under existing easements or ROW agreements. The success of this strategy hinges on how the existing easements are written and if they provide for addition of a new pipeline or for repurposing or modification of an existing one.

Regulation of any CO_2 pipelines constructed would fall under the purview of the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the federal level[24] and the Office of the State Fire Marshal (OSFM) at the state level.[25] A full exploration of the permitting and regulatory requirements for CO_2 pipelines can be found in Section 9.

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[22] World Bank (no date) Zoning and Land Use Planning. [51]

[23] Transportation Research Board of the National Academies of Sciences, Engineering, and Medicine (2004) Transmission Pipelines and Land Use. p. 34. [49]

[24] FECM (May 27, 2022) Statement: DOE Welcomes New Carbon Dioxide Pipeline Safety Measures. [35]

[25] OSFM (no date) Pipeline Safety and CUPA. [37]

2.3.3 Title V Air Permit

- Applicable for facilities with CO_2 capture, especially those that emit pollutants into the air
- Agency level: local air district, and potentially U.S. EPA
- Timeline: approximately 1 year

In California, air districts are the local regulators that implement federal Clean Air Act requirements, as well as other state-level regulations regarding emissions, for pollution sources within the region.[26] Any CCS project would likely have to engage these local air districts to receive air permits. Eastern Kern Air Pollution District (EKACPD) is the local regulator for eastern Kern County, while western Kern County falls under the authority of the San Joaquin Valley Air Pollution Control District (SJVAPCD).[27]

To gain a Title V operating permit, an institution or person that is constructing, altering, replacing, or operating any source that emits, may emit, or may reduce emissions must obtain preconstruction permit authorization before commencing construction as well as a permit to operate from their local air district.[28] For projects built on Indian and tribal lands within the borders of the United States, the U.S. EPA is required to issue operating permits instead.[29] Exemptions are limited to very low-emitting, minor equipment, such as engines on compressors or emergency generators, but full requirements for non-major sources are laid out in Code 40 of Federal Regulations.[30] It's particularly applicable to carbon management industries that operate in the CO_2 capture stage, because these types of facilities may emit other air pollutants in addition to the CO_2 that they are capturing, such as NO_x or particulate emissions, and fugitive emissions from some kinds of amine-based CO_2 scrubbers could produce volatile organic compound (VOC) emissions.

California, as a state, is required to develop state implementation plans (SIPs) to achieve National Ambient Air Quality Standards (NAAQS), for six criteria pollutants: ground-level ozone, particulates, carbon monoxide, lead, sulfur dioxide and nitrogen dioxide.[31, 32] Whether or not a state has achieved NAAQS attainment goals in a given pollution type determines the type of permit process that a new facility must pursue.

- Attainment areas: Prevention of Significant Deterioration (PSD) permits are required for new major sources or for making a major modification.[33]

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[26] CARB (no date) Government Roles and Contracts. [10]
[27] CARB (no date) California Map for Local Air District Websites. [8]
[28] EPA (November 29, 2022) Air Emissions Monitoring. [16]
[29] EPA (November 29, 2022) Air Emissions Monitoring. [16]
[30] EPA (May 25, 2022) Who Has to Obtain a Title V Permit? [23]
[31] CARB (no date) California State Implementation Plans. [9]
[32] EPA (January 20, 2023) Basic Information about Air Quality SIPs. [17]
[33] EPA (January 24, 2023) Prevention of Significant Deterioration Basic Information. [20]

- Non-attainment areas: Non-Attainment New Source Review (NNSR) permits are required for new major sources or for major sources making substantial modifications.[34]

The required mitigation action is stricter in non-attainment areas and requires achieving the Lowest Achievable Emissions Rate (LAER), as well as the use of offsets to the extent allowed or available.[35] Offsets are specific to each pollutant category, but specialized cases outlined by the EPA allow offsets from alternate sources at a 2-to-1 ratio.[36] In attainment areas, the corresponding requirement is Best Available Control Technology (BACT) for any "major new or modified sources."[37]

Table 2.1. Air quality attainment data for Kern County

Pollutant	EKAPCD[a]		SJVAPCD[b]	
	Federal	**State**	**Federal**	**State**
Ozone (1 hour)	Attainment	Nonattainment	Attainment	Severe Nonattainment
Ozone (8 hour)	Severe Nonattainment	Nonattainment	Extreme Nonattainment	Nonattainment
PM10	Attainment	Nonattainment	Attainment	Nonattainment
PM2.5	Attainment	Unclassified	Nonattainment	Nonattainment
Carbon Monoxide	Attainment	Unclassified	Attainment	Attainment
Nitrogen Dioxide	Unclassified	Attainment	Attainment	Attainment
Sulfur Dioxide	Unclassified	Attainment	Attainment	Attainment
Lead Particulates	Attainment	Attainment	Unclassified	Attainment

a. Eastern Kern Air Pollution Control District
b. San Joaquin Valley Air Pollution Control District

The California Ambient Air Quality Standards (CAAQS) are typically stricter than NAAQS requirements, but NAAQS attainment takes precedence "due to federal penalties for failure to meet federal attainment deadlines."[38, 39] Both NAAQS and CAAQS use 'attainment' or 'unclassified' and 'non-attainment' designations—an attainment or unclassified designation means an area meets or exceeds the standard for that compound, whereas

[34] EPA (January 24, 2023) Nonattainment NSR Basic Information. [19]
[35] EPA (January 24, 2023) Nonattainment NSR Basic Information. [19]
[36] EPA (2013) The Clean Air Act in a Nutshell: How It Works. p. 7. [22]
[37] EPA (February 22, 2016) RACT/BACT/LAER Clearinghouse: Basic Information. [21]
[38] CARB (no date) Ambient Air Quality Standards. [6]
[39] CARB (no date) California Ambient Air Quality Standards. [7]

non-attainment is used for areas that fail to meet the standard.[40] Table 2.1 summarizes Kern County's current status for major pollutants.

In addition to PSD and NNSR permitting, installation of carbon management facilities and associated equipment will likely trigger additional Clean Air Act Title V permitting under the local air district. The Title requires major sources of air pollutants and certain other sources to obtain an operating permit, operate in compliance with it, and certify compliance at least annually.[41]

2.3.4 California Environmental Quality Act (CEQA) Guidelines

In California, CEQA requires a project to identify significant environmental impacts of their activities, and to avoid or mitigate those impacts.[42] A project that may cause direct physical changes to the environment or an anticipated indirect change must comply with CEQA.[43] Most proposals for physical development need to comply with CEQA, but other projects which do not immediately result in physical development (like adopting a general or community plan) need to comply as well.[44]

For every project, an initial review of potential environmental effects must be conducted.[45] Depending on the initial review of the potential impacts of a project, CEQA may require the project to conduct a full environmental impact report (EIR).[46] If there are feasible alternative options or mitigation strategies available for the project to notably reduce its environmental impact, then a project cannot be approved as originally submitted.[47]

CEQA requires that an initial review determine the significance of a project's expected greenhouse gas emissions.[48] Under CEQA's definitions, greenhouse gasses "includes but is not limited to: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride."[49]

Regulated air pollutants under CEQA include nitrogen oxides (NO_x) and volatile organic compounds (VOCs), ozone-depleting substances (CFC and HCFC), particulate matter, carbon monoxide (CO), sulfur dioxide (SO_2) and lead. CEQA also evaluates greenhouse gas (GHG) emissions,[50] in which project-specific GHG emissions must be analyzed for their

[40] EPA (November 29, 2022) NAAQS Designations Process. [18]
[41] EPA (May 25, 2022) Who Has to Obtain a Title V Permit? [23]
[42] Governor's Office of Planning and Research (no date) Getting Started with CEQA. [25]
[43] CNRA (no date) FAQ about CEQA. [13]
[44] CNRA (no date) FAQ about CEQA. [13]
[45] CNRA (no date) FAQ about CEQA. [13]
[46] CNRA (no date) FAQ about CEQA. [13]
[47] CNRA (no date) FAQ about CEQA. [13]
[48] AER (January 1, 2023) 2023 CEQA. p. 189. [1]
[49] AER (January 1, 2023) 2023 CEQA. p. 317. [1]
[50] Governor's Office of Planning and Research (no date) CEQA & Climate Change. [24]

ability to contribute globally to climate change,[51] unless the project is exempted from CEQA.

2.4 Subsidies & Incentives

2.4.1 California Low Carbon Fuel Standard (LCFS)

California's LCFS is a market-based policy, first adopted in 2009 and implemented in 2011, that aims to diversify California's energy mix by setting annual carbon intensity (CI) benchmarks and encouraging the adoption of low-CI fuels under the oversight of the California Air Resources Board (CARB).[52] In 2018, the LCFS was extended by CARB from 2020 to 2030, with a goal of reaching a 20% CI reduction target from 2010 levels by 2030.[53]

The system operates based on CI life cycle assessments conducted by CARB, which "examines the GHG emissions associated with the production, transportation, and use of a given fuel" along with notable indirect impacts, and then gives the fuel in question a CI score.[54] CARB's model does not rely just on carbon dioxide emissions, but also emissions of methane, nitrous oxide, and other greenhouse gases.[55] After each fuel is scored based on its lifetime emissions, it is compared to a CI benchmark set by CARB that declines each year.[56] Fuels with CI scores lower than the benchmark will generate LCFS credits that year, whilst fuels that exceed the CI benchmark generate deficits.[57]

In short, the system grades fuels based on their relationship with the annual target—fuels that have a CI lower than the target will produce LCFS credits, while fuels that have a CI higher than the target have a deficit that must be fulfilled to meet the standard.[58] This deficit can be remedied by either generating LCFS credits directly or purchasing LCFS credits from another supplier in order to meet the annual target.[59] LCFS applies only for fuels used for transportation, including gasoline, diesel, and their alternatives.[60]

Under the LCFS, all "petroleum importers, refiners, and wholesalers" selling fuels in the California market are regarded as Regulated Parties (RPs).[61] Providers of clean, alternative fuels that already meet the relevant 2030 carbon intensity benchmark are exempt from the

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[51] Governor's Office of Planning and Research (no date) CEQA & Climate Change. [24]
[52] CARB (no date) About - Low Carbon Fuel Standard. [5]
[53] UC Davis Institute of Transportation Studies (no date) Status Review. [50]
[54] CARB (no date) About - Low Carbon Fuel Standard. [5]
[55] CARB (no date) About - Low Carbon Fuel Standard. [5]
[56] CARB (no date) About - Low Carbon Fuel Standard. [5]
[57] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[58] Boutwell (May 2, 2018) LCFS 101 - An Update. [4]
[59] Boutwell (May 2, 2018) LCFS 101 - An Update. [4]
[60] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[61] Boutwell (February 28, 2017) A Beginner's Guide. [3]

LCFS, but may opt-in to the program as RPs to receive credits for the fuels they sell in California.[62] The LCFS system hinges on the LCFS Reporting Tool (LRT), which serves as a central database where RPs must record the transaction-level information anytime that "transportation fuels are imported, refined, or sold in California."[63] (The LRT may also be referred to as the LRT-CBTS, or the LCFS Reporting Tool and Credit Bank & Transfer System.)[64] The LRT serves to track all transactions, and also serves to sum the credits and deficits for a given RP to track their compliance status in relation to the annual CI target.[65] If credits are used in an annual compliance report to offset deficits for an RP, those credits are retired; otherwise, LCFS credits generated or acquired by an RP do not sunset or decline in value over time.[66] Owners of credits can only sell or trade credits to other RPs in the system currently at a deficit, and parties that are not recognized as RPs are forbidden from holding any LCFS credits.[67]

In addition to credit generating fuels, the LCFS has provisions to generate credits through approved non-fuel activities that can help reduce transportation emissions at large.[68] This includes what CARB refers to as project-based crediting and capacity-based crediting under LCFS.[69] Project-based credit opportunities can include using renewable hydrogen at a facility generating transportation fuels, developing a direct air capture (DAC) facility to capture historic transportation emissions, and investments that reduce an existing transportation fuel facility's emissions, like using renewable energy or adopting carbon capture and storage (CCS).[70] Capacity-based credits are attainable by RPs that own hydrogen fueling equipment or zero-emission vehicle infrastructure.[71]

Starting in 2019, the LCFS began allowing the use of CCS technologies to "reduce emissions associated with the production of transport fuels" in California to generate LCFS credits—this included DAC projects.[72] To qualify, projects must meet CCS Protocol requirements, which encompass a variety of carbon management projects, as long as they lead to storage of captured CO_2 in depleted oil and gas reservoirs or saline formations onshore *or* are used for enhanced oil recovery (EOR) in oil and gas reservoirs.[73] Table 2.2 shows different types of CCS projects that can qualify to generate credits under the LCFS.

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[62] Boutwell (May 2, 2018) LCFS 101 - An Update. [4]
[63] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[64] CARB (no date) LCFS Registration and Reporting. [12]
[65] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[66] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[67] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[68] CARB (no date) LCFS Basics with Notes. p. 11. [11]
[69] CARB (no date) LCFS Basics with Notes. p. 11. [11]
[70] CARB (no date) LCFS Basics with Notes. p. 28. [11]
[71] CARB (no date) LCFS Basics with Notes. p. 33-35. [11]
[72] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 4. [48]
[73] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]

Table 2.2. Qualifications for CCS projects to meet LCFS standards.[74]

	Direct Air Capture Projects	CCS at Oil & Gas Production Facilities	CCS at Refineries Projects	All other CCS Projects (e.g. CCS with Ethanol)
Location of CCS project	Anywhere in the world	Anywhere, provided they sell the transportation fuel in California	Anywhere, provided they sell the transportation fuel in California	Anywhere, provided they sell the transportation fuel in California
Storage site	Onshore saline or depleted oil and gas reservoirs, or oil and gas reservoirs used for CO_2-EOR			
Credit method	Project-based	Project-based, under the Innovative Crude Provision	Project-based, under the Refinery Investment Credit Program	Project-based or fuel pathway
Earliest date which existing projects eligible	Any	2010	2016	Any
Requirements	Project must meet requirements specified in CCS Protocol			
Additional restrictions	None	Must achieve minimum CI or emission reduction	None	None

DAC facilities located anywhere in the world can generate LCFS credits by choosing to opt in to the LCFS program.[75] DAC projects are an exception to the general requirements of LCFS credits, as they are "not required to sell any transportation fuel into the California market to generate credits."[76] Even so, the rules around DAC project eligibility are tightly defined. If CO_2 captured by a DAC facility was used to create a synthetic fuel for sale in California, it wouldn't qualify for project-based crediting and would instead need to seek a separate fuel pathway in order to generate LCFS credits.[77]

California's LCFS credits can also be stacked with federal 45Q tax credits (Section 2.4.3).[78] There are no restrictions on obtaining both incentives as long as the responsible party adheres to the rules and regulations of both systems.

2.4.2 Inflation Reduction Act (IRA)

The Inflation Reduction Act (IRA) was signed into law on August 16, 2022 and encompasses a wide range of new policy directives spanning healthcare, tax compliance, and energy and

[74] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[75] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[76] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[77] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[78] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 20. [48]

environment issues (Figure 2.2).[79] Here, only the energy and environment directives are explored; other policy items included in the IRA are outside of the scope of this report.

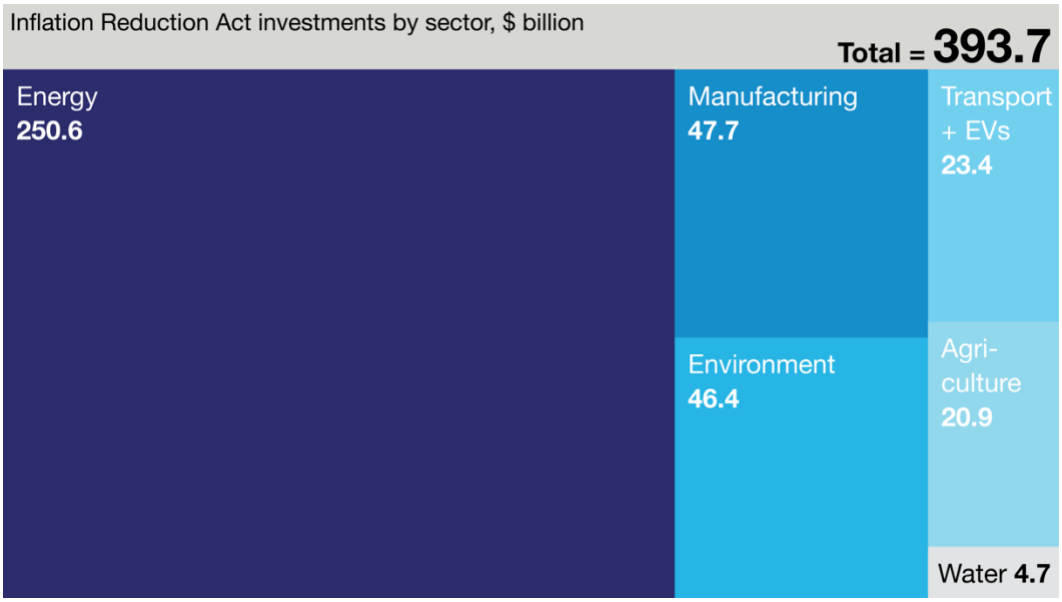

Figure 2.2. Scaled graphic indicating the amount of investment by sector, in billion USD, allocated under the Inflation Reduction Act.[80]

The diversity of climate investments in the IRA, as seen below, is extensive. Funding will be disbursed through grants, loan guarantees, and tax incentives, with tax incentives being the largest share of available funding under the IRA.[81] This includes tax credits for individuals associated with purchasing heat pumps and electric vehicles (new or used), as well as credits for businesses or utilities that are generating zero-carbon electricity, nuclear power, sustainable aviation fuels, or qualifying clean hydrogen.[82] It is worth noting that the time horizons and credit amounts differ based on sector.

The IRA also incorporates provisions aimed to bolster domestic production of goods. Facilities must "meet prevailing wage and apprenticeship requirements" to attain full eligibility under the IRA's tax credit system.[83] These requirements also impose specific requirements, as applicable, to specific initiatives. For example, attaining the full consumer EV tax credit is dependent on a sliding scale of how many of the materials in the battery

[79] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[80] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[81] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[82] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[83] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]

were recycled within North America or extracted in countries with whom the U.S. maintains free-trade agreements.[84]

Other provisions in the IRA are designed to aid in transitioning workers from fossil fuels to other energy industries. The IRA includes incentives for companies looking to develop solar or wind farms to locate in regions where coal facilities have recently discontinued operations.[85] It also includes some tailored worker benefits, like the development of a permanent federal trust aimed at supporting coal miners living with black lung disease.[86] Another angle of its transition-oriented policies is its expansion of support for hydrogen-based fuels and CCS, explored in the sections below.[87]

2.4.3 45Q Federal Tax Credits

The 45Q tax credit was introduced in 2008 as an incentive to develop carbon capture, use, and sequestration projects within the United States.[88] Over time, the credit's value has increased—as of the end of 2022, due to the Inflation Reduction Act (IRA), these credits were valued at \$85/ton CO_2 permanently stored and \$60/ton CO_2 used for enhanced oil recovery (EOR).[89] The values are higher for carbon captured via direct air capture (DAC) processes, where the values rise to \$180/ton CO_2 permanently stored and \$130/ton CO, for use in EOR.[90]

Changes in the IRA also extended the eligibility window for new projects to qualify.[91] Now, projects must begin construction by January 2033 in order to qualify for 45Q credits.[92] It also imposes updated minimums on the amount of CO_2 a facility must capture annually to qualify for credits: "18,750 tonnes per year for power plants (provided at least 75% of the CO2 is captured), 12,000 tonnes per year for other facilities, and 1,000 tonnes per year for DAC facilities."[93]

2.4.3 45V Federal Tax Credits

The hydrogen fuel benefits are dispensed through the new tax incentive 45V, in which producers of hydrogen with 'near-zero emissions' can earn \$3 per kilogram of hydrogen produced with no cap on the number of kilograms the producer can receive the incentive

[84] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[85] Plumer, Friedman (July 30, 2022) Democrats Got a Climate Bill. [39]
[86] Plumer, Friedman (July 30, 2022) Democrats Got a Climate Bill. [39]
[87] Plumer, Friedman (July 30, 2022) Democrats Got a Climate Bill. [39t]
[88] IEA (November 4, 2022) Section 45Q Credit. [29]
[89] IEA (November 4, 2022) Section 45Q Credit. [29]
[90] IEA (November 4, 2022) Section 45Q Credit. [29]
[91] IEA (November 4, 2022) Section 45Q Credit. [29]
[92] IEA (November 4, 2022) Section 45Q Credit. [29]
[93] IEA (November 4, 2022) Section 45Q Credit. [29]

for.[94] The exact structure of these benefits, however, will depend on rules that are still being written by the Treasury Department; until they have developed a clear definition for 'near-zero emissions,' it is difficult to guess what standards a producer would need to meet to be eligible for the $3/kilogram incentive.[95]

2.5 Additional California-Specific Policies

In California, there are some specific policies that will impact the avenues of carbon management activity that can be pursued, which are external to the permitting requirements outlined above, nor do they constitute as incentives, at least at this moment.

First, a recent package of climate bills that was signed last fall by Governor Gavin Newsom included multiple state bills relevant to carbon management efforts. SB 1314 effectively bans the utilization of any captured CO_2 to be used for enhanced oil recovery (EOR) in the state.[96] As a result, carbon management entities will need to identify other avenues of utilization or storage for their captured CO_2. SB 905 requires that the California Air Resources Board (CARB) establishes a "Carbon Capture, Removal, Utilization, and Storage Program."[97] Under SB 905, CARB must also set up a unified permit for California-based carbon capture, utilization and storage (CCUS) projects, establish a centralized database for California-based carbon management projects, and implement financial responsibility regulations for CO_2 storage operators to retain responsibility for a minimum of 100 years following their most recent CO_2 injection at a well site.[98]

Other statewide policies are likely to have indirect effects on carbon management efforts. California's Sustainable Groundwater Management Act (SGMA) from 2014 requires that state groundwater supplies be brought back into long-term balance by 2040,[99] which may limit the availability of freshwater supplies to Kern County and neighboring areas, depending on the region's hydrology over the coming decades. SGMA requires the development of local groundwater sustainability agencies (GSAs), formed as partnerships between city and/or county governments, irrigation districts, water districts, or other local bodies.[100] Each GSA submits plans to the state to meet SGMA's objectives, with a focus on implementing responsible groundwater management for their region.[101] The California Department of Water Resources (DWR) oversees implementation, giving routine assessments and providing technical assistance, and the State Water Resources Control

[94] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [40]
[95] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [40]
[96] IEA (November 4, 2022) SB 1314. [28]
[97] IEA (November 4, 2022) SB 905. [27]
[98] IEA (November 4, 2022) SB 905. [27]
[99] SWRCB (no date) SGMA. [43]
[100] SWRCB (no date) SGMA. [43]
[101] SWRCB (no date) SGMA. [43]

Board is entrusted with intervening in a basin's management if its sustainability plans fail.[102] With regulations like SGMA in place to protect local water supplies, water-intensive industries—like liquid direct air capture (L-DAC) or hydrogen production via electrolysis—may find it more difficult to locate in water-stressed regions. Issues relating to available freshwater supplies in Kern County are explored more in Section 8.1.4.

[102] SWRCB (no date) SGMA. [43]

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22. U.S. Environmental Protection Agency (EPA) (2013) The Clean Air Act in a Nutshell: How It Works. Unofficial summary. 23p. https://www.epa.gov/sites/default/files/2015-05/documents/caa_nutshell.pdf.

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CARBON MANAGEMENT TECHNOLOGIES

3. Direct Air Capture

TECHNOLOGY AT A GLANCE

- Industry is in early commercial stages: Globally, a cumulative ~10,000 metric tons CO_2 are captured each year by other projects[1]
- Current cost per metric ton CO_2 captured: $94-877 USD/ton CO_2
- Projected cost per metric ton CO_2 captured at scale: $60-200 USD/ton CO_2
- 200-240 acres of land use required per million metric tons CO_2 captured
- Key advantages of this technology in Kern County: minimal feedstock requirements or waste; solid-direct air capture (S-DAC) has the potential to capture water as well as CO_2
- Key concerns for this technology in Kern County: noise and vibration levels with large-scale projects, high energy demands, poor clarity on job creation potential

3.1 Technology Summary

Direct Air Capture (DAC) is a technology that captures carbon dioxide (CO_2) directly from the atmosphere, usually through a mechanical system, although some passive capture techniques are also being developed. In a mechanical system, fans or wind are used to drive ambient air through a contactor unit, where the air passes across a chemical sorbent

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

that selectively reacts with and traps CO_2, allowing the other components of the air to pass through and exit the system. Currently, the most developed adsorbent materials are in liquid or solid forms.[2]

3.1.1 Description: How it Works

DAC can be thought of as an engineered equivalent to photosynthesizing plants, except that DAC captures CO_2 from the atmosphere at a faster rate and with a much smaller land footprint than biomass. Furthermore, DAC delivers CO_2 in a pure, compressed form. Captured atmospheric CO_2 can be permanently and safely stored in geologic reservoirs to deliver negative emissions, or be used to produce low carbon intensity products, such as synthetic fuels that work in existing vehicles and infrastructure.[3]

Current DAC technologies are primarily distinguished by using one of two types of sorbent: liquid solvents (L-DAC) and solid sorbents (S-DAC). In both techniques, DAC pulls air from the atmosphere and passes it over the sorbent material. The sorbent material captures the carbon dioxide, and the rest of the air passes through and exits the DAC unit. L-DAC typically uses hydroxide solutions (a liquid solvent) as the bonding sorbent, whereas S-DAC relies on a CO_2 "filter" or dry amine-based chemical sorbents.[4] In both cases, the CO_2 from the air is chemically bound into a new compound, and then is subsequently broken down to release 1) a high-purity stream of CO_2 for storage, and 2) the original sorbent components for reuse. Figures 3.1 and 3.2 illustrate the multi-stage process of DAC's operational system, distinguished by the solid sorbent (S-DAC) and liquid solvent (L-DAC) technologies, respectively.

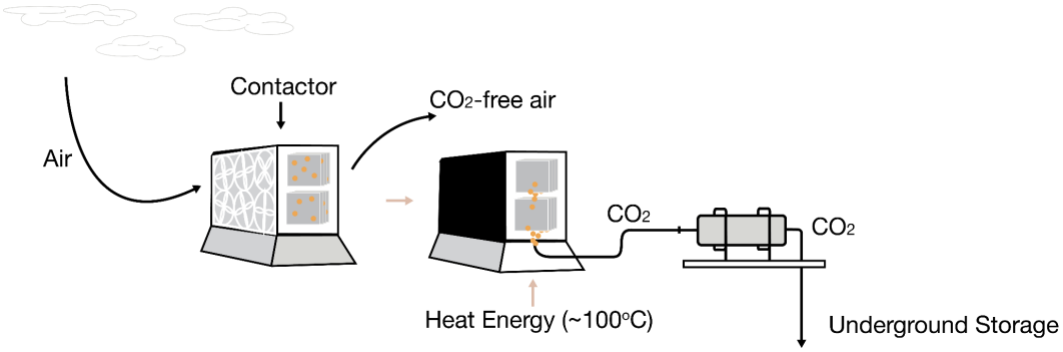

Figure 3.1. Schematic of S-DAC operation.[5] Step 1: ambient air enters the air contactor unit and CO_2 is absorbed onto a solid sorbent. Step 2: Heat exposure (± vacuum pressure) releases CO_2 from sorbent material and a concentrated stream of CO_2 is produced. Step 3: Sorbent is cooled, thereby reactivating it for reuse in the air contactor.

[2] IEA (2022) DAC Report. [40]

[3] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 149. [55]

[4] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]

[5] Larsen *et al.* (2020) Capturing New Business. [44]

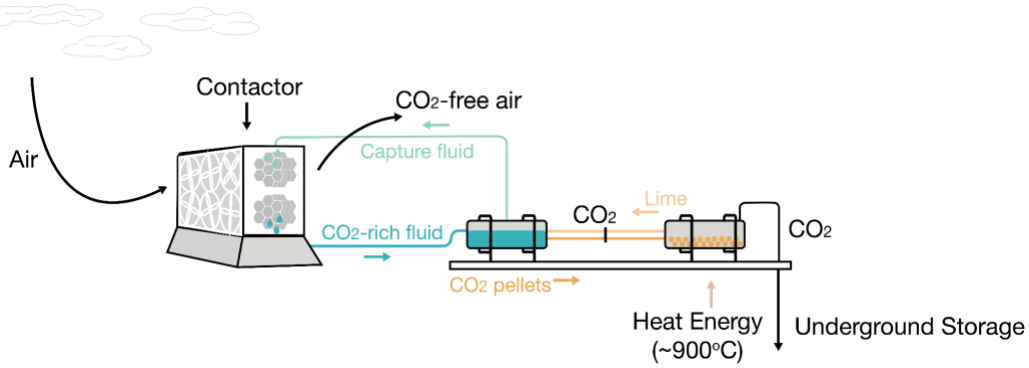

Figure 3.2. Schematic of L-DAC operation.[6] Step 1: ambient air enters the contactor and CO_2 reacts with capture fluid to produce carbonate. Step 2: Carbonate reacts with hydroxide to form small pellets. Step 3: Pellets are heated to produce lime and a concentrated stream of CO_2. Step 4: Lime from the calciner reactivates capture solution for reuse in contactor.

Both technologies require electricity and heat to operate; the electricity drives the fans and controls inlet systems, while the heat releases the trapped CO_2. However, S-DAC requires only temperatures of only ~100°C to break the chemical bonds linking the CO_2 to the sorbent material, whereas L-DAC requires temperatures around 900°C.[7,8] Such temperatures are difficult to reach using renewable energy sources like wind or solar. If natural gas is used to attain the necessary heat, the associated CO_2 released from the use of L-DAC technology would need to be recaptured and stored to avoid counteracting the benefit of DAC.[9]

3.1.2 State of Development

DAC is a relatively new industry that is still in the early stages of development.[10,11] As of the drafting of this report, large-scale commercial deployment of DAC does not exist, but several companies have developed pilot projects with limited commercialization that are capturing CO_2 on the scale of thousands of metric tons per year.[12] Some, but not all, of these pilot projects include geologic sequestration or utilization of the captured CO_2.[13] Because DAC technology is still in its infancy, there are few straightforward assessments of how the technology and business model of DAC will adapt to industrial scaling, although there is reason to expect that economies of scale and technological innovation will have

[6] Larsen *et al.* (2020) Capturing New Business. [44]
[7] IEA (2022) DAC Report. p. 10. [40]
[8] Ghiat, Al-Ansari (2021) A review of CCUS. p. 4. [31]
[9] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]
[10] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 189. [55]
[11] IEA (2020) CCUS in Clean Energy Transitions. p. 83. [41]
[12] Ozkan *et al.* (2022) DAC Status Report. [59]
[13] IEA (2020) CCUS in Clean Energy Transitions. p. 83. [41]

positive effects.[14] The earliest breakthrough paper describing a working direct air capture system was written by Geoffrey Holmes and David Keith of Carbon Engineering in 2012, specifically discussing an L-DAC system.[15] The following year, the first pilot-scale deployment of DAC was launched by the Swiss company, Climeworks, which utilizes S-DAC technology.[16] With only about a decade since its early breakthroughs, DAC technology still needs research, innovation, and further technological breakthroughs to reach its maturity at scale.

As of April 2022, there are 18 DAC plants currently operating worldwide, capturing approximately 0.01 Mt CO_2/year.[17] Companies leading the industry with the most developed DAC technology are Climeworks, Carbon Engineering and Global Thermostat. These companies are primarily focused on developing megaton facilities: plants that will operate at the scale of capturing millions of metric tons of CO_2 annually (Mt CO_2/year), and have progressed the furthest towards opening commercial, large scale DAC plants.[18,19]

Two commercial plants, developed by Climeworks, are currently operating in Switzerland and selling CO_2 to greenhouses and beverage companies for carbonation.[20] The latest plant to come online from Climeworks is Orca, launched in 2021 and capturing 4,000 metric tons of CO_2 per year for storage in basalt formations in Iceland.[21] The Orca pilot plant is also a test facility for CO_2 mineralization, in which CO_2 is sequestered in porous basalt where it can react with host minerals and form the carbonate solid $CaCO_3$, precluding any risk of leakage.[22] In North America, both Carbon Engineering and Global Thermostat have been operating a number of pilot plants, with Carbon Engineering, in collaboration with Occidental (Oxy), currently designing what would be the world's first megaton DAC facility, called 1pointfive, in the Permian Basin region of west Texas anticipated to be operational in 2024.[23, 24]

[14] Industry representative, personal communication, August 29, 2022.

[15] Holmes, Keith (2012) Liquid DAC. [36]

[16] McQueen *et al.* (2021) DAC Review. [51]

[17] 1pointfive (n.d.) DAC Technology. [1]

[18] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 193. [55]

[19] Lebling *et al.* (May 2, 2022) 6 Things to Know about DAC. [49]

[20] Climeworks (2015) Capricorn. [20]

[21] Climeworks (2021) Orca. [23]

[22] Reuters (September 13, 2021) World's largest plant capturing carbon from air starts in Iceland.

[23] 1pointfive (no date) DAC Technology. [1]

[24] GlobalNewsWire (2022) Occidental, 1pointfive to begin construction. [32]

3.1.2.1 Operational projects - examples

Orca Facility, Climeworks, Iceland

Launched in September of 2021, the Orca plant (Figure 3.3a) is currently the largest DAC plant in the world.[25] Located in Hellisheidi, Iceland, the plant has a carbon removal capacity of 4,000 metric tons per year.[26] The plant was developed as a collaboration between Climeworks (using their S-DAC technology) and Carbfix, an industry-research consortium that is piloting the development of underground storage of CO_2 through mineralization.[27] The facility consists of eight collector containers, with an annual CO_2 capture capacity of 500 metric tons each.[28] The containers are arranged around a central process hall that accommodate electrical and processing equipment, allowing the company to operate and control the facility remotely.[29] The DAC plant is strategically located in proximity with the Hellisheidi Geothermal Power Plant, which supplies the heat and electricity required to run the direct air capture process at low cost.[30] The Orca footprint is 8,600 square feet, equivalent to the square footage of approximately four urban houses.[31] This translates to a per ton CO_2 land use requirement of 2.15 square feet per ton of CO_2 captured.



Figure 3.3. a) The four collectors of the Orca DAC facility in Hellisheidi, Iceland.[32] The capture technology is S-DAC, from Climeworks. b) Conceptual plan for the in-development Mammoth DAC facility, also S-DAC and expected to be operational in 2024. Mammoth is co-located with the Orca facility, and is a scaled up equivalent of the first pilot facility.[33] Image credit: Climeworks.

[25] Climeworks (2021) Orca. [23]
[26] Climeworks (2021) Orca. [23]
[27] Climeworks (December 2, 2020) The rapid construction of Climeworks' new DAC and storage plant Orca. [24]
[28] Climeworks (2021) Orca. [23]
[29] Climeworks (2021) Orca. [23]
[30] Climeworks (2021) Orca. [23]
[31] Ozkan *et al.* (2022) DAC Status Report. [59]
[32] Climeworks (2021) Orca. [23]
[33] Climeworks (June 28, 2022) Climeworks takes another major step. [22]

The capital and operational costs of the Orca plant are covered in part by the sale of carbon credits in the voluntary carbon offset marketplace, where private buyers can purchase the capture and storage of CO_2 on a per-metric ton basis to offset their own emissions.[34] The Orca plant sells the most expensive carbon offset credits in the world, costing as much as €1,000 per metric ton of CO_2 removed.[35] Climeworks' clientele for carbon offset credits includes Microsoft, Swiss Re, Shopify and Audi.[36] Jan Wurzbacher, co-chief of Climeworks, said commercial demand had been so high that the plant was nearly sold out of credits for its entire 12-year lifespan, prompting the accelerated development of their next plan: the Mammoth DAC facility (Figure 3.3b).[37] Mammoth uses the same technological design as Orca, will also be sited in Hellisheidi, Iceland, and will also sequester the CO_2 via mineralization in Iceland's basalt-rock subsurface, but will have a nominal CO_2 capture capacity of 36,000 tons per year. The plant is expected to be operational in 2024.[38]

DAC 1 Facility, Carbon Engineering, US

DAC 1 is a megaton DAC plant in development in west Texas by the companies 1pointfive and Carbon Engineering. Operation is expected to begin in 2024.[39] The plant will use Carbon Engineering's liquid solvent system (L-DAC), which uses a potassium hydroxide (KOH) solution as the sorbing fluid that binds the CO_2.[40] The facility will be assembled as "a scalable setup" consisting of modular contactors (Figure 3.4a, from Carbon Engineering's pilot facility in British Columbia) that will require a land size of 0.2 km^2, not including energy land use, to reach its 1 $MtCO_2$/yr capture target.[41] High-temperature release and separation of the CO_2 and regeneration of the liquid solvent will be performed using natural gas as the thermal energy source.[42] Because this facility will be sited in the Permian Basin region, which has ideal subsurface reservoirs for geological sequestration, transport of the separated CO_2 to a permanent storage site will be minimal.[43] The initial phase of DAC 1 is focused on a first capture train with a planned capture capacity of 0.5 $MtCO_2$/year; the total capacity of the project will subsequently increase to 1 $MtCO_2$/year.[44,45]

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[34] Favasuli, Sebastian (June 10, 2021) Voluntary carbon markets. [30]
[35] Hook (September 8, 2021) World's Biggest DAC Plant. [37]
[36] Milkywire (2022) The Climate Transformation Fund: Milkywire Progress Report 2022. p. 8. [53]
[37] Hook (September 8, 2021) World's Biggest DAC Plant. [37]
[38] Climeworks (June 28, 2022) Climeworks takes another major step. [22]
[39] GlobalNewsWire (2022) Occidental, 1pointfive to begin construction. [32]
[40] IEA (2021) DAC 1. [39]
[41] Ozkan *et al.* (2022) Current DAC Status. p. 8.
[42] Hook (September 8, 2021) World's Biggest DAC Plant. [37]
[43] Grover (July 8, 2021) Old oil fields may be ideal for carbon sequestration. [33]
[44] IEA (2022) DAC Report. p. 18. [40]
[45] IEA (2021) DAC 1. [39]

1pointfive and Carbon Engineering have raised money to cover the capital costs of this project from corporate sponsors, including a multi-million dollar direct investment from United Airlines, and hope to further offset costs by making the most of existing policy incentives, including the federal 45Q tax credit and California's Low Carbon Fuel Standard (LCFS) program.[46] More information about these policies and the incentives they provide for DAC can be found in Section 3.4 of this report.



Figure 3.4. a) Carbon Engineering Innovation Centre, R&D Facility, Squamish, British Columbia.[47] b) A conceptual aerial view of the megaton Carbon Engineering + 1pointfive facility, DAC 1 (in development).[48] Image credit: Carbon Engineering.

3.1.2.2. Technological innovations on the horizon

In terms of future development, technological designs that emphasize modular and relatively simple DAC approaches are generally favored because they allow for simplified mass production and can be scaled up easily for deployment.[49] Achieving economies of scale by producing large volumes of standard parts may also accelerate DAC's deployment and shorten technology learning curves, which will help to reduce costs. Additional technological trends that are being explored by many DAC startup companies include passive air contact and use of natural sorbents. Some notable start-ups in the DAC space that are indicative of these trends are Carbon Capture Inc, Sustaera, Mission Zero, and Noya. These companies are primarily in the design and development stage of their pilot projects.

Two startup companies are worth particular note for the innovative alternatives they are developing to traditional liquid-solvent or solid-sorbent based DAC systems, which may be

[46] IEA (2021) DAC 1. [39]

[47] Carbon Engineering (June 30, 2021) Carbon Engineering Innovation Centre Update. [13]

[48] 1pointfive (no date) DAC Technology. [1]

[49] Shayegh, Bosetti, Massimo (2021) Future Prospects of DAC Technologies. p. 3. [64]

critical for reducing the operational costs of DAC, and helping bring it to market more quickly.

Heirloom

Heirloom is a startup in the early phase of development. It has yet to deploy its first facility (slated for 2023), but is notable because it is attracting some of the largest investments in new carbon removal technologies from venture investment leaders like Microsoft co-founder Bill Gates's Breakthrough Energy Ventures, and because it has the lowest estimated cost of any direct air capture technology.[50,51] Heirloom had developed an approach that optimizes passive carbon capture absorption using one of the most abundant natural resources on the surface of the earth: limestone. Limestone is composed of calcium carbonate, and is the primary feedstock for cement production.[52] To produce cement, limestone is heated in the presence of water at high temperatures (~900°C) to form lime and a pure stream of CO_2, exactly the same process of solvent regeneration in L-DAC systems.[53,54] The lime is then hydrated to form calcium hydroxide or slaked lime—the slaked lime, when exposed to air, will naturally react with CO_2 to re-form calcium carbonate.[55] Heirloom's technological innovation is to optimize natural carbonation of the lime during passive exposure to air, eliminating the need for fans or high-cost solvents.[56] The primary (and extremely inexpensive) feedstock of limestone, once converted to lime, can be re-used multiple times in a process of calcification (CO_2 absorption) and lime regeneration (CO_2 release).[57] Given the nascent stage of this company's development, specific information regarding the technical and operational requirements of such a process are not yet available, but with the exception of the high-cost solvent chemicals and water requirements for L-DAC, are likely to be similar.

Verdox

Another company in the early stages of development, called Verdox, is exploring a different alternative approach to liquid-solvent or solid-sorbent based DAC (L-DAC and S-DAC). Their Electro-swing Adsorption (ESA) technology is composed of a large, specialized battery that absorbs carbon dioxide from the air, or other gas stream, as it passes over charged electrodes.[58] When the electrodes are discharged, they release the concentrated carbon dioxide gas.[59] The technology works by alternating between charging and

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[50] Cision PR Newswire (March 17, 2022) DAC startup Heirloom raises $53MM. [16]
[51] Olick (December 5, 2022) Heirloom uses limestone to capture CO2. [58]
[52] PubChem (no date) Limestone. [61]
[53] McQueen *et al.* (2022) A scalable DAC process. p. 3. [52]
[54] Larsen *et al.* (2020) Capturing New Business. [44]
[55] McQueen *et al.* (2022) A scalable DAC process. p. 3. [52]
[56] McQueen *et al.* (2022) A scalable DAC process. p. 4. [52]
[57] McQueen *et al.* (2022) A scalable DAC process. p. 4. [52]
[58] Verdox (no date) Breaking new ground. [72]
[59] Verdox (no date) Breaking new ground. [72]

discharging, thus relying on only electricity to run—the process has no heat or water needs.[60] ESA is able to capture carbon dioxide from any concentration, down to roughly 400 parts per million currently found in the atmosphere.[61] The technology is attractive for its high efficiency of raw materials and energy relative to more established direct air capture methods, using about 1GJ/tCO_2, or about 10-20% of the energy requirements for L-DAC and S-DAC (see Section 3.1.3.2).[62,63] Verdox is still in the testing phase of technology development, having been awarded a Department of Energy Advanced Research Projects-Energy (ARPA-E) research grant in 2020.[64] Anticipated capital and operational costs of a pilot-scale project, once deployed, are projected to be ~ $50-100 per metric ton of CO_2 captured.[65]

3.1.3 Operational Needs

This section provides a synopsis of the land use, energy, feedstock, waste disposal and other operational needs of the representative technologies for this industry, aggregated from literature review and interviews with industry experts. Because L-DAC and S-DAC are the most advanced direct air capture technologies, these are the only two DAC approaches considered here and in subsequent sections. Alternative DAC technologies, such as passive air capture or ESA, may be appropriate candidates for a research and development incubator facility.

3.1.3.1 Land use requirements

One of the key benefits of DAC as a carbon management technology is that it can be sited in any location that is economical, because unlike point-source carbon capture technologies, which require concentrated CO_2 streams (such as those emitted from CO_2-emitting industries like steel or concrete manufacturing, see Section 5 of this report) the source of CO_2 - ambient air - is accessible anywhere. Thus, a DAC plant could be co-located next to a plant which requires CO_2 as a feedstock or on top of a geological storage site to minimize costs and secondary emissions associated with transporting the CO_2 via truck, rail or pipeline.[66] DAC can also be co-located with other types of CO_2 capture facilities.[67]

A second benefit of DAC is that the direct land footprint of DAC is smaller than that of alternative carbon-removal processes. Land requirements for DAC are controlled by 1) the

[60] Verdox (no date) Breaking new ground. [72]
[61] Chandler (2019) New Technology: ESA. [15]
[62] Voskian, Hatton (2019) Faradaic electro-swing reactive adsorption for CO_2 capture. p. 3530. [73]
[63] Chandler (2019) New Technology: ESA. [15]
[64] ARPA-E (May 20, 2020) Electro-swing adsorption for high efficiency DAC. [2]
[65] Stauffer (September 2, 2020) Electro-swing cell. [67]
[66] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 189. [55]
[67] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]

size of the contactor and 2) the spacing requirements of multiple contactors and contactor configuration.[68] Contactors are generally designed to be modular: easily transportable and stackable (e.g. Figures 3.3 and 3.5). Contactors from Carbon Engineering, a commercial L-DAC company, are about 23 ft long by 16 ft tall and 16 ft wide.[69] Climeworks, a commercial company with the largest existing capture capacity for S-DAC systems, has contactors the size of a standard shipping container, or about 40 ft long by 8 ft wide by 8.5 ft high.[70] Units cannot be too geographically concentrated within a site, as some units would be taking in air that has already been depleted in CO_2 by nearby contactor units.[71] Although the actual footprint required for the contactors is small, there would need to be ample space between sets of contactors to build an effective facility.

Figure 3.5 is a schematic representation of the physical footprint of a 1 $MTCO_2$/year DAC facility. The size, height and orientation of the contactor arrays is based off the original design of solvent-based L-DAC by the company Carbon Engineering, with the cross-sectional inlet of the contactor oriented normal to the land surface.[72] More recent designs from this company have a configuration in which fans are parallel to the land surface (Figure 3.4). The height of the pictured tower, with four vertically stacked units, is approximately 65 feet (20 meters) and over 650 feet long, and could capture 50,000-100,000 metric tons of CO_2 annually.[73] To capture 1 $MtCO_2$/year, process engineer and DAC expert Howard Herzog estimates that you would need 25-30 of Carbon Engineering's contactor rows in a facility, and they would have to be spread far enough apart to ensure that the exhaust of one row of units does not interfere with the inlet of another row.[74] Given that no DAC facilities exist at a scale above *thousands* of metric tons of annual CO_2 capture, no field tests exist to determine the optimal spacing between contactor rows. In a schematic representation of a 1 $MtCO_2$/yr facility developed by the American Physical Society, contactor rows were spaced 250 m (820 ft) apart, to ensure that CO_2-depleted air exiting one contactor would be replenished before reaching the next.[75] Using the APS's spacing estimate, the land footprint of Carbon Engineering's original design for a 1 $MtCO_2$ capture facility (25-30 contactor rows) would be about 300-360 acres, or 1.2-1.5 km^2. If we created the same framework for an S-DAC system modeled after Climeworks' Orca facility in Iceland, also creating 40-unit long rows, one contactor row would be able to capture ~40,000 metric tons of CO_2 annually.[76] Scaling accordingly, the footprint of a 1 $MtCO_2$/yr facility would be 190-230 acres, or 0.8-0.95 km^2, assuming the same 66-80% efficiency that

[68] IEA (2020) CCUS in Clean Energy Transitions. p. 87-88. [41]

[69] Heidel *et al.* (2011) Air contactor design. [34]

[70] Climeworks (no date) Capricorn. [18]

[71] Herzog (2021) DAC: A Process Engineer's View. 16:05-16:34. [35]

[72] Heidel *et al.* (2011) Air contactor design. p. 2865. [34]

[73] Heidel *et al.* (2011) Air contactor design. p. 2866. [34]

[74] Herzog (2021) DAC: A Process Engineer's View. 15:52-16:05. [35]

[75] APS (2011) DAC with Chemicals. p. 7. [3]

[76] The Orca facility in Iceland contains 4 units of 2 stacked contactors, each ~40 ft long on the air inlet side, and ~ 8 ft deep. The facility captures approximately 4,000 metric tons of CO_2 annually.

Dr. Herzog estimated for L-DAC systems.[77] These numbers are comparable to published estimates of L-DAC and S-DAC land use requirements, which range from 0.2-7 km^2 and 0.2-2 km^2, respectively (Table 3.1).[78,79,80,81] Further complicating land use estimates, DAC systems can make use of vertical space by stacking DAC contactors much higher than 2-4 units, and thus allowing for a far smaller footprint required for megaton-scale facilities.[82]

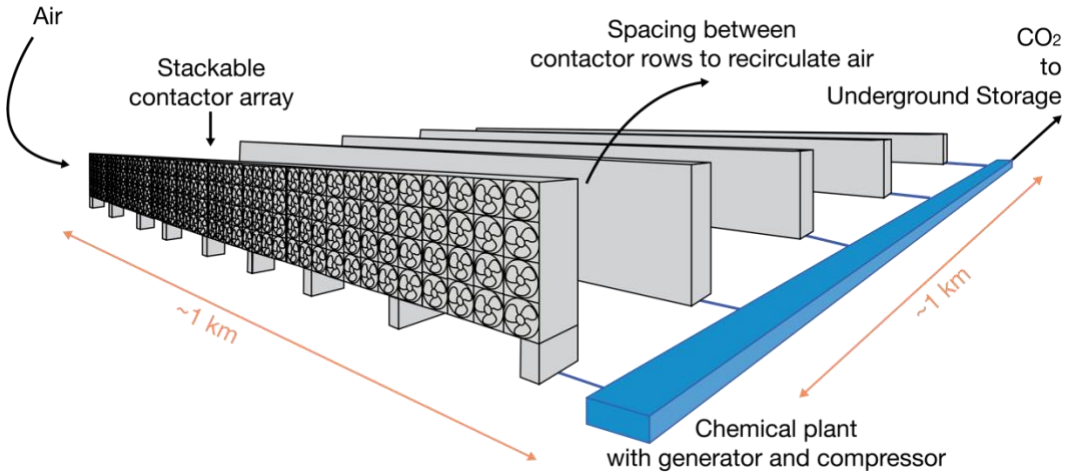

Figure 3.5. A conceptual drawing of a 1MtCO_2 DAC system, consisting of 10 m (33 ft) tall and 1 km (0.6 mile) long contactor structures and a facility for sorbent regeneration and CO_2 gas compression. Adapted from the American Physical Society[83] and Heidel et al. (2011).[84]

Indirect land use, resulting from the energy source needed to provide heat and electricity to a DAC facility, is generally much more significant than direct land use itself, but is dependent on the type of DAC sorbent (L-DAC or S-DAC) and the type of energy source in question.[85] For an L-DAC plant capturing one million tons of CO_2 annually powered entirely by solar PV, around 34 km^2 of land would be needed, whereas natural gas only requires 0.4 km^2.[86] However, L-DAC systems require heating temperatures of ~900°C (Table 3.1), and as of the publication of this report, there is not an at-market tool for converting solar or wind energy into process heat at those temperatures.[87] Thus, published land use estimates for

[77] Herzog (2021) DAC: A Process Engineer's View. 15:52-16:05. [35]
[78] Lebling *et al.*, WRI (2022) DAC: Assessing impacts to enable responsible scaling. p. 2. [48]
[79] IEA (2022) DAC Report. p. 39. [40]
[80] APS (2011) DAC with Chemicals. p. 7. [3]
[81] Lebling *et al.* (2022) Building DAC. [47]
[82] Aines, R. *Personal communication* (2022).
[83] APS (2011) DAC with Chemicals. p. 7. [3]
[84] Heidel *et al.* (2011) Air contactor design. p. 2865. [34]
[85] Baker *et al.* (2020) Getting to Neutral. p. 78. [6]
[86] Lebling *et al.* (2022) Building DAC. [47]
[87] McMillan *et al.*, NREL (2021) Opportunities for solar industrial process heat. p. vi. [50]

energy demand as a function of energy source for L-DAC have generally assumed that heat energy is derived from natural gas or geothermal sources, but that alternative renewable energy sources like wind and solar could provide the power needed for electricity.[88] In contrast, S-DAC requires maximum sorbent regeneration temperatures of only ~80-100°C (Table 3.1), and thus both heat and electrical energy can be supplied by existing at-market wind or solar energy technologies. For a 1 million metric ton S-DAC plant, energy sourced from natural gas would require a 0.26km^2 footprint, whereas solar requirements would be about 21km^2 (Table 3.1).[89]

Additional siting and footprint considerations

In addition to general land use considerations, attention needs to be paid to regional climate, dominant local airflows, and other meteorological conditions in the area, to identify preferred DAC technologies, optimal siting, and operational needs.[90] Humidity and average ambient temperatures are particularly important, because they can have large impacts on the capture productivity, energy efficiency, and water demands of DAC systems.

A recent study of S-DAC processes identified optimal capture productivity at low ambient temperatures, and much lower energy efficiency and capture productivity at higher ambient temperatures (Figure 3.6).[91] This is because solid sorbent materials not only absorb CO_2, but also water vapor from the air.[92] Although researchers agree that meteorological conditions will impact a DAC facility's effectiveness, findings are mixed as to these impacts. When looking specifically at Climeworks's S-DAC process, more water absorption from the atmosphere was found to reduce the sorbent's capacity for CO_2 sorption.[93] In overarching studies of amine-based solid sorbents for DAC, higher humidity was found to increase the sorbent's CO_2 capture capacity but increase the energy use of the chemical process, while higher temperatures led to both higher energy demand and lower productivity—and these effects interact with one another.[94] As seen in Figure 3.6, at ambient temperatures above ~20°C (68°F), increases in relative humidity also begins to negatively impact capture productivity and energy efficiency.[95] In water scarce regions, however, sorption of both water and CO_2 may be considered a technological benefit, as captured water could be put to new use. Similarly, the company Carbon Engineering, which employs L-DAC systems, is avoiding places with colder climates to avoid unwanted viscosity of the liquid solvent, while at the same time avoiding dry and hot places to

[88] Baker *et al.* (2020) Getting to Neutral. p. 78-79. [6]
[89] Baker *et al.* (2020) Getting to Neutral. p. 79. [6]
[90] Herzog (2021) DAC: A Process Engineer's View. 27:24-27:35. [35]
[91] Wiegner *et al.* (2022) S-DAC optimization. p. 12654. [75]
[92] Wiegner *et al.* (2022) S-DAC optimization. p. 12650. [75]
[93] Herzog (2021) DAC: A Process Engineer's View. 27:35-28:06. [35]
[94] Wiegner *et al.* (2022) S-DAC optimization. p. 12650. [75]
[95] Wiegner *et al.* (2022) S-DAC optimization. p. 12654. [75]

minimize evaporation of the liquid solvent, which leads to constant water loss and an increased possibility of leaking some of the captured CO_2.[96]

Table 3.1. Comparison of S-DAC and L-DAC key features.[a]

	S-DAC	L-DAC
CO_2 separation	Solid adsorbent	Liquid solvent
Specific energy consumption (GJ/tCO_2)	3.4-5.9	5.3-12.4
Share as heat consumption (%)	75-80%	80-100%
Share as electricity consumption (%)	20-25%	0-20%
Regeneration temperature	80-120°C	Around 900°C
Regeneration pressure	Vacuum	Ambient
Capture capacity	Modular (e.g. 50 tCO_2/yr per unit)	Large-scale (e.g. 0.5 to 1 $MtCO_2$/yr)
Net water requirement (tH_2O/tCO_2)	-2 to none	0-50
Life cycle emissions ($tCO_{2\text{-emitted}}/tCO_{2\text{-captured}}$)	0.03-0.91	0.1-0.4
Levelized cost of capture (USD/tCO_2)	Up to $540	Up to $340
Main advantages	• Possible net water production • Less capital-intensive • Modular • Operation can rely on low-carbon energy only • Novel and therefore more likely to see cost reduction	• Less energy-intensive • Large-scale capture • Operation relies on commercial solvents • Technology adapted from existing commercial units
Main trade-offs	• More energy-intensive • Manual maintenance required for adsorbent replacement	• More capital-intensive • Relies on natural gas combustion for solvent regeneration (with potential for full electrification in the future)
Land requirements	**S-DAC**	**L-DAC**
DAC footprint ($km^2/MtCO_2$)	0.2-2 (Median = 1.0)	0.2-7 (Median – 0.8)
Natural gas energy source ($km^2/MtCO_2$)	0.26	0.43
Solar energy source ($km^2/MtCO_2$) (with NG as a heat source – L-DAC only)	2	36 (5 + 0.37)
Wind energy source ($km^2/MtCO_2$) (with NG as a heat source – L-DAC only)	217	364 (51 + 0.37)

a. Data from: IEA (2021) DAC Report, p. 23-24, Baker *et al.* (2020) Getting to Neutral, p. 79, APS (2011) DAC with Chemicals, p. 7., Lebling *et al.* (2022) Building DAC, p. 12, Ozkan *et al.* (2022) Current DAC Status, p. 2-8, National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda, and this study.

[96] Herzog (2021) DAC: A Process Engineer's View. 28:06-29:59. [35]

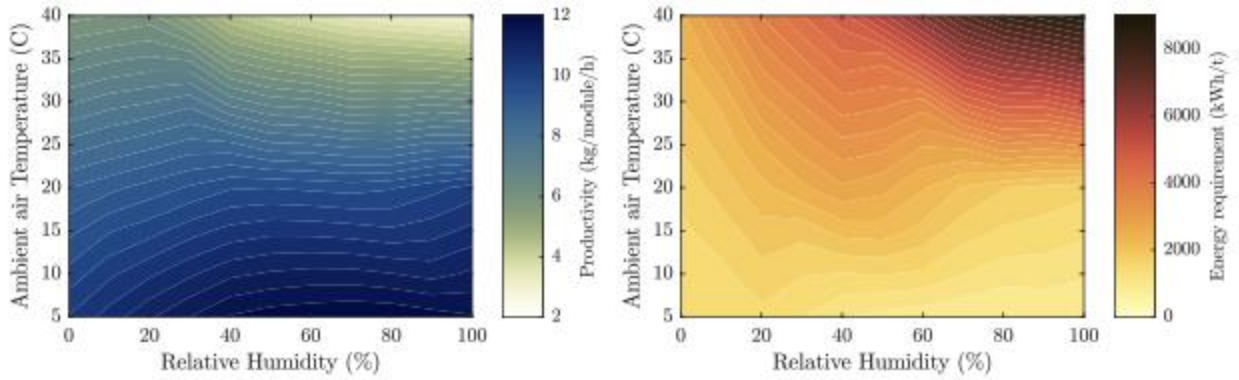

Figure 3.6. Productivity and specific energy requirements for S-DAC as a function of ambient temperature and humidity. Reproduced with permission from Wiegner et al. (2022)[97].

Land use estimates also have to anticipate less than 100% operational efficiency. H. Herzog estimated 66-80% of total DAC capacity would be operational at any given time, and a life-cycle assessment of Climeworks technologies estimated a carbon capture efficiency of 85-93%.[98,99] L-DAC contactors can "theoretically operate continuously at steady state without interruption" though they require regular maintenance.[100] However, S-DAC must operate using a batch operation which requires having multiple units in parallel.[101] At any one time, some contactor units will be in operation capturing CO_2, while the remaining contactor units are in their regeneration state, releasing CO_2 from the filters.[102]

3.1.3.2 Energy requirements

The energy requirement as well as per-ton cost of any carbon-dioxide removal technology is heavily influenced by the concentration of CO_2 in the main feedstock of the plant. For DAC, that feedstock is ambient air, which has CO_2 concentrations of a little over 400 parts per million, a small fraction of industrial-scale flue gas, which can be 5 to >90% CO_2.[103,104] The extremely dilute stream makes it difficult and energy-intensive to separate CO_2 from air relative to more established industrial point source carbon scrubbers.[105,106]

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[97] Wiegner *et al.* (2022) S-DAC optimization. [75]

[98] Herzog (2021) DAC: A Process Engineer's View. 15:52-16:05. [35]

[99] Deutz, Bardow (2021) Life-cycle assessment of an industrial DAC process. [25]

[100] IEA (2022) DAC Report. p. 22-23. [40]

[101] IEA (2022) DAC Report. p. 22-23. [40]

[102] IEA (2022) DAC Report. p. 22-23. [40]

[103] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 189. [55]

[104] IEA (2020) CCUS in Clean Energy Transitions. p. 101. [41]

[105] IEA (2022) DAC Report. p. 27. [40]

[106] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]

The amount of energy needed for DAC also depends on the technology. For L-DAC, the most energy-intensive component of the capture process is the thermal regeneration step (Figure 3.2), in which the carbonate pellets holding the sorbed atmospheric CO_2 are combusted to release a stream of high-purity CO_2 and regenerate the lime solvent additive (CaO).[107] This process requires heating to temperatures up to 900°C.[108,109] In comparison, the regeneration step for S-DAC sorbent only requires a temperature of 80–120°C.[110,111] The result is that, while both technologies require about 80% of their energy for heating and 20% for electricity, estimates of the total energy need for L-DAC ranges from 5.3-10.7 gigajoules per ton of CO_2 captured (GJ/tCO_2), whereas S-DAC requires about 3.4 to 5.8 GJ/tCO_2 (Table 3.1), or 1.5-3.0 and 0.9-1.6 MWh/tCO_2, respectively.[112,113] In existing pilot facilities, energy sources include geothermal (the Orca facility in Iceland), waste heat (Climeworks' first pilot plant in Hinwil, Switzerland) or natural gas with carbon capture (Carbon Engineering).[114,115] Using solar power to supply both heat and electricity energy is a feasible option for S-DAC, given the lower required heat generation temperatures, but to deliver heat up to 900°C for L-DAC technologies, is not feasible unless paired with a high-temperature industrial battery solution (see Section 7 on energy storage industries).[116] Estimates of the scale of solar installation required to supply 100% of the heat and electrical energy needs of a $1MtCO_2/yr$ DAC facility (assuming industrial battery use as needed) are provided in Table 3.2. Installed capacity for the solar fields were calculated following the equation:

MWh (energy supplied) = MW (installed capacity of facility) x (8760 hours in a year) x Capacity factor (E3.1)

where the capacity factor for solar panels in Kern County is 32.8%.[117,118] Solar acreage is calculated on the basis of ~7 acres per MW installed solar capacity.[119,120] With these values,

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[107] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 203. [55]

[108] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 196. [55]

[109] IEA (2022) DAC Report. p. 10. [40]

[110] Beuttler *et al*. (2019) The role of DAC in mitigation. p. 2. [8]

[111] Ozkan *et al*. (2022) Current DAC Status. p. 2. [59]

[112] Baker *et al*. (2020) Getting to Neutral. p. 79. [6]

[113] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 222. [55]

[114] Climeworks (2021) Orca. [23]

[115] Climeworks (May 31, 2017) Climeworks makes history. [21]

[116] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 211. [55]

[117] Thomson Reuters Practical Law Glossary (no date) Capacity factor. [69]

[118] NREL (no date) Utility-Scale PV. [56]

[119] Lorelei Oviatt, Kern County Department of Planning and Natural Resources, personal communication, September 21, 2022.

[120] SEIA (no date) Land use and solar development. [65]

a megaton L-DAC facility would require on average 830 MW installed solar capacity (range = 508-1034 MW), or a ~5800 acre solar field. S-DAC would require an average of 420 MW installed solar capacity (range = 329-561 MW), or ~2900 acres of solar panels.

3.1.3.3 Other operational needs

Waste disposal requirements

Because the only feedstock for DAC systems is air, and the only output is CO_2, there are no significant waste streams from DAC plants.[121] Minor anticipated sources of waste are replacement of parts, and of the solid or liquid sorbent materials once their regenerative capacity has declined. It is not clear how many iterations of regeneration are possible before sorbents will need replacement, but may be on the scale of many dozens of capture cycles.[122] L-DAC sorbents are primarily composed of strong bases such as NaOH or KOH.[123,124] As standard industrial salts, these compounds have well established regulation and disposal procedures.[125,126] Sorbent materials currently being tested for S-DAC technologies include metal–organic frameworks (MOFs), zeolites, activated carbon, silica materials, carbon nanotubes, porous organic polymers, and carbon molecular sieves.[127] These are solid, non-reactive and non-hazardous materials that are common in many chemical laboratories, and do not pose a hazardous waste risk.

Warehousing requirements

Warehousing could be minimal for DAC, as there's no feedstock related to the capture other than ambient air, which does not require storage.

Transportation & pipeline requirements

Transportation and pipeline needs for a site should be minimal—adsorbents or solvents may need to be moved in and out of the plant at regular intervals to ensure the contactors remain in working order, a process that would likely rely on trucks for transport. The most likely pipeline needs for any site would be a pipeline to move the CO_2 to storage or, for L-DAC, pipelines to bring in natural gas, hydrogen, or other materials to support its high thermal energy needs. Please refer to Section 9 of the full report for more information on transportation requirements for more information about pipelines and other transportation options for safely moving CO_2 offsite for geologic storage.

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[121] Simon Pang, DOE C-LEAP Technical Assistance, personal communication, September 29, 2022.

[122] Industry representative, personal communication, November 11, 2022.

[123] McQueen *et al*. (2021) DAC Review. p. 3. [51]

[124] IEA (2021) DAC 1. [39]

[125] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Research Agenda. p. 231. [55]

[126] EPA (no date) Substance Registry Service: Sodium hydroxide. [28]

[127] McQueen *et al*. (2021) DAC Review. p. 2. [51]

Table 3.2. Comparison of S-DAC and L-DAC energy requirements.[128]

	Energy Requirements:		Solar Requirements for a 1 $MtCO_2$/yr Facility:		
L-DAC	**GJ/t CO_2**	**MWh/t CO_2**	**Installed MW**	**Footprint (acres)**	**Footprint (km^2)**
minimum	5.3	1.46	508	3553	14
maximum	12.4	3.44	1199	8392	34
mean	9.2	2.55	889	6224	25
S-DAC					
minimum	3.4	0.94	329	2301	9
maximum	5.9	1.64	570	3993	16
mean	4.8	1.32	460	3223	13

3.2 Societal Impacts

3.2.1 Job creation potential

3.2.1.1 Number and types of jobs

The largest existing DAC project is 0.0004% the size of a megaton (million ton) capture facility, meaning that estimates of the job creation potential of this industry is highly speculative and must be based on growth trajectories of similar industries. The United Kingdom, which aims to capture 20-30 $MtCO_2$/yr by 2030, is anticipating 50,000 carbon capture-related jobs, translating to ~2,000 jobs per million tons of CO_2 sequestered.[129] The Rhodium Group estimated that construction, engineering and equipment manufacturing sectors combined could see at least 3,000 new jobs for every one million ton DAC plant, though the bulk of these jobs are in the initial plant investment period.[130] The breakdown of those jobs are as follows:

- >1500 jobs created from the equipment manufacturing process
- 657 jobs created from the engineering and design phase
- 721 jobs created from the construction phase
- 278 jobs created from operation and maintenance activities

[128] Data from: Baker *et al.* (2020) Getting to Neutral, p. 78, National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda, p. 222, and this study.
[129] United Kingdom Department for International Trade (2022) CCUS Investor Roadmap. p. 4. [71]
[130] Larsen *et al.* (2020) Capturing New Jobs. p. 15. [45]

- Additional job creation in supporting industries like the energy production sector.[131]

While it is not entirely clear how these estimates would scale, it is likely that some would grow more linearly than others. For example, operation and maintenance might not have significantly higher job creation potential at a 2 megaton DAC plant than a 1 megaton facility, but construction, manufacturing and supporting industries would.[132]

For the DAC 1 facility led by 1pointfive and Carbon Engineering, planned to capture 1 megaton per year, the reported permanent job estimate is about 75, with ~1,000 on-site construction jobs.[133] CarbonCapture Inc.'s Project Bison, a DAC hub planned for Wyoming with a goal of creating a 5 megaton DAC facility by 2030, is estimating the plant will support "more than 200 permanent jobs" in the state.[134] When compared to the Rhodium Group figure for a 1 megaton facility, these real facility estimates appear to reflect how permanent job potential is unlikely to scale proportionally for larger DAC facilities.

It is also critical to note that the job opportunities in several categories of the Rhodium Group estimate are not guaranteed to directly benefit local communities where a DAC facility is sited. This is particularly true for equipment manufacturing, engineering, and design. If a facility scale is large enough, it could provide an economic incentive to co-locate equipment manufacturing in the region.[135] However, it is recommended that concrete actions are taken to prepare both the industry and potential local workers for these new jobs to be sited in the region. One such action is to develop legally binding mechanisms ensuring that communities have the opportunity to benefit from available jobs and negotiate for other types of benefits beyond jobs. These agreements could take the form of a Community Benefit Agreement, a negotiated legal agreement between community groups and project developers that guarantees community benefits in exchange for a community's agreement to accept the project, or a Project Labor Agreement, an agreement between contractors and unions laying out the terms for a project. Project Labor Agreements can include Community Workforce Agreements, which require that the contractor hire a negotiated percentage of local, low-income or other marginalized workers, or that they collaborate with local organizations to provide job training programs and provide job quality specifications.[136]

3.2.2.2 Training pipelines

Direct jobs that would be based onsite—such as construction, operation and maintenance, and electricity generation and distribution—require skill sets that are transferable from

[131] Larsen *et al.* (2020) Capturing New Jobs. p. 15. [45]

[132] Roger Aines, DOE C-LEAP Technical Assistance, personal communication, September 28, 2022.

[133] Trendafilova, (August 26, 2022) Occidental Starts Construction Of Its First Large-Scale DAC Plant. [70]

[134] Arambel (October 7, 2022) CarbonCapture Inc. [5]

[135] Industry representative, personal communication, November 11, 2022.

[136] Lebling *et al.* (2022) Building DAC. [47]

other projects and industries, like fossil fuel and energy sectors.[137,138] As mentioned above, facility developers can work with local organizations and institutions to provide relevant training to take on these roles. This collaboration with local organizations to provide job training can be seen in Project Bison, where developers are already working with local community colleges in Wyoming to set up training programs for new positions at DAC facilities.[139]

3.2.2 Quality of Life

3.2.2.1 Location

The lack of dangerous feedstocks, waste streams or pollutants associated with DAC results in little to no health or environmental risk from the operation of DAC towards the local community. Key considerations that remain are:

1. Energy use: due to the enormous use of energy required to run DAC facilities, developers need to ensure that energy required for DAC doesn't compete with other existing uses, such as domestic and local industry.
2. Noise: a single DAC contactor unit operates much like a large fan or HVAC system, and thus is comparably loud.[140] One large HVAC air conditioner emits 50-70 decibels of sound, about the same as other home appliances (refrigerator, dishwasher, vacuum). This sound dissipates relatively quickly; 50 feet away from a unit the noise level would be about halved, to 25-45 decibels (comparable sounds are whispering, rustling leaves).[141] However, further research is warranted to assess how sound levels increase as multiple contactor units are combined.
3. Vibration: there is no clear data or discussion on the vibrational impact of DAC, but a megaton facility would have tens of thousands of contactors with rotating fan blades, it is a consideration. Several solutions exist to reduce the impacts of industrial vibration, including hardware, pads and mats designed to absorb vibration.[142]
4. Aesthetics: because DAC systems are modular, there is room for preference in whether towers are built very tall, to reduce the overall ground footprint, or kept low to minimize visual impact.

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[137] Larsen *et al.* (2020) Capturing New Jobs. p. 23-24. [45]

[138] Pollack (October 10, 2022) Firm has big plans for air capture. [60]

[139] Arambel (October 7, 2022) CarbonCapture Inc. [5]

[140] Simon Pang, DOE C-LEAP Technical Assistance, personal communication, September 28, 2022.

[141] WKC Group (no date) Sound attenuation - inverse square law. [76]

[142] Sorbothane Inc. (no date) Vibration Isolation in Industrial and Manufacturing Equipment. [66]

5. Commuting considerations: new roads and increased commuting for employees could increase traffic, and thus road noise and pollution for nearby residents.[143]

3.2.2.2 Multi-use potential

DAC contactors must be spaced far enough apart to prevent the CO_2-free exhaust from one contactor becoming the intake air for the next contactor.[144] The optimal configuration to prevent this is still in the design phase, and likely specific to the conditions of the facility site.[145] As a result, it is possible that there will be large swaths of available space between contactor rows that could have alternative uses, such as the siting of other facilities, part of the solar energy supply for the DAC units, or livestock grazing (depending on disruptiveness of noise and vibration of the contactor units).[146] Additionally, DAC can be placed on top of, or adjacent to other industrial facilities, as shown by Climeworks' DAC-1 plant, which is built on the roof of a municipal waste incinerator.[147]

3.3 Environmental Impacts

3.3.1 Water requirements

3.3.1.1 Minimum volume requirements

Water requirements for DAC are highly dependent on the chosen technology. While L-DAC requires significant amounts of water to dilute the hydroxide solution, some S-DAC technologies produce water as a byproduct of CO_2 absorption.[148, 149]

For L-DAC to capture one ton of CO_2, various sources estimate as little as 1 to more than 20 tons of water is needed to dilute the hydroxide solution that binds CO_2.[150,151,152] Water is not actually a feedstock in the L-DAC process, but is a component in the circulating solvent solution. Although that solution can be repeatedly regenerated, water must be regularly added to compensate for evaporation loss and, to a lesser degree, drift loss that occurs

[143] Lebling *et al.* (2022) Building DAC. [47]
[144] Herzog (February 4, 2021) DAC: A Process Engineer's View. 16:05-16:34. [35]
[145] APS (2011) DAC with Chemicals. p. 7. [3]
[146] Herzog (February 4, 2021) DAC: A Process Engineer's View. 32:05-32:32. [35]
[147] Evans (June 22, 2017) The Swiss company hoping to capture 1% of global CO2 emissions by 2025. [27]
[148] IEA (2020) CCUS in Clean Energy Transitions. p. 88. [41]
[149] Breyer *et al.* (2019) Direct air capture of CO_2. p. 2053. [9]
[150] Lebling *et al.* (May 2, 2022) 6 Things to Know about DAC. [49]
[151] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 199. [55]
[152] An et al. (2022) Impact of L-DAC. p. 7. [4]

during the sorbent-air contacting process.[153] The intensity of evaporation, and thus the H_2O needed for CO_2 captured, depends on the molarity of the hydroxide solvent and the relative humidity of ambient air. More concentrated solutions of hydroxide result in less water loss, as does higher ambient humidity.[154] For example, experiments conducted at relative humidity levels above 65%, for solutions with a concentration of 7.2 M NaOH or 2 M KOH effectively mitigated evaporative water loss.[155,156] In contrast, experiments conducted at ambient temperatures over 30°C and at relative humidity levels below 20%, water loss was higher than 20 metric tons of H_2O per ton CO_2 (Figure 3.7).[157]

In the case of S-DAC, water is used, but is contained and continuously recycled within closed-loop systems.[158] Under specific operating conditions, S-DAC can also *produce* fresh water as a byproduct of the CO_2 capture. Climeworks' solid sorbent system is an example, yielding approximately 0.8-2 metric tons of water per metric ton of CO_2 captured.[159] Other S-DAC technologies, like the process used by Global Thermostat, use steam condensation for sorbent regeneration.[160] These S-DAC systems are more water intensive, requiring up to 1.6 tons of water per metric ton of CO_2 captured.[161]

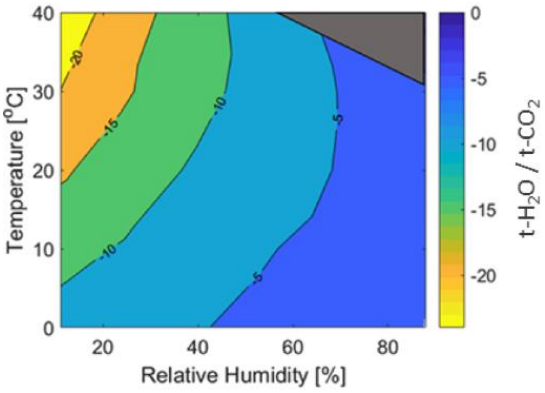

Figure 3.7. Net water consumption per metric ton of CO_2 capture using L-DAC technology, as a function of climate conditions. Reproduced with permission from An et al. (2022).[162] Kern County humidity and temperature highs in the summer and humidity and temperature lows in the winter winter are about 27% and 97°F (36°C), and 57% and 38°F (3°C), respectively,[163] meaning water consumption in Kern County would likely range from ~4-20 tons of water used per ton CO_2 captured.

[153] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 228. [55]
[154] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 199. [55]
[155] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 199. [55]
[156] Holmes, Keith (2012) Liquid DAC. p. 4395. [36]
[157] An *et al.* (2022) Impact of L-DAC. p. 7. [4]
[158] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 228-230. [55]
[159] Fasihi *et al.* (2019) Techno-economic DAC. [29]
[160] McQueen *et al.* (2021) DAC Review. p. 5. [51]
[161] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 230. [55]
[162] An *et al.* (2022) Impact of L-DAC. p. 7. [4]
[163] WeatherWX.com (no date) Kern County, California Climate Averages. [74]

3.3.2 Other potential impacts

DAC facilities are expected to produce zero or-near zero emissions onsite that could be hazardous to the environment or human health.[164] Hazardous waste is not a significant concern for DAC facilities, as reviewed in Section 3.1.3.2. Wastewater is also not generated in significant amounts in DAC processes, as the only water used is contained within close-loop systems. Solid waste buildup can occur in the CO_2 recovery equipment, as happens in traditional monoethanolamine (MEA) scrubbers that are used for point source carbon capture.[165] Similar environmental regulation and disposal guidelines would need to be followed. Chemicals used in sorbent plants would degrade over time as heat is applied to release captured CO_2, but those degradation products (e.g., ammonia) are expected to be contained within the DAC plant and not released into the environment, and have established regulation and disposal protocols (Section 3.1.3.2).[166]

3.4 Economic Impacts

3.4.1 Business Model

There are two primary revenue streams possible for a DAC development: private carbon credits or benefits from federal and state incentives.

Selling carbon credits to the voluntary carbon offset market

DAC developers can either seek private companies to invest in their carbon removal project, allow carbon credits to be purchased to offset their CO_2 emissions, or both. Companies such as Stripe, Shopify, and SwissRe have purchased carbon credits from DAC facilities to offset their CO_2 emissions.[167] Other companies are helping develop capture projects. United Airlines is investing in DAC directly via funding on the 1pointfive and Carbon Engineering project, in line with its commitment to become carbon neutral by 2050.[168] And Microsoft is both purchasing DAC removal carbon credits from Climeworks and, through its Climate Innovation Fund, is investing in the Climeworks Orca facility in Iceland.[169]

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[164] Lebling *et al.* (2022) Building DAC. [47]

[165] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 231. [55]

[166] Lebling *et al.* (2022) Building DAC. [47]

[167] Clancy (April 13, 2022) Stripe, Shopify, Alphabet, Meta and McKinsey will spend almost $1 billion on carbon removal. [17]

[168] Rucinski (December 10, 2020) United Airlines invests in a carbon-capture project. [63]

[169] Climeworks (July 13, 2022) Climeworks becomes first supplier of long-term, technology-based carbon removal. [19]

Utilizing federal and state incentives

A DAC plant that sequesters captured CO_2 into saline or other geologic formations is also eligible to take advantage of the 45Q tax credit, which, since the adoption of the U.S. Inflation Reduction Act, provides $180 per ton of CO_2 sequestered via DAC.[170] Moreover, DAC companies are eligible for the California Low Carbon Fuel Standard (LCFS) credit, which credits technologies that reduce transportation-derived greenhouse gas emissions.[171] DAC is eligible under the program because it removes CO_2 produced by gas-powered cars and trucks.[172] LCFS credits vary in price based on supply and demand within the credit marketplace, but from January 2018 to December 2022 ranged from $62 to $217 per metric ton CO_2.[173] 45Q and LCFS credits can be "stacked" (i.e. both credits given for one metric ton of carbon removed), such that, given historical LCFS prices, incentive revenue can be expected to be in the range of ~$242-$397 per metric ton CO_2.[174] Incentive credits cannot, however, be used in tandem with the voluntary carbon offset marketplace (for a summary of relevant policy and regulations pertaining to all carbon management industries, refer to Section 2 of this report).

3.4.2 Business Costs

Estimates of the current cost of carbon capture for DAC systems are highly variable, ranging in the published literature of the last decade from less than $100 per metric ton CO_2 captured to more than $1,000 per metric ton.[175] There are two reasons for the high variability. First, given the newness of the technology, all existing facilities are still in the testing or pilot scale. That means there are no large-scale facilities to directly assess cost, and ongoing research is continuously identifying lower-cost sorbent materials and optimal operating conditions.[176] Second, there are a large number of variables required for any techno-economic assessment of a new industry, and the assumptions used to determine each variable are different across different publications. In general, costs are assessed and reported through a 'Lifetime Cost Assessment' (LCA) model, or the summative cost per metric ton CO_2 of the capital costs (the prices of the equipment that make up the DAC facility), operational costs (including maintenance and labor), and energy costs (heat + electricity), normalized over the lifetime of the plant.[177,178] In some cases, costs related to

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[170] Carbon Capture Coalition (2022) The Inflation Reduction Act (IRA) of 2022. p. 2. [12]

[171] CARB (no date) About - Low Carbon Fuel Standard. [10]

[172] CARB (no date) Low Carbon Fuel Standard Basics. p. 11. [11]

[173] Neste (no date) California Low Carbon Fuel Standard Credit price. [57]

[174] Nagabhushan (November 10, 2018) California's CO2 reduction program opens doors to CCS. [54]

[175] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 190. [55]

[176] Ozkan *et al.* (2022) Current DAC Status. p. 9. [59]

[177] Fasihi *et al.* (2019) Techno-economic DAC. p. 965. [29]

[178] Carbonplan (no date) DAC cost calculator. [14]

the transport and permanent storage of captured CO_2 are also included (these are not accounted for here, but can be explored further in Section 9). Typically, the most significant drivers of cost uncertainty are the sorbent used and the source and cost of electricity.[179]

A summary of recent published estimates for DAC costs are presented in Tables 3.3 and 3.4, and a breakdown of how capital, operational and energy costs are estimated is detailed in the following sections. Current levelized costs for net CO_2 removed for the solid sorbent–based approach (S-DAC) range from \$89 to \$600/tCO_2, with the greatest variable being the type of adsorbent and energy source.[180] The cost range for the solvent-based approach (L-DAC) is \$156 to \$506/tCO_2, with the strongest control on price being the source of thermal energy.[181] Experts predict that these costs could fall significantly within the next decade, to ~\$100-200/tCO_2, and potentially as low as \$60/tCO_2 by 2040 or 2050, with the assumption that the technology will continue to grow and there will be cost reductions due to economies of scale (see Table 3.5, 'Future costs').[182,183]

3.4.2.1 Cost to build (upfront costs)

Capital cost consists mostly of the construction expenses needed to establish the facility from scratch, including the procuring equipment and construction materials and the cost of labor. For S-DAC systems, the equipment components that comprise capital expenditures (CapEx) are the adsorbent material (>90% of total capital costs), and the blower, vacuum pump, condenser and contactor.[184] Adsorbent materials range enormously in cost and efficacy, drive the greatest uncertainty in cost for S-DAC systems, and have the greatest potential to drop in cost due to further innovation.[185] L-DAC facilities are more capital-intensive, with necessary equipment including the contactor array (~30% of CapEx), the slacker, causticizer and clarificator (how the liquid solvent is produced and regenerated, ~20% of CapEx), the oxy-fired calciner (how the CO_2 is released and the lime regenerated, ~40% of CapEx) and the air separation unit and condenser (provides oxygen to the calciner, ~10% of CapEx).[186,187]

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[179] Ozkan *et al.* (2022) Current DAC Status. p. 11. [59]

[180] Ozkan *et al.* (2022) Current DAC Status. p. 7-8. [59]

[181] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 222. [55]

[182] Ozkan *et al.* (2022) Current DAC Status. p. 10. [59]

[183] Sutherland, B. R. (2019) Pricing CO_2 Direct Air Capture. p. 1572. [68]

[184] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 221. [55]

[185] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Research Agenda. p. 219. [55]

[186] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 206. [55]

[187] Ozkan *et al.* (2022) Current DAC Status. p. 10. [59]

For an average L-DAC system with a capacity of 1 million metric tons per year CO_2 removal, estimated upfront capital costs range from $675 million to $1.255 billion, if the building of clean energy infrastructure is not included (Table 4). Existing pilot L-DAC facilities are run with natural gas, which releases CO_2 that must also be captured. A 2019 study from the National Academy of Sciences, Engineering and Medicine (NASEM) included a techno-economic analysis of co-locating a PV solar + battery system that supplied electricity directly to a putative million ton L-DAC facility and to an electrolyzer, which produces green hydrogen (H_2) via electrolysis (see Section 6) that can be combusted to drive the calciner operation. The added capital expense of these components leads to a net cost to build of $1,921-3,045 million for a 1 million metric ton CO_2 capture facility.[188]

An average S-DAC system with a 1 million metric ton CO_2 capture capacity is estimated to cost $630-1,700 million to build (Table 3.3).[189] This does not include the cost of building any energy-supplying infrastructure.

Annualizing the total capital costs to a per ton CO_2 cost allows us to better assess total costs of varying carbon management industries by making it possible to calculate the collective cost of capital, operations and energy. Annualizing costs requires assumptions about the lifetime of the plant (typically estimated to be in operation for 20-30 years), and the weighted average cost of capital (WACC), or discount rate, which are used in combination to determine the capital recovery factor (also called the fixed charge rate or annuity factor) - an assessment of the combined cost of equity and debt over the lifetime of the facility.

The capital recovery factor (crf) is determined based on the following equation, where N = the facility lifetime in years: [190,191]

$$crf = (WACC \cdot (1+WACC)^N)/((1+WACC)^N - 1). \quad \text{(E3.2)}$$

Levelized capital costs, in turn can then be calculated as:

$$CapEx (\$/ton\ CO_2) = (Cost\ to\ Build\ Facility/Capture\ Capacity\ of\ Facility) \cdot crf \quad \text{(E3.3)}$$

In Tables 3.3-3.5, capital recovery factors range from 7.5-12.5%. This leads to a levelized CapEx rate (or annualized rate) of $76-205 per ton CO_2 for S-DAC, and $52-365 per ton CO_2 for L-DAC.

[188] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [55]
[189] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. 55]
[190] Fasihi *et al.* (2019) Techno-economic DAC. p. 958. [29]
[191] Carbonplan (no date) DAC cost calculator. [14]

Table 3.3. Estimated costs of S-DAC per metric ton CO_2 captured.

S-DAC				
Cost to build a facility capturing 1 million metric tons CO_2 annually				
$630-1700 million		NASEM (2019) Research Agenda. (Facility lifetime = 30 yrs, Capital Recovery Factor = 12%)		
~$820 million		Fasihi *et al.* (2019) Techno-economic DAC. (Facility lifetime = 20 yrs, Capital Recovery Factor = 9.4%)		
CapEx ($/ton CO_2)	**OpEx+Energy ($/ton CO_2)[a]**	**Energy Source**	**LCA Cost ($/ton CO_2)[b]**	**Reference**
$135	$93	Waste heat	$228	Baker *et al.* (2020) Getting to Neutral.
$191-196	$75-114	Geothermal	$266-310	Baker *et al.* (2020) Getting to Neutral.
$76-205	$11-22	Not included	$87-228[c]	NASEM (2019) Research Agenda.
		Waste heat	$600[d]	Ozkan *et al.* (2022) Current DAC Status.
		Geothermal	$205	McQueen et al. (2021) DAC Review.
		Natural gas	$223	McQueen et al. (2021) DAC Review.
$77	$57-96	Grid electricity ± waste heat	$134-174[e]	Fasihi *et al.* (2019) Techno-economic DAC
			$246	**MEAN Levelized Cost**

a. Energy costs are highly variable due to market fluctuations. The values here reflect energy cost estimates from the sited references at time of publication.
b. Some publications report only levelized cost analysis, without distinguishing capital and operational costs.
c. Some computational inconsistencies are due to rounding.
d. Reported operating cost of Climeworks pilot facility in Switzerland.
e. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.[192]

[192] IRS (no date) Yearly average currency exchange rates. [38]

Table 3.4. Estimated costs of L-DAC per metric ton CO_2 captured.

L-DAC				
Cost to build a facility capturing 1 million metric tons CO_2 annually				
$694-1,146 million		Keith et al. (2018) LDAC.[193] (Facility lifetime = 25 yrs, Capital Recovery Factor = 7.5-12.5%)		
$675-1,255 million		NASEM (2019) Research Agenda. (Facility lifetime = 30 yrs, Capital Recovery Factor = 12%, Natural gas)		
$1,921-3,045 million		NASEM (2019) Research Agenda. (Facility lifetime = 30 yrs, Capital Recovery Factor = 12%, H_2, Solar + battery)		
~$910 million		Fasihi *et al.* (2019) Techno-economic DAC. (Facility lifetime = 25 yrs, Capital Recovery Factor = 9.4%)		
CapEx ($/ton CO_2)	**OpEx+Energy ($/ton CO_2)[a]**	**Energy Source**	**LCA Cost ($/ton CO_2)[b]**	**Reference**
$52-87	$61-76	Grid electricity + natural gas	$113-163	Keith et al. (2018) LDAC.
$56-143	$70-89	Natural gas	$126-232	Keith et al. (2018) LDAC.
$81-151	$66-113	Natural gas	$199-357[c]	NASEM (2019) Research Agenda.
$230-365	$87-136	Green H_2 + Solar + battery	$317-501	NASEM (2019) Research Agenda.
		Natural gas	$94-232[d]	Ozkan *et al.* (2022) Current DAC Status.
$87	$121	Grid electricity	$208[e]	Fasihi *et al.* (2019) Techno-economic DAC
			$231	**MEAN Levelized Cost**

a. Energy costs are highly variable due to market fluctuations. The values here reflect energy cost estimates from the sited references at time of publication.
b. Some publications report only levelized cost analysis, without distinguishing capital and operational costs.
c. LCA is higher than CapEx+OpEx+Energy because it incorporates the cost factor resulting from emitting CO_2 from the natural gas energy source (i.e. every ton CO_2 captured by the process is partially offset by CO_2 emitted, and thus the *net* cost per ton CO_2 removed is greater).
d. Reported operating cost of Carbon Engineering pilot facility in Canada.
e. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.[194]

[193] Keith *et al.* (2018) A process for capturing CO_2 from the atmosphere. p. 1581. [42]
[194] IRS (no date) Yearly average currency exchange rates. [38]

Table 3.5. Anticipated change in cost of DAC[a] per metric ton CO_2 captured.

Anticipated Future LCA Cost ($/ton CO_2)		
2035	$100-200	Ozkan et al. (2022) Current DAC Status
2050	$60	Ozkan et al. (2022) Current DAC Status
2050	$60-80[b]	Ozkan et al. (2022) Current DAC Status

a. Includes both S-DAC and L-DAC.
b. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.[195]

3.4.2.2 Operational costs

Operational costs involve the maintenance and labor for the various equipment pieces and the facility. NASEM (2019) provided a detailed breakdown of operational components for L-DAC facilities and Baker et al. (2020) does the same for S-DAC. Both are summarized in Table 3.6.

Table 3.6. Operational expenses for a 1 million ton CO_2 capture DAC facility.

L-DAC - from NASEM (2019)[196]		
Maintenance	$18-33 million/yr[a]	Estimated as ~3% of total capital requirement
Labor	$6-10 million/yr	Estimated as 30% of maintenance cost
Makeup and waste removal	$5-7 million/yr	Includes replacement of hydroxide solution (≥$500/ton KOH), lime (≥$250/t $Ca(OH)_2$), water (≥$0.30/t H_2O), waste disposal (≥$260/t)
Energy Supply	See Section 2.4.2.3	
S-DAC - Baker et al. (2020) Getting to Neutral.[197]		
Maintenance	~$22 million/yr	~10-17% of total capital requirement (from Baker et al., Fig. 41)
Labor	~$7 million/yr	~30% of maintenance cost (from Baker et al., Fig. 41)
Energy Supply	See Section 2.4.2.3	

a. For a megaton facility, this is equivalent to $18-33/t$CO_2$, and so forth for each cost estimate.

3.4.2.3 Energy costs

A critical variable, and perhaps the most poorly constrained for DAC, is the cost of energy. This is because there is uncertainty about the amount of energy necessary (1.5-3.0 MWh/tCO_2 and 0.9-1.6 MWh/tCO_2, for L-DAC and S-DAC, respectively, as shown in Table 1),

[195] IRS (no date) Yearly average currency exchange rates. [38]
[196] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 207. [55]
[197] Baker *et al.* (2020) Getting to Neutral. p. 86. [6]

how that energy could be sourced (published estimates consider a coal, natural gas, natural gas with CCS, solar, wind, nuclear, geothermal, waste heat or a combination of these), and then, for each of these, their local costs, given regional variability with capacity factor (particularly for solar and wind), and resource accessibility.

Existing pilot DAC facilities use natural gas (Carbon Engineering, L-DAC), geothermal heat (Climeworks Orca Facility, S-DAC) or waste heat (Climeworks pilot facility, S-DAC) as their energy source. With natural gas, or any fossil fuel, either the CO_2 emissions resulting from energy generation must be also captured - adding to the cost of the energy source, or the *net* CO_2 capture capacity of the facility decreases.[198] This is modeled by use of a cost factor, whereby:

$$\text{Cost factor} = 1/1\text{-}x \quad \text{(E3.4)}$$

And x is the amount of CO_2 emitted by the facility per ton of CO_2 captured. If x is near or greater than 1, and thus the cost factor approaches infinity, the facility can be considered uneconomical. If coal is the fuel source, the *net* capture capacity of a million ton facility drops to 0-0.11 million tons CO_2 per year ($MtCO_2$/yr), making it effectively useless. A natural gas facility has a net capacity of 0.11-0.42 $MtCO_2$/yr, and natural gas with CCS (as done by Carbon Engineering) has a net capacity of 0.49-0.99 $MtCO_2$/yr.[199] All non-fossil fuel sourced energy supplies (geothermal, waste heat, nuclear, green hydrogen, wind, solar) have a cost factor that approaches 1, and a net capacity that approaches its intended capacity.

To summarize the range of possibilities, Table 3.7 lists all energy sources considered in the references cited within Tables 3.3 and 3.4, and/or considered in this analysis. Note that for operations that use fossil fuels without carbon capture as their energy source, net capture capacity will be less than intended capacity.

Table 3.7. Energy expenses for a 1 million ton CO_2 capture DAC facility.

L-DAC						
Energy Type		**Energy Need (MWh/tCO_2)**		**Levelized Energy Cost ($/MWh)[a,b]**		**Total Energy Cost ($/$tCO_2$)**
Thermal	**Electric**	**Thermal**	**Electric**	**Thermal**	**Electric**	
Natural gas (NG)		2.1-3.0	0.2-0.5	$19-74		$45-257
NG + CCS (oxy-combustion)		2.1-3.0	0.2-0.5	$50		$117-174
NG+CCS (oxy-comb.)	Solar PV + battery (elec.)	2.1-3.0	0.2-0.5	$50	$28-37 + $15	$151-231
Green H_2	Solar PV + battery (elec.)	2.1-3.0	0.2-0.5	$48-108	$28-37 + $15	$109-350

[198] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 194. [55]
[199] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 203. [55]

S-DAC						
Energy Type		Energy Need (MWh/tCO_2)		Levelized Energy Cost ($/MWh)[a,b]		Total Energy Cost ($/$tCO_2$)
Thermal		Electric	Thermal	Electric	Thermal	
Grid electricity		0.9-1.3	0.15-0.3	$169[200]		$185-278
Waste heat		0.9-1.3	0.15-0.3	$0-29[201]		$0-48
Waste heat	Grid	0.9-1.3	0.15-0.3	$0-29	$169	$26-91
Geothermal		0.9-1.3	0.15-0.3	$56-93		$61-153
Natural gas (NG)		0.9-1.3	0.15-0.3	$45-74[202]		$49-122
NG + CCS (oxy-combustion)		0.9-1.3	0.15-0.3	$50		$55-82
Green H_2		0.9-1.3	0.15-0.3	$48-108		$50-173
Solar PV + battery (elec.)		0.9-1.3	0.15-0.3	$28-37 + $15		$47-86

a. Cost estimates from: 1) Levelized cost of energy analysis - Version 15.0. Lazard. Published online, October 2021. 2) Moch, J.M., *et al.* Carbon Capture, Utilization, and Storage: Technologies and Costs in the U.S. Context. Harvard Kennedy School Belfer Center for Science and International Affairs. Published online January 2022. 3) NASEM (2019) Research Agenda, p. 211. Energy costs are subject to significant market fluctuations. 4. This study (Section 4)
b. Energy costs are subject to significant market fluctuations.

3.4.3 Regional benefits

3.4.3.1 Land availability and renewable energy potential

While the DAC technology itself represents one of the most efficient carbon management techniques available in terms of CO_2-capture potential per acre, the enormous energy requirements of the technology will require a significant land footprint if energy is supplied entirely by renewable energy. Thus DAC facilities aiming to run entirely on fossil-free sources would benefit from locations with optimal solar potential and an abundance of available land (please see Section 3.1.1.2 for detailed analysis).

3.4.3.2 Proximity to optimal underground CO2 storage

For any carbon management technology, levelized cost per ton of CO_2 captured increases significantly as a function of distance from an underground storage site.[203] Being located in

[200] EIA (no date) Average price of electricity monthly. [26]
[201] Bertrand *et al.* (2019) Regional waste heat valorisation. p. 454-468. [7]
[202] Lazard (October 2021) Lazard's levelized cost of energy analysis. [46]
[203] Larson *et al*. (2021) Net-Zero America: Potential Pathways, Infrastructure, and Impacts. p. 221-222. [43]

close proximity with established Class VI EPA wells should reduce operational costs, decrease planning, permitting and construction time for extensive pipeline infrastructure, and increase the business viability of a DAC plant.

3.4.3.3 Co-location advantages

L-DAC requires water and a high-temperature heat source to operate. As such, it would benefit from co-location with energy storage companies designed to provide industrial heat from clean energy—for example, green or blue hydrogen (Section 6) or heat batteries (Section 7), and potentially, water generating industries, such as S-DAC (Section 3.3.1) or some forms of BiCRS technologies (Section 4).

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4. Biomass CO_2 Removal and Storage

TECHNOLOGY AT A GLANCE:

- 2.5 million metric tons CO_2 captured annually by other projects, globally[1]
- Estimated cost per metric ton CO_2 captured: $30-400 USD/ton CO_2
- Projected cost per metric ton CO_2 captured at scale: $61-288 USD/ton CO_2
- ~180-400 acres of land use required per million metric tons of CO_2 captured
- Key advantages of this technology in Kern County: around 470,000 tons of agricultural waste produced annually in Kern Co., close proximity to consumers of low-carbon fuels (including synthetic fuels and green hydrogen) due to California's Low Carbon Fuel Standard (LCFS).
- Key concerns for this technology in Kern County: Differences in potential air impacts from gasification/pyrolysis and combustion of biomass. Changes in biomass waste availability in the future due to climate change. Variable water requirements.

4.1 Technology Summary

Biomass Carbon Removal and Storage (BiCRS) encompasses a range of technologies that convert biomass into smaller molecular components, allowing CO_2 to be separated and sequestered, either through underground storage or in long-lived applications.[2] BiCRS is a

[1] Values in this section are summarized from the suite of references cited herein and are explained in further detail in each subsequent section.
[2] NETL (no date) Carbon Dioxide Removal Program. [64]

relatively new category of carbon management technologies,[3] and is an umbrella term for any technology making use of biomass for the purposes of carbon capture, including Bioenergy with Carbon Capture and Storage (BECCS), one of the longest-established carbon management industries.[4] BECCS is a distinct subcategory of BiCRS because it has a markedly different end goal, despite using the same technological processes. While the rest of BiCRS technologies prioritize CO_2 removal and storage as the primary technological aim, the focus of BECCS is fuel and energy production from biomass, and carbon capture and storage (CCS) represents an optional industrial component that neutralizes the carbon emissions of the primary commodity of power generation.

4.1.1 Description

BiCRS takes advantage of a natural mechanism of carbon dioxide removal: the storage of CO_2 in vegetation via photosynthesis. Rather than allowing stored CO_2 to return to the atmosphere as occurs when plants, trees and other organic matter die and decompose, these resources can be collected and chemically modified to produce clean CO_2 for underground storage ± biofuels. Biomass can be sourced from agricultural, forest, industrial or municipal waste, or from dedicated crops, forestry, or cultivated algae.[5] Generally, waste biomass is the preferred source of BiCRS feedstock because there are fewer competing uses (as in forestry and agriculture), and it typically costs less than biomass sources that require dedicated cultivation (like agriculture or algae).

There are a variety of processes used to convert biomass into CO_2 + other (potentially useful) organic compounds, which are generally divided into categories: biochemical and thermochemical conversion.[6] Biochemical conversion involves using living microorganisms — typically yeast or bacteria — to convert biomass into biofuels, and the most commonly used and simplest biomass-to-energy process in the U.S. is biochemical conversion of corn to ethanol via fermentation.[7] In fermentation, biomass feedstock is pretreated with an acid or base solution to break down biomass cell material into simple sugars.[8] Yeast or bacteria is added to drive fermentation reactions that produce ethanol + CO_2 + residue materials (including water, solvents and residual solids), which are then separated from each other for various uses or sequestration.[9]

A simplified version of the biomass conversion reaction: [10]

$$C_6H_{12}O_6 \text{ (glucose)} \rightarrow 2C_2H_5OH \text{ (ethanol)} + 2CO_2 \text{ (carbon dioxide)} \quad \text{(R4.1)}$$

[3] Sandalow *et al.* (2021) BiCRS Roadmap. p. v. [80]
[4] NETL (no date) Carbon Dioxide Removal Program. [64]
[5] Sandalow *et al.* (2021) BiCRS Roadmap. p. 14-15. [80]
[6] Sandalow *et al.* (2021) BiCRS Roadmap. p. 27-29. [80]
[7] Sanchez *et al.* (2018) Near-term deployment of CCS from biorefineries. p. 4875. [79]
[8] EERE (no date) Biochemical conversion. p. 2. [70]
[9] EERE (no date) Biochemical conversion. p. 2. [70]
[10] ETIP Bioenergy (no date) Ethanol fact sheet. [31]

Other biomass conversion processes add to or amend this process in order to utilize more complex plant structures, like agricultural residues (e.g. straw, corn stover, nut shells, fruit pits) or other lignocellulosic raw materials (e.g. wood chips, waste from forest management).[11] In low temperature deconstruction (also a form of biochemical conversion), enzymes or chemicals are used to break down the more starchy or woody materials into simple sugars in a process called hydrolysis (Figure 4.1).[12] High-temperature deconstruction comprises all *thermochemical* forms of biomass conversion, with the three primary methods being pyrolysis, gasification and hydrothermal liquefaction. Each of these methods use extreme heat and pressure to break down the biomass feedstocks into a suite of solid, liquid and gaseous components.

During pyrolysis, biomass is rapidly heated in an oxygen-free environment to temperatures of 500-700°C to produce gasses and a solid residue (biochar).[13] The biochar is removed, and the gasses are cooled, causing some of the vapor to condense into a liquid "bio-crude" oil. The remaining gas, called syngas (a combination of CO_2, CO, H_2, and light hydrocarbons) can be further distilled to separate the CO_2 from the combustible gasses, which can be used to provide heat for the reaction.[14]

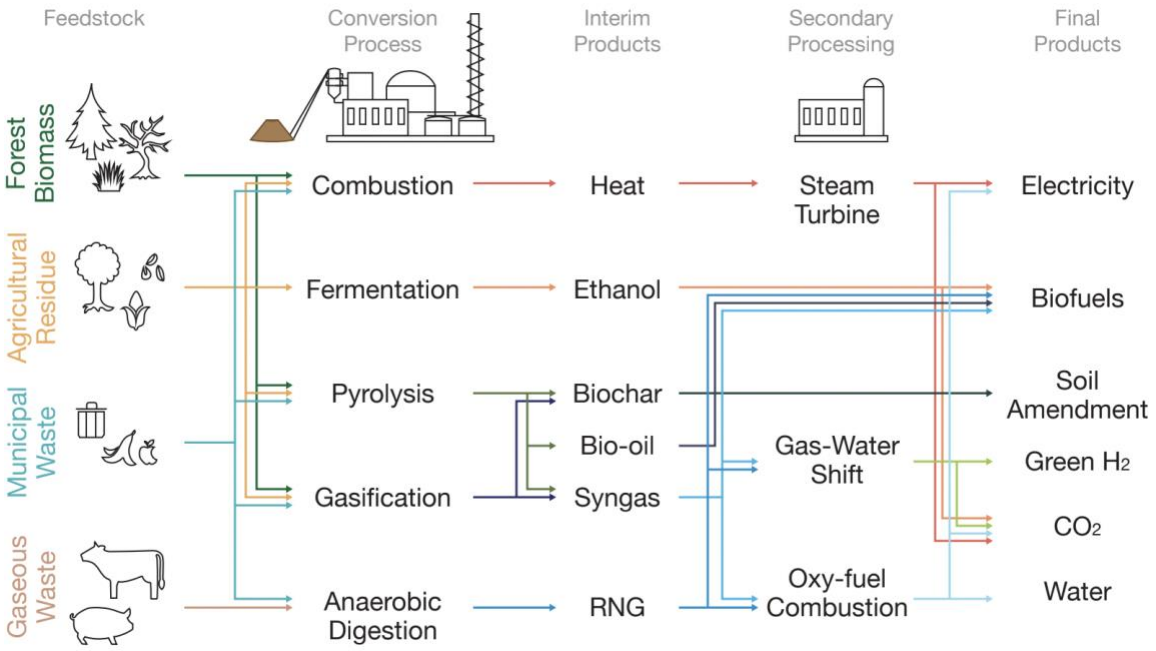

Figure 4.1. Summary of the potential feedstocks, processes, and products of biomass conversion. Adapted from Sandalow *et al.* (2021).[15]

[11] ETIP Bioenergy (no date) Biochemical value chains. [30]
[12] EERE (no date) Biofuel Basics. [71]
[13] EERE (no date) Biofuel Basics. [71]
[14] ARS (no date) What is pyrolysis? [2]
[15] Sandalow *et al.* (2021) BiCRS Roadmap. p. 28. [80]

Gasification occurs under even higher temperature conditions, above 700°C, and in the presence of some oxygen, but the reaction is controlled so that – like pyrolysis – combustion does not take place.[16] Instead, the biomass is converted into CO, H_2 and CO_2.[17] In a second step called a water-gas shift reaction, the carbon monoxide is reacted with water to form more hydrogen gas and carbon dioxide: $CO + H_2O \rightarrow CO_2 + H_2$.[18] The H_2 gas can then be sold as hydrogen fuel, known as green hydrogen.

Hydrothermal liquefaction is the preferred process when using wet feedstocks like algae[19] or municipal solid waste.[20] Thermal conversion takes place under moderate temperatures (200-300°C) and elevated pressures to form liquid bio-crude oil and biochar.

Finally, biomass can be directly combusted to create steam or heat to be used as a direct source of energy. These types of bioenergy power plants can be fitted with post-combustion carbon capture technology that scrubs CO_2 from gaseous byproducts to form a bioenergy with carbon capture and storage (BECCS) power station.[21] CO_2 capture rates can be as high as 90%[22] and it can be retrofitted onto existing power stations.

Post-capture combustion works similarly to point-source capture. An advantage of the technology is that it could easily be retrofitted to existing power plants[23] and is now considered ready for massive-scale deployment.[24] Amine absorption technology is the most common carbon dioxide binding chemical to be used in CCS, but other chemicals such as hot potassium carbonate (HPC) could be viable as well.[25]

Other capture technologies, such as oxy-fuel or pre-combustion technologies, are either relatively untested or inefficient.[26] Oxy-fuel combustion, as the name implies relies on combustion (rather than pyrolysis or gasification) in the presence of a pure or mostly-oxygen gas stream, rather than standard air.[27] The process relies on three primary components: an air separation unit to generate oxygen stream, an oxy-combustion boiler for the combustion itself, and then filtering the flue gas to remove pollutants and compress CO_2 for storage or use.[28] Compared to traditional combustion, oxy-fuel systems produce

[16] EERE (no date) Hydrogen Production: Biomass Gasification. [72]
[17] EERE (no date) Hydrogen Production: Biomass Gasification. [72]
[18] EERE (no date) Hydrogen Production: Biomass Gasification. [72]
[19] EERE (no date) Biofuel Basics. [71]
[20] Sandalow *et al.* (2021) BiCRS Roadmap. p. 28. [80]
[21] Donnison *et al.* (2020) BECCS win-wins. [21]
[22] Adams, Mac Dowell (2016) Off-design point modeling of a 420 MW CCGT power plant [1], as cited in Donnison *et al.* (2020) BECCS win-wins. [21]
[23] Mumford *et al.* (2015) Review of solvent based carbon-dioxide capture technologies. [60]
[24] Bui *et al.* (2018) Carbon capture and storage (CCS): the way forward. [12]
[25] Gustafsson *et al.* (2021) BECCS energy penalty. [43]
[26] Donnison *et al.* (2020) BECCS win-wins. [21]
[27] NETL (no date) Oxy-combustion. [65]
[28] NETL (no date) Oxy-combustion. [65]

about one-fourth the volume of flue gas emissions, making it easier to capture pollutants (including SO_x, NO_x, particulates, and mercury) from the gas, which is primarily composed of CO_2.[29] Furthermore, oxy-fuel pollution can reduce the amount of pollutants formed, such as NO_x.[30] This makes it far easier to purify and capture the CO_2 emissions to abate them.[31] However, challenges—high capital costs, energy usage, and difficulty with oxygen separation—have made it difficult for oxy-fuel combustion systems to be cost-competitive.[32]

4.1.2 State of Development

The key technological elements in BiCRS processes (biomass drying and pelletizing, gasification, anaerobic digestion, biomass boilers, CO_2 capture and separation, geologic storage and monitoring) are mature and commercially available at scale today in various industries, but have been combined for the explicit purpose of biomass carbon removal and storage in only a few instances.[33] 16 facilities are in operation at commercial-scale, though few are exercising their maximum capacity to store the carbon they are extracting from biomass.[34] However, several commercial-scale operations that emphasize carbon management are in the planning, development or pilot phase.[35,36]

4.1.2.1 Commercial Scale Examples

Illinois Basin Decatur Project, Decatur, Illinois

This five-year pilot project is a collaboration of the Illinois State Geological Society (ISGS), the Archer Daniels Midland Company (ADM), Schlumberger Carbon Services, and other subcontractors.[37] CO_2 is sourced as a byproduct of ADM's corn ethanol facility.[38] The pilot plant successfully injected approximately 1 million metric tons of CO_2 derived from biofuel production into a saline reservoir from November 2011 to November 2014. The success of this pilot led to a second commercial scale project, called IL-CCS project, which began operation in 2016.[39]

The IL-CCS project never met its stated aims of annually injecting one million tons of the carbon dioxide byproduct of the ethanol production process, to a depth of more than 7,000

[29] NETL (no date) Oxy-combustion. [65]
[30] NETL (no date) Oxy-combustion. [65]
[31] NETL (no date) Oxy-combustion. [65]
[32] NETL (no date) Oxy-combustion. [65]
[33] Sandalow *et al.* (2021) BiCRS Roadmap. p. 51. [80]
[34] EFI (2022) Surveying the BECCS Landscape. p. 3-4. [28]
[35] Sandalow *et al.* (2021) BiCRS Roadmap. p. 51. [80]
[36] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 149. [62]
[37] Finley (2014) An overview of the Illinois Basin – Decatur Project. [33]
[38] Voegele (December 19, 2016) EC approves state aid for third Drax unit conversion. [93]
[39] Ahlberg (February 20, 2012) Innovation in CCS. [3]

feet in the Mt. Simon Sandstone saline aquifer of the Illinois basin.[40] According to the EPA, the plant's annual sequestered CO_2 emissions as of 2021 are less than 500 thousand tons,[41] which is significantly less than what was projected.[42] ADM receives tax credits of $20 per ton of carbon sequestered, and as of 2020, has received $281 million in total federal funding for both the Decatur and IL-CCS projects.[43,44]

Drax Power Stations, North Yorkshire, UK

The Drax Power Station is a biomass-to-power plant working to transition into a bioenergy + carbon capture and storage (BECCS) facility as part of the Zero Carbon Humber industrial cluster in northern England.[45] The project is supported by the UK Government, with the stated goal of being the first net zero carbon industrial cluster in the nation, with Drax aiming to be carbon-negative by 2030.[46]

Drax converted four out of six existing 645 MW coal power units to generate over 2.5 GW of electricity from biomass combustion.[47] They are in the process of piloting carbon capture and storage technologies to pair with the biomass facility, but cannot fully deploy CCS until transportation and storage infrastructure has been established and there is a policy framework or carbon marketplace in place that allows revenue generation for companies that produce negative emissions.[48] Drax uses wood pellets as the main feedstock of their power plant, primarily sourced from their factories in North America,[49] and estimates they will eventually be able to capture up to 8 million metric tons of carbon dioxide each year, starting with a first BECCS unit operational by 2027.[50]

Kore Infrastructure, Los Angeles, California

Kore Infrastructure has designed a proprietary pyrolyzer unit that can be added to existing installations.[51] Kore's process is a slow pyrolysis process operating at temperatures above 1000°F without oxygen, creating a biogas and carbon-rich biochar as products.[52] Most of the energy requirements are met using the biogas generated by the pyrolysis process, and

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[40] Ahlberg (February 20, 2012) Innovation in CCS. [3]
[41] GHG Data – EPA (no date) Archer Daniels Midland Co. [40]
[42] Hettinger (November 19, 2020) ADM's carbon capture program. [46]
[43] USASpending (no date, information through September 30, 2022) FAIN DEFE0001547 Grant Summary. [90]
[44] Hettinger (November 19, 2020) ADM's carbon capture program. [46]
[45] Drax (no date) BECCS and negative emissions. [23]
[46] Harris (2021) Deployment of bio-CCS: Drax. [45]
[47] Harris (2021) Deployment of bio-CCS: Drax. p. Summary-6. [45]
[48] Harris (2021) Deployment of bio-CCS: Drax. p. 6-7. [45]
[49] Drax (no date) Our History. [26]
[50] Frontier Economics (2021) Supporting BECCS. p. 4. [34]
[51] Kore Infrastructure (no date) A Fully Integrated System. [55]
[52] Kore Infrastructure (no date) A Fully Integrated System. [55]

the overall reaction generates more energy output than it consumes.[53] Once created, the generated biogas can be upgraded into renewable natural gas (RNG) or hydrogen.[54] Their business model is designed to meet multiple needs, either by setting up their system—along with biomass procurement and operation and maintenance assistance—for another company's onsite location, or by offering waste or energy services, by serving as waste disposal or as a source of natural gas, hydrogen, biogas, or biochar.[55] Currently, their largest operating facility is located in Los Angeles and serves SoCalGas, processing 24 tons of feedstock daily.[56] The SoCalGas facility opened in August 2021.[57]

Their process is rated at technology readiness level 7,[58] meaning it had a successful operating pilot at commercial-scale.[59] Given the approval of strict air quality districts in California and their eligibility for LCFS credits for biogas, RNG, or hydrogen gas,[60] it can be reasonably expected that Kore expects their operations to be scalable in the California market.

4.1.2.2 Development Phase Examples

Clean Energy Systems, multiple sites in California

Rather than building facilities from scratch, Clean Energy Systems (hereafter CES) has been purchasing old biomass power plants throughout California and retrofitting them to bring them back online as BiCRS facilities.[61] Within Kern County, CES has been running a biomass plant at Kimberlina as a 'proof of concept' facility,[62] a 40-acre site for R&D, sub-commercial, and commercial activities and currently the world's largest oxy-fuel combustion plant.[63] Their largest project currently in permitting is the Mendota BiCRS Project.[64] At Mendota, CES plans to set up a 20-year commercial facility that will convert biomass into carbon-negative grid electricity using oxy-fuel combustion.[65]

CES's oxy-fuel combustion system works by burning fuels (including, but not limited to, natural gas, gas generated on-site, synfuel, and landfill or bio-digester gas) alongside

[53] Kore Infrastructure (no date) A Fully Integrated System. [55]
[54] Kore Infrastructure (no date) A Fully Integrated System. [55]
[55] Kore Infrastructure (no date) A Fully Integrated System. [55]
[56] Kore Infrastructure (no date) A Fully Integrated System. [55]
[57] Kore Infrastructure (no date) A Fully Integrated System. [55]
[58] Kore Infrastructure (no date) A Fully Integrated System. [55]
[59] GAO (2020) Technology Readiness Assessment Guide. p. 11. [42]
[60] Kore Infrastructure (no date) A Fully Integrated System. [55]
[61] Industry representative, personal communication, October 4, 2022.
[62] Industry representative, personal communication, October 4, 2022.
[63] Clean Energy Systems (no date) Site Locations. [19]
[64] Clean Energy Systems (no date) Mendota BiCRS. [17]
[65] Clean Energy Systems (no date) Mendota BiCRS. [17]

oxygen gas and water "at near-stoichiometric conditions."[66*] Crucially, the water in question can be recycled or even untreated water without inhibiting the oxy-fuel combustion reaction.[67] The primary products of the reaction are CO_2 and steam, with CES reporting carbon capture rates of 100% for the produced CO_2.[68] However, how CES plans to store or use their captured CO_2 seems unclear. The EPA reports their Class VI well application was withdrawn,[69] and their website's suggestion of using captured CO_2 for enhanced oil recovery (EOR)[70] would violate language in California's SB 1314.[71]

Mote, Los Angeles, California

Mote, a Culver City-based cleantech startup, is planning to build a $100 million biomass to hydrogen energy plant with carbon sequestration on 5 acres of unincorporated land in Kern County, pending securing financing, government approval and permits.[72] The plant will extract carbon dioxide and hydrogen via gasification from wood waste from farms, forestry, and other resources.[73] The hydrogen gas will be sold to hydrogen fuel station operators, and the CO_2 will be sequestered into deep underground saline aquifers or retired oil wells.[74] Mote's first facility expects to produce approximately 60,000 kg of carbon-negative hydrogen (green hydrogen) per day, which translates to 450,000 tons of CO_2 captured per year from biomass and available for permanent sequestration.[75]

Mote's business model will provide cost-competitive green hydrogen and carbon removal credits to the wide economy and take advantage of rebates from the federal tax credit for CCS projects (45Q) as well as California's Low Carbon Fuel Standard (LCFS).[76] In May 2022, Mote announced that they had secured commitments for over 450 thousand tons of feedstock for their production.[77] Working with Fluor, an industry leading engineering, procurement and construction (EPC) firm, to execute the Front-End Loading 2 (FEL-2), Mote plans to begin construction in 2023 and be fully operational by 2025.[78]

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[66] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
* Under stoichiometric conditions, the proportion of air (in this case, oxygen) to fuel is such that all of the combustible material will be completely combusted, leaving no oxygen remaining.
[67] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
[68] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
[69] EPA (April 24, 2023) Class VI Wells Permitted by EPA. [29]
[70] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
[71] IEA (November 4, 2022) SB 1314. [47]
[72] Fine (January 3, 2022) Mote unveils plans for carbon capture plant. [32]
[73] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [87]
[74] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [87]
[75] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [87]
[76] Mote Hydrogen (no date) Mote. [59]
[77] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [13]
[78] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [13]



Figure 4.2. Digital rendering of a planned Mote Hydrogen facility in southern California, featuring a parking lot, office buildings, a gasifier building with conveyor belts for moving biomass, several large vertical tanks, and two evaporation ponds. Credit: Mote, Inc.

InterEarth, Australia

InterEarth is in the pilot phase of its operations, investigating the efficacy of shallow biomass burial. Their current model involves heavily trimming local trees, digging six-meter deep pits into salty groundwater, burying the tree matter and monitoring equipment, and refilling the pit to test if the salty water will successfully prevent the organic materials from releasing their stored carbon dioxide.[79*] Tests of the efficacy of their model are still ongoing, but they estimate that – if successful – the technology could be used to bury as much as 1 billion metric tons of carbon (nearly 4 billion metric tons of CO_2) annually, at a cost of less than $50 USD per ton.[80] At least 4-5 more years of monitoring the pilot projects are necessary to establish the efficacy of the technique. For reference, globally, about 140 billion tons of biomass waste is produced each year.[81]

Charm Industrial, San Francisco, California

Charm Industrial is a new start-up utilizing a two-part pyrolysis processing model, which should reduce the physical footprint required for a facility.[82] In general, pyrolysis generates biochar (or charcoal), bio-oil, and hydrogen gas, but the proportions of the products are dependent on the speed and heat of the pyrolysis process.[83] For their feedstock, Charm has

[79] Rathi (March 15, 2022) Carbon Pickling. [77]

* The 'salty groundwater' in question here is not naturally formed saline aquifers, which would be found much deeper than 6 meters below ground, but salty groundwater formed after farming practices in the region disturbed the groundwater table and accelerated the accumulation of salt. See Rathi (March 15, 2022) Carbon Pickling [77] for more information.

[80] Rathi (March 15, 2022) Carbon Pickling. [77]

[81] Tripathi *et al.* (2019) Biomass waste utilisation in low-carbon products. [88]

[82] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]

[83] Bolan *et al.* (2022) Applications of Biochar. p. 151. [9]

been utilizing agricultural wastes from central California.[84] Charm has experimented with yielding a variety of pyrolysis products in their efforts to sequester carbon dioxide—originally they looked at maximizing biochar yield, then pivoted to hydrogen production, and currently have found success in focusing on bio-oil.[85] Bio-oil is viscous and prone to solidifying, making it a weak fuel source but a promising candidate for carbon sequestration, as its tendency to solidify makes carbon dioxide leaks highly unlikely.[86] Furthermore, working with bio-oil has cost advantages over other forms of sequestration; bio-oil "would be cheaper to inject than CO2 gas captured from the air or from a power plant, since CO2 has to be compressed into a form that can be pumped underground."[87] However, financing larger projects using Charm's bio-oil process will likely rely on changes within the federal and state policy landscape. Bio-oil sequestration is currently not eligible for the federal 45Q tax credit program or recognized by California's Low Carbon Fuel Standard (LCFS), though Charm is pushing for policy changes to recognize the potential of bio-oil.[88] Charm is optimistic about scaling up their operations in the near future and Kern County could be a favorable location, as Charm indicates they are looking for new sites to operate with minimal transportation needs and available agricultural waste for feedstocks.[89]

4.1.2.3 Planning Phase Examples

San Joaquin Renewables Project, McFarland, California

The San Joaquin Renewables (hereafter SJR) project is a planned venture of Frontline Bioenergy, an Iowa-based company currently operating a commercial-scale gasification plant in Montana and a demonstration pyrolysis plant in Iowa.[90] According to SJR, the project will operate as a renewable natural gas (RNG) facility and could be considered either a BiCRS or BECCS project—they are aiming to maximize their potential bioenergy output from agricultural waste via gasification, but will also be sequestering carbon dioxide on-site "deep underground in an EPA class VI sequestration well."[91] The SJR project is in permitting with the City of McFarland, California and has secured up to $165 million in funding for development and construction from Cresta Fund Management and Silverpeak Energy Partners.[92] SJR is also seeking permitting to site their class VI well for carbon

[84] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[85] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[86] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[87] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[88] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[89] Reinhardt (October 21, 2021) Largest Permanent Carbon Removal Delivery of All Time. [78]
[90] Frontline Bioenergy (no date) Our Projects. [35]
[91] San Joaquin Renewables (no date) The Project. [81]
[92] NewsWire (October 27, 2021) San Joaquin Renewables Secures $165 Million. [69]

sequestration within the City of McFarland; their permit application is still undergoing review by the EPA.[93]

SGH2 Energy, Lancaster, California

SGH2 Energy is a producer of green hydrogen using a patented "plasma-enhanced thermal catalytic conversion process" of gasification which operates at temperatures of 3500°-4000°C and produces a clean stream of hydrogen and carbon dioxide with reportedly "no toxins or pollution."[94] A plan for permanent CO_2 storage has not yet been specified by the company. According to SGH2's technical overview, "Lawrence Berkeley National Lab has found that for every ton of hydrogen produced, our process displaces 23 to 31 tons of carbon dioxide. That's 13 to 19 tons more carbon dioxide avoided than other fossil-free hydrogen production processes, which rely on electrolysis from renewable energy."[95] Their process has yet to be tested at commercial scale. Costs per kilogram of hydrogen produced by this process are competitive relative to the existing hydrogen market, as they estimate a cost of $2-3/kg hydrogen for their process compared to a $10-13/kg hydrogen range for electrolysis-based blue hydrogen production.[96] SGH2 Energy is planning to build a facility in Lancaster, California, just south of Kern County's boundary with LA County. The Lancaster plant would generate 3.8 million kg of green hydrogen utilizing 42,000 tons of recyclable waste annually supplied by the City of Lancaster, saving the city an estimated $50 to $75 per ton of waste annually due to avoided landfill space and processing costs.[97] The City of Lancaster is required to sort and supply a feedstock of recyclables for use by SGH2 Energy, and in exchange, will receive co-ownership of the facility.[98] The Lancaster facility is designed for a 5-acre industrial lot scheduled to open in the first quarter of 2023, and is estimated to support the creation of 35 full-time positions once operational.[99]

4.1.3 Operational Needs

4.1.3.1 Land use requirements

A BiCRS facility designed for commercial scale will likely have a large physical footprint, as the volumes of biomass to be sorted and converted will be extensive and need appropriate space to be stored and treated.[100] The overall land footprint for BECCS is estimated at between 1,000 and 17,000 km^2 per million tons of CO_2 removed, depending on location and the source for the biomass (e.g. forest and agricultural residues, and purpose-grown

[93] EPA (April 24, 2023) Class VI Wells Permitted by EPA. [29]
[94] SGH2 Energy (no date) Technology. [83]
[95] SGH2 Energy (no date) Technology. [83]
[96] SGH2 Energy (no date) Technology. [83]
[97] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[98] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[99] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[100] Koornneef *et al.* (2012). Global potential for biomass and carbon dioxide capture, transport and storage. [54]

energy crops).[101] Since we are focusing on scenarios where facilities could rely on existing waste biomass—rather than growing dedicated crops—we have chosen to emphasize the likely footprint of the facility itself where pyrolysis, gasification, or other biomass conversion would take place.

Based on scaling existing facility size estimates and interviews with industry representatives, the estimated physical footprint for a BiCRS facility capturing 1 million metric tons of CO_2 annually is 180 to 400 acres. The unscaled estimates, with their years indicated and estimated capture capacity represented by circle size, are illustrated in Figure 4.3. These estimated acreages do not account for land used to grow biomass for processing (as ideally, biomass will be sourced as waste from existing local agriculture and forestry partners) or external energy use needs, which will vary by plant design and efficiency.

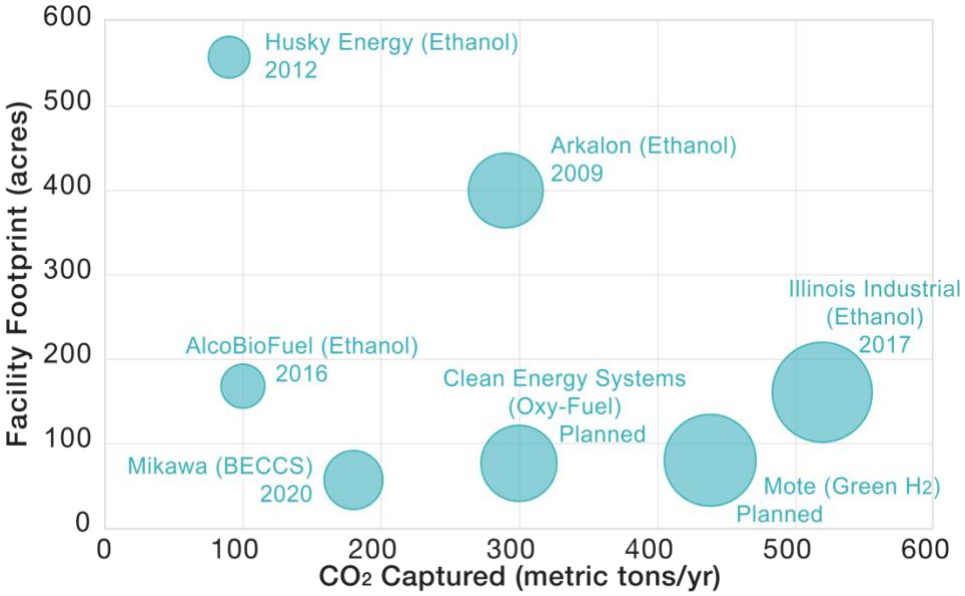

Figure 4.3. Land use requirements of existing and planned BiCRS/BECCS facilities as a function of their CO_2 capture potential. Footprint sizes were either reported directly from operator data or were measured digitally using publicly available satellite imagery.

The plant itself will typically involve a small handful of buildings (3-5) with a conveyor belt to bring in biomass from outdoors, as well as piles of biomass for processing and (depending on the facility) evaporation ponds for wastewater.[102] The tallest installation at a facility would be a gas flare, with an estimated height of 100 feet.[103] Typically, most of the acreage for a plant is dedicated to biomass storage and electricity generation.[104]

[101] IEA (2020) CCUS in Clean Energy Transitions. p. 87. [49]

[102] Industry representative, personal communication, September 8, 2022.

[103] Industry representative, personal communication, September 8, 2022.

[104] Industry representative, personal communication, September 8, 2022.

4.1.3.2 Energy requirements

The energy requirements of a BiCRS facility are opaque. Based upon the variety of conversion methods available and the lack of commercial-scale facilities operating with the goal of sequestration, rather than bioenergy, there is a wide error range for any estimates about energy usage. As such, it is best to evaluate projects billed as BECCS projects on their energy requirements, as there is a greater availability of information to analyze.

As bioenergy facilities, BECCS facilities will have an energy-positive process—meaning they produce more energy output than they consume to process the biomass via pyrolysis or gasification. This energy output can be producing electricity for the grid or generating synthetic fuels for consumers. For every metric ton of CO_2 captured at a BECCS facility, the estimated energy output is 0.83 MWh.[105] This is simply a representative example for a woody biomass-based facility but other estimates may differ substantially, as many bioenergy projects only report their energy output, not the total energy generated or the amount used to sustain their pyrolysis or gasification reactions, and the energy content of the biomass material may differ.

Due to the high temperatures needed for pyrolysis or gasification, facilities require an energy source for heat. For BiCRS/BECCS, this energy is typically supplied by the biomass itself, which contains energy, or by the fuels (syngas, hydrogen, or other products) that are produced on-site as products by breaking down biomass. Depending on the model, some pyrolyzers need external fuel to start the process,[106] which can be supplied from renewable sources like green hydrogen, renewable natural gas (RNG), or biodiesel.

For BECCS, energy requirements will also depend greatly on the plant's thermal efficiency.* Capturing carbon dioxide from the flue gas, which is commonly the source of carbon dioxide in post-combustion technology, of an energy conversion plant requires energy input.[107] As a result, the net energy efficiency of the plant is lowered. However, larger BECCS power stations are expected to have higher thermal efficiencies at 30% - 36%.[108] Higher thermal efficiency means the plant requires less energy to run the system, and subsequently lowering the cost of capital and operating expenses. Although current operational BECCS plants have yet to reach the million metric tons of CO_2 capture range, recent BECCS development shows that larger plant sizes are feasible.[109] For instance, Drax

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[105] NREL (2022) Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. p. 13. [66] In this report, the finding is reported as net negative emissions of 1.2 metric tons of CO_2 per MWh—converting to be in terms of per metric ton of CO_2 gives the 0.83 MWh figure reported above.

[106] Industry representative, personal communication, September 21, 2022.

* Thermal efficiency is a performance measure of a device that uses thermal energy, which measures the ratio of the heat that becomes useful work.

[107] Bui *et al.* (2017) Bio-energy with CCS (BECCS) performance evaluation [11], as cited in Gustafsson *et al.*, (2021) BECCS energy penalty. [43]

[108] Austin (no date) Size matters [7], as cited in Donnison, *et al.* (2020) BECCS win-wins. [21]

[109] IEA (2020) CCUS in Clean Energy Transitions. [49]

Power Station has a capacity from biomass of 2,595 MW[110] and, as of 2018, operates with a thermal efficiency of 38% or more.[111] They estimate that the installation of CCS equipment in their power plant will decrease their thermal efficiency to 37%, so the change in efficiency due to the addition of carbon capture will be relatively small.[112]

4.1.3.3 Other operational requirements

Waste disposal requirements

The reaction products for biomass conversion and their disposal requirements will differ depending on the conversion process used by a given company. Reaction products outside of the main three—solid biochar, liquid bio-oil, and hydrogen gas—typically fall into the following categories.

Unless operating at extremely high temperatures, biomass processing generates ash and fine particulates, which can be accumulated and sold as a fertilizer product.[113] Water is often used in these processes for cooling or scrubbing, generating varied qualities of wastewater—some processes generate water clean enough for direct reuse in agricultural irrigation, whilst others hold wastewater and sludge in on-site evaporation ponds until it can be sent for proper treatment.[114, 115] Although some reaction products can be reused in other applications, non-hazardous industrial wastes will have to be landfilled. Items in this category include spent catalyst and any solid waste generated from spent material, like dolomite, silicates, or heavier ash.[116]

Of the standard three products generated via biomass pyrolysis, biochar is typically the least sought-after product, as bio-oil and hydrogen gas can both be upgraded into usable fuels. This means the solid biochar, or charcoal, generated by a pyrolysis-based biomass plant needs a designated end-of-life trajectory. Fortunately, biochar is both safe and more useful than most industrial waste products, and thus is less likely to be landfilled or otherwise discarded. A range of academic literature on biochar has identified uses including carbon storage, as a soil amendment, as a soil conditioner for contaminant immobilization, or as a catalyst for various uses.[117,118] Resale of biochar for agricultural uses is the most common existing use, as it can be added in livestock feed, used as a treatment for increased soil fertility, or mixed in with compost or other organic materials to prevent

[110] Drax (no date) Drax Power Station. [24]
[111] Drax (May 11, 2018) Tweet. [27]
[112] Donnison *et al.* (2020) BECCS win-wins. [21]
[113] Industry representative, personal communication, September 8, 2022.
[114] San Joaquin Renewables (no date) The Project. [81]
[115] Industry representative, personal communication, September 8, 2022.
[116] Industry representative, personal communication, September 8, 2022.
[117] Bolan *et al.* (2022) Applications of Biochar. p. 151. [9]
[118] Lee, Kim, Kwon (2017) Biochar as a Catalyst. p. 70. [58]

nutrient leaching.[119] Biochar can also be used to remediate sites contaminated by oil and gas or mining operations, as its high porosity makes it a promising material to sequester chemicals from heavy metals to volatile organic carbons (VOCs).[120] There have also been studies conducted regarding the viability of using biochar as a cover for landfill waste disposal.[121]

Warehousing requirements

Warehousing for a BiCRS operation will likely need to be extensive, as any commercial-scale facility would likely be dealing with thousands of tons of biomass daily for processing.[122] The source and quality of the feedstocks—for example, if it's delivered already dehydrated or in its raw form—will likely dictate the amount of space needed for biomass storage. There will also need to be ample space for storing byproducts like biochar before their sale or disposal. In interviews with experts,[123] facility size was estimated to require approximately 80 acres of land to accommodate the storage of feedstocks, on-site electricity generation, and evaporation pools for wastewater, as well as necessary buildings for processing. Gas-fired facilities would be 3 stories tall and processing is estimated to require 3 of these buildings, though figures on estimated square footage are unavailable. Other facilities have had much smaller warehousing requirements—SGH2 Energy's entire Lancaster hydrogen plant fits on a 5 acre industrial lot because their feedstocks are regularly replenished under their agreement with the city, reducing the need to store large amounts of feedstock on-site.[124] Based upon this wide range of warehousing needs and total acreage presented by biomass firms, this requirement is likely flexible depending on contract terms and the feedstocks being processed.

Transportation requirements

In capturing carbon dioxide from biomass for sequestration, the most preferred facility sites are either co-located with a viable biomass source to eliminate transporting biomass, or located on-site with a sequestration well, to avoid needing to transport carbon dioxide for storage.[125] Transporting biomass often requires some pre-processing and is conducted using trains or trucks. When possible, rail is preferable to trucking, as it has lower costs—especially over longer distances—and lower externalities, according to the Government Accountability Office (GAO).[126] Rail can require upfront investments to build new tracks,

[119] Usmani (August 25, 2021) Things You Should Know About the Different Uses of Biochar. [91]
[120] Simekin Inc. (no date) Biochar. [85]
[121] Bordoloi *et al.* (2021) Role of biochar as a cover material in landfill waste disposal system. [10]
[122] Approximately 1,000 tons per day biomass for a 400k CO_2/yr facility (According to data from an industry representative, personal communication, September 8, 2022).
[123] Industry representative, personal communication, September 8, 2022.
[124] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[125] Stolaroff *et al.* (2021) Transport for Carbon Removal Projects. p. 3. [86]
[126] Stolaroff *et al.* (2021) Transport for Carbon Removal Projects. p. 3. [86]

depending on the region's existing infrastructure, so trucks are typically used for shorter distances.

Byproducts of BiCRS processes, from hydrocarbon fuels and grid electricity to biochar, would require transportation offsite to be used by customers. These transportation considerations should be taken seriously, as without proper planning, the carbon efficiencies of BiCRS could be lost in trying to sustain a market for related goods reliant on increased carbon emissions for transport.

Infrastructure & Pipeline requirements

Initial deployment of BiCRS should consider the availability of surrounding existing infrastructure to minimize the costs and complexities of long-distance transport of either carbon dioxide, biomass feedstock, and biofuel distributions.

Given that Kern County has appropriate geology for long-term carbon sequestration underground, any BiCRS facility should try to locate as close to an injection site as possible, limiting the need for extensive pipework to handle the supercritical carbon dioxide fluid. However, the pipeline requirements for carbon dioxide are not specialized—their requirements are well-understood due to decades of prior manufacturing and use in the U.S. For more details on carbon dioxide transport, particularly pipeline transport, please refer to Section 9 of this report.

Other requirements

Sequestering carbon underground requires clearing a number of legal and permitting hurdles. Although Kern County and other parts of California's Central Valley are seen as prime real estate for carbon sequestration from a geological perspective, it may be more complex to get all of the legal and regulatory matters aligned and have local landowners on board.[127]

Another hurdle comes into play when using hydrogen as fuel: "There is very little refueling infrastructure and even fewer fuel cell-powered heavy duty vehicles" already in existence.[128] Ensuring biomass-to-hydrogen production timelines match up with the development and scale of hydrogen-fueled technology will be critical to the success of a green hydrogen project. For further exploration of biomass-based green hydrogen considerations, please see Section 6 of this report.

4.1.4 Carbon Capture Potential

The carbon capture potential of BiCRS and BECCS is highly promising, though restricted regionally based on resource use constraints. On average, "biomass is roughly half carbon by weight," so if processed efficiently the carbon removed from biomass is substantial.[129]

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[127] Baker *et al.* (2020) Getting to Neutral. p. 7. [8]

[128] Hanley (May 22, 2020) Lancaster, California Will Be Home To World's Largest Renewable Hydrogen Plant. [44]

[129] Sandalow *et al.* (2021) BiCRS Roadmap. p. 7. [80]

However, biomass can also be utilized for other applications in agriculture and construction that also repurposes or stores its carbon content—often the local context will determine if the financial cost and carbon benefits balance out in favor of a BiCRS or BECCS facility, or repurposing products for other uses.

Based upon the best estimates in the literature, experts posit that "roughly 2.5 to 5.0 $GtCO_2$/year could be removed from the atmosphere and stored by 2050 using biomass produced with minimal environmental impact."[130] Here, 'minimal environmental impact' means without repurposing other productive landscapes, like agricultural lands or forests, to grow biomass dedicated crops or using other carbon-rich materials like forests for biomass feedstocks.

Furthermore, biomass that decays anaerobically in other settings, like landfills, produces methane in addition to carbon dioxide, thus contributing multiple greenhouse gas emissions into the atmosphere.[131] Thus for biomass-rich materials that are routinely landfilled, such as household organic wastes, the carbon removal potential could be even greater than expected as it would prevent the production of multiple forms of carbon-based pollutants.

However, quantifying the overall impacts of a BiCRS or BECCS facility will depend on the full life-cycle analysis (LCA) of a specific project. In a full LCA, it would be possible to identify how much carbon the plant material holds and the amount that could be captured in a given gasification or pyrolysis process, but also the carbon intensity of other steps, like transporting biomass, processing and/or dehydrating biomass, or sending finished products aside from CO_2 to market. Existing LCAs conducted for different BECCS models have indicated that net emissions can differ considerably depending upon the feedstock, conversion method, and carbon capture method used by a given facility.[132]

4.2 Societal Impacts

4.2.1 Job creation potential

4.2.1.1 Number and types of jobs

Because BiCRS facilities at commercial scale are quite rare, the most relevant data to approximate job creation is to examine commercial-scale BECCS operations using likely BiCRS feedstocks available in Kern County, namely agricultural waste and municipal organic waste.

[130] Sandalow *et al.* (2021) BiCRS Roadmap. p. vi. [80]

[131] LMOP (April 21, 2023) Basic Information About Landfill Gas. [56]

[132] Almena *et al.* (2022) Carbon dioxide removal potential from decentralised bioenergy. p. 9-11. [5]

Fulcrum Bioenergy's first commercial plant in Reno, NV, capable of processing 175,000 tons of landfill waste annually, supports over 100 permanent jobs.[133] Looking at estimates for upcoming projects under Fulcrum's umbrella, there is also a large requirement for construction workers to build these facilities—anywhere from 1,000 to 1,200 jobs created in the construction process, though these positions are not permanent.[134,135] San Joaquin Renewables, who is planning to sequester carbon on-site though at a smaller facility, predicts its operation will sustain 45-50 full-time employees.[136] In industry interviews, some operators estimated smaller staff needs—closer to 25 for a full facility, even for a facility processing up to 219,000 tons of biomass annually.[137] Given this wide range of jobs figures across different biomass facility models, it appears that permanent job creation is not clearly correlated with facility capacity.

The Drax plant in the UK, as it converts from bioenergy to BECCS, is estimated to generate over 4,000 direct jobs annually during the CCS construction phase from 2024 to 2028.[138] Once Drax has been fully converted to BECCS, it is expected to support an estimated operations and maintenance staff of up to 800 employees.[139] After the facility is operational, it could further generate 2,300 indirect and 4,100 induced jobs.[140] Given that Drax claims that full BECCS operations at their facility would result in the removal of about 8 million metric tons of CO_2 per year, which would make it the largest CO_2 capture and storage project globally,[141] it makes sense that these estimates are much higher than those of other BiCRS or BECCS facilities.

It is worth noting that scaled estimates for the million metric tons per year of CO_2 capture range for other facilities generate much smaller estimates, somewhere in the range of 45 to 150 full-time jobs created. Although some estimates range lower or higher, as seen in Table 4.1, the 45 to 150 range seems like the most consistent estimate based on both scaling existing facilities and any literature estimates, with an average of 102 jobs estimated per million metric tons of CO_2 captured annually. It is important to note that biomass facility jobs are not expected to necessarily scale linearly with plant size (in terms of CO_2 capture potential), as can be seen in the range of permanent jobs associated with already-existing facilities. Furthermore, the possibilities of increased automation and remote monitoring means that steps should be taken in the planning and permitting process to ensure jobs for any new carbon management facility benefits local communities.

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[133] Fulcrum BioEnergy (no date) Sierra BioFuels Plant & Feedstock Processing Facility. [37]

[134] Fulcrum BioEnergy (no date) Trinity Fuels Plant. [38]

[135] Fulcrum BioEnergy (no date) Centerpoint Biofuels Plant. [36]

[136] San Joaquin Renewables (no date) The Project. [81]

[137] Industry representative, personal communication, October 4, 2022.

[138] Vivid Economics (2020) Delivering Jobs at Drax. p. 18. [92]

[139] Vivid Economics (2020) Delivering Jobs at Drax. p. 19. [92]

[140] Vivid Economics (2020) Delivering Jobs at Drax. p. 25. [92]

[141] Drax (July 12, 2022) Drax submits plans to build world's largest carbon capture and storage project. [25]

Table 4.1. Job creation estimates for planned and current BiCRS/BECCS facilities, globally.

Facility Name[a]	Year Operational	Annual CO_2 Capture[b]	Reported Jobs		Scaled Employment (per 1MtCO_2/yr)	
			Perm.[c]	Const.[d]	Perm.[c]	Const.[d]
Drax Power Station, Humber, UK	2024-2028	8	800	4,000	100	500
Mendota BiCRS Project, Mendota, CA	Future	0.3	25		83	
Calgren Renewable Fuels, Pixley, CA	2015	0.15	20		133	
Mote, Los Angeles, CA	2024	0.438	100		228	
Stockholm Exergi, Stockholm, SE	2019	0.8	35		44	
Illinois Industrial CCS, Decatur, IL	2017	0.444	11		25	
AVERAGE					**102**	**500**

a. Facility details are fully outlined in Appendices A-C.
b. In million metric tons (Mt). Where actual figures are available, they are used, otherwise data reported correspond with press releases or projections.
c. Permanent jobs.
d. Construction jobs.

4.2.2.2 Training pipelines

In conversations with industry experts, we found that oftentimes, facilities like to recruit locally where possible, though local hiring can be dependent on the specific skills needed. Some facilities that specialize in retrofitting old power plants or other infrastructure into BiCRS or BECCS facilities have found that since existing employees already know the plant well, they can be easily kept on and retrained as necessary, keeping all workforce demands local.[142]

For the Drax plant, there are concerns regarding the challenges in labor and skills supply due to the lack of specialist skill in key manufacturing sectors as required by the plant.[143] This will need to be addressed with a combination of a direct apprenticeship scheme, early investment in the next generation of workers, and endorsement of vocational work at a local school.[144]

[142] Industry representative, personal communication, October 4, 2022.
[143] Vivid Economics (2020) Delivering Jobs at Drax. p. 29. [92]
[144] Vivid Economics (2020) Delivering Jobs at Drax. p. 29-30. [92]

4.2.2 Quality of Life

4.2.2.1 Location

At existing biomass-based plants, noise is a common concern for area residents. For example, a safety valve at the Drax Power Station, when opened, generates a sound so loud that residents 2.5 miles from the station reported that they were awoken by the noise.[145] It is anticipated that mitigation is possible with sound-dampening design within buildings.[146] Siting away from residential areas and incorporating sound dampening materials in construction would likely mitigate noise at nearby communities.

Given that burning is the traditional disposal method for agricultural and forestry wastes, moving to process agricultural waste at a BiCRS or BECCS facility could lead to lower emissions; potentially up to 95-99% lower than they would be if the biomass was burned instead.[147] Biomass-based facilities which produce emissions or pollutant discharge will need to adhere to a federal Title V operating permit. For Kern County, developers would need to obtain permit authorization to construct and operate before commencing construction, and a permit to operate from Eastern Kern Air Pollution Control District (EKAPCD) or San Joaquin Valley Air Pollution Control District (SJVAPCD).[148]

4.2.2.2 Multi-use potential

There is multi-use potential for BECCS and BiCRS facilities, although examples are limited. Feedstock generation from nearby agricultural waste can be considered a multi-use byproduct of the primary agriculture industry. For the facilities themselves, noise pollution generated by biomass processing would need to be addressed, but co-locating community facilities with processing plants is possible. A waste-to-energy plant located in central Copenhagen, Denmark – called Amager Bakke – was designed to be a public recreational facility as well as a power plant.[149] The building, which converts municipal waste to electricity, is topped with a hiking trail and artificial ski slope. While Amager Bakke does not capture CO_2, it sets a precedent for the possibility of innovative proposals that could integrate other businesses or community facilities with BiCRS/BECCS facilities.

[145] The York Press (January 26, 2008) Drax fault causes 'deafening' noise. [89]
[146] Doyle (2015) White Rose Carbon Capture and Storage (CCS) Project: Environmental Permit. [22]
[147] San Joaquin Renewables (no date) The Project. [81]
[148] CARB (no date) California Air Districts. [14]
[149] Crook (October 8, 2019) BIG opens Copenhill power plant topped with rooftop ski slope in Copenhagen. [20]

4.3 Environmental Impacts

4.3.1 Water requirements

4.3.1.1 Minimum volume requirements

Water requirements vary depending on the conversion process used to process the biomass intake, but is low under every well-understood conversion pathway. The largest lifetime intake of water in the BiCRS life-cycle is that required for actually growing the biomass in question. As long as dedicated feedstock crops are not being grown to sustain the facility (i.e. the biomass in question is agricultural or forestry waste), it is likely the water would have been used anyway. In fact, biomass is frequently 'de-watered' before conversion, aside from supercritical water extraction,[150] so it's actually likely that facilities will be generating some volume of wastewater in the process.

However, in case there needs to be a dedicated feedstock crop to feed the facility, sustainable agriculture practices which reduce water consumption could reduce the additional water withdrawal.[151] However, a study shows a potential tradeoff between land use pressure and water consumption. For instance, to reduce land use one might choose to grow crops with higher yields which require higher water volume. If we include the water consumption to grow the feedstock, the total amount of water to deliver 12 Gt carbon dioxide per year through BECCS would account for 3% of the total amount of water currently used by human activities.[152]

Information about San Joaquin Renewable's current process appears to corroborate these assumptions. Their method requires some water vapor to gasify biomass, but also produces "irrigation-quality water" as a product of its conversion process, resulting in a net gain in water.[153] A diagram illustrating their model is included below in Figure 4.4.[154] With that said, these are assumptions—the water demands of any project may differ based upon their conversion method, kinetics, biomass source, or other factors.

4.3.1.2 Minimum quality requirements

As discussed above, water is not a necessary component to most BiCRS conversion processes, with some BiCRS processes even generating a net gain of water in the process. However, water availability issues in future projections are still poorly understood.[155]

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[150] Lee, Conradie, Lester (2021) Review of supercritical water gasification. p. 1. [57]

[151] Ai *et al.* (2021) Global bioenergy with carbon capture and storage potential. [4]

[152] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]

[153] San Joaquin Renewables (no date) The Project. [81]

[154] San Joaquin Renewables (no date) The Project. [81]

[155] Sandalow *et al.* (2021) BiCRS Roadmap. p. 18. [80]

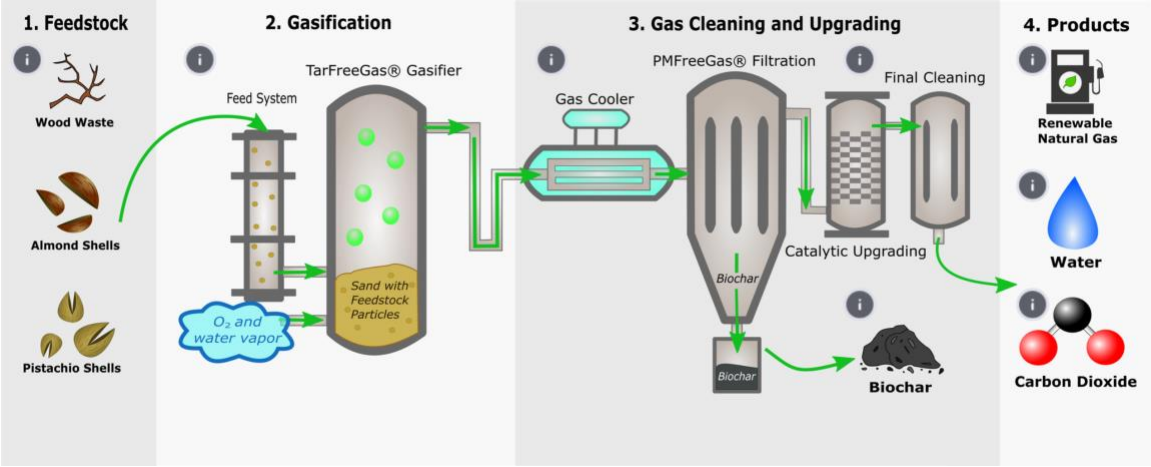

Figure 4.4. The biomass gasification process employed by San Joaquin Renewables.[156] Image credit: San Joaquin Renewables.

4.3.2 Air quality

Data availability for distinctions between biomass pyrolysis, gasification, and combustion with respect to emission impacts is limited, largely because most studies restrict themselves to a single type of biomass feedstock or single type of biomass conversion process, if not both. For this reason, we have chosen to highlight findings from coal, which is fossilized organic material from wetlands[157] and has clearly understood data due to decades of use with all three technologies. Although the comparison is imperfect, it provides useful insight into the differences between conversion types. The primary benefit of pyrolysis and gasification, from an emissions perspective, is the high temperatures and pressures of the biomass conversion generate a syngas stream of emissions that makes it simpler to separate out criteria air pollutants (including NO_x and SO_x) as well as trace contaminants including mercury, cadmium, arsenic, and selenium.[158]

4.3.3 Other potential impacts

Some types of biomass production damage ecosystems, hurt local farmers, or increase emissions.[159] The American ethanol industry has been a notable offender, as its push to grow biofuel crops has contributed to deforestation with little to no clear carbon reduction benefits.[160]

Any biomass plant will have to consider the land use impact associated with feedstock production. If there are no land use changes because biomass would be sourced from

[156] San Joaquin Renewables (no date) The Project. [81]
[157] Schweinfurth (November 23, 2016) Coal—A Complex Natural Resource. [82]
[158] NETL (no date) 6.5. EMISSIONS ADVANTAGES OF GASIFICATION. [63]
[159] Sandalow *et al.* (2021) BiCRS Roadmap. p. 12. [80]
[160] Sandalow *et al.* (2021) BiCRS Roadmap. p. 12. [80]

waste and residues from existing land uses, the impact will be little to zero.[161] If biomass feedstock needs are to come from dedicated agriculture soil, 380 to 700 Million hectares of land area is needed to deliver the global BiCRS sequestration potential of 12 GT per year carbon dioxide.[162] Change in local land cover, or extensive withdrawal of water from irrigation sources, will impact the climate in regions as far as a few hundred kilometers downwind.[163]

Land use change would also potentially cause indirect impacts, such as initiating new competition with other land uses, such as food-production, wood production, or residential land, which could lead to changes in the market for related commodity supplies and prices.[164] Given the abundance of potential biomass waste feedstocks in California in the form of agriculture waste, forest residues and municipal waste,[165] a significant volume of BiCRS facilities could be operational without the need to cultivate bioenergy crops – and their downstream effects – in the region.

4.4 Economic Impacts

4.4.1 Business Model

Whether a project defines itself as BiCRS or BECCS, the business model generally depends on the ability to outweigh fixed costs (i.e. levelized capital costs, labor expenses, taxes) and flexible costs (i.e. costs of energy use, biomass, transport) with income (i.e. selling products and/or carbon credits).

BiCRS and BECCS technologies have a number of revenue streams, depending on the outputs they prioritize in the gasification or pyrolysis process. All of these processes will generate CO_2 for permanent sequestration, and thus will be eligible for the 45Q federal tax credit.[166] As of 2022, the 45Q tax credit totaled $85/ton CO_2 for every ton permanently stored and $60/ton CO_2 for every ton used in enhanced oil recovery (EOR).[167] Due to California's SB 1314, captured CO_2 effectively cannot be used for EOR within the state.[168] Most biomass projects will also generate bioenergy products, which can be sold as electricity or fuel; BECCS processes will aim to maximize the potential bioenergy output. For gasification, the

[161] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]
[162] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]
[163] Jia *et al.* (2019) Land-climate interactions - Executive Summary. [51]
[164] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]
[165] Baker *et al.* (2020) Getting to Neutral. p. 4. [8]
[166] IEA (November 4, 2022) Section 45Q Credit. [48]
[167] IEA (November 4, 2022) Section 45Q Credit. [48]
[168] IEA (November 4, 2022) SB 1314. [47]

hydrogen gas created can be sold as a product—this economic opportunity is explored more in Section 6.4 of this report, which addresses the business of hydrogen production.

At the start of 2022, there were 16 operational facilities classified as BECCS facilities,[169] though some items on this list—like Charm Industrial—would likely be better described as BiCRS. An estimated 50 additional facilities are currently under development.[170] As for expanding the amount of BiCRS/BECCS facilities in the future, reduced costs in various technological pathways will help reduce the economic barriers, but the primary hurdle to scaling is anticipated to be generating new institutional arrangements and stakeholder consensus.[171] In short, most of the expected barriers are political and institutional in nature, rather than economic or technical.[172]

Most companies currently working on biomass facilities are working with large upfront capital investors and planning to fund their sequestration through a mixture of tax credits, selling carbon offsets, and/or selling byproducts (syngas, biochar, etc). Biomass conversion technologies can produce products aside from CO_2, including biochar and biofuels. As mentioned above, biochar can be used for a variety of agricultural and industrial applications. In recent years, biochar has sold for amounts ranging from $9 to $42 per cubic foot of biochar, with variations depending on the type, texture, quality, and sale venue.[173] Biofuels can vary considerably depending on the process in question: ethanol from fermentation,[174] hydrogen from gasification or fast pyrolysis,[175] or synthetic fuels generated by upgrading bio-oil.[176] For RNG and hydrogen fuel, the sale comes with additional benefits, as these fuels can often qualify for other state and federal subsidies.[177,178] More details about these economic incentives established via policy for various lower-carbon fuels can be found in Section 2, and specific information for hydrogen incentives can be found in Section 6.

The other avenue of revenue is the carbon credit market, of which there are both governmental and private options available. For the government carbon market, there are benefits at the federal and state level, with the 45Q tax credit and depending on the products and their intended market, can also be eligible for California's LCFS credits. For BiCRS or BECCS projects that generate alternative fuels for sale in California—including renewable natural gas, hydrogen, or electricity[179]—should be eligible for Low Carbon Fuel

[169] EFI (2022) Surveying the BECCS Landscape. p. 3-4. [28]
[170] GCCSI (no date) CO_2RE Facilities Database. [41] (See Appendices A-C).
[171] Sandalow *et al.* (2021) BiCRS Roadmap. p. 2. [80]
[172] Sandalow *et al.* (2021) BiCRS Roadmap. p. 2. [80]
[173] Pokharel, Comer (December 7, 2021) Economics of biochar. [75]
[174] Sanchez, *et al.* (2018) US Biorefineries. p. 4875. [79]
[175] Arregi *et al.* (2016) Hydrogen production from biomass by fast pyrolysis. p. 25975. [6]
[176] Nanda *et al.* (2021) Catalytic and Noncatalytic Upgrading of Bio-Oil to Synthetic Fuels. p. 2. [61]
[177] Natural Gas Intelligence (no date) How do you price RNG? [67]
[178] Piper, Krause, Janzow (February 27, 2023) The Hydrogen Credit Catalyst. [73]
[179] Casetext (April 14, 2023) Cal. Code Regs. tit. 17 § 95482. [16]

Standard (LCFS) credits, though uses like electricity would need to demonstrate their contribution to lowering state transportation carbon intensity.[180] LCFS credits between 2018 and 2022 varied between $62 and $218 per ton of CO_2 reduced.[181] The most recent price updates can be found on the California Air Resources Board LCFS credit dashboard, which posts LCFS price averages from the preceding week every Tuesday.

In speaking with industry experts, some BiCRS facilities have been selling their energy as electricity to the grid currently, but are planning to convert to more lucrative alternative energy sources, like selling hydrogen to consumers, once there is a sustained market and distribution network nearby.[182] This reflects the adaptivity of biomass-based energy facilities—depending on the current energy market, the biomass content can be converted into different materials to meet local needs.

4.4.2 Business Costs

Combining the estimated capital and operational costs—capital costs, feedstock costs, fixed and variable operating costs—of BiCRS/BECCS, outlined below, results in an estimated cost per ton CO_2 of $61-288, which aligns well with industry estimates of $88-288.[183]

4.4.2.1 Cost to build (upfront costs)

The estimated capital costs for constructing a BiCRS/BECCS facility capable of capturing 1 million metric tons of CO_2 annually ranges from $350 million to $1.2 billion, based on scaled estimates. This range has been corroborated by industry representatives. If a BiCRS/BECCS facility ran for 30 years, the average capital cost per metric ton of CO_2 would fall between $30-189. Given that estimates in the academic literature for BECCS typically range from $30 to $400 per metric ton of CO_2,[184] the scaled estimates calculated in this study appear quite reasonable.

Costs can also vary depending on the inputs a facility requires, and between BiCRS and BECCS processes, the largest differences typically originate from energy needs. Biomass pyrolysis or gasification will generate thermal heat, and many facilities can be largely or fully energy self-sufficient by utilizing this heat to meet the plant's energy needs. For BECCS facilities, the process is optimized to maximize the bioenergy output—whether it be heat, electricity, or fuel—leaving excess energy available to sell. However, this often requires upfront investment to reuse process heat or build off-grid renewables of heat-to-electricity equipment to support any on-site electricity needs.

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[180] CARB (October 2022) Carbon Capture and Sequestration Project Eligibility FAQ. [15]

[181] Neste (updated daily) California Low Carbon Fuel Standard Credit price. [68]

[182] Industry representative, personal communication, October 4, 2022.

[183] Kalra *et al*. Technical CO_2 Removals Market. p. 10. [52]

[184] Fuss *et al*. (2018) Negative emissions. p. 12. [39]

4.4.2.2 Operational costs

Operational costs on-site will involve maintenance and repairs, staff, monitoring, and any taxes. In terms of fueling their conversion processes, facilities will also need access to biomass feedstocks, which vary in terms of seasonal availability and cost. Not only do these materials need to be purchased (or obtained through another standing arrangement) and then chipped and dried, they also must be transported to the facility via train or truck.[185] Feedstock costs are often the largest estimated category in assessing a facility's operational costs. However, costs can vary widely—items like municipal solid waste (MSW) or some agricultural residues, like pistachio shells or almond hulls, are already collected and processed, making them easy to purchase at relatively low additional cost.[186] Other materials that require collection directly from the field, or processing steps like chipping or drying for forestry waste, can increase the cost of biomass feedstocks.[187] In general, placing facilities within close proximity of CO_2 storage sites and large quantities of biomass to use results in lower overall costs per ton CO_2 by reducing the transportation burden at both ends.[188]

Within the operational costs, there are fixed and variable expenses at play. Fixed operating costs—such as routine maintenance and labor costs—are typically estimated at 2-7% of the capital costs;[189] breaking down the estimated capital costs per ton CO_2 gives an estimated range from $1-13 per ton of CO_2 in fixed operating costs. Variable operational costs—such as unplanned maintenance, waste disposal, or non-biomass feedstocks—range from $10-27 per ton CO_2.[190] As mentioned above, biomass feedstock costs are typically the largest cost category, and can vary considerably depending on the type of biomass and the distance it needs to be moved. Based on the estimates available, a good range is approximately $20-60 per ton CO_2.[191,192] Combining these estimates, you would get a range of operating costs per ton CO_2 of $31-100.

4.4.3 Regional benefits

Businesses looking to start commercial-scale BECCS and BiCRS operations are drawn to southern California locations, including operations eyeing Kern County specifically. Due to the region's promising geography for underground carbon sequestration and relative abundance of agricultural waste feedstocks, there are clear assets to siting a BiCRS or BECCS facility in Kern County. These benefits would also extend beyond the county: in a

[185] Stolaroff *et al*. (2021) Transport for Carbon Removal Projects. p. 3. [86]
[186] Stolaroff *et al*. (2021) Transport for Carbon Removal Projects. p. 3. [86]
[187] Stolaroff *et al*. (2021) Transport for Carbon Removal Projects. p. 3. [86]
[188] Fuss *et al*. (2018) Negative emissions. p. 12. [39]
[189] IRENA (2012) Biomass for Power Generation. p. i. [50]
[190] IRENA (2012) Biomass for Power Generation. p. 35. [50]
[191] IRENA (2012) Biomass for Power Generation. p. 28. [50]
[192] NREL (2022) Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. p. 109. [66]

study of CO_2 removal options for California at-large, experts found that "NNBFs [net-negative biofuels], and specifically biomass gasification to hydrogen, had the largest potential and among the lowest cost of carbon removal options for California."[193]

4.4.3.1 Proximate feedstocks

Feedstocks for biomass carbon capture are abundantly available in Kern County, and the available feedstocks are highly preferred from a climate perspective. Both the area's high concentration of agricultural waste and steady supply of municipal organic waste could be used to fuel a BiCRS facility in the region. Within California, there is an estimated 55 million tons (Mt) of biomass available annually for energy applications, not including energy crops.[194] Within Kern County, the 2019 County Crop Report determined that 237,000 tons of almond hulls and shells and 236,000 tons of biomass were produced from the local agriculture industry.[195] The collective ~470,000 tons of biomass would be enough to support a ~620,000 ton CO_2 capture BiCRS facility—see Section 11 for more details about these calculations in relation to local agricultural waste.

4.4.3.2 Proximate consumers

Depending on the process used to extract carbon from oven-dried biomass, a byproduct of BiCRS facilities using slow pyrolysis processing is biochar—a material which can be applied to crop fields to improve soil fertility.[196] Given agriculture's large footprint in the area, this could produce a symbiotic relationship, with farms supplying agricultural waste feedstock and consuming the carbon-rich biochar produced by a local BiCRS facility.

There may also be proximate consumers for other biofuel or carbon offsets given the relative closeness of both Los Angeles and the Bay Area. Regional leaders in the digital technology space, such as Stripe in San Francisco, have been key investors in start-ups working towards carbon removal strategies.[197]

4.4.3.3 Co-location advantages

The primary co-location advantage for biomass processing facilities is the ability to share infrastructure for common needs—CO_2 transport for sequestration or use, onsite water supplies, and the potential of using electricity from a shared solar array or other off-grid power source with other companies. Co-locating reduces the costs, and therefore risks, of each player within the carbon management park.

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[194] Stolaroff *et al.* (2021) Transport for Carbon Removal Projects. p. 2. [86]

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5. CO_2-emitting Industries

TECHNOLOGY AT A GLANCE:

- Point source carbon capture is a technique applied to industrial and energy facilities that emit large concentrations of CO_2. The technology is commercially available and used in over 30 energy plants and manufacturing facilities worldwide, but its cost (and thus level of deployment) varies as a function of facility type.[1]
- Of the many industries that could use point source carbon capture, the steel industry was the most practical to investigate for purposes of location in Kern county.
- Carbon capture in the steel industry is in an early commercial stage: globally, there is 1 steel mill operating with carbon capture.
- Several techniques for producing low carbon steel are in the pilot or demonstration phase, and are explored briefly here, although they would not involve capture and storage of CO_2, and thus would not qualify as a carbon management technology.
- Current cost per metric ton CO_2 captured from steel: \$68-114 USD/ton CO_2.
- Projected cost per metric ton CO_2 captured at scale: \$40-90 USD/ton CO_2.
- Key advantages of this technology in Kern County: steel mills can provide hundreds of high paying jobs, many of which do not require post-secondary education.
- Key concerns for this technology in Kern County: steel mills do produce emissions, wastewater and solid byproducts that will have to be mitigated to meet regional environmental and safety standards.

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

5.1 Technology Summary

5.1.1 Description: How it Works

5.1.1.1 Point Source Carbon Capture

Many industries and energy facilities produce CO_2 as a byproduct of their processing activities, collectively accounting for about half of global greenhouse gas emissions.[2,3] However, most of these industries and facilities can employ a technology called *point source carbon capture*, which scrubs CO_2 from significant points of exhaust before they are released to the atmosphere. In contrast to Direct Air Capture (DAC, Section 3) and Biomass with Carbon Removal and Storage (BiCRS, Section 4), which are designed to remove human-derived CO_2 emissions from the ambient air, point source capture prevents the release of CO_2 before it is emitted. Point source carbon capture is at an advanced state of technological development, and many techniques are commercially available today that can be used to trap CO_2 from the exhaust of coal and natural gas power plants and boilers, or in the industries of natural gas processing, petrochemical development, fertilizer development, iron and steel manufacture, cement production and paper mills.[4] Despite this, only about 230 million metric tons of CO_2 are captured annually,[5] less than 1% of the 28 billion metric tons of CO_2 emitted from these sectors globally each year.[6]

Of those facilities that do employ carbon capture, most in operation today use a solvent-based approach, illustrated in Figure 5.1.[7] Rather than directly emitting CO_2-bearing flue gas through exhaust chimneys of a plant or facility, the flue gas is diverted to a separate *absorption tower*, where it is mixed with a liquid solvent. The solvent has either chemical properties that cause the CO_2 to readily dissolve into the fluid (for example having a mildly basic pH),[8] or a component of the solvent physically attracts the CO_2, such that it is drawn out of the flue gas and sorbs onto the surface of the molecular component in the capture fluid.[9] The flue gas is returned to the chimney and released; the CO_2-rich capture fluid is transferred to a stripping tower (or capture tower), where the CO_2 is separated from the solvent. In chemical solvents, this is accomplished by increasing the temperature (making

[2] Ritchie, Roser, Rosado (February 15, 2023) CO_2 and Greenhouse Gas Emissions. [68]

[3] Ge *et al.* (February 6, 2020) GHG emissions by sector. [35]

[4] Bettenhausen (July 18, 2021) Improving carbon capture. [5]

[5] IEA (2020) CCUS in clean energy transitions. p. 109. [41]

[6] Ge *et al.* (February 6, 2020) GHG emissions by sector. [35]

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[9] Bettenhausen (July 18, 2021) Improving carbon capture. [5]

the CO_2 exolve as a gas). In physical solvents, pressure is decreased such that CO_2 is more stable as a gas than bound to the surface of the in-solvent physical adsorbents.[10]

A less common capture technique makes use of membranes (mostly used for natural gas processing). Membranes are permeable physical barriers that allow gasses to pass through at variable rates, effectively separating some gas molecules from others.[11] Like physical solvents, membranes are used in processes that have high concentrations of CO_2 in the flue gas stream, whereas chemical solvents are more efficient when CO_2 makes up less than 15% of the flue gas.[12]

The cost (and thus feasibility) of point source carbon capture is directly proportional to the concentration (or partial pressure) of CO_2 in the exhaust stream, and is therefore industry specific.[13] Carbon capture technology for gas streams with CO_2 concentrations higher than 25% have been used in industrial applications since the 1940s[14], and technologies currently exist that can capture CO_2 from gas streams with concentrations as low as hundreds of parts per million (as in the atmosphere). But to date, CO_2 point source capture has not been implemented on a large scale due to lack of financial or regulatory incentives.[15]

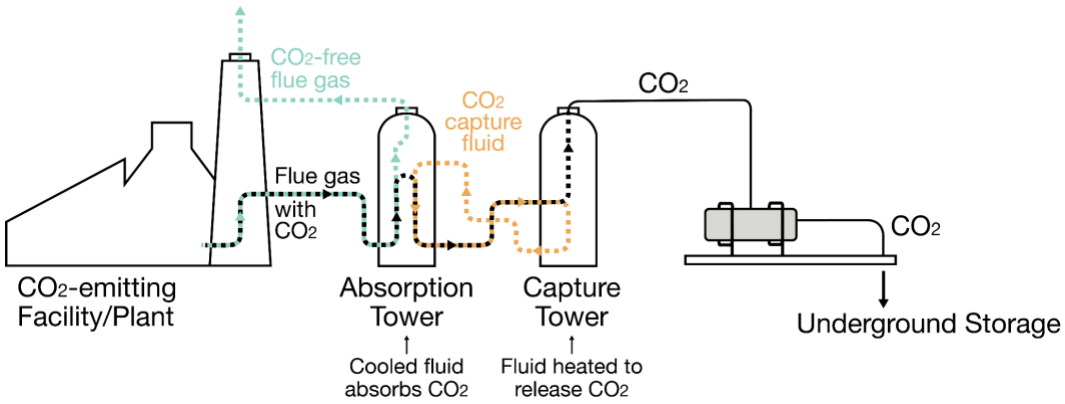

Figure 5.1. Generalized schematic of point source carbon capture. Adapted from Kearns et al. (2021).[16]

Industries for which point source capture is applicable for the purpose of carbon capture are summarized in Table 5.1. For the purposes of this analysis, our mandate was to explore industries for which there are existing or planned facilities in Kern County, and that might reasonably be included in a carbon management business park. According to the EPA

[10] Kearns *et al*. (2021) CCS readiness and costs. p. 15. [45]
[11] Kearns *et al*. (2021) CCS readiness and costs. p. 16. [45]
[12] Bettenhausen (July 18, 2021) Improving carbon capture. [5]
[13] Kearns *et al*. (2021) CCS readiness and costs. p. 3. [45]
[14] Kearns *et al*. (2021) CCS readiness and costs. p. 10. [45]
[15] Kearns *et al*. (2021) CCS readiness and costs. [45]
[16] Kearns *et al*. (2021) CCS readiness and costs. p. 13. [45]

Facility Level Information on GreenHouse gases Tool (FLIGHT), Kern County has 44 facilities that reported significant CO_2 emissions in 2021,[17] and are divided into the following sectors:

- 15 Power plants
- 20 Petroleum and natural gas systems or refineries
- 4 Agriculture and/or food processing facilities
- 2 Waste facilities (Bakersfield and Clean Harbors landfills)
- 2 Cement facilities
- 1 Mine (Borax - boron mine and refinery)

Agricultural facilities and landfills - while sources of emissions - are not viable candidates for point source capture because greenhouse gas emissions are diffuse, rather than concentrated from a single or few point(s) of exhaust (although waste could be diverted from landfills to a BiCRS facility, see Section 4). The cement and borax facilities are site dependent, meaning that although point source carbon capture could be a viable carbon management option in these industries, facilities are located adjacent to the mine or quarry from which raw material is extracted, and thus are not likely candidates for development in a dedicated carbon management park. Finally, because the business park under consideration would utilize renewable energy sources and is intended to be complementary rather than additive to the existing oil and gas sectors of Kern County, we have excluded investigation of power plants, natural gas processing, and petroleum refineries from this analysis. For additional information on the potential of point source capture for these CO_2-emitting industries, the interested reader is referred to two recent reports from the International Energy Agency on carbon capture utilization and storage (CCUS) in clean energy transitions[18] and the role of CCUS in low-carbon power systems.[19]

Another CO_2-emitting industry is not yet operating in Kern County but may be in the future. The San Diego-based Pacific Steel Group announced in April 2022 that it plans to build a state-of-the-art steel plant in southeast Kern County, with construction beginning in 2025.[20] As of the publication of this report, Pacific Steel Group's proposal is under planning and permitting review by the county.

Steel mills are technologically diverse. Depending on the type of steel production employed, they can produce as much as 2.4 tons of CO_2 for every ton of steel produced (Table 5.2), or – with the most advanced technologies – no CO_2.[21] Here, we examine the

[17] EPA (no date) FLIGHT. [27]

[18] IEA (2020) CCUS in clean energy transitions. [41]

[19] IEA (2020) The role of CCUS in low-carbon power systems. [42]

[20] Cox (March 14, 2022) 'Green steel' plant proposed for Mojave. [21]

[21] Soderpalm (August 19, 2021) Sweden's HYBRIT delivers world's first fossil-free steel. [72]

steel industry both as a potential carbon management industry and as an emerging clean energy technology.

Table 5.1. Industrial sources of emissions with commercial carbon capture facilities, globally.

Industry	CO_2 Concentration in Exhaust[a]		Cost of Capture[b]	Commercial Facilities[c]	
	vol %	Partial Pressure[d]	(USD/mtCO_2)	Operational	In Development
Natural gas processing	2-65	0.05 - 5	$15-25	15	12 (9)[e]
Fertilizer (ammonia) production	18-40	0.3 - 2.5[f]	$25-40	4	1 (7)
Bioethanol production[g]	85-100	0.085 - 0.10	$15-30	4	35 (3)
Production of other chemicals	7-92	0.2 - 0.27	$25-40	4	2 (7)
Hydrogen production (Blue H_2)	15-20	0.3 - 0.5	$50-80	3	12 (18)
Power generation - coal	12-15	0.012 - 0.014	$45-100	3	7 (4)
Power generation - NG	3-5	0.003 - 0.005	$50-100	0	9 (14)
Waste to energy[g]	10-12	0.010 - 0.012	$15-85	0	3 (3)
Iron and steel production	4-35	0.004 - 0.060	$60-100	1	0 (1)
Cement production	14-33	0.014 - 0.033	$60-120	0	2 (7)
TOTAL				**34**	**83 (73)**

a. Gale *et al.* (2005) IPCC Sources of CO_2. p. 79-80., Kearns et al. (2021) CCS readiness and costs. p. 25.
b. Sources: Sanchez et al. (2017) CCS from biorefineries,[22] Fuss et al. (2018) Negative emissions,[23] IEA (2020) CCUS in clean energy transitions.
c. Global CCS Institute Facility Database.[24]
d. Units are in MPa. (0.1 MPa = 1 bar = 0.99 atmospheres of pressure)
e. Those in parentheses are in early development stages. All other facilities are in construction or advanced development. For details, see Appendices A-C.
f. Up to 25% of captured CO_2 is used to convert produced ammonia to urea to create fertilizer.[25]
g. These industries can are examples of BiCRS/BECCS, and are discussed further in Section 4.

5.1.1.2 Steel Production and Carbon Emissions

There are a variety of production routes for steel, which vary as a function of the iron source material being used. Source materials include iron ore, the raw material mined from geologic deposits, direct reduced iron (DRI), which is formed by reducing iron ore in the presence of natural gas or a coal derivative, and recycled scrap steel. Integrated steel plants

[22] Sanchez *et al.* (2017) Near-term deployment of CCS from biorefineries. [70]
[23] Fuss *et al.* (2018) Negative emissions. p. 20. [32]
[24] GCCSI (no date) CO_2RE Facilities Database. [36]
[25] TFI (no date) State of the fertilizer industry: Environment & Energy. [78]

can produce steel from any of these sources, typically using a *blast furnace* (BF) to convert iron ore to reduced iron, and using a *basic oxygen furnace* (BOF) to convert the reduced iron, DRI and/or scrap steel to new steel products.[26]

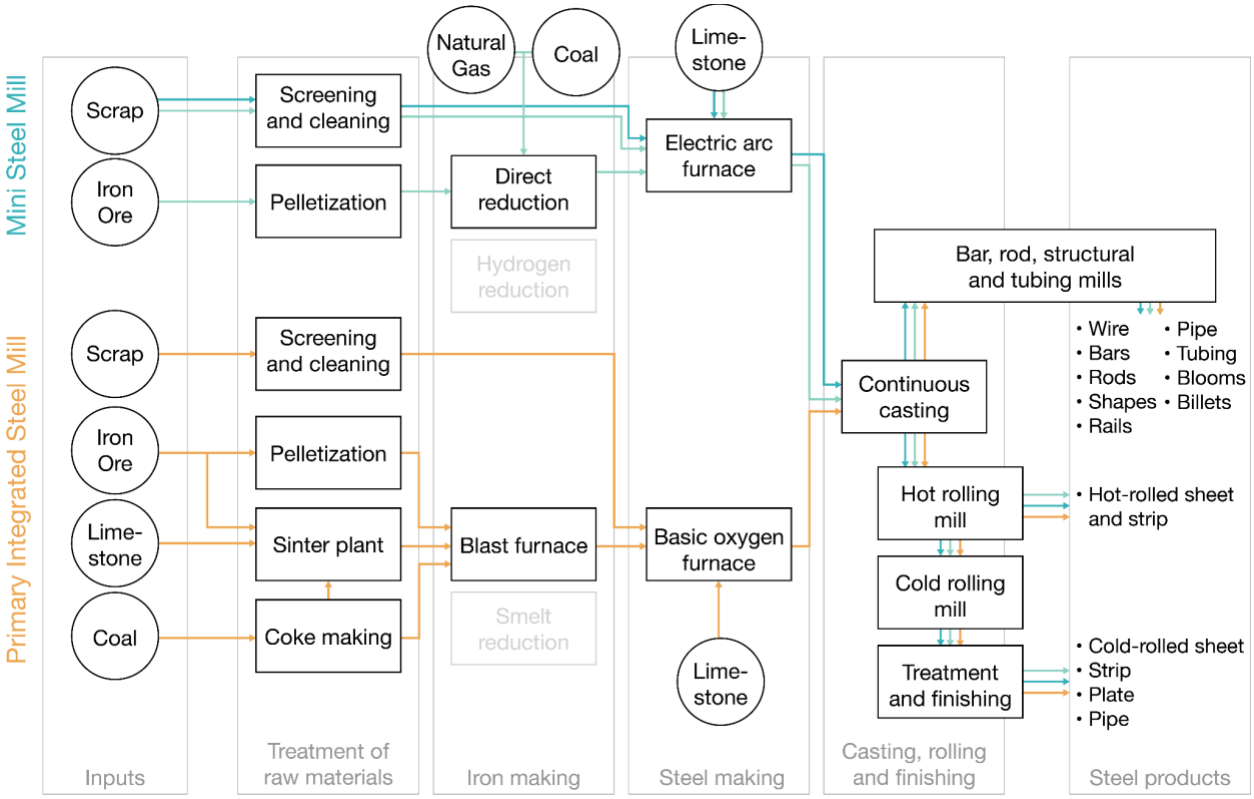

Figure 5.2. Process pathways for the two main methods of iron and steel production, blast furnace + basic oxygen furnace (BF-BOF, typical in integrated steel mills) and the electric arc furnace (typical in mini mills that use scrap ± direct reduced iron (DRI) as an iron source. Adapted from de Beer et al. (2003).[27]

These types of steel facilities currently account for over 70% of global steel production,[28] but since the 1960's[29] a new type of mill, called mini mills, are becoming increasingly common and are now the predominant mill type in the United States.[30] Mini mills (and even more recently, micro mills)[31] use a technology called *electric arc furnaces* to re-melt, refine and alloy scrap steel, or less commonly, DRI. Because they do not require the raw materials (iron sinter and/or pellets and coke) or extremely high heat needed to reduce iron ore in a

[26] de Beer *et al.* (2003) Emissions from iron and steel production. [24]
[27] de Beer *et al.* (2003) Emissions from iron and steel production. p. 14. [24]
[28] Kueppers *et al.* (2022) Iron and Steel. [49]
[29] Stubbles (2009) The minimill story. [76]
[30] CRU (2022) Steelmaking emissions analysis. [22]
[31] Anderton (August 6, 2015) Micro steel mills are competitive. [3]

blast furnace, these smaller mills are able to produce steel at cost-competitive rates with the significantly larger integrated steel mills. Their growth potential is simply limited by the availability of scrap steel or DRI.[32]

Table 5.2. CO_2-equivalent emissions as a function of steel-making process and process step.

Process Step	Direct CO_2 Emissions[a] (tCO_2/t steel)	Capture Eligible? (tCO_2/t steel)	Energy Use (GJ/t steel)	CO_2 from NG Energy Source[b] (tCO_2/t steel)
Electric Arc Furnace + Scrap (EAF)				
Treatment of raw materials	0	N/A	N/A	N/A
Iron making	N/A	N/A	N/A	N/A
Steel making	0.04-0.12	No	1.3-3.3	0.06-0.15
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10
TOTAL	**0.11-0.32**	**No**	**1.3-5.5**	**0.06-0.25**
Electric Arc Furnace + Direct Reduced Iron (DRI-EAF)				
Treatment of raw materials	0.02-0.05	No	1.9	0.09
Iron making	0.52-1.05	Yes	10.9-16.1	0.5-0.74
Steel making	0.04-0.12	No	1.3-3.3	0.06-0.15
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10
TOTAL	**0.65-1.44**	**0.42-0.84**	**14.1-23.5**	**0.65-1.08**
Blast Furnace + Basic Oxygen Furnace (BF-BOF)				
Treatment of raw materials	0.05-0.5	Some	1.75-3.2	0.08-0.15
Iron making	1.3-1.5	Yes	9.8-13.5	0.45-0.62
Steel making	0.13-0.21	Yes	7.9-11	0.36-0.51
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10
TOTAL	**1.55-2.43**	**0.92-1.12**	**19.5-29.9[c]**	**0.89-1.38**

a. Data from de Beer et al. (2003) Emissions from iron and steel production, CRU (2022) Steelmaking emissions analysis, and Fan and Friedmann (2021) Low-carbon production of iron and steel, Fruehan et al. (2000) Minimum energies to produce steel.

b. Natural gas CO_2 emission factor from Our World in Data.[33]

c. ~6 Gj of process heat are created per ton of steel produced, reducing this total value to ~13.5-24 Gj/ton of steel of net-energy requirements. (IEA (2020) Iron and Steel Roadmap.)

[32] de Beer *et al.* (2003) Emissions from iron and steel production. [24]

[33] Our World in Data (no date) Carbon dioxide emissions factor. [63]

The intensity of CO_2 emissions produced during the steelmaking process is dependent on the steelmaking route used, and thus integrated steel mills, mini mills, and scrap-specific mini mills have very different emissions profiles.[34] To break down the sources of CO_2 emissions associated with each type of steelmaking process, and its potential for capture or mitigation, in the following sections we examine each step of steelmaking systematically. A flow chart outlining each step in steel making, and how those steps vary by process, is provided in Figure 5.2, and a summary of the sources and volume of greenhouse gas emissions from each step is provided in Table 5.2.

Treatment of raw materials

To make new steel, raw iron ore (the oxidized iron material mined from geologic formations) must be reduced to metallic iron,[35] which must then be treated by the addition or removal of carbon and other trace metals to achieve an alloy with the desired properties (i.e. strength, hardness, ductility, or weldability).[36] Luckily, once made, steel is an excellent candidate for recycling. Scrap steel, which is the steel discarded as waste either during manufacture or from products at the end of their useful life, can be repeatedly turned back into new steel, while retaining its original properties.[37]

Every steel manufacturer uses some amount of scrap to produce new steel.[38] In dedicated scrap mini mills, scrap represents 100% of the raw material for steel production. In regions where scrap is scarce, mini mills will supplement scrap with metallic iron converted from ore via the direct reduction (direct reduced iron, or DRI) method.[39] In integrated steel mills, scrap is most commonly combined with pig iron, the material made from iron ore using a blast furnace (Figure 5.3).[40]



Figure 5.3. a. Hot iron pellets. Pellets are generally ~1cm in diameter. b. Iron sinter, on A4 size paper, for scale. Image credits: Wikimedia commons, RobSimmons 223311, CC BY-SA 4.0 and Borva53, CC BY-SA 4.0.

[34] de Beer *et al*. (2003) Emissions from iron and steel production. p. ii. [21]
[35] IIMA (no date) About Metallics. [43]
[36] Mar (September 28, 2017) Chemical composition of steel. [57]
[37] World Economic Forum (January 17, 2023) Steel scrap and how it can help reach net zero. [90]
[38] World Steel Association (2021) Scrap use in the steel industry. [91]
[39] de Beer *et al*. (2003) Emissions from iron and steel production. p. 21. [24]
[40] IIMA (no date) About Metallics. [43]

The preparation of scrap material for recycling into new steel products is relatively minimal - it involves collection, cleaning, and sorting.[41,42] However, creation of metallic iron (either DRI or pig iron) requires the conversion of iron ore into a form that can be fed into the smelter or furnace. Two conversion processes are used: pelletization (for DRI and pig iron) and sinter plants (for pig iron only).[43] Pelletization occurs in a pellet plant, which can be cited at the ore mine or steel mill, and involves first crushing and grinding iron ore, and then forming 'green balls' of material by aggregating the iron grounds with crushed limestone, clays, and water. The balls are hardened for transport and loading through an *induration process*; they are dried, fired in a kiln at temperatures up to 1350°C, and cooled.[44] Sinter plants prepare iron ore by combusting it at ~1300-1480°C with limestone and coke breeze (used as the fuel) to produce a carbon-rich, porous clinker.[45] Formation of raw iron (pig iron or DRI) is often measured in 'tons of hot metal.'[46] For each ton of hot metal, about 1.5-1.7 tons of pellets or sinter is required.[47,48]

In integrated mills, coke is another raw material that needs to be treated in preparation for iron making. Coking is the process of converting metallurgical coal to the porous, carbon-rich material 'coke.' Metallurgical coal is heated to temperatures up to 1125°C, melting and releasing any volatiles, and then re-solidifying as coke.[49] About 0.3-0.5 tons of metallurgical coal are used for each ton of hot metal produced.[50]

Pelletization, sintering and coking all emit CO_2 - about 0.02-0.05, 0.3-0.4, and 0.03-0.10 tons CO_2 per ton hot metal, respectively.[51,52] The combined impact of these emissions on the carbon intensity of final steel products derived from a given steel production pathway is detailed in Table 5.2.

Iron making

In integrated steel making, iron pellets, sinter, and coke are combined in a *blast furnace* (Figure 5.4) to form hot iron metal, or in its cooled form, pig iron. Coke is used as a fuel - combusting to help the furnace reach the melting temperatures of iron (as much as 2000°C[53]), as a reductant - accepting oxygen from the iron oxides in the ore material to

[41] Peters *et al.* (2021) Improve the EAF scrap route for a sustainable value chain. p. 10. [66]
[42] de Beer *et al.* (2003) Emissions from iron and steel production. p. 14. [24]
[43] de Beer *et al.* (2003) Emissions from iron and steel production. p. 38-40. [24]
[44] de Moraes *et al.* (2018) Iron ore pelletizing process: An overview. [25]
[45] de Beer *et al.* (2003) Emissions from iron and steel production. p. 13-15. [24]
[46] Fan, Friedmann (2021) Low-carbon production of iron and steel. [30]
[47] Uys, Kirkpatrick (1963) The beneficiation of raw materials in the steel industry. [84]
[48] Van Wortswinkel, Nijs (2010) ETSAP - Iron and Steel. [86]
[49] Kentucky Geological Survey (no date) Coal to make coke and steel. [46]
[50] de Beer *et al.* (2003) Emissions from iron and steel production. p. 16. [24]
[51] de Beer *et al.* (2003) Emissions from iron and steel production. p. 15-17. [24]
[52] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 833. [30]
[53] IIMA (no date) About Metallics. [43]

produce metallic iron and CO_2, and as a charger - increasing the carbon content of the iron, which is critical for processing to steel in the *basic oxygen furnace*.[54] Within the steel making process, blast furnaces represent the largest source of CO_2 emissions, about 70% of emissions in an integrated plant.[55] For each ton of steel produced,[56] about 1.3-1.4 tons of CO_2 are released.[57]

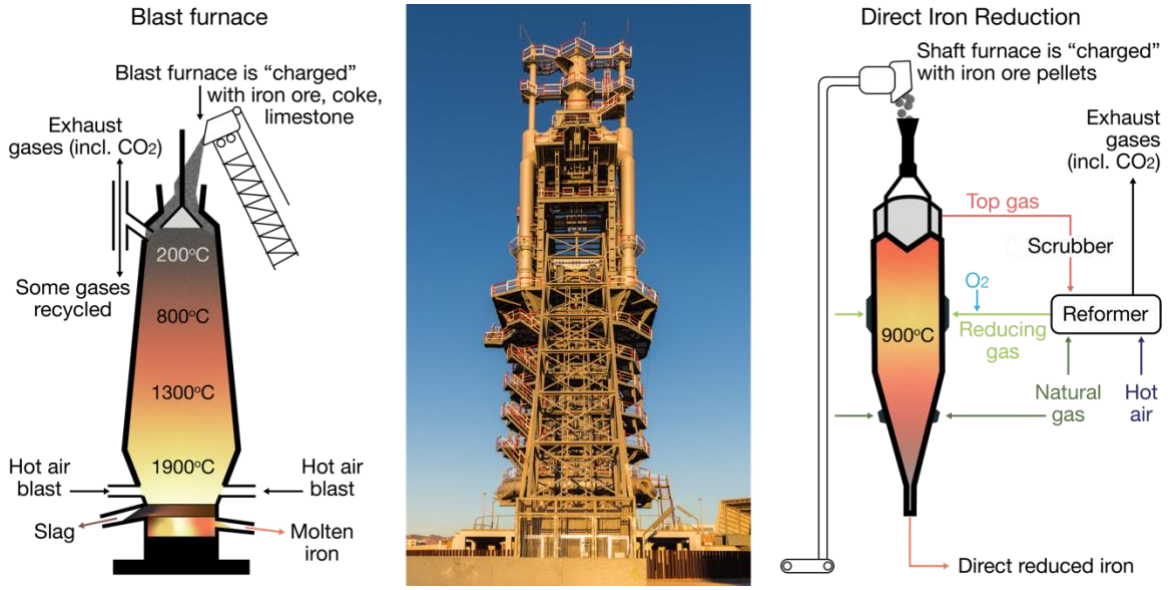

Figure 5.4. a. Schematic of iron production via blast furnace. b. Blast furnace, Port of Sagunto, Spain. Image credit: Wikimedia Commons, Diego Delso, CC BY-SA 4.0. c. Schematic of direct reduced iron production (modeled after the Midrex process, one of several flow processes for DRI). Adapted from International Iron Metallics Association. DRI facilities are of a similar scale to blast furnaces – the shaft furnace is a multi-story scaffolded building, with an attached conveying system for the iron ore pellet charge.

Direct reduced iron is an alternative to pig iron that can be used in *electric arc furnaces*. It has a significant advantage over the blast furnace in terms of emissions because it does not require coke as a fuel or additive. Rather, a natural gas- or coal-derived reducer, called syngas ($CO + H_2$), is used to remove oxygen from the pelletized iron ore. This process takes place in solid state; the ore never actually melts. Thus, required temperatures for the process are much lower, reaching only 900-1000°C. Because iron is not melted, impurities present in the ore are retained in the DRI product. This can mean additional additives will

[54] de Beer *et al.* (2003) Emissions from iron and steel production. p. 18-21. [24]

[55] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 831. [30]

[56] Some references report emissions in tons of hot metal (what emerges from the iron making process), whereas other references report emissions as a function of tons of steel. de Beer *et al.* (2003) Emissions from iron and steel production (p. 26) reports that hot metal comprises 65-90% of steel output, the balance being from scrap. To maintain continuity, we assume that 0.9 tons of hot metal are used to produce 1 ton of steel, with scrap steel comprising the remaining steel input.

[57] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 833. [30]

be needed in the steel-making step to extract unwanted impurities or to add under-represented elements, like carbon, that control desired steel properties.[58,59] The combustion of coal or natural gas to produce DRI emits between 0.5 and 1.0 tons of CO_2 per ton steel (Table 5.2).[60]

Two other processes are worth noting briefly here: smelt reduction and hydrogen steel production. Smelt reduction is an alternative mechanism for producing pig iron that employs direct reduction of iron ore fines (omitting the pelletization or sintering step) in the presence of coal.[61] The technology is mature, but has seen very little penetration in the global iron production market, likely because it is more expensive than conventional blast furnace-basic oxygen furnace (BF-BOF) production, but more carbon intensive than scrap-EAF or DRI-EAF processes.[62]

Hydrogen-blended, or hydrogen fueled steel production are clean-energy alternatives to existing steel production, that are still in the early development or demonstration stages of technological readiness. These technologies would adapt existing BF, DRI, and smelting reduction reactors to operate with H_2 as part or all of the reducing agent and fuel source for the ironmaking step of steel production, resulting in reduced or eliminated process emissions of CO_2.[63]

Steel making

Once crude iron has been produced, it is introduced into a furnace to further refine to steel. The purpose of this step is to remove any undesired impurities from the source iron, and to adjust the concentration of carbon and other desirable elements that imbue steel with specific properties optimized for its final intended use.[64] Basic oxygen furnaces (BOFs) are traditionally used in integrated mills, with iron sourced primarily from blast furnaces, with scrap and occasionally DRI to supplement.[65] The furnace is a large and pear-shaped reactor, where pure oxygen is blown into the vessel to react with the liquid iron metal. Carbon, and other impurities, are oxidized by the iron and separated, creating CO_2 gas and a metal-oxide-rich slag.[66] The molten and purified steel are separated and transported to a finishing facility for casting and rolling (Figure 5.2). BOFs are enormous, housed in buildings that can be as much as 80 meters (~260 feet) high. This is to accommodate the gravity feed equipment, oxygen lance and off-gas cooling systems.[67]

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[58] IIMA (no date) About Metallics. [43]
[59] de Beer *et al*. (2003) Emissions from iron and steel production. p. 21-23. [24]
[60] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 835. [30]
[61] IEA (2020) Iron and Steel Roadmap. p. 91. [40]
[62] IEA (2020) CCUS in clean energy transitions. p. 65. [41]
[63] IEA (2020) Iron and Steel Roadmap. p. 91. [40]
[64] de Beer *et al*. (2003) Emissions from iron and steel production. p. 26. [24]
[65] de Beer *et al*. (2003) Emissions from iron and steel production. p. 26-27. [24]
[66] Britannica.com (no date) Primary Steelmaking. [7]
[67] Britannica.com (no date) Primary Steelmaking. [7]

In mini steel mills (and some integrated mills), the electric arc furnace (EAF) is used in the steel making step. This process involves using a high-current electric arc to melt steel scrap (± DRI), which is chemically adjusted by varying the melting temperature and "charging" with DRI, pig iron and limestone (for slag formation). Because EAF is less oxidizing than BOF, steels made by this process typically have higher carbon contents than BOF steel, and CO_2 emissions from the EAF are lower - about 0.4 to 0.12 tons of CO_2 is released per ton of steel processed in an EAF, compared to 0.14 to 0.21 tons of CO_2 per ton steel in BOF processes (Table 5.2). An EAF furnace is much smaller than a BOF, with a shell diameter ranging from ~6-9 meters (20-30 feet), and able to process 100-300 tons of steel melt at a time.[68]



Figure 5.5. a. Basic oxygen furnace being charged at the ThyssenKrupp steel mill in Duisburg. Image credit: Wikimedia Commons, Katpatuka, CC BY-SA 3.0. b. Electric arc furnace of the Georgsmarienhütte GmbH steel plant in Germany. Wikimedia Commons, GMH official, CC BY-SA 3.0.

Casting, rolling and finishing

Most steel facilities use continuous casting (rather than ingot casting) to cool and prepare steel for shaping into a range of final products.[69] In this process, liquid steel is continuously fed into short, vertical water-cooled copper molds. The outer most shell of the steel 'strand' is solidified, allowing them to be rolled out of the copper molds, as the inside continues to cool and solidify. Once solidified, the steel is cut into billets, blooms or slabs (distinguished by size), which are then shaped into finished products.[70] Such shaping takes place through rolling and finishing operations - hot rolling (done immediately after the slabs have been cast) and cold rolling (done once the slabs are cooler than their recrystallization

[68] Britannica.com (no date) Primary Steelmaking. [7]

[69] de Beer *et al*. (2003) Emissions from iron and steel production. p. 63. [24]

[70] de Beer *et al*. (2003) Emissions from iron and steel production. p. 31. [24]

temperature) are used to reduce slab thickness and ensure thickness uniformity,[71] and further cutting to the preferred shape and size of the final steel product. An analysis performed for the Steel Manufacturers Association[72] estimated that high-temperature heat emissions related to this portion of the steel making process was between 0.07 and 0.22 tons CO_2 per ton steel (Table 5.2), with lower values being associated with younger, more efficient facilities.

5.1.1.3 Carbon Capture in the Steel Industry

Pilot studies and research on the application of carbon capture as a decarbonization solution in the steel industry has been most closely applied to integrated mills, where blast furnaces produce ~80% of the mill's emissions (Table 5.2).[73] Retrofitted carbon capture devices on the blast furnace could capture as much as 65% of CO_2 emissions, and an additional ~10-20% could be conserved by adding oxygen and combusting the exhaust stream (composed of CO + CO_2) to provide heat energy to the furnace or other plant facilities.[74,75] It is possible to apply commercially available carbon capture devices to other components of the integrated mill system (coke production, sinter production and the BOF), but as these produce a smaller fraction of total emissions, capturing CO_2 from these sources is likely not cost-effective for a globally-traded industry that must operate on tight profit margins.[76] For example, when blast furnace gas is combusted in the presence of air, the concentration of CO_2 in the exhaust is about 27 vol%. In contrast, the composition of off-gas from a basic oxygen furnace includes only about 16 vol% CO_2.[77] Thus, the basic oxygen furnace produces less CO_2 to capture, and does so at a higher price per ton CO_2 captured.

DRI can also be designed or retrofitted with carbon capture, with the possibility of capturing as much as 80% of CO_2 emissions, although the lower concentrations of carbon in the flue gas make this process more challenging and expensive than carbon capture for BF-BOF.[78] The only commercially operating steel mill with carbon capture in the world - in Abu Dhabi, U.A.E. - captures carbon from the DRI process (see Section 5.1.2.2). An alternative decarbonization approach for DRI is using green hydrogen (produced via electrolysis or gasification of biomass, see Sections 6 and 4, respectively) as a carbon-free replacement fuel, but adapting the EAF technology for this fuel is far from technologically ready, and could be prohibitively expensive until the cost of producing green hydrogen decreases.[79,80]

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[71] American Steel Products Company (January 5, 2017) What is a rolling mill? [2]
[72] CRU (2022) Steelmaking emissions analysis. [22]
[73] CRU (2022) Steelmaking emissions analysis. [22]
[74] de Beer *et al.* (2003) Emissions from iron and steel production. p. 71. [24]
[75] EPRS (2021) Carbon-free steel production. p. 15-16. [28]
[76] IEA (2020) CCUS in clean energy transitions. p. 64-65. [41]
[77] Gale *et al.* (2005) Chapter 2: Sources of CO_2. p. 80. [33]
[78] EPRS (2021) Carbon-free steel production. p. 15-16. [28]
[79] Liberty Steel Group (no date) A direct reduced iron (DRI) plant. [53]
[80] IEA (2020) Iron and Steel Roadmap. p. 91. [40]

EAF, like the blast furnace, emits an exhaust stream of CO + CO_2, which could be captured or re-used for its waste heat. However, even less CO_2 is emitted per ton of steel in this process than the BOF or raw material treatments (Table 5.2), making it unlikely that capture would ever be cost effective. In fact, for most EAFs, the emissions produced by creating the grid-sourced electricity needed to operate the facility are more than double the direct emissions from the furnace,[81] and thus supplying an EAF mini mill with off-grid, carbon-free electricity would be the most efficient decarbonization approach for these kinds of facilities. While such a facility would produce low-carbon steel, it would not be considered a carbon management industry, as no appreciable carbon capture could take place.

Some researchers have proposed powering the EAF with natural gas via oxy-fuel combustion, rather than grid or renewable-sourced electricity.[82] Oxy-fuel combustion combusts natural gas (or biomass-derived syngas, or renewable natural gas) in the presence of a pure oxygen stream, creating outputs of a pure stream of CO_2, water and electricity (see Section 4).[83] Thus, a mill could produce low-carbon steel and CO_2 for capture. If a scrap mini mill were powered entirely by natural gas with oxy-fuel combustion, approximately 0.06-0.25 (~0.15 on average) tons of CO_2 would be produced per ton of steel produced. Using oxy-fuel combustion from natural gas to power a DRI-EAF mini mill would produce about 0.65-1.08 tons of CO_2 per ton of steel, and for a BF-BOF mill it would produce about 0.89-1.38 tons of CO_2 per ton of steel (Table 5.2).[84]

5.1.2 State of Development

The technological readiness of carbon capture in the steel industry is a two-part problem: first, what is the state of development of point source carbon capture technology? Second, to what extent is such technology (or other decarbonization technologies) ready to be implemented within the steel sector? Here, we will give a brief summary of the state of development of point source carbon capture, with a focus on the most developed approach: chemical solvents. Then we will highlight global examples of decarbonization efforts in the steel industry, with a focus on carbon capture and green hydrogen substitution.

5.1.2.1 Point Source Carbon Capture

Chemical and physical solvents have been in commercial use for decades, and technological development in this space has been focused on reducing the costs of such solvents so that they can be used in industries that produce more diffuse gas streams, or where profit margins are tight.[85] Examples of cost-saving innovations include creation of water-lean solvents, which require a much lower energy input to regenerate the solvent (release the CO_2), simply because less water needs to be boiled. Ion Clean Energy is a

[81] CRU (2022) Steelmaking emissions analysis. [22]
[82] de Beer *et al*. (2003) Emissions from iron and steel production. p. 73. [24]
[83] IEA (2020) CCUS in clean energy transitions. p. 99. [41]
[84] de Beer *et al*. (2003) Emissions from iron and steel production. p. 13-15. [24]
[85] Kearns *et al*. (2021) CCS readiness and costs. p. 12. [45]

commercial company that produces water-lean liquid solvent capture plants, and more recently, Pacific Northwest National Lab developed a technique that uses an oil-based instead of water based solvent, reducing water requirements by as much as 97%.[86,87] Another next-generation solvent technology comes from the company Saipem. They have identified a biologically-derived enzyme that speeds a naturally slow carbonate salt solvent. The increased capture efficiency allows more CO_2 to be captured with a smaller stripper (and thus smaller footprint and lower capital costs), and the carbonate salt technology has the added benefits of being able to regenerate with hot water, rather than steam (so waste heat can be used as an energy source), and producing no hazardous waste byproducts.[88,89]

Another company, Carbon Clean, is also driving cost savings by modularizing and reducing the physical footprint of their carbon capture technology. Their carbon capture system is the size of a shipping container, and can capture up to 35,000 metric tons of CO_2 annually. That is about one tenth the size of conventional carbon capture facilities.[90] Carbon Clean is developing a variety of projects in California, and globally. It is working with Cemex in Victorville, CA to capture carbon at a cement plant,[91] and with Chevron to create a pilot facility in Kern County that would capture CO_2 from a gas turbine at the Kern River Eastridge cogeneration plant.[92,93] They have also launched a demonstration facility in India, capturing 5 metric tons of CO_2 per day from the blast furnace of Tata Steel's Jamshedpur plant.[94]

5.1.2.2 Example Projects in the Steel Industry

In the steel industry, scrap-based mini mills powered by carbon-free energy are the optimal solution for decarbonizing the sector. However, although ~85% of steel waste is recycled as scrap, it is not enough to meet the global demand for steel.[95] In terms of carbon capture as a decarbonization solution for ore-sourced steel making, DRI is the most technologically advanced. Carbon capture applied to smelt reduction or blast furnace process gas is still in the development to demonstration stages.[96] Replacing hydrocarbons (coke, coal and natural gas) with hydrogen as the reduction agent and/or fuel, is also still in development stages.[97] Below is a sample of key leaders in each of these innovations.

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[86] Kearns *et al*. (2021) CCS readiness and costs. p. 13. [45]

[87] Clifford (January 24, 2023) New technique from U.S. national lab promises to strip carbon dioxide. [18]

[88] Kearns *et al*. (2021) CCS readiness and costs. p. 13. [45]

[89] Saipem (no date) CO_2 Solutions. [69]

[90] Clancy (May 18, 2022) Meet the startup shrinking industrial carbon capture. [16]

[91] Carbon Clean (February 9, 2021) CEMEX Awarded Grant from US Department of Energy. [12]

[92] Carbon Clean (February 24, 2022) Chevron announces investment in Carbon Clean. [13]

[93] Kumar (May 18, 2022) Chevron to launch carbon capture project in San Joaquin Valley. [50]

[94] Carbon Clean (September 14, 2021) India's first blast furnace carbon capture plant. [11]

[95] IEA (2020) Iron and Steel Roadmap. p. 62. [40]

[96] IEA (2020) CCUS in clean energy transitions. p. 62. [41]

[97] IEA (2020) CCUS in clean energy transitions. p. 62. [41]

Al Reyadah CCUS Project, Abu Dhabi, U.A. Emirates

The first (and as of this report's publication, only) fully commercial carbon capture and storage facility for the iron and steel industry is at a DRI plant in Abu Dhabi, where an existing facility was retrofitted with traditional liquid solvent capture technology (using monoethanolamine, or MEA, which is the industry leading solvent). The project was launched in 2016, and captures 800,000 metric tons of CO_2 annually, for enhanced oil recovery use (EOR) in nearby onshore oil fields. $15 billion US of seed funding was supplied from the government of Abu Dhabi to launch the project.[98]

CO2 Ultimate Reduction in the Steelmaking Process (COURSE50), Japan

Since 2008, a consortium of Japan's steel manufacturers has been working on experimental technologies to reduce emissions in BF-BOF steel plants through hydrogen reduction of iron in the blast furnace and capture of blast furnace off-gas. The project was commissioned and financed by the New Energy and Industrial Technology Development Organization.[99] So far, the project has been able to reduce blast furnace emissions by ~10% through supplementing coke with hydrogen. Continuing work focuses on development of novel chemical absorbents and physical adsorption technologies for BF carbon capture.[100]

STEPWISE Project, Luleå, Sweden

Funded through the European Union's Horizon 2020 Low Carbon Energy programme, the STEPWISE Project aims to create a demonstration scale facility of sorption-enhanced water-gas shift (SEWGS) carbon capture for blast furnace gas. The pilot plant is a retrofit of the SSAB steel plant in Luleå, Sweden, and is able to capture 14 metric tons of CO_2 per day. The aim of the technology is to improve the efficiency of conversion of CO in the blast furnace off-gas to CO_2, which is currently a highly energy-intensive process. Such improvement has the potential to reduce BF emissions by 85%, reduce the energy requirement of capture by 60%, and the cost by 25%. While the pilot plant is operational, the extent to which these goals are achieved is still being investigated.[101,102]

HYBRIT Project, Luleå, Sweden

Launched by three private companies in 2016 (SSAB, LKAB and Vattenfall), the HYBRIT initiative aims to develop a completely fossil-free value chain for steel production, using fossil-free pelletization, electricity and hydrogen. A pilot facility for producing fossil-free sponge iron (the output of DRI) was commissioned in 2020, and a pilot facility for hydrogen storage in a rock cavern facility launched in September 2022.[103] In August 2021, SSAB

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[98] The University of Edinburgh (no date) Al Reyadah: Project Details. [79]

[99] Tonomura *et al.* (2016) Concept and current state of CO_2 Ultimate Reduction. [81]

[100] COURSE50 (no date) To the future of the low carbon blast furnace. [20]

[101] Stepwise (no date) STEPWISE: a H2020 Project. [75]

[102] van Dijk *et al.* (2017) Cost effective CO_2 reduction in the iron & steel industry. [85]

[103] HYBRIT (September 23, 2022) HYBRIT: Milestone reached. [39]

produced the world's first fossil-free steel using HYBRIT technology at its pilot facility - in which DRI is produced with 100% hydrogen as the fuel and reducing agent.[104]

Boston Metal, United States

Boston Metal, a steel startup company in the United States, is developing an alternative technique for direct reduction of iron that uses *electricity* as the reducing agent, rather than hydrocarbons or hydrogen. Called Molten Oxide Electrolysis (MOE), the technology works by heating iron in a cell to 1600°C, in the presence of an electrolyte solution (i.e. water containing dissolved salts). The iron ore becomes molten, and an inert anode placed in the electrolyte solution is electrified, driving an electrical current through the molten iron that splits the bonds between iron and oxygen in the ore:

$$Fe_2O_3 + e^- \rightarrow Fe + O_2 \qquad (R5.1)$$

The process is anticipated to be cost competitive with traditional BF-BOF steel production, but is still being validated in the industrial environment. Demonstration facilities are planned for 2024, with the aim of commercial operation by 2026.[105]

Rocky Mountain Steel, Colorado

Rocky Mountain Steel, based in Pueblo, Colorado was the first integrated steel mill built in the U.S. west of the Mississippi River, having been in operation since 1882.[106] Today, it no longer operates as an integrated mill, but rather a scrap steel mill - recycling scrap into rails for train tracks, pipes and re-bar.[107] In 2022, the company broke ground on developing the first steel mill to run almost entirely on solar power. Construction of the solar project that will power the mill is ongoing at the time of writing this report, but will use 750,000 solar panels, located on ~1,800 acres, to provide more than 90% of the mill's power needs.[108]

Mojave Micro Mill, Kern County, California

In May 2022, the Pacific Steel Group announced plans to develop a state-of-the-art 'green steel' micro mill in the Mojave Desert of Kern County. The mill would be a 100% scrap-EAF mill, modeled after a similar mill that is in development in Mesa, Arizona, that has an expected opening date in 2023. The Mojave facility would be powered at least partially by local renewable energy (solar), and would produce up to 380,000 tons of steel annually.[109] It would use MIDA-Micromill technology from the company Danieli, which also produced the Mesa, Arizona facility, and a similar plant in Durant, Oklahoma.[110] In terms of development status for the Mojave Micro Mill, the Pacific Steel Group has submitted a

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[104] HYBRIT (no date) HYBRIT Demonstration. [38]

[105] Boston Metal (no date) Molten Oxide Electrolysis for steel decarbonization. [6]

[106] The Center for Land Use Interpretation (no date) Rocky Mountain Steel, Colorado. [77]

[107] EVRAZ North America (no date) EVRAZ Rocky Mountain Steel. [29]

[108] Lawrence (March 2, 2022) World's largest solar-powered steel mill breaks ground in Colorado. [51]

[109] Cox (May 13, 2022) 'Green steel' plant proposed for Mojave. [21]

[110] Danieli (July 29, 2015) Danieli to supply second MIDA to CMC. [23]

development proposal for the project, and the project is currently undergoing the public environmental review process pursuant to the California Environmental Quality Act.[111]

5.1.3 Operational needs

This section provides a synopsis of the land use, energy, feedstock, waste disposal and other operational needs of the representative technologies for the steel industry that employs carbon management and/or clean energy technologies. Information was aggregated from literature review and interviews with industry experts.

Integrated steel mills that employ primarily BF-BOF steel making technology are quite distinct from mini mills in terms of their footprints, operational needs, and steel output. An integrated steel mill typically produces 3 million tons or more of steel annually, whereas mini mill production capacity is about 1 million tons per year.[112] Micro mills (and even nano mills), like the Mojave Micro Mill that is currently in development (see Section 5.1.2.2), produce even less - on the order of 200,000-500,000 tons of steel per year.[113] Additionally, integrated mills are dependent on primary ores (iron ore and metallurgical coal for coke), and so have traditionally been located close to these natural resources and/or along major waterways where transport of raw materials is possible.[114] Although located close to major rail and road transportation routes, Kern County is distantly located from any significant iron or coal natural resources, and is unlikely to be suitable for a large-scale integrated steel mill. Thus, for the purposes of this study, we will focus on the requirements and impacts of mini- and micro mills that use scrap as a primary feedstock, with DRI as a potential supplementary feedstock, if future regional demand outpaces the availability of scrap metal.

Considering that this industry is being evaluated in the context of its role as a carbon management industry, it is also worth noting the needs and impacts that such a facility will have in terms of its CO_2 output as well as its steel output. To this end, we considered three mini mill scenarios in the impact analyses that comprise the remainder of this report section. The scenarios are based on the direct and indirect (energy-sourced) CO_2 emissions profiles described in Table 5.2, and are as follows:

1. A scrap-based mini mill powered by solar energy, in which **0 tons of CO_2 can be captured per ton steel produced** (direct emissions are not easily captured, and the solar energy source is emission-free).
2. A scrap based mini mill that utilizes oxy-fuel combustion of natural gas, producing an average of **~0.15 tons CO_2 that can be captured per ton of steel** (full range is 0.06-0.25 tons CO_2 per ton steel).

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[111] Kern County Planning and Natural Resources Department (October 28, 2022) Notice of Preparation (NOP). [47]

[112] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 833. [30]

[113] Millennium Steel (May 25, 2017) Mini mills, micro mills, nano mills. [58]

[114] Anderton (August 6, 2015) Micro steel mills are competitive. [3]

3. A mini mill that utilizes DRI with point source capture for 100% of its iron source and oxyfuel combustion of natural gas as its energy source. Point source capture can capture up to 80% of DRI emissions,[115] or ~0.42-0.84 tons CO_2 per ton steel produced. Combined with the CO_2 produced from oxy-fuel combustion (0.65-1.08 tons CO_2 per ton steel), this method would produce, on average, **~1.3 tons CO_2 per ton steel produced** (full range is 1.07-1.50 tons CO_2 per ton steel).

A steel mill that utilized DRI and oxy-fuel combustion (the most emissions-intensive scenario) would need to produce about 770,000 tons of steel annually to emit 1 million tons of CO_2. The same size facility utilizing only scrap and solar energy, or scrap and oxy-fuel combustion, would emit 0 tons CO_2 and ~115,000 tons CO_2, respectively. For the purposes of understanding the impacts of a steel facility in Kern County, data from existing steel mills and published estimates are normalized both to a 1 million ton (Mton) steel production capacity (for consideration of impact per ton steel), and to a 770,000 ton (770 kton) steel production capacity (for consideration of impact per million tons CO_2, noting that such a value is a *maximum* CO_2 output estimate).

5.1.3.1 Land use requirement

There are myriad existing examples of mini steel mills that can be utilized to approximate the land use requirements for this industry. As of 2022, 71% of the domestic U.S. steel supply was produced in 101 mini mills across the country.[116] Table 5.3 provides a representative sampling of U.S. mini and micro mills, denoting their production capacity (in annual steel output) and land footprint. The footprint to steel output ratio for these facilities is diverse, suggesting flexibility in land use needs, depending on the cost and availability of land. The facilities investigated have annual steel outputs ranging from 350,000 tons to 1.2 million tons. For comparative purposes, the land use to output ratio was normalized, producing a range of 140 to 1,071 acres used per million tons (Mton) of steel production, with an average footprint of 663 acres/Mtons. Similarly, to a 770,000 ton steel mill, which could produce *up to* 1 million tons of CO_2 (see Section 5.1.3), would use 129 to 825 acres per million tons of CO_2 produced, with an average footprint of 510 acres per 770kton steel mill.

[115] EPRS (2021) Carbon-free steel production. p. 15-16. [28]

[116] Watson (2022) Domestic Steel Manufacturing. [88]

Table 5.3. Land use requirements for example mini- and micro-steel mills in the United States.

Facility Name[a]	Year Operational	Annual Steel Output	Facility Footprint		Normalized Footprint	
		(kton steel)	km^2	Acres	(acres/ Mton steel)	(acres/770 kton steel)
Mojave Micro Mill, CA (proposed)	2025+	380	0.70	174	458	353
CMC Mesa Plant (II), AZ	2023	500	0.34	84	168	129
HighBar LLC, Osceola, AK	2024	600	2.43	600	1000	770
Nucor Steel, Brandenburg, KY	2022	1,200	3.64	900	750	578
CMC Durant Plant, OK	2017	350	1.52	375	1071	825
Nucor Steel, Davidson Co, NC	2024	430	0.93	229	533	410
MEAN		**577**	**1.59**	**394**	**663**	**510**

a. These six mills will be used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all future references to these sites, references are detailed in Table 5.7.

5.1.3.2 Energy Requirements

As detailed in Table 5.2, the primary energy needs for a scrap-based steel mill come from the electric arc furnace (EAF), which requires about 1.3-3.3 GJ (=0.4-0.9 MWh) of energy per ton of steel produced.[117,118] Casting, rolling and finishing the hot steel that is made in the EAF into usable products requires another ~0.02-2.2 GJ (0.01-0.6 MWh)/ton steel.[119] If DRI is made on site from pelletized iron ore feedstock, it would contribute an additional 10.9-16.1 GJ (3.0-4.5 MWh) of energy needs,[120] increasing the facility's energy requirements by an order of magnitude.[121] It is important to note that DRI requires temperatures of 900-1000°C to reduce the iron ore in the presence of a reduction agent like natural gas, syngas or hydrogen. Such high temperatures cannot be directly supplied by solar-derived electricity without also utilizing a heat battery (see our section on energy storage). Capturing carbon from DRI requires additional energy input: point source capture using advanced chemical solvent technologies demands about 2.5-3 GJ (0.7-0.8 MWh) of energy per ton of CO_2 captured, which translates to an additional energy demand of about 1.1-1.3 GJ (0.3-0.35 MWh) per ton steel produced via DRI-EAF.[122] Finally, Pelletization requires about 1.9 GJ (0.5 MWh) of energy per ton of steel, and while this step can be done at the

[117] Fruehan *et al.* (2000) Minimum energies to produce steel. p. iii. [31]
[118] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 835. [30]
[119] Fruehan *et al.* (2000) Minimum energies to produce steel. p. iii. [31]
[120] de Beer *et al.* (2003) Emissions from iron and steel production. p. 22. [24]
[121] IEA (2020) Iron and Steel Roadmap. p. 29 + 42. [40]
[122] Kearns *et al.* (2021) CCS readiness and costs. p. 36. [45]

steel mill site, it is more commonly done at the mine where iron is sourced,[123,124] so is not included in the energy analysis here.

Estimates of the scale of solar installation required to supply 100% of the heat and electrical energy needs of a steel mill are calculated following the equation: [125]

MWh (energy supplied) = MW (installed capacity of facility) x (8760 hours in a year) x Capacity factor (E5.1)

where the capacity factor for solar panels in Kern County is 32.8%.[126] Solar acreage is calculated on the basis of ~7 acres per MW installed solar capacity.[127,128] With these values, a 770,000 ton steel mini mill utilizing only scrap and solar energy would need about 690-2,900 acres of solar fields to supply the electricity demand. A 770,000 ton DRI mini mill using solar energy and only capturing CO_2 from process emissions of iron reduction would need 6,400-11,255 acres of solar fields (with heat battery storage) to operate. However, in this scenario, only 320,000 tons of CO_2 could be captured annually. A mini mill using oxy-fuel combustion with carbon capture as the sole power supply would require no solar input.

In addition to solar energy, two other potential power supplies for mini mills are explored here: oxy-fuel combustion of natural gas (or alternatives like syngas or renewable natural gas) with carbon capture, and combustion of hydrogen gas.

Oxy-fuel Combustion

Oxy-fuel combustion is a process in which hydrocarbon-based fuels are combusted in a specialized chamber in the presence of a pure stream of oxygen (± an inert carrying agent, like purified CO_2). Normally, we combust fuels in the presence of air, which produces a series of partial reactions that convert the hydrocarbons to CO_2, CO, and a variety of unreacted residues that can be grouped as "volatile organic compounds" or VOCs. These products instantly mix with the surrounding air to produce a dilute stream of CO_2, making it difficult – and expensive – to separate the CO_2. In oxy-fuel combustion, the only inputs in the reaction are hydrocarbons and oxygen, and the reaction can be controlled so that the only products are H_2O (water) and CO_2. Because the reaction is taking place in a vacuum, rather than in the presence of air, the CO_2 product does not become diluted, and thus can easily (and cheaply) be separated for storage. Oxy-fuel combustion technology is generally at the large prototype or pre-demonstration stage of development.[129]

Two examples of companies developing oxy-fuel combustion technologies are Clean Energy Systems and NET Power. Clean Energy Systems designs oxy-fuel turbines (the

[123] Carlson (no date) Iron ore pellet production a bottleneck for steel producers. [14]

[124] Cision PR Newswire (October 21, 2021) Iron ore pellets demand to surpass 399 Mn tons in 2021. [15]

[125] Thomson Reuters Practical Law Glossary (no date) Capacity factor. [80]

[126] NREL (no date) Utility-Scale PV. [59]

[127] Lorelei Oviatt (Kern County), personal communication, September 21, 2022.

[128] SEIA (no date) Land use and solar development. [73]

[129] IEA (2020) CCUS in clean energy transitions. p. 99. [41]

reaction chambers for oxy-fuel combustion) using technology adapted from rocket engine design, to optimize the combustion reaction.[130] They have a pilot facility in Kern County and are in the process of converting several biomass power plants into Biomass Carbon Removal and Storage (BiCRS) facilities in California (see Section 4.1.2.4). NET Power has developed a form of oxy-fuel combustion called the Allam-Fetvedt power cycle, which uses the pure CO_2 produced from the combustion process as a streaming agent that carries heat energy and new pure CO_2 and H_2O streams, optimizing the efficiency of the process.[131,132]

Hydrogen Fuel

Green hydrogen, or hydrogen that is derived from non-CO_2 emitting processes, like electrolysis (see Section 6) or biomass gasification with carbon capture (see Section 4), has enormous potential in helping to decarbonize iron and steel production, because it can work both as a fuel source, powering high-temperature operation of the DRI and EAF, and as an iron reducing agent, further reducing the necessity of coke or natural gas in the iron-refining process.[133] One company, SSAB in Sweden, has successfully fossil-free steel, using green hydrogen in the production process. Their work is currently at the demonstration stage (see Section 5.1.2.2). If hydrogen is used to power steel production and act as a reducing agent, the steel made will be carbon emissions free (a clean technology), but would not be a source of CO_2 for carbon capture.

5.1.3.2 Other Operational Requirements

Waste disposal requirements

Steel production from EAFs produce a variety of byproducts, including metal dusts, slag, wastewater, and gaseous emissions,[134] each of which needs to be handled appropriately on- or offsite, following state and federal regulations. Slag is relatively inert, and can be repurposed in other industrial applications, like construction.[135] Dust creation is a bigger issue, as on average, EAFs produce about 10 kilograms of dust per metric ton of steel, which can have a variety of heavy metals in it: zinc, lead, cadmium, chromium, and nickel. However, there are a variety of available mitigation measures that can minimize the hazard of dust creation, including: locating operational facilities inside enclosed buildings, selecting a feed quality (steel scrap or iron pellets) that have low concentrations of impurities or heavy metals, use fabric filters and other dry dust collection methods[136].

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[130] Clean Energy Systems (no date) Oxy-fuel Combustion. [17]

[131] Kearns *et al.* (2021) CCS readiness and costs. p. 17. [45]

[132] Patel (November 10, 2022) NET Power's first Allam Cycle 300-MW gas-fired project. [64]

[133] Bartlett, Krupnick (February 18, 2021) The potential of hydrogen for decarbonization. [4]

[134] World Bank Group (1998) Mini Steel Mills. p. 341. [89]

[135] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[136] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

In terms of wastewater, mini mills can produce up to 80 cubic meters (~21,000 gallons) of wastewater per metric ton of steel produced.[137] Like the dust, wastewater can have high concentrations of metals, totaling up to 3,000 milligrams per liter of water. That is about equivalent to 0.3% of the water being dissolved or suspended solids. These solids can be removed from settling, creating sludges that then need to be properly disposed of following environmental and safety guidelines. With proper treatment, the wastewater can be recycled to minimize the water demands of steel production.[138] Additionally, many of the metals that are concentrated in steel mill wastewater are of interest in development of clean energy technologies. Recovering critical metals from fluids, like waste waters of mining and industrial processes, is beginning to be explored,[139] and could warrant further investigation, both in its potential for an alternative revenue stream, and as a solution for waste mitigation.

The variety of methods described here (and for gas emissions, in Section 5.4.2) to manage and minimize waste from steel mills is not meant to be comprehensive, but is intended to illustrate that solutions already exist to address secondary products of steel production. Like any industrial facility hosted within a carbon management park, environmental and safety impacts of a steel mill would be assessed through a public process, and if approved, all facilities would be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

Warehousing requirements

Warehousing is a necessity at steel mills, both to hold a reserve of iron feedstock (whether steel scrap or iron pellets), and steel product. Although no explicit information could be found on storage requirements for feedstock or product, aerial and satellite imagery of existing steel mills suggests that whether storage is in enclosed warehouses or open air depends on regional preferences and regulation.

Transportation and pipeline requirements

Steel scrap and/or iron pellets will need to be delivered to a mini mill facility, and products will likely be sold nationally or internationally. Therefore, access to rail and shipping lanes are high priorities for steel industries. The availability of rail in Kern County, and its proximity to ports along the West Coast both make it an attractive site for steel production.

[137] World Bank Group (1998) Mini Steel Mills. p. 341. [89]

[138] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[139] Can Sener *et al.* (2021). Recovery of critical metals from aqueous sources. [9]

5.2 Societal Impacts

5.2.1 Job creation potential

5.2.1.1 Number and types of jobs

On average, it takes 1.5 man-hours to produce a ton of steel, with some mini mills able to produce a ton of steel with only 0.5 man-hours, due to increased efficiency and automation.[140] Given this range, a 770,000 ton steel mill could produce about 200-600 full-time equivalent jobs. This approximated range is consistent with job creation estimates reported from recently built U.S. micro mills, which, scaled to 770,000 ton steel production capacity, would produce on average ~400 permanent jobs. Details of these job estimates are given in Table 5.4.

Of the example steel mills examined in Table 5.4, two provide estimates of job growth in relation to facility construction. The 600,000 ton High Bar LLC steel mill in Arkansas, and the 430 thousand ton Nucor Steel mill being developed in North Carolina report generating 600 and 500 construction jobs, respectively. Scaled to a 770,000 ton facility, a steel mill could provide up to 900 short term jobs in construction. Additionally, such a facility would produce thousands of indirect jobs to support facility needs, such as solar and battery installation jobs.

According to a 2022 Congressional Research report,[141] the average annual wage of steel workers in 2020 was $88,325 USD, higher than both the national average in manufacturing ($73,397 USD), and the median national household income across all sectors ($71,186 USD)[142] for that year. Steel product manufacturing (casting, rolling, and finishing steel into final products) accounted for about 40% of the job market in 2020, and had an average annual wage of $68,585 USD.[143] Reported annual salary for the example steel micro mill manufacturing jobs support this average, with salaries ranging from $60,000-$140,000 plus benefits, with higher salaries associated with technical positions (see Appendix D for complete reference list).

5.2.2.2 Training pipelines

Most jobs in the iron and steel industry require a high school diploma or equivalent and may involve an apprenticeship training program. A significant amount of training is done on-the-job.[144] This is likely particularly true for steel product manufacturing. However, with sector wide goals of decarbonization and digital transformation, the steel industry is

[140] Perry (March 16, 2018) Increased productivity is eliminating steel industry jobs, not imports. [65]
[141] Watson (2022) Domestic Steel Manufacturing. p. 9. [88]
[142] U.S. Census Bureau (September 13, 2022) Income in the United States. [83]
[143] Watson (2022) Domestic Steel Manufacturing. p. 9. [88]
[144] Vault Firsthand (no date) Steel industry workers. [87]

increasingly looking for more trained or specialized workers.[145] The World Steel Association has a published fact sheet emphasizing the need for skilled workers in metallurgy, materials science, physics, chemistry, engineering, environment, mathematics, information technology and computer science, languages, business, and accountancy.[146]

Table 5.4. Reported job creation estimates for example mini- and micro-steel mills in the U.S.

Facility Name[a]	Year Operational	Annual Steel Output	Facility Footprint		Normalized Jobs (per 770 kton steel)	
		(kton steel)	Perm.[b]	Const.[c]	Perm.[b]	Const.[c]
Mojave Micro Mill, CA (proposed)	2025+	380	400		811	
CMC Mesa Plant (II), AZ	2023	500	186		286	
HighBar LLC, Osceola, AK	2024	600	200	600	257	770
Nucor Steel, Brandenburg, KY	2022	1,200	400		257	
CMC Durant Plant, OK	2017	350	225		495	
Nucor Steel, Davidson Co, NC	2024	430	200	500	358	895
MEAN		**577**			**411**	**833**

a. These six mills are used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all other references to these sites, references are detailed in Table 5.7.
b. Permanent jobs
c. Construction jobs

5.2.2 Quality of Life

5.2.2.1 Location

Steel mills do emit fine materials and gasses that can have harmful health effects, like particulate matter, lead, nitrous oxides (NO_x), and sulfur oxides (SO_x), although there are techniques mills can use to trap matter and minimize emissions[147] (see Section 5.3.2). Any mill developed within the carbon management park would be required to submit an environmental impact report and undergo pre-development review and operational monitoring to ensure emissions impacts remain within federal and state determined safety standards.

[145] Maldonado-Mariscal *et al.* (2023) Skills intelligence in the steel sector. [56]
[146] World Steel Association (2021) Working in the steel industry. [94]
[147] World Bank Group (1998) Mini Steel Mills. [89]

Steel mill operations are also loud[148,149] – with most operational equipment emitting noise at levels that require hearing protection for workers.[150] It is possible to design steel mills in ways that diffuse noise levels to minimize noise pollution in the vicinity. One steel mill in New Zealand integrated several noise-minimizing solutions into their facility, and measured noise levels about 0.75 miles from the facility of ~45 decibels, a typical sound level for an urban neighborhood.[151]

5.2.2.2 Multi-use potential

Steel mills are among the most land intensive of the carbon management industries investigated in this report (Appendix D, Figure D.1), and as that land use involves warehousing of large volumes of feedstocks, enclosed buildings housing large manufacturing equipment, and warehousing (and treatment) of products and byproducts, it is unlikely that the land allocated to a steel mill would be well suited for multi-use potential. That being said, there is a plethora of opportunity in co-locating such an industry with other carbon management and clean energy technologies, explored in detail in Section 5.4.3.3.

5.3 Environmental Impacts

5.3.1 Water requirements

5.3.1.1 Minimum volume requirements

Steel mills require water to operate, primarily for cooling, but secondarily for equipment descaling, dust scrubbing and other processes. On average, steel mills that use electric arc furnaces require a water intake of 7,400 gallons of water per metric ton of steel produced, but discharge 7,000 gallons of water (about 94% of intake water), for a net water requirement of 400 gallons per metric ton of steel.[152] It is also notable that the range in water use from plant to plant varies widely, suggesting that there are a variety of process configurations that can minimize water use and water waste. The most comprehensive publicly available assessment of water use in the steel industry was a report published by the World Steel Association (WSA) in 2011.[153] They examined water usage in 8 EAF steel plants (and 17 integrated plants, not discussed here), whose water intake ranged from 290 gallons of water per metric ton of steel produced, to over 18,000 gallons of water per metric

[148] Hojati *et al.* (2016) Determining the noise exposure pattern in a steel company. [37]
[149] Nyarubeli *et al.* (2018) Variability and determinants of occupational noise exposure. [61]
[150] OSHA (no date) Occupational Noise Exposure. [62]
[151] New Zealand Steel (no date) Reducing noise. [60]
[152] World Steel Association (2020) Water management in the steel industry - Fact Sheet. [93]
[153] World Steel Association (2011) Water management in the steel industry - Full Report. [92]

ton of steel.[154] The strongest control on water use intensity was whether water used for cooling was circulated or merely used one time ("once-through cooling"). In regions where water resources are abundant, once-through cooling can have minimal environmental impact, while also being cost effective, but given that only 25% of EAF plants examined by the WSA report used once-through cooling, water-circulation cooling appears to be a well-established technique in the industry.[155]

Discharged water from steel mills can be treated and reused, or returned to the source.[156] The extent of treatment required will depend on the original water composition and its use in the steelmaking process. Water that is used for cooling never actually comes into contact with material or equipment, so does not require the same level of treatment as that used for descaling and dust scrubbing. Water used for these latter purposes could have a significant amount of dissolved solids, including metals and oil and gas residues,[157] that would need to be treated before water could be reused (see Section 8 for a summary of water treatment techniques and applications). If water is recirculated within the steel mill to minimize waste, it needs to be cooled and desalinated between uses. This could be energy and time intensive, but in the context of a carbon management business park, it is also a synergistic opportunity. If a thermal network were integrated into a carbon management park, waste heat in the form of hot process water from the steel mill could potentially supply heat energy to other co-located industries, and the cooled water could be circulated back to the steel mill for reuse.

5.3.1.2 Minimum quality requirements

Water for steel manufacturing can come from a variety of sources, with EAF mills examined by the World Steel Association using freshwater (potable water), groundwater, brackish water, seawater, and other non-potable water as sources.[158] Gray (reclaimed) water, of which there is an abundance in California (see Section 8), could be used similarly, minimizing the impact on local fresh water sources. Depending on the water source used, and its role in the steel making process, a variety of pre-treatment processes may be necessary, all of which are well established techniques. These include biological control or disinfection for reclaimed water, demineralization, desalination, distillation, filtration, reverse osmosis, and softening.[159] For further information, interested readers should refer to Section 8 of this report, as well as the WSA report on water use in the steel industry.

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[154] World Steel Association (2011) Water management in the steel industry - Full Report. p. 31. [92]
[155] World Steel Association (2011) Water management in the steel industry - Full Report. p. 32. [92]
[156] World Steel Association (2020) Water management in the steel industry - Fact Sheet. [93]
[157] World Bank Group (1998) Mini Steel Mills. p. 342. [89]
[158] World Steel Association (2011) Water management in the steel industry - Full Report. p. 32. [92]
[159] World Steel Association (2011) Water management in the steel industry - Full Report. p. 39-40. [92]

5.3.2 Other potential impacts

5.3.2.1 Criteria pollutants from operation

Two sources of atmospheric pollutants should be considered in the context of steel as a carbon management industry. First, there is the production of steel itself, and then there are emissions related to power generation for steel production, which - if it is in the form of oxy-fuel combustion with carbon capture, can have associated non-CO_2 emissions.

In the electric arc furnace (the steel making phase of production), scrap metal is "charged", or combined with DRI, pig iron (from integrated mills) and/or limestone, to add or remove impurities in the steel that control its properties (like strength and ductility). Elements that are separated out of the steel form a metal-oxide rich slag and small amounts of CO2 (not enough to be economically captured) and other gas or fine particulate emissions.[160] The slag is a waste byproduct that can typically be used in other industrial processes (see Section 5.1.3.2), and therefore poses little environmental risk.

Particulate emissions emitted from the EAF (and to a lesser degree from other steps in the steel making process) include particulate matter composed of iron and iron oxides, and depending on the composition of the source iron could also include heavy metals such as zinc, chromium, nickel, lead, and cadmium. Gaseous pollutants such as NO_x, CO, SO_2, and volatile organic compounds (VOCs) can also be emitted.[161,162] These emissions can be captured and scrubbed from facility exhaust streams, to keep facility emissions under regulated limits. Techniques for trapping emissions include locating the EAF in an enclosed building, using hoods to evacuate dust into dust arrestment equipment, using scrubbers to attract gasses, and using equipment like cyclones, baghouses, and electrostatic precipitators to further attract and trap dust. However, regular maintenance and monitoring of facilities is critical to prevent fugitive emissions.[163]

If natural gas (or synthetic natural gas or RNG) is used with oxy-fuel combustion and carbon capture and storage to power some or all of the steel-making processes, emissions associated with such combustion must also be considered. Thus far, this is difficult. There are few detailed studies of the emissions resulting from oxy-fuel combustion, and those emissions seem to be dependent on the fuel used (coal vs. natural gas vs. biomass), the oxygen/fuel ratio, and the combustion technique.[164] However, it appears that overall, gaseous emissions and particulate matter emissions from oxyfuel combustion are

[160] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[161] Environmental Protection Agency (EPA) (2009) Emission factor documentation. p. 5. [26]

[162] Van Wortswinkel, Nijs (2010) ETSAP - Iron and Steel. p. 6. [86]

[163] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[164] Senior *et al.* (2013) Emissions from oxyfuel combustion. [71]

considerably lower than emissions related to traditional air-fired combustion.[165,166] Integrating flue gas filtering processes into the oxy-fuel combustion process can also eliminate pollutants from any flue gas stream, as the Allam-Fedtvedt power cycle does for NO_x and SO_x.[167]

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used in any given facility will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

5.4 Economic Impacts

5.4.1 Business Model

Unlike other carbon management industries investigated in this report (DAC and BiCRS, in Sections 3 and 4, respectively), the capture and sequestration of CO_2 is not a primary objective or product of CO_2-emitting industries. Thus, the only motivations that a CO_2-emitting industry will have to capture and store carbon are financial (if the CO_2 can be sold as a product or for a financial credit), or through pressure, whether regulatory or from consumers. A 2021 feasibility analysis by the Global CCS Institute examined the factors common to commercially operating point source capture facilities, that made them economically viable.[168] At the time, there were 28 operational facilities in the world (as of the writing of this report there are 35, according to the GCCSI facilities database, see Appendix A). Every single one of those operations had at least one of the following characteristics, and all but 1 had at least two:

1. They were capturing CO_2 from the lowest-cost point sources: natural gas processing, fertilizer production, bioethanol production, chemical manufacturing (23 facilities)
2. They sold their CO_2 to enhanced oil recovery (EOR) operations to offset costs (23 facilities).
3. Their country of operation provided grant support, tax credits, or had a government provision for carbon capture (17 facilities.)
4. Their country of operation was Norway, the only nation that implements a carbon tax (2 facilities).

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[165] Senior *et al.* (2013) Emissions from oxyfuel combustion. [71]

[166] Kosowska-Golachowska, M. *et al.* (2022) Pollutant emissions during oxy-fuel combustion of biomass. [48]

[167] Allam, R. *et al.* (2017) Demonstration of the Allam Cycle. p. 5953-5954. [1]

[168] Rassool *et al.* (2021) CCS in the circular carbon economy. p. 7. [67]

Since the publication of GCCSI's report, the outlook for point source carbon capture has become more promising. Recent innovations in "water-lean" capture amine technology is helping the cost of capture decrease, even for industries with more dilute exhaust emissions.[169,170] Additionally, the 2022 Inflation Reduction Act raised the amount of the 45Q tax benefit for CO_2 capture and storage processes other than direct air capture (DAC) to $85 per ton stored,[171] meaning that even at the current state of technological development, every CO_2-emitting industry has the potential to entirely offset the cost of capture carbon with a tax credit (Table 5.1). This is particularly important for industries that are traded on international markets, like steel, in which the need to remain cost competitive allows for very low profit margins and little flexibility for added cost.[172] Additional policies that could further encourage the adoption of carbon capture in the steel industry, specifically, include those that encourage the purchase of low-carbon or clean energy products (e.g. Buy Clean incentives), thereby increasing their market demand, or those that would create a regulatory framework for allowable carbon-intensity of domestically manufactured or purchased products.[173]

5.4.2 Business Costs

For point source carbon capture facilities, capture equipment is most commonly retrofitted onto existing infrastructure, adding to the baseline cost of producing the primary industry output. As mentioned in Section 5.1, the concentration of CO_2 within the gas stream emitted from an industrial facility is proportionally related to the cost of capture. This is illustrated in occurs for two reasons:

1. More dilute streams require larger process equipment. This is because lower concentrations of CO_2 mean a higher total gas volume processed per ton of CO_2. Thus, the total size of equipment also needs to be larger to process the greater volume of gas. Additionally, higher CO_2 concentrations are more reactive - the CO_2 will transfer more rapidly from the source gas to the solvent than at low CO_2 partial pressures - thus speeding the time of the reaction. Faster reactions mean less necessary contact time between source gas and solvent, and thus smaller capture equipment, reducing capital costs.[174]
2. More energy is required to capture more dilute CO_2. At high partial pressures, CO_2 can be captured using "physical" solvents - those in which the CO2 is bound to the surface of the a substance via electro-magnetic attraction, forming a weak bond (called van der Waals bonds) that is easily broken by modestly decreasing the

[169] Jiang, Y. *et al.* (2023) Energy-effective and low-cost carbon capture from point-sources. [44]
[170] Clifford (January 24, 2023) New technique from U.S. national lab promises to strip carbon dioxide. [18]
[171] Carbon Capture Coalition (2022) IRA. p. 2. [10]
[172] IEA (2020) CCUS in clean energy transitions. p. 159. [41]
[173] Watson (2022) Domestic Steel Manufacturing. p. 15. [88]
[174] Kearns *et al.* (2021) CCS readiness and costs. p. 26-27. [45]

pressure or increasing the temperature of the system. In contrast, low-concentration CO_2 generally requires selective "chemical" solvents to be use - those which trap CO_2 by forming stronger chemical bonds, that can only be broken by increasing temperatures significantly. The higher temperatures needed for solvent regeneration directly translate to higher energy needs, and therefore higher cost.[175]

An additional relevant factor to the cost of carbon capture is the scale of deployment. An impact analysis by the Global Carbon Capture and Storage Institute determined that economies of scale could drive cost decreases considerably when moving from pilot scale (thousands of metric tons of capture annually) to commercial scale (hundreds of thousands of metric tons of capture annually), with costs reaching a minimum at capture rates above ~400 thousand metric tons of CO_2 capture per year.[176] In their analysis, economies of scale reduced carbon capture costs for natural gas and coal power generation by about 40% and 20%, respectively. Figure 5.6, adapted from the GCCSI report, illustrates both controls on the cost of point source carbon capture: the x-axis showing how increasing concentrations (partial pressures) of CO_2 in industry flue gas decreases the levelized cost of carbon capture, and the error bars reflecting the range in cost of capture at any given CO_2 concentration due to the scale of capture at any given facility.

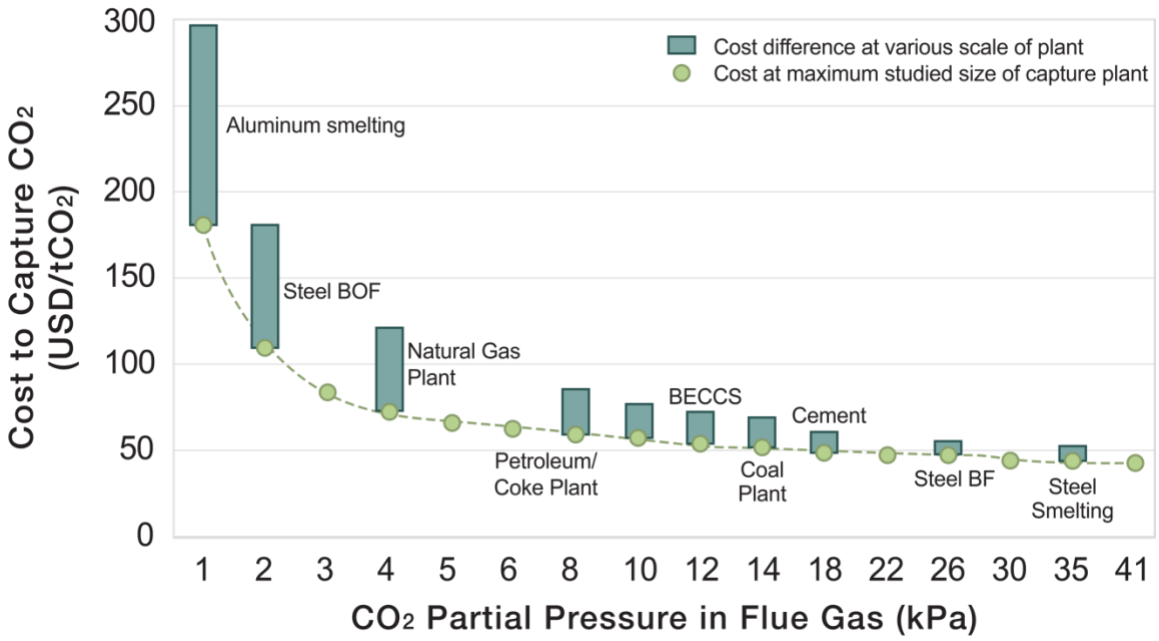

FIGURE 5.6. Levelized cost of carbon capture per metric ton CO_2 as a function of CO_2 partial pressure and operational scale, with the largest capacity capture facilities demonstrating the lowest cost at any given partial pressure. Adapted from Kearns et al. (2021) CCS readiness and costs.

[175] Kearns *et al.* (2021) CCS readiness and costs. p. 26-27. [45]

[176] Kearns *et al.* (2021) CCS readiness and costs. p. 31. [45]

To compare the relative costs of different carbon management industries (DAC, BiCRS, or point source capture), a 'Lifetime Cost Assessment' (LCA) model is used. The LCA is the total cost per metric ton CO_2 resulting from the cost of building the facility (capital costs), the cost of maintenance and labor (operational costs), and the cost of energy (heat + electricity), over the lifetime of the plant. However, for a micro steel mill, the cost of carbon capture is a comparatively small addition to the cost of building the mill. For simplicity, we assess the costs of creating the mill, and of capturing carbon from the mill separately. A micro steel mill that uses scrap and clean energy (0 tons CO_2 emissions per ton steel) would cost about $398-848 per ton steel produced. A scrap mill that used oxy-fuel combustion for energy would cost ~$407-903 per ton steel produced, with the added cost of CO_2 capture being ~$68-112 per ton CO_2. A mill that used direct reduced iron (DRI) with point source carbon capture and oxy-fuel combustion would cost ~$586-975 per ton steel produced, and the average cost of CO_2 capture would be $75-114 per ton CO_2. These estimated ranges are broken down in Table 5.5 and explained in detail below.

Table 5.5. Levelized cost per ton steel produced, by steel mill configuration.

Cost (USD per ton steel)[a]	Scrap-EAF + solar	Scrap-EAF + oxyfuel	DRI-EAF w. CCUS + oxyfuel	DRI-EAF + hydrogen
Cost to build steel mill (CapEx)	$88-125	$88-125	$88-125	$114-194
Feedstock (scrap steel or iron pellet)	$192-557	$192-557	$81-154	$157-267
Fixed operation & maintenance (OpEx)	$77-116	$77-116	$77-116	$90-153
Energy (solar, natural gas or green H_2)	$41-50	$40-88	$243-433	$226-508
Total Levelized Cost	**$398-848**	**$397-886**	**$489-828**	**$587-1,122**
Oxy-fuel combustion (Cap+OpEx)	--	$10-17	$59-97	--
DRI point source capture (Cap+OpEx)	--	--	$38-50	--
Total Levelized Cost Including Capture	**$398-848**	**$407-903**	**$586-975**	**$587-1,122**

a. See text for references for each estimated cost.

5.4.2.1 Cost to Build (upfront costs)

We can get a rough estimate of the capital expenditures, or cost to build a steel mini mill based on the six example mills listed in Table 5.5, which have been recently built, or are currently in development (detailed references for each of these sites is provided in Table 5.7). These mills, which produce between 350 and 1,200 thousand tons of steel annually, would cost $250 million to $1.7 billion dollars to construct. Normalizing those capital costs to the size of a steel mill that could capture up to 1 million tons of CO_2 annually (while producing ~770 thousand tons of steel), gives a range in capital costs between ~$460 million and $1.9 billion (average value is $680 million USD). If we annualized these costs, assuming a facility lifetime of 30 years and a capital recovery factor of 12.5% (see Section

3.4.2.1 for a detailed explanation of this calculation), the levelized capital cost of these normalized facilities ranges from ~$73-172 USD per ton steel produced. Such values closely approximate the estimated capital costs of DRI-EAF steel mills reported in the International Energy Agency (IEA)'s 2020 report on iron and steel technology.[177] They report a minimum CapEx for DRI-EAF of $88 USD per ton steel produced, but include an ~40% uncertainty to account for cost variability across regions, resulting in a CapEx range of $88-125. For the sake of consistency with the published literature, this is the CapEx range we employ in our levelized cost analysis (table 5.5). It is important to note that we approximate the same CapEx value for the scrap-EAF and DRI-EAF mills, and the added capital costs of CO_2 stemming from point source capture equipment (in the DRF-EAF with CCUS + oxy-fuel scenario) is accounted for separately.

Table 5.6. Reported capital expenditures for new or developing EAF mills.

Facility Name[a]	Year Operational	Annual Steel Output	Capital Costs (CapEx)	Normalized CapEx (per 770k tons steel)
		(kton steel)	million USD	million USD
Mojave Micro Mill, CA (proposed)	2025+	380	$350	$709
CMC Mesa Plant (II), AZ	2023	500	$300	$462
HighBar LLC, Osceola, AK	2024	600	$500	$642
Nucor Steel, Brandenburg, KY	2022	1,200	$1,700	$1,091
CMC Durant Plant, OK	2017	350	$250	$550
Nucor Steel, Davidson Co, NC	2024	430	$350	$627
MEAN		**577**		**$680**

a. These six mills are used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all other references to these sites, references are detailed in Table 5.7.

5.4.2.2 Operational Costs

Operational costs fall into two categories: fixed costs (labor and maintenance) and variable costs (price of feedstocks). For scrap mills, the feedstock is steel scrap, which due to supply chain disruptions and the COVID-19 coronavirus, fluctuated significantly in recent years. Between January 2020 and March 2023, steel scrap ranged from $192-557 USD per ton.[178] Iron ore, the raw material feedstock for DRI-EAF, has also fluctuated, ranging from $81-154 USD in 2022 and 2023.[179] Reported fixed operational costs range from $77-116 USD.[180,181]

[177] IEA (2020) Iron and Steel Roadmap. p. 108. [40]

[178] SteelBenchmarker (April 24, 2023) Price History: Tables and Charts. [74]

[179] Trading Economics (no date) Iron Ore. [82]

[180] IEA (2020) Iron and Steel Roadmap. p. 108. [40]

[181] M'barek *et al.* (2022) Global steel production costs. [54]

5.4.2.3 Energy Costs

Scrap-EAF mills require ~0.95MWh of energy production per ton steel (see Table 5.2), and DRI-EAF mills with point source capture require about 5 MWh per ton steel (see Section 5.1.3.2). If powered by solar with industrial scale battery storage, energy costs are estimated to be $43-52 USD/MWh ($28-37/MWh for solar energy + $15/MWh for battery storage).[182] Natural gas prices, based on a three year average, range from $43-92/MWh.[183] Combining these rates, we obtain an estimated cost of energy of $41-50 USD per ton steel for a scrap-EAF mill powered by solar, $40-88 USD per ton for a scrap-EAF mill powered by natural gas, and $211-461 USD per ton for a DRI-EAF mill with point source capture powered by natural gas. A steel mill powered by hydrogen would produce would not require the infrastructure or additional energy demand needed for point source capture. Thus, a DRI-EAF mill would require only about 4.7 MWh per ton steel produced. Costs for fossil-free green hydrogen range from ~$1.60-3.60 USD per kg (Section 6), or about $48-108 per MWh. Thus, green hydrogen energy costs for a scrap-EAF mill would be about $46-103 USD per ton steel, and for a DRI-EAF mill would be about $226-508.

5.4.2.4 Carbon Capture Costs

Finally, for mini-mills that are emitting appreciable CO_2, the capital and operational costs of capture via oxy-fuel combustion and point-source capture from DRI are additive to the costs of simply operating the mill. If these costs can remain under the $85 USD federal tax credit 45Q,[184] then carbon capture can be cost-effective, or even serve as an additional form of revenue. In the IEA's 2020 economic analysis of steel production, they estimated the combined capital and operational costs of post-combustion point source carbon capture, when applied to a DRI-EAF mill, to range from $38 to 50 USD per ton of steel. Given that about 0.42 tons of CO_2 can be captured via DRI point source capture per ton of steel made, the capture cost per ton CO_2 is $90-119 USD, within the cost range reported by the GCCSI (Figure 5.6).[185] Separately, a 2017 European techno-economic study of oxy-fuel combustion provided an estimated cost range of €71-116 EUR per ton CO_2 captured in 2014 currency. Converting those values to 2023 USD,[186,187] equates to an oxy-fuel combustion cost per ton of CO_2 captured of $68-112 USD.

A scrap-EAF mill that uses oxy-fuel combustion with capture produces, on average, 0.15 tons of CO_2 per ton steel (Table 5.2). At a cost of $68-112 USD per ton of CO_2, there would be an added net levelized cost to steel production of $10-17 USD per ton of steel (Table 5.5). A DRI-EAF mill, which is much more energy-intensive, would produce, on average, 0.87 tons of CO_2 via oxyfuel combustion, resulting in an added levelized cost to steel

[182] Lazard (October 2021) Levelized cost of energy analysis. [52]

[183] Gamage *et al.* (March 9, 2023) Forging a clean steel economy in the United States. [34]

[184] Carbon Capture Coalition (2022) IRA. [10]

[185] Kearns *et al.* (2021) CCS readiness and costs. p. 31. [45]

[186] Macrotrends (no date) Euro Dollar Exchange Rate. [55]

[187] Bureau of Labor Statistics (no date) CPI Inflation Calculator. [8]

production of $59-97 USD per ton steel. The additional 0.42 tons of CO_2 captured via point source capture in a DRI-EAF mill add $38-50 USD per ton steel.[188] The total cost of carbon capture for a DRI-EAF mill with oxy-fuel combustion is $97-147 USD per ton of steel produced, and an average cost of CO_2 capture of $75-114 USD per ton CO_2.

5.4.3 Regional benefits

5.4.3.1 Proximate feedstocks

The primary feedstocks for mini mills are scrap steel or pelletized iron ore. Kern County, while not rich in geologic iron resources, has an advantage in its location along major rail and interstate routes, and adjacent to the Pacific Coast and associated shipping lanes. Abundant domestic and international steel scrap could be readily available for processing in this region. Pelletized iron could be similarly shipped along such routes. Additionally, because steel-making is such an energy-intensive, close proximity to abundant clean energy, whether in the form of solar energy, green hydrogen, or oxy-fuel combustion of RNG or biomass-derived syngas, Kern County (and a potential carbon management park) offer significant opportunities for accessible clean energy.

5.4.3.2 Proximate consumers

The same proximity to highly populated areas, as well as rail, interstate and shipping routes are also advantageous for the sale of steel, a product that is traded on an international marketplace.

5.4.3.3 Co-location advantages

Steel produces a relatively smaller amount of CO_2 emissions than BiCRS/DAC - and thus development of dedicated CCUS compression, transport and storage infrastructure may not be economically viable for a stand-alone facility.[189] Co-location and sharing infrastructure with other industries that produce larger amounts of CO_2 could allow for cost-effective capture of CO_2 from steelmaking, even in smaller plants that produce significantly less than 1 million tons of CO_2 annually.

[188] IEA (2020) Iron and Steel Roadmap. p. 108. [40]

[189] IEA (2020) CCUS in clean energy transitions. p. 166. [41]

Table 5.7. References for representative micromill facilities in the U.S.

Facility Name	Year Operational
Mojave Micro Mill, CA (proposed)	Cox (2022) 'Green steel' plant proposed for Mojave.
CMC Mesa Plant (II), AZ	SE Mesa plant double steel production. East Valley Tribune. Published online April 20, 2021. Accessed March 19, 2023 from https://www.eastvalleytribune.com/money/se-mesa-plant-double-steel-production/article_78424896- a137-11eb-816a-d787277d5d29.html.
	CMC Steel Arizona - Breaking Ground on the World's First Combination Micro Mill. Queen Creek Independent. Published online January 6, 2022. Accessed March 19, 2023 from https://www.yourvalley.net/queen-creek-independent/stories/cmc-steel-arizona-breaking-ground-on-the-worlds-first-combination-micro-mill,279239.
	CMC sees spring start for Arizona micro-mill. Association for Iron & Steel Technology. Published online January 12, 2023. Accessed March 30, 2023 from https://www.aist.org/news/steel-news/2023/january/9-13-january-2023/cmc-sees-spring-start-for-arizona-micro-mill.
HighBar LLC, Osceola, AK	Chen, I. US' HighBar plans to invest rebar mill in Arkansas. Published online November 3, 2022. Accessed March 19, 2023 from https://yieh.com/en/NewsItem/137424.
	Kamczyc, A. Highbar LLC announces site for first rebar mill. Recycling Today. Published online November 2, 2022. Accessed March 19, 2023 from https:// www.recyclingtoday.com/news/highbar-llc-announces-site-for-first-rebar-mill/.
Nucor Steel, Brandenburg, KY	Gregg, J. The New Steel City: Brandenburg Braces for Massive Steel Plant. Spectrum News 1. Published online July 19, 2019. Accessed March 19, 2023 from https://spectrumnews1.com/ky/louisville/news/2019/07/19/small-kentucky-town-ready-for-big-steel-plant.
	Otts, C., Ragsdale, T. Nucor starts work on Brandenburg, Ky. steel mill. WDRB.com. Published online Octobter 23, 2020. Accessed March 19, 2023 from https://www.wdrb.com/in-depth/nucor-starts-work-on-brandenburg-ky-steel-mill/article_68b6530c-156b-11eb-8d81-ffc75a1b85c1.html.
	New Nucor Steel Brandenburg Plate Mill Rolls First Plate. Nucor. Published online January 3, 2023. Accessed March 19, 2023 from https://nucor.com/news-release/19471.
CMC Durant Plant, OK	Ground broken for new steel mill in Durant. News On 6. Published online April 30, 2016. Accessed March 19, 2023 from https://www.newson6.com/story/ 5e360f752f69d76f62039b57/ground-broken-for-new-steel-mill-in-durant.
	Commercial Metals Co. receives air permit. The Journal Record. Published online February 4, 2016. Accessed March 19, 2023 from https://journalrecord. com/2016/02/04/commercial-metals-co-receives-air-permit/.
	Commercial Metals Company selects Durant, Okla., for new micro mill. Oklahoma Commerce. Published online July 30, 2015. Accessed March 19, 2023 from https://www.okcommerce.gov/commercial-metals-company-selects-durant-okla-for-new-micro-mill/.

Facility Name	Year Operational
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Clean Energy Technologies

6. Hydrogen Production

TECHNOLOGY AT A GLANCE

- There are many ways to produce hydrogen, which are at different degrees of technical readiness. Here we examine blue hydrogen (commercially operational), green hydrogen via electrolysis (commercial demonstration phase), and green hydrogen via biomass (pilot and early demonstration phase).[1]
- Current costs per kilogram H_2 produced: $1.30-10.60 USD/kg H_2
- Current cost of CO_2 capture: $125-257 USD/ton CO_2 (green hydrogen from biomass), ~$82 USD/ton CO_2 (blue hydrogen from steam methane reforming+carbon capture and storage [SMR+CCS])
- Projected costs reductions per kilogram H_2 produced at scale: 20-50%
- Key advantages of this technology in Kern County: close proximity to feedstocks for some production methods (agricultural waste for green hydrogen from biomass, natural gas for blue hydrogen from SMR+CCS), located within the largest hydrogen market in the U.S., abundant renewable energy can make green hydrogen via electrolysis cost-competitive with other techniques
- Key concerns for this technology in Kern County: high energy and water demands for green hydrogen via electrolysis, potential for air pollutants - particularly from blue hydrogen via SMR+CCS - warrants further investigation, the hydrogen market is still quite nascent and will require large infrastructure investments before it can scale significantly

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

6.1 Technology Summary

In looking for alternative fuels to traditional hydrocarbons (including gasoline and diesel), both scientific experts and policymakers have turned to hydrogen as a potential fuel of the future, as it does not generate carbon emissions when burned.[2] Hydrogen is highly abundant, but most commonly is chemically bound in the compounds of other familiar substances, like water (H_2O) or methane (CH_4, which is natural gas). To use hydrogen as a fuel, it must be isolated from those compounds.[3] In this section, we present a brief overview of the variety of processes available to generate hydrogen gas (H_2), with a focus on two forms of hydrogen that are considered to produce little or no CO_2 emissions in their production: green and blue hydrogen.

6.1.1 Methods of Hydrogen Production

Hydrogen can be produced via several different methods, which for short-hand discussions have been categorized into a color key system, with each color indicating the production technique. Understanding this system is useful for research and discussions about the hydrogen industry and when thinking about the viability and trade-offs of given production methods. (Note, hydrogen itself is a colorless gas; the color system is simply a convenient notation device, but describes only the difference in hydrogen generation technique. There is no difference in the visual, physical, or chemical properties of hydrogen gas derived from these different production methods).[4]

While most applications of this color key system use commonly agreed upon definitions for each color, there is not a regulatory or industry standard, so some sources may have differences in what processes they include under each color. In this section, we provide a brief overview of the hydrogen labeling system, giving the commonly agreed upon definitions of each color. Then, we will examine the three forms of hydrogen production that would be most relevant for consideration in a carbon management and clean energy industrial park: green hydrogen via electrolysis, green hydrogen via biomass, and blue hydrogen.

6.1.1.1 The Hydrogen Color System

Unless otherwise noted, all definitions of the hydrogen color key system are derived from National Grid, an electricity distribution company operating in the United States and United Kingdom.[5]

Green hydrogen production refers to production techniques that generate no greenhouse gas byproducts. Most commonly, this is achieved via a process known as electrolysis,

[2] FuelCellWorks (November 28, 2022) 'Gold Hydrogen' Is an Untapped Resource. [31]
[3] EPA (September 13, 2022) Green Vehicle Guide: Hydrogen Fuel Cell Vehicles. [28]
[4] National Grid (no date) Hydrogen Colour Spectrum. [50]
[5] National Grid (no date) Hydrogen Colour Spectrum. [50]

wherein clean energy (like solar or wind) is used in an electrochemical reaction to split water molecules into hydrogen and oxygen. However, other non-carbon emitting techniques, such as gasification of biomass to form pure streams of H_2 and CO_2 gasses, combined with carbon capture, also qualify as green hydrogen.[6]

Blue hydrogen production refers to the conversion of methane (natural gas) to hydrogen via a process called steam reforming, which – like gasification from biomass – generates both hydrogen and carbon dioxide. In blue hydrogen generation, generated CO_2 is captured via point source capture technologies (see Section 5) reducing the carbon-intensity of hydrogen generation.

Gray hydrogen production also refers to steam reforming methane (natural gas), but does not incorporate the carbon capture processes necessary to reduce emissions. Currently, gray hydrogen is the most commonly used production process to generate hydrogen.

Black and brown hydrogen production relies on using pure coal or lignite (brown coal) to generate hydrogen, by gasification of the coal resulting in hydrogen as a byproduct. This is understood to be one of the most environmentally harmful ways to produce hydrogen.

Pink hydrogen production refers to the process of electrolysis, where water is split into hydrogen and oxygen, akin to green hydrogen. Unlike green hydrogen, though, it relies on nuclear power to sustain the electrochemical reaction. Some sources refer to this with other similar colors, like purple or red.[7]

Turquoise hydrogen production involves a process called methane pyrolysis, which converts methane to hydrogen and solid carbon, called "carbon black."[8] Carbon black has many industrial uses, but this method of hydrogen production has yet to operate at a commercial scale.

Yellow hydrogen production is a less commonly used and newer term, referring specifically to hydrogen production via electrolysis fueled by solar power. As such, yellow hydrogen is a subcategory of green hydrogen.

White hydrogen refers to hydrogen that does not need to be produced, but that is naturally occurring in geologic formations and could be accessed via fracking. At present, there are no plans or strategies to mine hydrogen, and opinions are mixed as to whether naturally-occurring hydrogen gas even exists. The National Renewable Energy Laboratory (NREL) states that hydrogen gas is not naturally-occurring, but there is growing optimism from other scientists that naturally-occurring hydrogen may be abundant beneath the Earth's surface.[9]

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[6] Cormos (2023) Green hydrogen production from decarbonized biomass gasification. [20]

[7] Willige (July 28, 2022) The colors of hydrogen. [84]

[8] Willige (July 28, 2022) The colors of hydrogen. [84]

[9] Coy (February 27, 2023) A Gold Mine of Clean Energy May Be Hiding Under Our Feet. [21]

6.1.1.2 Envisioning hydrogen production in Kern County

Given the current economy, climate, and resources of Kern County, and the developmental objectives of a carbon management and clean energy industrial park, only some hydrogen production approaches were identified as warranting exploration in this study. The following production methods were ruled out:

- Black/brown and pink hydrogen production make little sense to explore at this juncture, given Kern County's current and anticipated energy mix.
- White hydrogen production is still within very early stages of technological development and will require significant further research before it is ready for commercial demonstration.
- Turquoise hydrogen is still within very early stages of development. Although it is not examined extensively here, production is very similar to other forms of biomass gasification and pyrolysis, which are described in detail in Section 4.
- Yellow hydrogen is a type of green hydrogen, and thus will be examined briefly in the discussion of hydrogen via electrolysis.
- Gray hydrogen production, given its large, unmitigated greenhouse gas emissions footprint, is incompatible with the park's guiding principle of hosting carbon management and clean energy industries.

Green hydrogen (via electrolysis or biomass gasification) and blue hydrogen production are potential clean energy or carbon management technologies that could feasibly be adopted in a Kern County carbon management park, and we explore each of these in this report. Given that more than one production method can be classified as 'green hydrogen,' the nomenclature used in this report will always specify both the color key and the process of production, to avoid ambiguity: hydrogen via electrolysis (green), hydrogen via biomass gasification (green), and hydrogen via steam methane reforming (SMR) + CCS (blue). Finally, because hydrogen production via biomass gasification with carbon capture is a form of Biomass with Carbon Dioxide Removal and Storage (BiCRS), most of the information on this method of hydrogen production is also contained in the BiCRS/BECCS section of this report (Section 4) and is cross-referenced accordingly.

6.1.2 Green and Blue Hydrogen Description: How it Works

6.1.2.1 Green hydrogen via Electrolysis

Hydrogen production via electrolysis involves using an electric current to drive an electrochemical reaction in which water is split into its constituent elements, hydrogen and oxygen:[10]

$$H_2O \rightarrow H_2 + \tfrac{1}{2}O_2 \qquad \text{(R6.1)}$$

[10] AFDC (no date) Hydrogen Production and Distribution. [6]

There are a variety of machines, called electrolyzers, that can sustain this electrochemical reaction to produce hydrogen, using varying techniques, which are reviewed here.

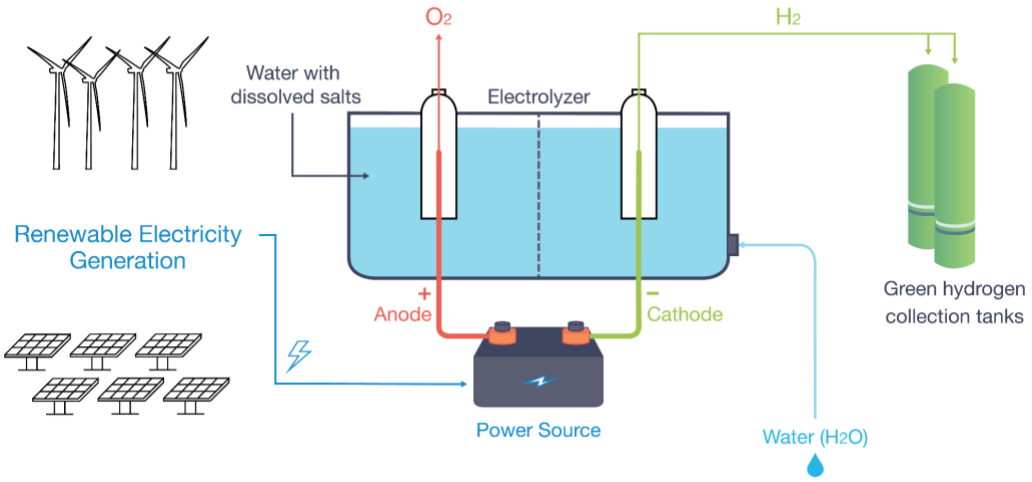

Figure 6.1. Schematic of the process of producing hydrogen via electrolysis: renewable energy provides electricity to power a cathode and anode placed in a water + dissolved salt solution. The electric current created breaks water (H_2O) molecules into hydrogen and oxygen.

The most well-established method, alkaline electrolysis, has existed for more than two centuries. Alkaline electrolysis uses an electrochemical cell, where a cathode and anode are placed in an electrolyte solution, which is a water-based solution with salts (Figure 6.1).[11] When voltage is applied to the cell, water molecules are reduced by electrons at the cathode to produce hydrogen gas and negatively charged hydroxide (OH^-). The hydroxide ions will be electrically attracted to the anode, and by placing a membrane between the anode and cathode, the hydrogen gas molecules can be separated from the negatively charged hydroxide ions. At the anode, the hydroxide ions are oxidized, producing oxygen gas, and releasing water molecules and electrons back to the electrolyte solution (see reactions R6.2 + R6.3):[12]

Cathode reaction: $2H_2O + 2e^- \rightarrow H_2 + 2OH^-$ (R6.2)

Anode reaction: $2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^-$ (R6.3)

Hydrogen gas is separated from the electrolyte solution to be dried (removing any H_2O vapor), cleaned (involving the removal of oxygen impurities),[13] and depending on the end use, compressed.[14] The reactions in the electrolyte solution (R6.2 + R6.3) generate heat; if this heat is harnessed during the process, it can help improve the cell's overall energy

[11] Lichner (March 26, 2020) Electrolyzer overview. [47]
[12] Brauns, Turek (2020) Electrolysis review. [12]
[13] Brauns, Turek (2020) Electrolysis review. [12]
[14] Lichner (March 26, 2020) Electrolyzer overview. [47]

efficiency.[15] Alkaline electrolysis represents a *type* of electrochemical cell, which is often used as a kind of battery. For a general explanation of electrochemical cells and reduction-oxidation reactions, please see Section 7.1.1 of this report.

Most new hydrogen via electrolysis projects today use a different process that relies on a proton exchange membrane (PEM).[16] Here, instead of a liquid electrolyte solution, water is pressed through a stack of two electrodes with a polymer membrane in between (Figure 6.2). At the anode, the water reacts to form oxygen, hydrogen ions (H^+), and electrons; the hydrogen ions can then move selectively across the membrane, a specialty solid plastic material,[17] towards the cathode.[18] The electrons are moved to the cathode side as well through an external circuit, as they cannot pass through the membrane.[19] On the cathode side, the hydrogen ions and electrons combine, forming hydrogen gas.[20]

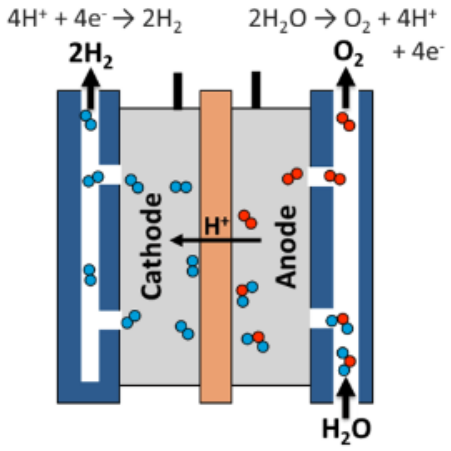

Figure 6.2. Schematic of a proton exchange membrane. Image credit: U.S. Department of Energy.[21]

There is a third electrolysis technology—solid oxide electrolysis (SOE)—that is rising in prominence, but alkaline and PEM systems are far more common for commercial applications. It is explored briefly here for comprehensiveness, but future sections on hydrogen via electrolysis primarily focus on alkaline and PEM systems. The electrolyte in these systems is a solid ceramic that selectively allows negatively charged ions to pass through at high temperatures—in this case, the negative ion is oxygen (O^{2-}).[22] Water enters at the cathode as steam, where it combines with negative ions brought in via the external

[15] Lichner (March 26, 2020) Electrolyzer overview. [47]
[16] Lichner (March 26, 2020) Electrolyzer overview. [47]
[17] EERE (no date) Hydrogen Production: Electrolysis. [58]
[18] EERE (no date) Hydrogen Production: Electrolysis. [58]
[19] EERE (no date) Hydrogen Production: Electrolysis. [58]
[20] EERE (no date) Hydrogen Production: Electrolysis. [58]
[21] EERE (no date) Hydrogen Production: Electrolysis. [58]
[22] EERE (no date) Hydrogen Production: Electrolysis. [58]

circuit to form hydrogen gas and O^{2-}.[23] Once formed, the oxygen ions pass through the solid ceramic membrane to the anion, where the oxygen ions react to form oxygen gas and electrons that will supply the external circuit.[24]

Many projects currently emphasize "power-to-hydrogen" or "power-to-gas" initiatives, where excess renewable energy—when it is available from the grid—is channeled to electrolyzers to create hydrogen.[25, 26]

6.1.2.2 Green Hydrogen via Biomass Gasification

There are a variety of ways to treat biomass in order to produce an energy-rich product and CO_2 byproduct that can be captured for permanent storage, which are detailed in Section 4 of this report. The most relevant in the context of hydrogen is a process called gasification, a two-step process in which first, biomass is reacted with steam and oxygen at high temperatures (>700°C) and pressure, converting it into gaseous components – primarily CO, CO_2, and H_2.[27] In the second step, called a water-gas shift reaction, the carbon monoxide (CO) is reacted with water to produce more CO_2 and H_2, along with a small amount of heat.[28] The resulting products are two streams of high-purity gasses: CO_2 for permanent storage, and H_2 for fuel use. Pyrolysis, the high-pressure and high-temperature process used to create turquoise hydrogen from methane, is a technique that can also be applied to biomass to produce CO_2 and a variety of hydrocarbon byproducts, and is also detailed further in Section 4.

6.1.2.3 Blue Hydrogen via Steam Methane Reforming (SMR) + CCS

Hydrogen via steam methane reforming (SMR) + CCS relies on an interconnected series of processes to transform methane (CH_4) and water (H_2O) into hydrogen (H_2) and CO_2. In the initial SMR reaction, steam reacts with methane in a high-pressure container with a catalyst to produce syngas, a mixture of hydrogen, carbon monoxide, and carbon dioxide.[29] As an endothermic reaction, SMR requires heat for the reaction to proceed—requiring about 206 kJ of heat energy per mol of methane.[30,31] (Steam reforming can be used to generate hydrogen from other hydrocarbon fuels, like propane or gasoline, but SMR is the most

[23] EERE (no date) Hydrogen Production: Electrolysis. [58]
[24] EERE (no date) Hydrogen Production: Electrolysis. [58]
[25] AFDC (no date) Hydrogen Production and Distribution. [6]
[26] Shibata (2015) Hydrogen Production from Variable Renewables. p. 27-28. [70]
[27] EERE (no date) Hydrogen Production: Biomass Gasification. [57]
[28] EERE (no date) Hydrogen Production: Biomass Gasification. [57]
[29] Student Energy (no date) Steam Methane Reforming. [74]
[30] Student Energy (no date) Steam Methane Reforming. [74]
[31] National Research Council and National Academy of Engineering (2004) The Hydrogen Economy. p. 199. [51]

common choice for hydrogen production, as it is the cheapest and most efficient.[32,33]) Like gasification, the next step is typically a water-gas shift reaction, where the carbon monoxide generated in SMR is reacted with more steam in the presence of a catalyst to form more hydrogen, carbon dioxide, and a small amount of heat.[34] The final step, pressure-swing adsorption, removes the carbon dioxide and other gasses from the final products, leaving a pure stream of hydrogen gas.[35]

Once separated from the hydrogen gas stream, the carbon dioxide generated in the SMR and water-gas shift steps can be purified, compressed, and transported for permanent underground storage, preventing it from entering the atmosphere and contributing to climate change. In gray hydrogen production (from SMR without CCS), for every kilogram of hydrogen produced, approximately 9 kilograms of CO_2 is generated.[36] With carbon capture and storage attached, the estimated emissions of SMR hydrogen production drops to 1-5 kilograms of CO_2 generated per kilogram of hydrogen.[37] Although this reduces the impacts of SMR, it does not make the process carbon-neutral—blue hydrogen still releases CO_2 into the atmosphere. This is explored in further detail in Section 6.3 on the environmental impacts of hydrogen production.

6.1.3 State of Development

Blue hydrogen via SMR + CCS, green hydrogen via electrolysis and green hydrogen from biomass are all commercially operational processes that are ready to be scaled up, but hydrogen production from electrolysis and biomass gasification in particular are currently deemed too costly to be competitive with less environmentally-friendly hydrogen production methods.

In addition to the hydrogen production methods detailed here, and in the color classification summary (Section 6.1.1.1), there are several emerging hydrogen production techniques that are still in the early research and development stage. It is beyond the scope of this study to detail each of these emerging technologies, but a list of their names is provided for the interested reader who would like to explore further. Hydrogen production techniques still in the experimental phase include processes like photo-electrochemical solar water splitting, solar high-temperature thermochemical cycles, high-temperature electrolysis, photo-biological conversion, bio-derived conversion, microbial conversion and generating hydrogen from aluminum scrap.[38]

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[32] Student Energy (no date) Steam Methane Reforming. [74]
[33] AFDC (no date) Hydrogen Production and Distribution. [6]
[34] Student Energy (no date) Steam Methane Reforming. [74]
[35] Student Energy (no date) Steam Methane Reforming. [74]cf
[36] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[37] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[38] Bezdek (2019) The hydrogen economy. [8]

Below, we provide brief summaries of extant companies or projects that are representative of the three hydrogen production techniques explored here.

6.1.3.1 Example projects

Electrolysis: Air Liquide, Bécancour, Québec

Air Liquide's facility in Bécancour is discussed at length in Section 6.1.4, as a case study for operational needs of electrolysis. This facility has the largest operating electrolyzer of its kind in the world—a 20 MW PEM electrolyzer developed with Cummins technology.[39] This 20 MW capacity was obtained by a four-module configuration of HyLYZER 1000-30 units, which are 5 MW each.[40] The facility is run using grid hydropower resources from Hydro-Québec, an almost-all renewable source of energy.[41]



Figure 6.3. Digital rendering of the planned alkaline electrolysis facility in Lancaster, California, under construction by Element Resources. Image credit: Element Resources.

Electrolysis: Element Resources, Lancaster, California

At the planned Lancaster Energy Center, Element Resources intends to set up an electrolysis site on 1,165 acres with an electrical capacity of 135 MW using alkaline electrolysis.[42] The primary reason for the large land footprint is the electricity demand, which will be met using solar photovoltaic (PV) panels installed on-site. Their estimated hydrogen output per year, once fully operational, is 18,750 metric tons per year.[43]

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[39] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]

[40] Collins (January 27, 2021) World's largest green-hydrogen plant inaugurated. [19]

[41] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]

[42] Element Resources (no date) Lancaster Energy Center. [24]

[43] Element Resources (no date) Lancaster Energy Center. [24]

Biomass Gasification: Mote, Los Angeles, California

Mote, a Culver City-based cleantech startup, is planning to build a $100 million biomass to hydrogen energy plant with carbon sequestration on 5 acres of unincorporated land in Kern County, pending securing financing, government approval and permits.[44] The plant will extract carbon dioxide and hydrogen via gasification from wood waste from farms, forestry, and other resources.[45] The hydrogen gas will be sold to hydrogen fuel station operators, and the CO_2 will be sequestered into deep underground saline aquifers or retired oil wells. Mote expects to produce approximately 7,000 metric tons of carbon-negative hydrogen (green hydrogen) annually, which translates to ~150,000 metric tons of CO_2 captured from biomass and available for permanent sequestration.[46]

Mote's business model will provide cost-competitive green hydrogen by partly offsetting their costs with income from the storage of CO_2. They will either take advantage of carbon removal credits in the voluntary carbon credit market, or of rebates from the federal tax credit for CCS projects (45Q) as well as California's Low Carbon Fuel Standard (LCFS).[47] In May 2022, Mote announced that they had secured commitments for over 450 thousand tons of feedstock for their production.[48] Working with Fluor, an industry leading engineering, procurement and construction (EPC) firm, to execute the Front-End Loading 2 (FEL-2), Mote plans to begin construction in 2023 and be fully operational by 2025.[49] A digital rendering of their planned facility is shown in Figure 6.4.

Steam Methane Reforming: Air Products, Texas & Louisiana

Air Products has deployed retrofitted carbon capture to two existing hydrogen via SMR facilities in Texas, and is now planning a more ambitious project: building the world's largest SMR + CCS facility in Louisiana, planned to go online in 2026.[50] The Louisiana Clean Energy Complex webpage states they expect to capture over 5 million tons of CO_2 annually from SMR + CCS hydrogen production, expecting that they'll capture 95% of the CO_2 generated during the process.[51] According to Air Products, this would position them to be the largest CCS plant in the world. If they can attain this 95% capture rate in practice, it would be a higher capture rate than any reported estimates for SMR with CCS found in the literature during the preparation of this report. Total planned investment for the project amounts to $4.5 billion, and the project would create an estimated 170 permanent jobs and another 2,000 positions during the construction phase.[52]

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[44] Fine (January 3, 2022) Clean tech startup Mote unveils plans for $100M plant. [30]
[45] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [76]
[46] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [76]
[47] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [76]
[48] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [14]
[49] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [14]
[50] Air Products (no date) Carbon Capture. [3]
[51] Air Products (no date) Louisiana Clean Energy Complex. [4]
[52] Air Products (no date) Louisiana Clean Energy Complex. [4]



Figure 6.4. Digital rendering of a planned Mote Hydrogen facility in southern California, featuring a parking lot, office buildings, a gasifier building with conveyor belts for moving biomass, several large vertical tanks, rows of biomass feedstock, and two evaporation ponds. Image credit: Mote, Inc.

6.1.4 Operational Needs

6.1.4.1 Land use requirement

The scale of a commercial hydrogen facility is generally described in terms of how much energy it is able to produce annually (its MW capacity), rather than the physical footprint that it would occupy, meaning published descriptions of land use needs from operators are rare. Furthermore, given the rapid rate of technological innovation and plans to scale up production in this sector, most existing facilities are significantly smaller than planned future facilities. As such, experts have largely been approximating facility footprints based "on engineering estimates, rather than plot optimization based on real experience."[53]

For hydrogen via electrolysis, the largest currently active site in the world is Air Liquide's site in Bécancour, Quebec, which began production in January 2021.[54] It has a capacity of 20 MW and can generate over 8.2 metric tons per day of hydrogen; their plant relies on hydropower from Hydro-Québec for its nearly-all renewable energy source.[55] The Bécancour facility relies on four proton exchange membrane (PEM) electrolyzers to generate its hydrogen, which are approximately the size and shape of very round water towers.[56]

Estimates aggregated by the International Renewable Energy Agency (IRENA) can help refine size estimates for future hydrogen facilities that would be larger than Bécancour, as

[53] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]
[54] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]
[55] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]
[56] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]

is expected to become common if hydrogen is to be a widely-used fuel in the future. In a 2014 study, IRENA estimated that a 100 MW capacity electrolyzer would require ~6,300 m^2 (1.55 acres) of land.[57] For reference, a 100 MW electrolyzer would produce about 50,000 kilograms of H_2 per day[58] (that is the equivalent to about 50,000 gallons of gasoline production per day[59]).

Later studies of 100 MW capacity facility designs generated smaller estimates than this initial figure, with a 2017 study estimating a footprint of 3,500 m^2 (0.86 acres) and a 2018 study estimating a footprint of 4,500 m^2 (1.11 acres).[60] In regards to even larger facilities, a 2017 study by Siemens predicted a 300 MW capacity electrolyzer facility would need 15,000 m^2 (3.71 acres).[61] Relative to other industrial energy facilities that produce electricity or fuel, these are relatively modest land use requirements.[62,63]

The accuracy of these estimates will be easier to determine moving forward, as companies have begun planning and constructing facilities in the hundreds of MW capacity range. A 100 MW hydrogen via electrolysis facility run by RWE Generation is planned for Lingen, Germany as part of the world's first publicly-accessible hydrogen network.[64]

6.1.4.2 Energy requirements

Hydrogen production is an extremely energy intensive process, particularly for electrolysis, because of the strength of the chemical bonds that need to be broken between the hydrogen and oxygen ions within a water molecule. For hydrogen production via electrolysis, the efficiency of the reaction generally ranges between 60-81%, depending on the technology used.[65] This means that for every 100 MW of electricity used to drive an electrolysis reaction, about 60-81 MW of energy value is produced in the form of hydrogen fuel. That is equal to a production rate of about 43,600-58,900 kg of H_2 produced each day,[66] with one kg of H_2 having about the same energy content as one gallon of gasoline. If all of the hydrogen currently produced in the world (about 69 million metric tons annually) was

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[57] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]

[58] EERE (August 2018) Global Electrolyzer Sales Reach 100 MW per Year. [55]
This DOE estimate assumes that the electrolyzer is running full-time with 50 kWh of electricity needed per kilogram of hydrogen produced to arrive at this estimate.

[59] Hydrogen Program (no date) Hydrogen Conversion Factors. p. 1. [35]

[60] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]

[61] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]

[62] Stevens *et al*. (2017) The Footprint of Energy. p. 1. [73]

[63] Boyett (January 27, 2023) Henderson history: Third time wasn't the charm for local synthetic fuel plants. [11]

[64] Celovic (March 19, 2020) First Publicly Accessible Hydrogen Network. [15]

[65] IEA (2019) The Future of Hydrogen. p. 43. [37]

[66] National Research Council and National Academy of Engineering (2004) The Hydrogen Economy. p. 240. [51]
*1kg of hydrogen has an energy value ("lower heating value") of about 33.3 kWh, and 60-81MW of energy value translates to 525,600-700,800 MWh of energy production in a year.

generated using electrolysis, it would require 3,600 terawatt hours (TWh) of electricity, more than the total annual electrical output of the European Union—a staggering energy demand.[67] To put that energy demand in a domestic perspective, if hydrogen were to replace US gasoline consumption (requiring about 135 million tons of hydrogen annually[68]), producing that hydrogen via electrolysis would use nearly twice the amount of electricity that currently powers the entire United States.[69,70,71]

A biomass gasification facility producing 1 million tons of CO_2 for capture can produce about 70,000 tons of hydrogen if it is powered entirely through an external source of energy.[72] For a facility to be self-sufficient (effectively needing no external energy input), about 30% of the syngas produced in the gasification step of hydrogen production is needed.[73] In this case, for every million tons of CO_2 produced, only about 50,000 tons of hydrogen is produced.[74] Whether and to what degree produced syngas or external energy sources are used depends on the relative cost of available energy sources, and the marketplace value of green hydrogen. If green hydrogen is far more valuable than other energy sources, facilities may use electricity or other fuels to produce the hydrogen, so they can sell as much of what they generate as possible. If prices are relatively equivalent, or green hydrogen prices decline to be cheaper than other fuels, facilities will likely opt to use some of the generated hydrogen to power the facility.

Most of the energy needs for biomass hydrogen production are used to attain the necessary heat and pressure to gasify the organic feedstock. The exact amount of required heat energy is difficult to ascertain, as the process is still relatively new, and most technical information regarding any individual gasification technique is proprietary. The fact that most facilities meet this energy need with their own supply of syngas, also leads to its often being unreported. Regardless of the scale of heat energy requirements, if solar-sourced energy were used, it would need to be paired with heat batteries, which likely would make it uneconomical compared to utilizing a portion of the syngas. As for the electricity demands, most facilities either pursue a grid connection as back-up or set up their own solar panels to meet any electrical demand. For a facility capturing 1 million metric tons of CO_2, the estimated solar capacity would be 135 MW, occupying ~945 acres, just to meet the electricity needs.[75]

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[67] IEA (2019) The Future of Hydrogen. p. 43. [37]

[68] EIA (May 1, 2023) FAQ: How much gasoline does the United States consume? [25]

[69] IEA (2019) The Future of Hydrogen. p. 43. [37]

[70] Hydrogen Program (no date) Hydrogen Conversion Factors. p. 1. [35]

[71] Our World in Data (no date) USA Electricity Generation. [60]

[72] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. Supplementary Table S4. [85]

[73] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. p. 3. [85]

[74] This estimate is consistent with yield estimates from an industry representative, personal communication, September 8, 2022.

[75] Industry representative, personal communication, September 8, 2022.

For SMR + CCS, there is no expected electricity demand, as the SMR process can be driven using internally generated waste heat, but there is a requirement of 3.4 kilograms of natural gas (methane) input per kilogram of hydrogen generated.[76] If waste heat is not employed to support the heat necessary for the SMR and water-gas shift reactions, then additional natural gas (methane) may be needed to meet the heat energy requirements.

6.1.4.3 Other operational requirements

Waste disposal requirements

During electrolysis, two gaseous products are created: hydrogen gas (H_2) and oxygen gas (O_2). Most electrolyzer plants choose to release their oxygen gas directly into the atmosphere,[77] but the oxygen could hypothetically be packaged and sold for use in metal processing, stone and glass production, chemical manufacturing, or for medical uses.[78] If these uses were pursued, the oxygen would likely need to be compressed and given warehouse space before it could be shipped to end users.

If the water source for electrolysis is not delivered at the necessary purity to go straight into an electrolyzer, then it may require additional on-site filtration, which produces minerals (mostly salt) that will need to be disposed of.[79] For a plant generating 45 metric tons of hydrogen gas daily using water directly from municipal supplies, the estimated weekly mineral production was about one dumpster worth of material for disposal.[80,81] A 100 MW hydrogen electrolysis facility, which produces slightly more H_2 (about 50 metric tons daily),[82] would need just over one dumpster per week. In the long term, another category of expected waste will be the electrolyzer stacks themselves, which typically require replacement on a 7 to 11 year timescale depending on the electrolyzer type.[83]

For hydrogen production via biomass gasification, all of the reaction products—hydrogen, CO_2, biochar—can be sold for use or permanently sequestered. It is only equipment that should require a waste disposal strategy at end-of-life, which will be component specific, depending on whether it can be recycled or needs to be landfilled. Further information about gasification products and disposal can be found in Section 4.1.4.2 of this report.

For hydrogen production via SMR + CCS, the picture is similar to biomass gasification—once all of the steps have been completed, the only process outputs should be hydrogen,

[76] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]
[77] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 1. [64]
[78] Lenntech (no date) Oxygen. [44]
[79] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[80] Governor Kathy Hochul (October 20, 2021) Construction Start at Largest Green Hydrogen Plant in North America. [34]
[81] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[82] Hydrogen Program (no date) Hydrogen Conversion Factors. p. 1. [35]
[83] UK Department of Business, Energy & Industrial Strategy (2021) Hydrogen Production Costs. p. 19. [77]

CO_2, and a small amount of heat.[84] None of these products require waste disposal, unless there are any impurities in the methane gas stream that would result in small amounts of gaseous waste.[85] The hydrogen and CO_2 can be packaged for sale or sequestration, and the heat would ideally be cycled back into the process or directed towards a co-located industry for use. Again, only equipment that requires replacement should need separate waste disposal practices.

Warehousing requirements

For all methods of hydrogen production, the most likely warehousing requirement will be a site to compress and store the hydrogen for transport once formed. Both hydrogen production via biomass gasification and via SMR + CCS will also create CO_2 that must be compressed and transported off-site, ideally to geologic storage, to minimize environmental impacts.

Hydrogen production via electrolysis may require similar infrastructure to store oxygen if they plan to sell it instead of releasing it.

For hydrogen production via biomass gasification, a facility will need biomass on hand to gasify (i.e. Figure 6.3), and these facilities often have drying warehouses on-site to prepare the biomass for processing.[86] Since these facilities will generate other byproducts, like biochar, that can be sold, it is likely that they will need other buildings to process and store these products for shipment.

Transportation requirements

Over short distances, hydrogen can be transported via pipeline, truck, or rail.[87] With that said, pure hydrogen gas is extremely hard to transport. It can be compressed, liquefied, or converted temporarily into a metal hydride (fuel cell) in order to be transported.[88] Given that hydrogen is the lightest and smallest element in the universe, hydrogen gas is the lowest density gas. Hydrogen gas is also extremely flammable when mixed with even small amounts of air, so leaks or other malfunctions in transport could be extremely hazardous.[89] As such, it would be an extensive challenge to retrofit existing transport methods for safe use with hydrogen. Rather, new, dedicated infrastructure (pipelines, hydrogen compression or conversion technologies, and appropriately designed tanker and shipping vessels) will need to be developed. Technologies to scale up the cooling and compressing of hydrogen for commercial-scale transport are still in the research and development phase.[90] Based on the current state of the industry, consensus is that mass transport of

[84] Student Energy (no date) Steam Methane Reforming. [74]
[85] EERE (no date) Hydrogen Production: Natural Gas Reforming. [59]
[86] Zafar (July 25, 2022) Everything you should know about biomass storage methods. [86]
[87] Pascal (June 20, 2022) Different methods of storing, transporting, and distributing hydrogen. [61]
[88] Brown (April 27, 2022) The next frontier. [13]
[89] Brown (April 27, 2022) The next frontier. [13]
[90] Brown (April 27, 2022) The next frontier. [13]

hydrogen by sea will not be commercially viable until the mid-2030s,[91] limiting viable hydrogen markets over the next decade to those accessible by onland routes.

Currently, long-distance transport of hydrogen is conducted by converting hydrogen into chemical intermediates and then moving the intermediates to a final destination, where it can then be converted back into hydrogen gas for use. The intermediates used as energy carriers will likely be compounds like methylcyclohexane (organic hydride).[92] Methylcyclohexane can be imported and exported globally and is less dangerous to transport than pure hydrogen, as it remains a liquid at standard temperature and pressure and is chemically stable.[93, 94] The Chiyoda Corporation has already successfully demonstrated this process, using a mixture of toluene and hydrogen to generate methylcyclohexane in Brunei, transporting the methylcyclohexane over sea using a chemical tanker to Japan, and then using a dehydrogenation process on Japanese shores to supply the hydrogen for industrial facilities.[95]

In short, because of its molecular structure, hydrogen gas will require development of entirely new transportation networks and usage infrastructure than that used in our existing natural gas economy.[96] This new infrastructure will need to develop at a significant pace in order to ensure the economic viability of any large-scale hydrogen production facility.

Pipeline requirements

In the United States, there are approximately 1,600 miles of hydrogen pipelines[97] under the regulation of the federal Pipeline & Hazardous Materials Safety Administration (PHMSA).[98] Regulating hydrogen pipelines in the United States has been under the purview of the U.S. Department of Transportation (DOT), PHMSA's parent agency, since 1970 due to 49 CFR Part 192.[99]

Although hydrogen can be moved alongside natural gas at concentrations up to 15% hydrogen with only minor modifications required in a natural gas pipeline, moving hydrogen at higher concentrations of purity will require more substantial modifications or new pipeline infrastructure.[100]

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[91] Brown (April 27, 2022) The next frontier. [13]
[92] Shibata (2015) Hydrogen Production from Variable Renewables. p. 27. [70]
[93] Shibata (2015) Hydrogen Production from Variable Renewables. p. 27. [70]
[94] Kurosaki (2018) Introduction of Liquid Organic Hydrogen Carrier. p. 4. [43]
[95] FuelCellWorks (February 10, 2022) Hydrogen Transportation in the Form of MCH by Chemical Tanker. [32]
[96] Bossel, Eliasson (no date) Energy and the Hydrogen Economy. p. 1. [9]
[97] EERE (no date) Hydrogen Pipelines. [56]
[98] PHMSA (no date) Hydrogen. [63]
[99] PHMSA (no date) Hydrogen. [63]
[100] EERE (no date) Hydrogen Pipelines. [56]

6.1.5 Carbon Capture Potential

The carbon capture potential associated with hydrogen production differs depending on the process under consideration.

To generate hydrogen via electrolysis, no CO_2 should be produced unless the energy to sustain the reaction is sourced from a non-renewable resource. As we are only considering electrolysis conducted with renewable resources—like wind or solar—in this analysis, this production process should not be generating carbon for capture. It would exist as a clean energy industry, rather than a carbon management industry.

To generate hydrogen via biomass gasification, CO_2 will be created as a byproduct of hydrogen production. However, recovery rates of these carbon emissions are quite high (over 90%),[101] allowing nearly all the CO_2 produced onsite to be compressed and transported for permanent underground storage. Between 50,000 to 70,000 tons of hydrogen can be generated via biomass gasification per every 1 million tons of CO_2 produced, depending on how the facility's energy needs are met.[102]

To generate hydrogen via SMR + CCS, CO_2 will be created through multiple stages of production in both the initial SMR reaction and the subsequent water-gas shift reaction.[103] Given that gray hydrogen production (SMR without CCS) produces about 9 kilograms of CO_2 per kilogram hydrogen, while the estimate for blue hydrogen production (SMR + CCS) is 1-5 kilograms of CO_2 per kilogram hydrogen, the carbon capture and storage potential of SMR + CCS should range from 4-8 kilograms CO_2 per kilogram hydrogen produced.[104] This would correspond to a capture rate of 44-88% of the CO_2 emissions generated by hydrogen production via SMR. Some recent models have stated that carbon capture from SMR has a maximum removal capacity of 90%.[105]

6.2 Societal Impacts

6.2.1 Job creation potential

6.2.1.1 Number and types of jobs

There are no average industry estimates across types of hydrogen production methods, and no public methodology for arriving at these estimates. Some studies have projected that nationwide, hydrogen-related jobs in the United States could number almost one million by 2030, but these jobs are expected to disproportionately benefit highly-skilled and

[101] Patrizio *et al.* (2021) CO_2 mitigation or removal. p. 1-2. [62]
[102] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]
[103] Student Energy (no date) Steam Methane Reforming. [74]
[104] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[105] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

well-paid technical and professional workers.[106] Thus training workers to take on these new positions in the workforce will be essential to keeping jobs within local communities.

There are a few specific case studies we can use to approximate job creation potential in hydrogen production. Air Products, for their planned SMR + CCS facility in Louisiana designed to capture over 5 million tons of CO_2 annually, has projected the creation of 170 permanent jobs with an average salary of $93,000.[107] For hydrogen production via biomass gasification, this study assumes that the number and type of jobs will not vary significantly from other biomass gasification facilities covered in Section 4 of this report—for specifics on those job figures, please see Section 4.2.1.1. A similar case study reporting jobs for a large scale electrolysis facility has not been found.

6.2.2.2 Training pipelines

A U.S. Department of Energy (DOE) study on the implementation of a hydrogen economy between 2020 and 2050 found that many American workers would need new skills for the hydrogen economy, and that training and retraining programs would need to be established to fill this gap.[108] Unfortunately, the DOE's reporting does not provide depth on what training would be necessary or the likely occupations (and anticipated earnings) associated with the growth of hydrogen production.[109]

A wide range of skill levels are expected to engage with the hydrogen economy at-large (including hydrogen production, transport, and use), with experts anticipating that the hydrogen economy will include experts with graduate education, but also "include jobs that require associate's degrees, long-term on-the-job training, or trade certifications – and lead to jobs that pay higher than US average wages."[110] Furthermore, Plug Power, a company currently constructing electrolyzer facilities in the United States, has specifically referenced that a skilled workforce in the region was desirable for planning where to locate electrolyzer plants.[111] Setting up programs at local community colleges and universities to provide specialized training to take on roles in hydrogen production is a crucial way to support these nascent industries and ensure new, high-paying jobs in the region benefit local community members. By establishing local programs to train workers in these skills, it could attract hydrogen investment opportunities to the overall region; existing regional benefits for Kern County specifically are explored in Section 6.4.3.

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[106] Bezdek (2019) The hydrogen economy. [8]

[107] Air Products (no date) Louisiana Clean Energy Complex. [4]

[108] Bezdek (2019) The hydrogen economy. [8]

[109] Bezdek (2019) The hydrogen economy. [8]

[110] Bezdek (2019) The hydrogen economy. [8]

[111] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 1. [64]

6.2.2 Quality of Life

6.2.2.1 Location

Hydrogen production via electrolysis is generally a quiet process—a facility in western New York describes the actual electrolyzer as "silent."[112] The loudest equipment on site are the compressors, used to cool hydrogen post-production to prepare for transport. The impact of the compressor noise can be mitigated by placement inside a building far from the site boundary, allowing the sound to disperse over distance.[113]

Hydrogen generated via biomass gasification will have more components that can generate noise, as well as some outdoor equipment (ex. conveyor belts to transport biomass) that would be hard to dampen except with distance from population centers. The loudest components of the operation—such as the engine and compressor—should be housed in insulated materials to dampen the machinery noise.[114] Other equipment like blowers and coolers inside the plant can also contribute noise, as well as any noise from equipment to transport biomass to the site and transport co-products off-site for distribution.[115] For a facility capturing 1 million tons of CO_2 annually, about 1,800 tons of feedstock (~90 tractor-trailer truckloads) need to be delivered each day,[116] which could contribute to noise and traffic in nearby communities. As a result, anticipated overall site noise can be a determining factor in siting a new biomass gasification facility.[117]

SMR processes can be quite loud, with on-site noise near the reformer loud enough to cause ear damage and fatigue to personnel.[118] Ensuring there is adequate hearing protection available for workers, as well as that noise level surveys for the site and surrounding area do not exceed local regulations, is essential for any proposed SMR + CCS site.[119]

The full life-cycle of hydrogen production, transport, and use can generate a range of pollutants, which may have health impacts for nearby populations – the full spectrum of these emissions is explored in Section 6.3.2.

[112] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[113] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[114] IEE (2009) Guideline for Safe and Eco-friendly Biomass Gasification. p. 41. [36]
[115] IEE (2009) Guideline for Safe and Eco-friendly Biomass Gasification. p. 22. [36]
[116] EPA (no date) Biomass Preparation. p. 23. [26]
[117] IEE (2009) Guideline for Safe and Eco-friendly Biomass Gasification. p. 29. [36]
[118] EIGA (no date) Combustion Safety for Steam Reformer Operation. p. 13. [29]
[119] EIGA (no date) Combustion Safety for Steam Reformer Operation. p. 13. [29]

6.2.2.2 Multi-use potential

Currently, most hydrogen is produced on the same site where it is used, making hydrogen a key co-location opportunity for heavy, heat-reliant industries and transportation hubs like train depots, airports, and shipping ports.

The multi-use potential of hydrogen production sites for community spaces is more narrow—with both biomass gasification and SMR + CCS being relatively hot and requiring stringently-controlled conditions to maximize efficiency, opportunities for community use on-site are unlikely. Hydrogen production via electrolysis may offer multi-use potential, as the production process is relatively quiet, making it potentially an attractive prospect for school field trips for scientific demonstration.

However, the risks of hydrogen could make such facilities intrinsically a poor candidate for multi-use opportunities. If handled improperly, hydrogen can cause fires or explosions, and since hydrogen gas is very light and odorless, leaks can be exceedingly difficult to detect before hydrogen concentrations exceed its lower flammability limit in air.[120] This risk can be reduced by designing hydrogen facilities with key features (like sloped and vented roofs) that leave hydrogen space to escape, so it is not trapped to mix with air in a sealed space.[121] Overall, since hydrogen gas will need to be handled carefully on-site to protect workers, permitting other uses or untrained people to the site could be logistically difficult.

6.3 Environmental Impacts

The environmental impacts of hydrogen production are significant, particularly given that most hydrogen production taking place today is derived from natural gas and coal (gray, black and brown hydrogen). Annual global CO_2 emissions from hydrogen are equivalent to the combined annual CO_2 emissions of the United Kingdom and Indonesia, or approximately 830 million metric tons of CO_2 a year.[122] For reference, in 2021, the United States emitted approximately 5 billion metric tons of CO_2,[123] so current hydrogen production would be equal to about 16.6% of annual CO_2 emissions in the United States. Implementing less carbon-intensive methods of hydrogen production is important for reducing emissions and air pollution, regardless of the potential uptake of hydrogen as a fuel. Building a sustainable future relies upon diversifying the energy sources used to generate hydrogen and utilizing less carbon-intensive production practices than the industry currently uses.[124]

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[120] OSHA (no date) Green Job Hazards - Hydrogen Fuel Cells: Fire and Explosion. [53]

[121] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]

[122] IEA (2019) The Future of Hydrogen. p. 14. [37]

[123] Richie, Roser (no date) United States: CO_2 Country Profile. [67]

[124] IEA (2019) The Future of Hydrogen. p. 17. [37]

6.3.1 Water requirements

6.3.1.1 Minimum volume requirements

For hydrogen production via electrolysis, the volume requirements of water are proportional to the output of hydrogen generated in the facility. As such, large hydrogen electrolyzers correspond to large water requirements by volume. For every two molecules of water put in an electrolyzer, two molecules of hydrogen (H_2) are created, assuming 100% efficiency.[125] However, real-world electrolyzers will suffer inefficiencies that means this 1:1 ratio will not hold in reality, and given the vast difference in molecular weight and size of a water molecule and a hydrogen gas molecule, put in terms of mass, water to hydrogen ratios are significantly higher than 1:1. Published estimates of the theoretical minimum water demand for electrolysis are as low as 9.1 liters (or 2.4 gallons) of water per kilogram of hydrogen.[126] In practice, electrolyzer operators have found that it takes approximately 12 liters (or 3 gallons) of water to produce every kilogram of hydrogen created via electrolysis.[127]

Although experts are working to reduce the water requirements needed for hydrogen production via biomass gasification, currently, water is used to perform the water-gas shift reaction to generate hydrogen and purify the gaseous products. Some forms of gasification rely on steam or supercritical water, which can increase the overall water demand. The most conservative facilities use about equal quantities of biomass and water in their process.[128] There is some potential for water reuse; water is used to purify gas, allowing contaminants like SO_x or NO_x to dissolve into aqueous species. Once H_2 and CO_2 streams have been purified, the water is separated from them, carrying contaminants with them as dissolved components that can settle out. That water is typically stored in evaporation ponds on site, and could be treated for reuse with appropriate equipment.[129] Currently, the estimated water use for a biomass hydrogen facility capturing a million metric tons of CO_2 per year ranges between 266 and 1840 acre-feet of water each year.[130] That equates to about 15.0-103.6 liters (or about 3.9-27.4 gallons) of water needed to produce one kilogram of hydrogen via biomass gasification.*

A full life-cycle analysis for hydrogen production via SMR + CCS found that per kilogram of hydrogen generated, the process consumed 6 to 13 liters (or 1.6-3.4 gallons) of water.[131]

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[125] LibreTexts (August 9, 2022) 23.9: Electrolysis of Water. [46]

[126] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 10. [41]

[127] Valdez (August 11, 2022) Electrolyzers and Water. [79]

[128] Industry representative, personal communication, September 8, 2022.

[129] Industry representative, personal communication, September 8, 2022.

[130] See the Comparative Analysis spreadsheet.

* This calculation uses a ratio of estimated hydrogen output to water usage derived from data obtained in an interview with an industry representative, personal communication, September 8, 2022.

[131] Valdez (August 11, 2022) Electrolyzers and Water. [79]

This is corroborated by other studies, which placed the water demand for SMR and the subsequent water-gas shift reaction combined at 9.7 liters (or 2.6 gallons) of water per kilogram of hydrogen produced.[132]

Given these relatively high water use figures across production methods, hydrogen production may be a poor fit for water-stressed regions like Kern County, as freshwater is already overallocated.[133] The strain on local water resources could be reduced if highly purified, reclaimed or recycled water could help meet this need, a subject that is explored in Section 8 of this report on water treatment.

6.3.1.2 Minimum quality requirements

For electrolysis, the water quality threshold is extremely high—the water used in electrolyzers "needs to be as pure as possible."[134] The water used in an electrolyzer should be distilled and/or deionized, to preserve the efficiency and lifetime of the equipment.[135] Membrane-based electrolyzers require water to be of type II purity, though operate better with water of type I purity, which is even more filtered.[136]

6.3.2 Air quality

An electrolyzer itself does not produce gaseous emissions other than H_2 and O_2. Any emissions associated with electrolysis will therefore come from its power supply. A full life-cycle analysis study of electrolyzer options fueled by different energy sources in Colombia found that wind-powered electrolysis was the most air quality-friendly option when looking at methane (CH_4), CO_2, NO_x, SO_x, and particulate matter emissions.[137] Any fossil-free, renewable energy supply will minimize emissions for electrolysis, with remaining life cycle emissions profiles reflecting third-order, upstream (manufacturing and construction) and downstream (end-of-life) related emissions.

In contrast, generating hydrogen via biomass gasification can create direct air pollutants, including carbon monoxide (CO), NO_x, methane (CH_4), and a small amount of soot (particulate matter[138]),[139] although if the feedstock source for gasification is agricultural waste, forest waste or municipal waste that would otherwise have degraded through crop burning, wildfire or landfill decomposition, the net effect of using gasification on air quality

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[132] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[133] IEA (2019) The Future of Hydrogen. p. 43. [37]

[134] Valdez (August 11, 2022) Electrolyzers and Water. [79]

[135] Spiegel (November 7, 2017) Introduction to Electrolyzers. [72]
[Note: this information derives from a response provided in the comment section by the Fuel Cell Store account.]

[136] Jonsson, Mässgård (2021) An Industrial Perspective on Ultrapure Water Production for Electrolysis. p. 17. [40]

[137] Ullman, Kittner (2022) Environmental impacts associated with hydrogen production. [78]

[138] Weidman, Marshall (August 10, 2012) Soot Pollution 101. [83]

[139] Ahmed *et al.* (2019) Emissions factors. p. 221. [1]

is likely to be an improvement. There are few published studies comparing emissions from biomass gasification to combustion (what happens in bioenergy generation plants) or open burning, but what information is available suggests a significant reduction in criteria pollutants with gasification. Examples include a comparative study of coal gasification versus traditional coal-fired powerplants by the National Energy Technology Laboratory.[140] Their study showed a significant decrease in SO_x, NO_x, particulate matter and CO_2 emissions in gasification relative to traditional combustion. While the feedstock is different, the organic matter in coal and the organic matter in biomass can be expected to respond similarly to thermochemical processing. Another study found that less NO_x, CO, CH_4, CO_2 and soot was emitted from small scale biomass gasification plants, when compared to open burning.[141] And finally, the planned San Joaquin Renewables facility (described in Section 4.1.2.7) anticipates the emissions impact of their gasification facility will be far more favorable than open pile burning (commonly employed in the San Joaquin Valley today) —with a minimum of a 95% reduction in VOCs, 96% reduction in NO_x, 99% reduction in CO, and 99% reduction in particulate matter released relative to biomass burning.[142]

Blue hydrogen from SMR with CCS also produces both criteria air pollutants and greenhouse gasses aside from CO_2.[143] These emissions included VOCs, NO_x, CO, SO_2 and both large (PM_{10}) and small ($PM_{2.5}$) particulate matter* in the criteria air pollutants, and CH_4 and nitrous oxide (N_2O) as additional greenhouse gasses.[144] Researchers found that VOC, NO_x, and CO emissions per kilogram of hydrogen produced decreased as facility size increased, with an anticipated cause that larger facilities (in terms of expected hydrogen output) may have emissions control technologies that capture different pollutants.[145] Other emissions, though, showed little correlation with the facility size by anticipated hydrogen output, making it difficult to gauge how much other emissions categories can be effectively minimized.[146]

Finally, recent has identified some risk of using hydrogen as a fossil-alternative fuel, due to hydrogen's ability to act as an indirect greenhouse gas, warming the atmosphere on short-term (years to decadal) timescales.[147] When combusted, hydrogen reacts with oxygen to form water vapor, which in the stratosphere, can trap heat. Hydrogen that leaks from operations or is offgassed can also drive production of other greenhouse gasses, including

[140] NETL (no date) Emissions advantages of gasification. [49]

[141] Ahmed *et al.* (2019) Emissions factors. p. 221. [1]

[142] San Joaquin Renewables (no date) The Project. [69]

[143] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 4. [75]

* Particulate matter emissions are often reported in terms of the size of the particles—PM_{10} refers to particles smaller than 10 micrometers (μm), and $PM_{2.5}$ to particles smaller than 2.5 μm.

[144] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 4. [75]

[145] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 16. [75]

[146] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 16. [75]

[147] Ocko, Hamburg (2022) Climate consequences of hydrogen emissions. p. 9349. [54]

methane, ozone, and water vapor in the atmosphere, mostly through indirect pathways.[148] Although both hydrogen via electrolysis and hydrogen via SMR + CCS will have significant climate benefits compared to fossil fuel systems on 100-year timescales by reducing the amount of CO_2 released to the atmosphere, some studies suggest that in the short term (first 20 years after adoption), green hydrogen via electrolysis may only halve the impact of emissions from fossil-fuel use and blue hydrogen via SMR + CCS could potentially worsen immediate climate impacts by increasing emissions of methane and hydrogen in the short term.[149]

When used as a fuel, hydrogen can also generate NO_x in the atmosphere. During hydrogen combustion, enough heat is present to cause atmospheric nitrogen and oxygen to form NO_x in an endothermic reaction.[150] Atmospheric NO_x can have detrimental effects for humans, including respiratory symptoms like the development of asthma, as well as environmental harms, including acid rain and nutrient pollution in waterways and coastal areas.[151] NO_x emissions from hydrogen boilers or engines can be minimized by controlling combustion conditions or by scrubbing NO_x from post-combustion flue gasses.[152]

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used in any given facility will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

6.3.3 Other potential impacts

In many cases, hydrogen fuel is not the most effective solution for reducing greenhouse gas emissions—if a technology can run directly on clean energy or renewable electricity, that is typically a much more efficient power source.[153] However, for industries and processes that are difficult to electrify, hydrogen could be an excellent alternative to fossil fuels. Hydrogen has been explored as a fuel for heavy-duty transport (planes, freight rail, or trucking) or to produce the heat necessary to create products like ceramics, steel, and concrete.[154,155,156] In the context of a carbon management business park, where several industries could be co-located, on-site production of hydrogen may provide a valuable industrial heat energy source. However, a detailed techno-economic and environmental

[148] Ocko, Hamburg (2022) Climate consequences of hydrogen emissions. p. 9350. [54]
[149] Ocko, Hamburg (2022) Climate consequences of hydrogen emissions. p. 9349. [54]
[150] Douglas *et al.* (2022) NO_x Emissions from Hydrogen-Methane Fuel Blends. p. 2. [23]
[151] EPA (August 2, 2022) Basic Information about NO2. [27]
[152] Lewis (2021) Optimising air quality co-benefits in a hydrogen economy. p. 201. [45]
[153] Bottorff (January 4, 2022) Hydrogen: Future of Clean Energy or a False Solution? [10]
[154] Gitlin (2022) Forget passenger cars. [33]
[155] Baxter *et al.* (November 16, 2020) Which sectors need Hydrogen, which don't. [7]
[156] Roberts (January 31, 2023) This climate problem is bigger than cars and much harder to solve. [68]

impact analysis will be crucial when considering whether hydrogen is the most cost-effective and environmentally-efficient fuel option for such industries.

6.4 Economic Impacts

6.4.1 Business Model

Hydrogen is the primary product of electrolysis, biomass gasification and SMR with CCS, and in the future will most likely be sold primarily as a fuel product for transportation and industrial uses. Today, the infrastructure required for such end-use applications is not yet well established. Thus, most hydrogen currently produced goes to other purposes, such as in oil refining, to remove sulfur from natural gas distribution streams or in the production of synthetic fertilizers.[157, 158] Global demand for hydrogen has been steadily rising since 1975, both for direct applications (in oil refining and ammonia production) and indirect applications (methanol, synthetic fuels, and direct reduced iron steel production).[159]

Currently, the costs of hydrogen production are cheapest for more environmentally destructive processes like gray hydrogen, with blue and green forms of hydrogen being the most expensive. In 2020, the cost to generate a kilogram of hydrogen was $0.70 for SMR with no CCS (gray hydrogen), $1.30 for SMR with CCS (blue hydrogen), and $3 for solar-powered electrolysis (green/yellow hydrogen).[160] The cost differential is primarily due to the significantly higher energy demand (and thus energy cost) of electrolysis relative to steam methane reforming.[161] Any opportunities to lower the energy costs of electrolysis can therefore help this technique become cost competitive with gray hydrogen production. For example, when created using excess renewables from the grid, the production cost goes down to about $1.60 per kilogram (in 2020 dollars).[162] Depending on the availability of excess renewable resources in coming years, green hydrogen could become cost competitive with blue hydrogen within the next decade.[163] If a carbon tax were to be imposed, nationally or internationally, on CO_2 emitting power generation processes, like gray hydrogen, that could also equalize the cost differential between production methods, by penalizing the more environmentally destructive gray hydrogen production.[164]

Currently, the high cost of green hydrogen is considered to be the "brick wall" for global hydrogen production—it does not make sense to scale up production or end-use infrastructure until there are efficient and cheap ways to generate hydrogen that also do

[157] Cunningham (no date) The economics of hydrogen in a carbon constrained world. [22]
[158] IEA (2019) The Future of Hydrogen. p. 17. [37]
[159] IEA (2019) The Future of Hydrogen. p. 18. [37]
[160] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[161] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[162] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[163] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[164] Climate Now (October 18, 2021) Pricing carbon around the globe. 01:21. [17]

not contribute to greenhouse gas emissions, and solutions to the barriers to reaching commercial scale and competitive market costs in this space have yet to be realized.[165] In the United States, a tax incentive designated in the Inflation Reduction Act (IRA) of 2022 could change this picture by making environmentally-friendly hydrogen production methods more economically favorable. Under the new tax incentive, producers of hydrogen with 'near-zero emissions' can earn $3 per kilogram of hydrogen produced with no cap on the number of kilograms the producer can receive the incentive for.[166] This is exceptionally good news for hydrogen generated via electrolysis with renewable energy, as $3/kilogram is about the average cost of production, so any sales of their hydrogen would be profit. The exact structure of these benefits, however, will depend on rules that are still being written by the Treasury Department; until they have developed a clear definition for 'near-zero emissions,' it is difficult to guess what standards a producer would need to meet to be eligible for the $3/kilogram incentive.[167] In a worst-case scenario, the benefits could flow to companies that are still releasing large amounts of greenhouse gas emissions in the hydrogen production process, either via using methane as a feedstock or relying on grid electricity generated by fossil fuels to meet the high energy demands of electrolysis or gasification.[168]

Two other potential revenue streams are worth noting. First, in California, Low Carbon Fuel Standard credits (LCFS, see Section 2) are designed to promote switching from fossil fuels to low-carbon fuels in the transportation sector, and could provide an additional revenue stream for green hydrogen projects (from electrolysis or biomass). However, any hydrogen produced from fossil fuels—including blue hydrogen formed from SMR + CCS—would be ineligible for LCFS credits.[169] From 2018-2022, the LCFS credit has ranged from $62-218.[170] Second, federal incentive 45Q provides a tax benefit for CO_2 capture and storage processes other than direct air capture (DAC) of $85 per ton stored, for which green hydrogen via biomass gasification and SMR + CCS could be eligible. Hydrogen producers would need to choose between the 45Q and 45V federal tax credits; they cannot receive both.[171]

6.4.2 Business Costs

6.4.2.1 Cost to build (upfront costs)

The cost and efficacy of electrolyzers is projected to become more favorable in the near-term future, given that this field has seen greater investments in research and development

[165] Bezdek (2019) The hydrogen economy. [8]
[166] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [65]
[167] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [65]
[168] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [65]
[169] Bezdek (2019) The hydrogen economy. [8]
[170] Neste (no date) California Low Carbon Fuel Standard Credit price. [52]
[171] Webster (September 20, 2022) The Inflation Reduction Act will accelerate clean hydrogen adoption. [82]

and economies of scale.[172] There are a wide range of levelized cost estimates available, but costs for large electrolysis facilities are poorly established. Additionally, these cost estimates vary widely based on capacity and the type of electrolyzer in question. A small PEM electrolyzer generating one cubic meter of hydrogen (≈11.126 kg H_2) per hour would likely be less than $8,000, but a commercial-scale facility would require a much larger capacity, either by running a lot of small units or building specialized large electrolyzers.[173] A compilation from the International Council on Clean Transportation (ICCT) of levelized capital cost estimates for different types of electrolyzers as a function of their price per kW and price per kg H_2 is presented in Table 6.1.[174] In general, alkaline electrolyzers are the cheapest to purchase upfront, primarily because they do not require any precious metals to operate.[175,176] Alkaline electrolyzers have a longer expected lifetime than PEM electrolyzers as well.[177]

Another study, which focused only on PEM electrolyzers, is consistent with the ICCT's meta-analysis. They provide an estimated total levelized cost of production that incorporates capital and energy costs. Depending on whether grid energy, solar, or wind is used, production costs of electrolysis facilities with existing technology varied between $4.22 and $6.27 per kilogram of hydrogen produced.[178]

For AE electrolyzers, the largest share of the capital cost is devoted to the electrolyzer stack, accounting for 50% of the estimated capital costs.[179] Although large alkaline electrolyzers have been built before in North America, Africa, Asia, and Europe, most large facilities were decommissioned in the late 20th century, so there are large uncertainties in projecting current costs for a new alkaline electrolyzer facility based on the costs of existing stock.[180] For PEM electrolyzers, about 60% of the capital cost is associated with the electrolyzer stack.[181]

Costs for electrolyzers are expected to decline sharply with advances in the electrode and membrane materials and improvements in manufacturing.[182,183] Additional, economies of scale resulting from significant increases in production capacity are expected to further

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[172] IEA (2019) The Future of Hydrogen. p. 16. [37]
[173] Lichner (March 26, 2020) Electrolyzer overview. [47]
[174] Christensen (2020) Costs from Electrolysis. p. 18. [16]
[175] IEA (2019) The Future of Hydrogen. p. 43. [37]
[176] Lichner (March 26, 2020) Electrolyzer overview. [47]
[177] IEA (2019) The Future of Hydrogen. p. 44. [37]
[178] Vickers *et al.* (2020) Cost of Electrolytic Hydrogen Production with Existing Technology. p. 1. [80]
[179] IEA (2019) The Future of Hydrogen. p. 46. [37]
[180] IEA (2019) The Future of Hydrogen. p. 43. [37]
[181] IEA (2019) The Future of Hydrogen. p. 46. [37]
[182] IEA (2019) The Future of Hydrogen. p. 46-47. [37]
[183] Vickers *et al.* (2020) Cost of Electrolytic Hydrogen Production with Existing Technology. p. 3. [80]

reduce electrolysis costs by 20-40%. The chart below illustrates the expected cost declines for both alkaline and PEM electrolyzers.[184]

Table 6.1. Anticipated capital cost estimates for hydrogen from electrolysis.[a]

Electrolyzer type	2020 $/kW	2020 $/kg H_2[b]	Sources
Capital costs for development in 2020			
Alkaline electrolysis (AE)	$500-1268	$1.90-4.80	IEA (2019) The Future of Hydrogen,[185] IRENA (2019) Renewable Energy Perspective,[186] BloombergNEF (2019) H2 from Renewables,[187] ICCT (2020) Costs from Electrolysis.[188]
Proton exchange membrane (PEM)	$385-2068	$1.50-7.90	
Solid oxide electrolysis (SOE)	$677-2800	$2.60-10.60	
Capital costs for development in 2030			
Alkaline electrolysis (AE)	$400-1208	$1.50-4.60	IEA (2019) The Future of Hydrogen, IRENA (2019) Renewable Energy Perspective, BloombergNEF (2019) H2 from Renewables, ICCT (2020) Costs from Electrolysis.
Proton exchange membrane (PEM)	$365-1968	$1.40-7.50	
Solid oxide electrolysis (SOE)	$647-2175	$2.50-8.30	
Capital costs for development in 2050[c]			
Alkaline electrolysis (AE)	$80-1090	$0.30-4.10	IEA (2019) The Future of Hydrogen, IRENA (2019) Renewable Energy Perspective, BloombergNEF (2019) H2 from Renewables, ICCT (2020) Costs from Electrolysis.
Proton exchange membrane (PEM)	$150-1781	$0.60-6.80	
Solid oxide electrolysis (SOE)	$500-1968	$1.90-7.50	

a. Adapted from ICCT (2020) Costs from Electrolysis.
b. 1kW ≈ 263kg H_2
c. For IEA (2019), cost estimates described as 'long term.'

For biomass gasification that generates hydrogen and CO_2, the capital cost of a facility that could capture 1 million tons of CO_2 would be ~$278 million to $328 million.[189] If the facility operated for 30 years, the capital costs over the lifetime of the facility would be ~$24-52 per

[184] IEA (2019) The Future of Hydrogen. p. 47. [37]

[185] IEA (2019) The Future of Hydrogen. [37]

[186] IRENA (2019) Hydrogen: A renewable energy perspective. [39]

[187] Hydrogen: The Economics of Production From Renewables. Bloomberg New Energy Finance, Technical Report, September 2019. (Data available through Christensen (2020) Costs from Electrolysis.)

[188] Christensen (2020) Costs from Electrolysis. p. 18. [16]

[189] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85] Note: In figures in Wu, Lan, and Yao (2023), these estimates appear lower (approximately $241 to $285 million) as they correspond to a facility capturing 868,000 metric tons of CO_2 per year (see the supplementary material, Table S4 for CO_2 capture rates by scenario). In this report, all Wu, Lan, and Yao (2023) estimates are presented in-text as scaled figures for a million ton facility, to ensure consistency between carbon management industries when possible.

ton of CO_2 (assuming a capital recovery factor of 7.5-12.5%; see Section 3.4.3.1 for details).[190] Both capital and operating costs for biomass-based hydrogen production vary depending on the energy source, which varies across plant designs. In general, self-sustaining plants—which can meet their own energy needs—are the most expensive to build, but have the lowest operational costs.[191] Plants that receive some or all of their energy from external sources are typically cheaper to construct, but more expensive to operate and maintain.[192] It is worth noting that the cost range for most biomass plants, as outlined in Section 4.4, exceeds the range presented here. As the cost estimates here are derived from a single study, and it is likely that hydrogen production via biomass gasification will closely resemble other biomass-based plants, considering the larger variability in capital costs of biomass-conversion facilities in general may be worthwhile.

For SMR facilities in general (gray and blue hydrogen), there are a large number of constituent parts required to contain the entire reaction sequence and limit the escape of pollutants like particulate matter and NO_x.[193] Adding CCS equipment to the SMR process (blue hydrogen) generally results in an estimated capital cost increase of 50%.[194] When also accounting for the operation and maintenance of a facility over its lifetime, however, the distributed cost addition of carbon capture to SMR is anticipated to result in a ~13% increase in total levelized production cost.[195] A recent techno-economic study of hydrogen production for SMR + CCS estimated a levelized capital cost of $0.28/kg hydrogen.[196] This model assumes that SMR without CCS emits 8.5 kilograms CO_2 per kilogram hydrogen but SMS with CCS emits only 1.2 kilograms of CO_2. Thus, we can estimate that for every kilogram of hydrogen produced via SMR + CCS, 7.3 kilograms of CO_2 will be captured.[197] If we assume a facility capturing 1 million metric tons of CO_2 per year, it will generate about 137,000 tons (or 137 million kg) of hydrogen per year. For a capital recovery factor (crf) between 7.5 and 12.5% (see Section 3.4.2.1),[198] the cost to build such a facility would be about $300-510 million USD.

This estimate is relatively well-aligned with planned investment in the Air Products facility currently being constructed in Louisiana. Air Products states that it will cost about $4.5 billion to build, own, and operate their facility with a capture capacity of over 5 million tons of CO_2 annually.[199] Scaling capital expenditures of $300-510 million USD/ton CO_2 to a 5

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[190] Adapted from: Carbonplan DAC cost calculator.

[191] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]

[192] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]

[193] Simon *et al*. (August 13, 2021) Economics of Hydrogen Energy. [71]

[194] IEA (2019) The Future of Hydrogen. p. 42. [37]

[195] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[196] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[197] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[198] Calculated using: Levelized capital expenditure ($/kg$H_2$) = (Cost to build/Annual capacity of the facility)*crf

[199] Air Products (no date) Louisiana Clean Energy Complex. [4]

million ton facility, suggests that capital costs will represent one third to over half of the total investment costs, the remainder presumably coming from operation, maintenance and the cost of the feedstock methane.

6.4.2.2 Operational costs

For an electrolyzer, the stacked membranes inside the machine must be replaced about every 7 to 10 years.[200] The British government estimates the replacement period for electrolyzer membrane stacks varies with the technology type, with alkaline stacks requiring replacement every 9 years, PEM stacks requiring replacement every 11 years, and SOE stacks requiring replacement every 7 years, assuming a 30-year facility lifetime.[201] Fixed operational costs will also include labor, administrative costs, maintenance, insurance, and taxes.[202] Alkaline electrolysis systems also have relatively high maintenance costs throughout their lifetimes due to the variety of equipment needed to pump, clean, and store the electrolyte solution and to filter out and clean the hydrogen.[203] The ICCT economic analysis of electrolysis states that most techno-economic models estimate fixed operational costs (labor and maintenance) as 1-3% of capital expenditures. Based on the range of capital costs summarized in Table 6.1, fixed operation costs of modern electrolyzers are about \$4-84 USD/kW (or \$0.02-\$0.32 USD/kg H_2), with their preferred operating cost estimate of \$40-50 USD/kW (\$0.15-0.19 USD/kg H_2).[204] Variable costs will largely be electricity costs, which can vary considerably over time (and even be zero, if a facility is using excess energy from renewables or the grid). The ICCT model estimates variable operating costs of \$0.08 USD/kg H_2.[205]

For a biomass gasification plant, operational costs are expected to range from approximately \$60 million to \$101 million for a facility capable of capturing a million metric tons of CO_2 annually.[206] The feedstock costs—amounting to approximately \$44 million annually—are the largest share of the operating costs.[207] If these costs were reduced, it would lower the annual operating expenses notably. The next big cost categories come

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[200] Simon *et al*. (August 13, 2021) Economics of Hydrogen Energy. [71]

[201] UK Department of Business, Energy & Industrial Strategy (2021) Hydrogen Production Costs. p. 19. [77]

[202] UK Department of Business, Energy & Industrial Strategy (2021) Hydrogen Production Costs. p. 19. [77]

[203] Lichner (March 26, 2020) Electrolyzer overview. [47]

[204] Christensen (2020) Costs from Electrolysis. p. 18. [16]

[205] Christensen (2020) Costs from Electrolysis. p. 18. [16]

[206] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85] Note: In figures in Wu, Lan, and Yao (2023), these estimates appear lower (approximately \$52 to \$88 million) as they correspond to a facility capturing 868,000 metric tons of CO_2 per year (see the supplementary material, Table S4 for CO_2 capture rates by scenario). In this report, all Wu, Lan, and Yao (2023) estimates are presented in-text as scaled figures for a 1 million ton facility, to ensure consistency between carbon management industries when possible.

[207] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]

from chemical, material, and utility costs, while labor, maintenance, and waste treatment make up a relatively small amount of the operating expenses.[208] These operational costs, combined with capital costs, result in a total levelized cost of about $2.50-$3.60 per kilogram of hydrogen produced, which translates to an estimated range of $125-257 per metric ton of CO_2 captured.

Finally, for any SMR plant, the majority of operational costs are variable; they depend on the cost of methane (natural gas) in the market at a given time, and can account for 45-75% of overall production costs (including capital costs).[209] However, the addition of a carbon capture component also adds additional operating costs and maintenance responsibilities for an operator.[210] In modeling SMR + CCS with a 90% carbon capture rate, the estimated variable operating cost (the energy costs for running the facility) amounted to $0.88 per kilogram of hydrogen,[211] and the additional costs for carbon capture, including separation, purification, compression, pipeline transport, and injection add up to about $0.60/kg hydrogen,[212] or $82 USD/ton CO_2.[213] Translated to total annual operating costs for a facility capturing one million metric tons of CO_2 each year, these amounts should come out to approximately $120 million USD and $82 million USD, respectively, and combined with the estimated capital expenditures, the total levelized production cost of SMR + CCS is ~$1.76 USD/kg H_2.

6.4.3 Regional benefits

California is already among the top three hydrogen-producing states in the U.S.[214] Additionally, the hydrogen market is strong in California—the state is home to 71% of all fuel cell EVs in the county and maintains the largest number of hydrogen fueling stations by far.[215] California also hosts a wide variety of industries that would be hard to fully electrify (such as cement and concrete manufacturing), thus making them prime candidates to transition to alternative fuels like hydrogen.[216] A large amount of credit for the growth of the hydrogen market in California is due to the state's carbon cap-and-trade program, which incentivizing the growth of hydrogen through a carbon credit marketplace.[217] With

[208] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]
[209] IEA (2019) The Future of Hydrogen. p. 42. [37]
[210] IEA (2019) The Future of Hydrogen. p. 42. [37]
[211] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]
[212] Simon *et al*. (August 13, 2021) Economics of Hydrogen Energy. [71]
[213] Given the ratio of 1 kg H_2 production resulting in 7.3 kg CO_2 capture. From Katebah, Al-Rawashdeh, and Linke (2022) Analysis of hydrogen production costs in Steam-Methane Reforming.
[214] AFDC (no date) Hydrogen Production and Distribution. [6]
[215] AltaSea (October 28, 2022) Sustainable Green Hydrogen Market. [5]
[216] AltaSea (October 28, 2022) Sustainable Green Hydrogen Market. [5]
[217] Magill (February 23, 2021) California And Texas Vie To Be America's Hydrogen Capital. [48]

existing demand already in the region and sector-wide growth anticipated, Kern County is a promising locale for companies looking to develop hydrogen fuels.

6.4.3.1 Proximate feedstocks

For hydrogen produced via biomass gasification, Kern County's agricultural waste could become a supply of feedstock to generate hydrogen and capture CO_2. This theme is touched upon at greater length in Section 11.2.1 on the potential relationship between local agriculture and biomass-based carbon management facilities. For SMR+CCS, Kern County is home to the state's largest oil and gas fields and produces 78% of the state's total natural gas production.[218]

6.4.3.2 Proximate consumers

As mentioned above, one of the strengths of locating in the region would be a proximate consumer base. All of the approximately 15,000 consumer cars in the U.S. that are fuel cell EVs are located in California, which is the only state with a network of retail hydrogen fueling stations to make them usable.[219] Kern County's proximity to the port of Los Angeles, the busiest shipping port in North America,[220] also holds promise for the hydrogen industry - both as an access point for international trade, and because hydrogen holds potential as a fossil-free fuel source for the shipping industry.[221]

6.4.3.3 Co-location advantages

Locating alongside carbon management industries could have benefits for a hydrogen production facility. If generating hydrogen via electrolysis, an electrolyzer could utilize water generated as a byproduct of some carbon management industries, such as S-DAC (Section 3), depending on the water quality.

If generating hydrogen via steam reforming and CCS, co-location could have multiple benefits. Steam reforming and the water-gas shift reaction could similarly use water generated from other industries in their production process, and the transport and sequestration needed for permanent underground storage of CO_2 could be shared infrastructure with other carbon management industries in the park.

6.4.3.4 Other

For hydrogen production via electrolysis, which relies on renewable energy to avoid carbon emissions, California and the American Southwest is a highly promising region to bring down production costs, given the extremely high solar and wind energy potential in the region (Figure 6.5). Given the significant impact that electricity costs have on the market

[218] KEDF (2021) The economic contribution of the oil and gas industry in Kern County. p. 1. [42]
[219] Voelcker (September 26, 2022) Hydrogen Fuel-Cell Vehicles. [81]
[220] Port of Los Angeles (no date) The Port of Los Angeles. [66]
[221] Climate Now (May 2, 2022) The bottom line on sustainable shipping. 23:29. [18]

competitiveness of green hydrogen from electrolysis, the renewable energy potential of Kern County and the surrounding region is a remarkable asset for this industry.

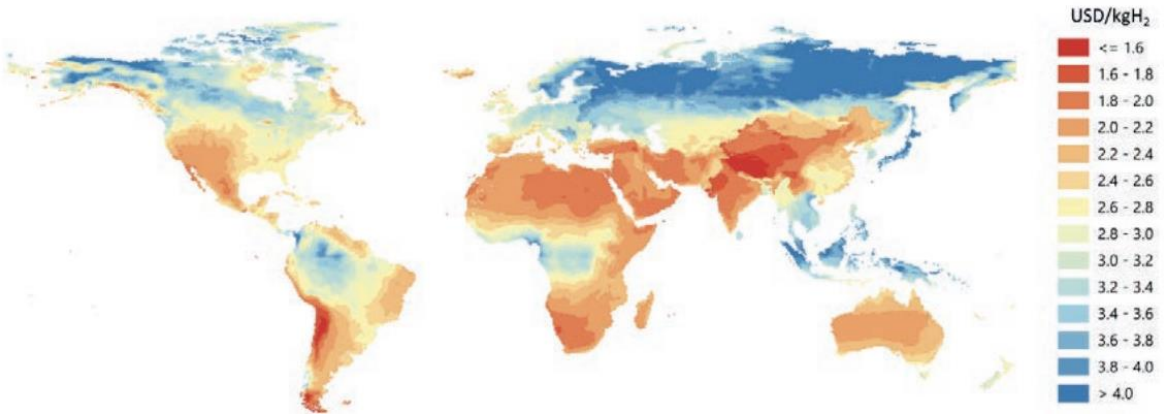

Figure 6.5. Global map demonstrating the cost viability of locations where renewable energy generation (wind or solar energy) and hydrogen production via electrolysis are co-located.[222] The California coast, as well as the American Southwest, show promising cost estimates for electrolysis-generated hydrogen. Image credit: International Energy Agency.

[222] IEA (2019) The Future of Hydrogen. p. 49. [37]

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7. Battery and Energy Storage Solutions

TECHNOLOGY AT A GLANCE

- Energy storage solutions come in a wide variety of form, many of which are fully commercial, and others of which are still in early research and development stages.[1]
- Lithium-ion batteries are currently the most widely used technology for utility-scale energy storage.
- Installation of large energy storage facilities is unlikely to create many jobs, but can produce a variety of societal benefits, like eliminating the need of fossil-based peaker power plants, and providing increased grid reliability.
- Adding energy storage to solar or wind power supplies increases the cost by ~$5-39, but the cost of batteries has decreased 97% in the last 3 decades, and is projected to continue becoming less expensive.
- Key advantages of this technology to Kern County: it ensures a continuous clean energy supply to any industries sited in a carbon management park, and potentially to the local grid, and can provide a fossil-free source of industrial heat to industries that require it.
- Key concerns for this technology in Kern County: environmental and safety risks vary by battery type, and further assessment to identify the optimal storage approach for the region and needs of the carbon management park will be necessary.

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

7.1 Technology Summary

Since 2020, wind and solar energy have become the cheapest form of electricity generation in most parts of the world, and their costs have continued to decrease year over year.[2,3] The sunny and arid climate of Kern County is particularly well suited for these renewable energy sources, and as such is host to the largest commercial solar project and among the largest commercial wind energy projects in the United States.[4] Such abundant, fossil-free energy is particularly attractive to carbon management industries for two reasons. First, many carbon management industries are energy intensive, with energy costs representing their largest operational expense. Thus, minimizing the price per kWh of electricity used is critical to ensuring facilities are economically viable. Second, most carbon management industry's business model depends on the *net* amount of CO_2 removed or prevented from entering the atmosphere, which means that if such industries are powered by carbon-emitting fuels, their carbon capture efficiency (and thus potential for revenue) is reduced.[5]

Wind and solar are examples of variable renewable electricity (VRE) – they only generate electricity when the sun is shining or the wind is blowing, and the intensity of the electricity the generate depends on weather conditions.[6] Battery storage solutions are a way to smooth fluctuations in energy supply, by storing excess energy generated by renewables during highly productive periods and then releasing that energy to meet electricity or heat demands during periods of lower productivity.[7] For solar energy, for example, this could mean storing excess energy during the day and releasing it at night, when the sun is not out to generate additional power.

To support renewables and decarbonization objectives, the International Energy Agency (IEA) predicts that globally, energy storage will need to scale up to 266 GW of storage capacity by 2030—in 2017, global energy storage capacity was 176.5 GW—to keep climate change under 2°C of warming.[8] To support the development of a clean energy and carbon management industrial park in Kern County, it is worth assessing the degree to which energy storage solutions would need to be integrated with local renewable energy generation in order to provide sufficient, continuous power that meets the needs of any industries locating within the park.

7.1.1 Description: How it works

In this report, we define energy storage technologies as devices that take in any form of renewable energy, store that energy in various forms, and then release energy as electricity

[2] Masterson (July 5, 2021) Renewables were the world's cheapest source of energy in 2020. [33]
[3] Lazard (2021) Levelized cost of energy. [28]
[4] CSUB (no date) Energy in Kern County. [5]
[5] National Academies of Sciences, Engineering, and Medicine (2019) Research Agenda. p. 222. [36]
[6] IRENA (2017) Electricity Storage and Renewables. p. 10. [26]
[7] MIT (2022) The Future of Energy Storage. p. xi. [32]
[8] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

or heat to be used on demand. A summary of the more widely used energy storage technologies are listed in Table 7.1, along with the characteristics of each storage type that typically define its most suitable applications.

As the aim here is to understand storage solutions that could support a carbon management park in Kern County, we will focus on off-grid technologies with rechargeable, industrial-scale potential that can provide intermediate to longer-duration storage, and will produce energy in the form of electricity or in the form of heat. Some energy storage solutions are eliminated based on Kern's geography and resources. For example, pumped-storage hydropower (PSH) systems have been used in the United States for a century, and currently constitute 95% of energy storage facilities nationally, but are a poor fit for Kern given its largely arid climate.[9] This section will also cover hydrogen-based batteries, with the assumption that the hydrogen utilized for this energy storage is produced through low-carbon processes—for more on hydrogen production, please refer to Section 6 of this report.

Table 7.1. Characteristics of selected energy storage types.[10]

	Max Power Rating (MW)	Discharge Time	Max Cycles or Lifetime	Energy Density (Wh/l)	Round-Trip Efficiency
Pumped hydro	3,000	4h - 16h	30-60 years	0.2-2	70-85%
Compressed air	1,000	2h - 30h	20-40 years	2-6	40-70%
Molten salt (thermal)	150	hours	30 years	70-210	80-90%
Li-ion battery	100	1min - 8h	1,000-10,000 cycles	200-400	85-90%
Lead-acid battery	100	1min - 8h	6-40 years	50-80	80-90%
Flow battery	100	hours	12,000-14,000 cycles	20-70	60-85%
Hydrogen	100	mins - week	5-30 years	600 (at 200bar)	25-45%
Flywheel	20	secs - mins	20,000-100,000 cycles	20-80	70-95%

7.1.1.1 Electricity storage

Most of the batteries discussed in this report rely on the same basic electrochemical process: reduction-oxidation (redox) reactions. In redox reactions, electrons move between one molecule and another molecule; the substance losing electrons is oxidized and the substance gaining electrons is reduced.[11] It may sound counterintuitive that the substance

[9] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[10] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[11] Chemistry LibreTexts (July 1, 2019) Batteries. [9]

gaining electrons should be 'reduced', but reduction is referring to the overall charge of a particle, not how many electrons it has. Because electrons are negative, the overall charge of the substance gaining electrons will be a less positive number; it will be reduced.[12]

In a battery system, the site where oxidation (electron loss) occurs is called the anode, and the site where reduction (electron gain) occurs is called the cathode.[13] These processes occur simultaneously in a redox reaction, and the electrons lost in one part of a battery system will be the same as the electrons gained in another part of the system. When these redox processes occur with a wire to capture the electric charge, it constitutes an electrochemical (or Galvanic) cell—the basic principle of most electric batteries.[14] Here, we explore three types of electrochemical batteries: lithium-ion, flow, and molten salt. While the constituent parts of each of these electric batteries can look quite different, they all share the components shown in Figure 7.1: in addition to the cathode and anode, there is an electrolyte, separator, and two current collectors.[15] The role of each of these components when a battery charges or discharges can be described in the context of each of the four battery types that are detailed below.

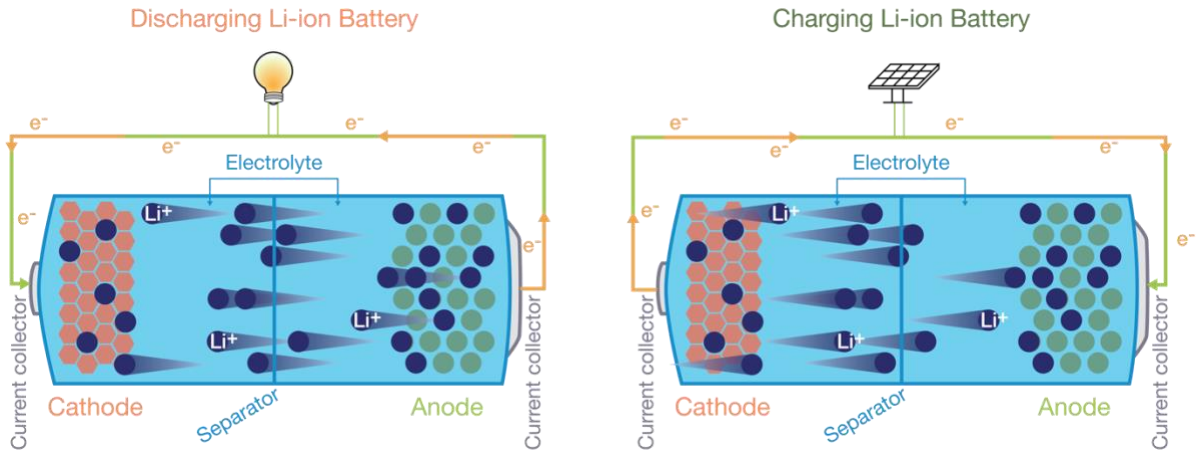

Figure 7.1. Schematic of lithium-ion electric battery storage.[16]

Lithium-ion batteries

Lithium-ion (Li-ion) batteries are what are typically used for mobile energy storage applications, such as in consumer electronics like cell phones, and in electric vehicles.[17]

[12] Chemistry LibreTexts (July 1, 2019) Batteries. [9]
[13] Chemistry LibreTexts (July 1, 2019) Batteries. [9]
[14] Chemistry LibreTexts (July 1, 2019) Batteries. [9]
[15] Minos (February 28, 2023) How lithium-ion batteries work. [35]
[16] Minos (February 28, 2023) How lithium-ion batteries work. [35]
[17] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

During a discharge cycle (when energy is being released from the battery), lithium that is stored in the anode gets ionized, meaning it converts to a lithium ion (Li^+) and an electron.

$$Li^o \rightarrow Li^+ + e^- \quad \text{(R7.1)}$$

The lithium ion is carried through the battery via the electrolyte, a liquid solution containing dissolved salts, to the cathode. A porous separator allows the lithium ions to pass through the electrolyte solution towards the cathode, but prevents the passage of electrons within the battery structure. Thus, the cathode becomes concentrated with positively charged lithium ions, and the electrons collect near the negative current collector. The charge differential drives the electrons to travel along the external electrical circuit, creating an electric current that can provide electricity to an external device. Electrons are collected at the positive current collector, and recombined with the lithium ions, to form elemental lithium that is stored in the cathode. When all the lithium has migrated from the anode to the cathode, the battery is "empty" and needs to be recharged. Charging the battery works in the reverse direction of discharging: lithium ions are released by the cathode and received by the anode.[18,19]

$$Li^+ + e^- \rightarrow Li^o \quad \text{(R7.2)}$$

Advantages of the Li-ion battery is that it is highly efficient and energy dense (Table 7.1), being able to discharge as much as 90% of the energy used to charge, and able to provide a large amount of power from a relatively small battery, which is why these are particularly advantageous for mobile applications like phones, laptops and cars. Typically, these types of can supply a charge for a few hours, and they can go through the discharge/recharge cycle about 1,000-10,000 times,[20] meaning they usually need to be replaced within ~10 years.[21]

Flow batteries

Flow batteries can exist in a variety of forms and designs, but are primarily distinguished from standard rechargeable batteries (like Li-ion batteries) because the electroactive materials in a flow battery are dissolved within electrolyte solutions, rather than stored within one or the other electrode as they are in conventional rechargeable batteries (Figure 7.2).[22]

In a flow battery, the electrolyte solution is stored in two separate tanks, with an anolyte tank replacing the anode and a catholyte tank replacing the cathode in a standard electrochemical cell.[23] These tanks are separate from regenerative cell stacks (or the reaction unit), wherein electrolytes are pumped in from the tanks to charge and discharge

[18] Minos (February 28, 2023) How lithium-ion batteries work. [35]
[19] Clean Energy Institute (no date) What is a lithium-ion battery and how does it work? [8]
[20] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[21] Le (August 4, 2020) Flow Batteries. [29]
[22] IRENA (2017) Electricity Storage and Renewables. p. 86. [26]
[23] IRENA (2017) Electricity Storage and Renewables. p. 86. [26]

the system using reversible chemical reactions.[24] The separate tanks can remain charged for long periods without experiencing degradative effects, making them an appealing solution for long-term energy storage.[25]

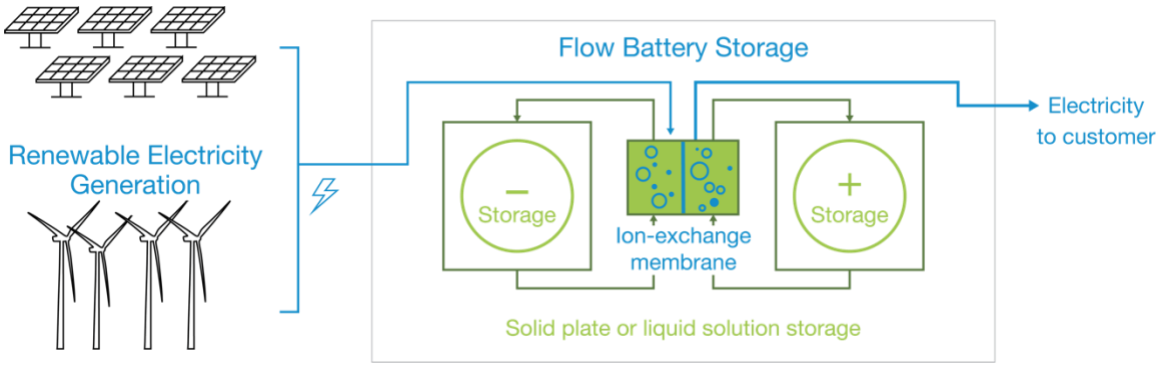

Figure 7.2. Schematic of flow battery electricity storage.

A flow battery is considered 'pure flow' if both the anolyte and catholyte are stored outside the cell stacks and only flow in during operation; if one or more of the electrolyte materials are stored within the cell stacks, then the flow battery is considered to be a 'hybrid' flow battery.[26] Within this overarching split between pure and hybrid flow, there are other subcategories defined by the materials used or the physical state of the active materials, as seen in the IRENA categorization below (Figure 7.3).[27]

Flow batteries are attractive for stationary applications as they are 100% recyclable, nonflammable, easily rechargeable, and approach the same high efficiency of Li-ion batteries, but with much longer lifetimes.[28] Many battery storage providers are looking to scale up their flow battery capacities, particularly flow batteries that rely on vanadium,[29] a material that is abundant and does not degrade through charge/recharge cycles.[30] Canadian company CellCube has deployed vanadium flow batteries in Australia, Vietnam, and South Africa, and British company Invinity is working with the Energy Superhub Oxford to create the UK's largest flow battery system.[31]

[24] IRENA (2017) Electricity Storage and Renewables. p. 86. [26]
[25] Le (August 4, 2020) Flow Batteries. [29]
[26] IRENA (2017) Electricity Storage and Renewables. p. 86-87. [26]
[27] IRENA (2017) Electricity Storage and Renewables. p. 87. [26]
[28] Le (August 4, 2020) Flow Batteries. [29]
[29] Le (August 4, 2020) Flow Batteries. [29]
[30] Rapier (October 24, 2020) Why vanadium flow batteries may be the future. [47]
[31] Le (August 4, 2020) Flow Batteries. [29]

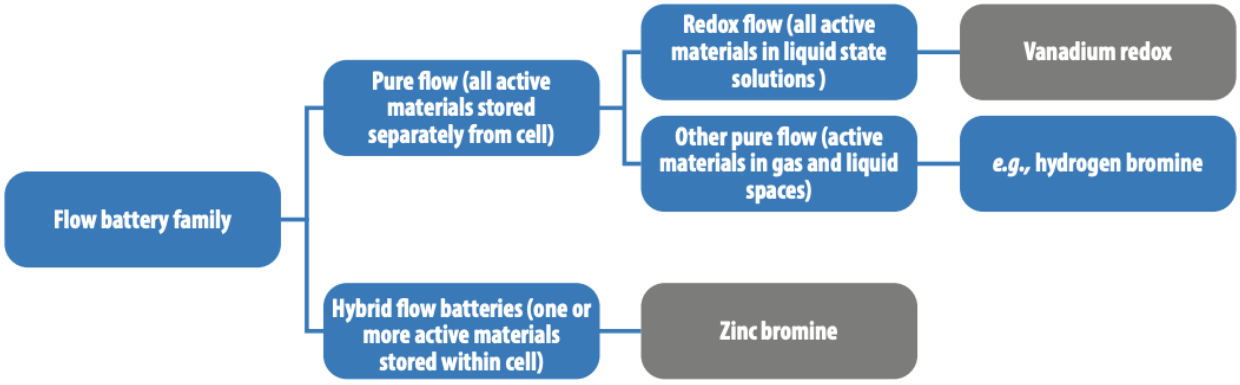

Figure 7.3. Categories of flow battery systems. Image credit: IRENA (2017).[32]

Molten salt batteries

As the name implies, molten salt batteries use a salt, in a liquid, molten state to act as the electrolyte in an electrochemical battery. These systems are often called high-temperature batteries, as high temperatures are necessary to keep the active materials in a liquid state.[33] When the temperature is lowered, the molten salt "freezes," or solidifies, allowing them to store their charge in an inactive state for up to months at a time.[34] Molten salt technologies are the most common kind of "thermal electricity storage", currently accounting for about 75% of global thermal storage capacity.[35] (Although these batteries operate at high temperatures, they deliver energy as electricity rather than heat, hence their categorization as electricity storage rather than as heat storage.)

In one example of the molten salt battery – the sodium beta battery – the anode is molten sodium while the cathode (and membrane) is constructed of beta-aluminum (β''-Al_2O_3).[36] The system works by using sodium ion transport across the membrane to store or release energy from the battery.[37]

A similar iteration of the high-temperature battery replaces the beta-aluminum with molten sulfur as the cathode and is known as the sodium sulfur (NaS) battery.[38*] The anode and cathode are separated by a solid ceramic of sodium alumina, which only allows positively-

[32] IRENA (2017) Electricity Storage and Renewables. p. 87. [26]
[33] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
[34] Dhar (April 15, 2022) Molten-salt battery freezes energy over a whole season. [14]
[35] IRENA (2017) Electricity Storage and Renewables. p. 21. [26]
[36] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
[37] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
[38] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
* Element S can be spelled as sulfur (American English) or sulphur (British English). In this report, all references have been standardized to American spelling, but the original source uses British spelling. Both spellings refer to the same element.

charged sodium ions to pass through its surface.[39] Operation relies on the system maintaining temperatures of 300-350°C to keep the active materials liquid, which can make it difficult for these batteries to operate intermittently.[40] However, these systems are highly efficient, with an average efficiency of 89%.[41] Sodium sulfur batteries are already installed at dozens of sites in Japan and Abu Dhabi, assisting with voltage control and power reliability.[42]

Currently, molten salt tanks (while molten) lose about 1% of their stored heat per day—after two weeks, their capacity has gone down to about 85%.[43] Research conducted at Pacific Northwest National Laboratory (PNNL) demonstrated that freezing and thawing molten salt creates a rechargeable battery that stores energy more effectively and inexpensively for weeks or months on end.[44] If scaled up, these research findings could help make the most of the high efficiency of these batteries by extending the timespan they can effectively store energy for future use.

7.1.1.2 Compressed Air Energy Storage (CAES)

Compressed air energy storage (CAES) systems do not rely on a chemical process, but rather in storing energy through pressurized air that can then be deployed as necessary. It does this by compressing ambient air (or another gas) and storing it at high pressure underground—when additional electricity generation is required, the compressed air is heated and expanded in a turbine connected to a generator, producing power.[45]

Utility-scale CAES was first deployed in the 1970s, at capacities of around 290 MW, so the technology is well-established and understood even for large-scale storage needs.[46] CAES systems now encounter high costs associated with storing compressed air and relatively low capacities for these systems, with research and development efforts for this technology focused on addressing these obstacles.[47] Estimated efficiencies for CAES range from 40-70%.[48]

7.1.1.3 Thermal/heat storage

Energy does not always need to be stored, or delivered, in the form of electricity. For some industrial and commercial facilities, storing heat energy is more important for sustaining

[39] ESA (no date) Batteries. [18]
[40] ESA (no date) Batteries. [18]
[41] ESA (no date) Batteries. [18]
[42] ESA (no date) Batteries. [18]
[43] MIT (2022) The Future of Energy Storage. p. 122. [32]
[44] Blaustein (May 6, 2022) Rechargeable Molten Salt Battery. [2]
[45] ESA (no date) Why Energy Storage - CAES. [19]
[46] ESA (no date) Why Energy Storage - CAES. [19]
[47] Xiaotao *et al.* (2017) Performance Study of Salt Cavern Air Storage. p. 1. [61]
[48] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

their operations. This includes steel, iron, cement, and chemical manufacturing, which all require high heat to fuel their primary processes.[49] Globally, about half of the world's energy consumption is in the form of heat energy.[50]

Most thermal energy storage systems rely on heating a medium—like water, salt, or rocks—and then placing this material in an insulated environment so it retains heat.[51] The type of medium used to store energy determines the system's classification: sensible (water and rock), latent (water, ice, or salt hydrates), and thermochemical reactions (i.e. chemical reactions and sorption processes).[52] In sensible storage, when heat is needed, cold water is pumped onto the heated material to generate steam (Figure 7.4).[53,54] Depending on the needed energy use, the steam can be used directly to heat a facility, or indirectly to turn turbines and generate electricity.[55] If the heat is converted back into electricity for use, the system averages only 47% round-trip efficiency (i.e. only 47% of the power put into the system as electricity will come back out as electricity).[56] In contrast, delivering stored energy in the form of heat can have a round-trip efficiency as high as 90%.[57] Thus, using the heat directly is ideal where possible, but relies on the industrial heat needs of co-located processes.

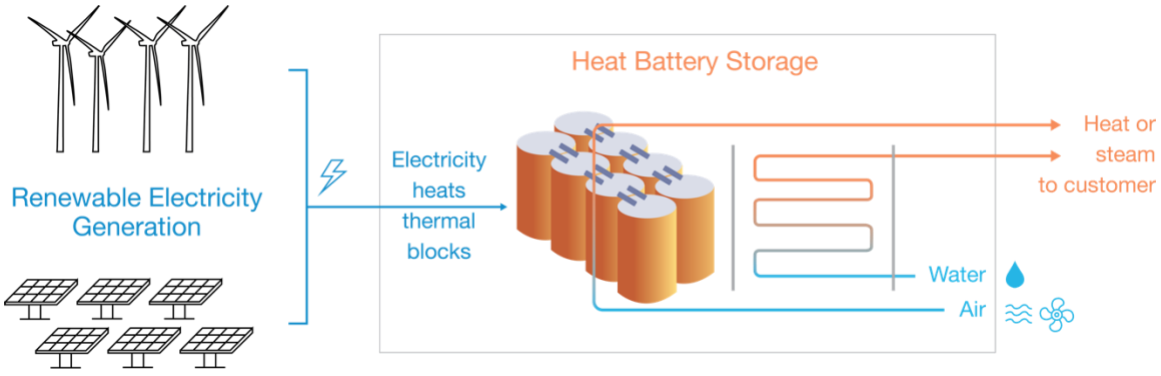

Figure 7.4. An example of sensible thermal storage, modeled after the operational design of Rondo Energy (see Section 7.1.2.1).

Whereas sensible storage relies on changing the temperature of the storage medium to release or absorb heat as needed, latent systems change the phase of the material without

[49] MIT (2022) The Future of Energy Storage. p. 4-5. [32]
[50] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[51] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[52] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[53] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[54] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[55] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[56] MIT (2022) The Future of Energy Storage. p. 114. [32]
[57] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

changing the temperature to release energy—both a phase change and temperature change can occur in the same material concurrently, though.[58] The last system type, thermochemical, relies on chemical reactions taking place on the surface of a material to release or absorb heat. These systems can adapt renewable energy into heat to be stored and released, or capture waste heat for use in other processes.[59]

Utility-scale heat storage systems can balance energy supply and demand across timescales from daily to seasonally,[60] making them a versatile solution for both short- and long-term needs. Since most of the processes addressed in this report require heat rather than cooling, we emphasize the capacity of this technology to store heat energy, but the process can work conversely, to provide residential or industrial cooling.[61]

7.1.1.4 Hydrogen Fuel Cells

Fuel cells are another energy storage solution that can be deployed to support energy needs in a range of sectors, including transportation, commercial and residential buildings, and for industrial-scale energy storage.[62] Fuel cells operate similarly to batteries, but rather than cycling back and forth between discharging and recharging the energy stored, fuel cells thermochemically transform fuel to produce electricity and heat. Therefore, fuel cells – much like a gasoline-powered car – can only produce energy for as long as fuel is being supplied. Although fuel cells can use a wide range of fuels to operate, most focus has been directed towards the potential of using hydrogen in fuel cells, given that their only byproducts are electricity, heat, and water.[63]

Like a standard chemical battery, fuel cells have an anode and a cathode placed on either side of an electrolyte.[64] Fuel is introduced at the anode and air is introduced at the cathode. The fuel molecules are separated to create positively charged ions (protons in the case of hydrogen) and electrons; the positively charged ions migrate across the electrolyte to the cathode, while the electrons move towards the cathode via an external circuit, creating an electric current. At the cathode, the positive ions and electrons reunite and react with oxygen from the air stream to form a new molecule in an exothermic (heat-generating) reaction.[65] For the case of hydrogen fuel, the reaction progresses as follows:

$$\tfrac{1}{2}O_2 + 2e^- + 2H^+ \rightarrow O^{2-} + 2H^+ \rightarrow H_2O + \textit{heat} \qquad \text{(R7.3)}$$

[58] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[59] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[60] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[61] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[62] EERE (no date) Fuel Cells. [41]
[63] EERE (no date) Fuel Cells. [41]
[64] EERE (no date) Fuel Cells. [41]
[65] EERE (no date) Fuel Cells. [41]

Over traditional combustion engines, fuel cells have many advantages—they operate at higher efficiencies, have fewer (sometimes zero) emissions, are quiet to operate, and do not form air pollutants on-site that harm human health.[66]

Currently, fuel cells are rarely used for utility-scale energy storage applications, although research and development programs, both publicly and privately supported, aim to increase the longevity and reliability of fuel cell systems, so that they can become a technologically and economically viable option.[67,68] The primary area of interest for utility-scale storage with renewable energy sources is *reversible* hydrogen fuel cells. Just like other hydrogen fuel cells, they generate electricity and heat using air and hydrogen fuel.[69] However, the systems can also function in reverse—when there's excess renewable energy available, these cells can store that energy in the form of hydrogen by using the excess renewable energy to break apart water into hydrogen and oxygen, a process known as electrolysis.[70] Then, this hydrogen can be used to fuel the cell when the intermittent renewable energy source declines,[71] helping to balance out energy production and energy use schedules. (A full exploration of hydrogen production via electrolysis is available in Section 6.1.1.2 of this report.)

Technological progress still needs to be made before reversible hydrogen fuel cells are commercially ready. One issue is that commercial-scale fuel cells and electrolyzers currently deploy different catalysts to support the electrolysis/combustion reactions. For one piece of equipment to do both jobs, a new device would need to be developed to get around these catalytic differences.[72] One has been developed, called a proton conducting fuel cell (PCFC), but the device cannot yet maintain the power output needed for most practical applications.[73]

7.1.2 State of Development

The state of development for these technologies is mixed, with some utility-scale batteries already having been commercially available for decades while others are still in the research and development space. Pumped hydropower storage and compressed air energy storage (CAES) are two examples of energy storage solutions that have existed for many decades.[74] The majority of newly-deployed utility-scale projects are focused on lithium-ion

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[66] EERE (no date) Fuel Cells. [41]
[67] EERE (no date) Fuel Cells. [41]
[68] Service (March 12, 2019) New fuel cell could help fix the renewable energy storage problem. [53]
[69] EERE (no date) Types of Fuel Cells. [42]
[70] EERE (no date) Types of Fuel Cells. [42]
[71] EERE (no date) Types of Fuel Cells. [42]
[72] Service (March 12, 2019) New fuel cell could help fix the renewable energy storage problem. [53]
[73] Zhang, Hu (2021) Progress in proton-conducting oxides as electrolytes. p. 995-997. [62]
[74] Irving (April 29, 2021) World's largest compressed air grid "batteries" will store up to 10GWh. [27]

batteries.[75] For those technologies that are still in development, the U.S. Department of Energy (DOE) is working to accelerate innovation, so that they can quickly reach commercial scale operations and contribute to national and international goals of rapidly decarbonizing the economy.[76] A summary compiled by the Massachusetts Institute of Technology (MIT) of development statuses for a variety of energy storage technologies, as well as the ancillary industries that support them (mining and processing of critical minerals, battery recycling or up-cycling, and development of infrastructure to support the production and distribution of hydrogen for fuel cells) is given in Table 7.2. Most technologies fall in a range of developmental stages because of ongoing innovations aimed at optimizing and scaling energy storage.

Table 7.2. Status of development for energy storage + ancillary industries, as of 2022.[77]

	Current Innovation Status[a]				
Technology	**Idea creation**	**R&D**	**Pilot scale**	**Demonstration**	**Deployment**
Li-ion batteries		■		■	■
Flow batteries (inorganic)		■		■	■
Flow batteries (organic)	■	■	■		
NaS batteries				■	■
Metal-air batteries		■	■		
Pumped hydro storage				■	■
Thermal storage		■	■	■	
Hydrogen		■			
Ancillary Industries					
Critical materials supply chain	■	■	■		
Battery recycling	■	■	■	■	
H_2 production, transport, storage	■	■		■	

a. Shaded region(s) denote one or more technology types in the relevant stage of readiness. Because there are several battery types in each technology category, more than one current innovation status may exist.

One energy storage technology that we have not explored extensively in this report due to its still being in very early stages of development are metal-air batteries, in which electricity is released through the spontaneous oxidation of a common metal (i.e. zinc, iron,

[75] IEA (September 2022) Grid-Scale Storage. [25]
[76] Blaustein (May 6, 2022) Rechargeable Molten Salt Battery. [2]
[77] MIT (2022) The Future of Energy Storage. p. xiv. [32]

aluminum) by air.[78] A spontaneous reaction is one that is thermodynamically favorable - it will progress naturally without external forcing (like the addition of heat or pressure). As a corollary to other electro-chemical redox batteries, here the metal is the anode material during discharge and the cathode is a porous material that allows the air to pass through and react with the electrolyte to form hydroxyl ions. The hydroxyl ions react with the metal, producing oxidized metal and free electrons. For example:

$$FeO_{metal} + OH^- \rightarrow FeO(OH)_{goethite} + e^- \quad \text{(R7.4)}$$

Although a zinc-based metal-air battery was first proposed in 1878, they are most commonly used today in small, often disposable, consumer electronics, and their deployment for utility-scale storage has yet to be proven.[79] If metal-air batteries can be scaled, they would have key advantages over other battery types: their theoretical specific energies exceed standard lithium-ion batteries by magnitudes of 5 to 50, depending on the type of metal used, and do not have the same overheating risks as lithium-ion battery cells (see Section 7.2.2).[80] While, attaining these high specific energies has not yet been achieved in practice, and currently, these systems are not cost-competitive with most other types of electrochemical battery storage,[81] this example of the potential for innovation and development is worth keeping in mind. With the speed at which new technologies are evolving in the battery space, the utility-scale battery storage options that seem most practical now may look very different even in a few years.

7.1.2.1 Example projects

Electrical Storage: Fluence, headquarters in Arlington, Virginia

Fluence is an energy storage technology and service provider that is run by Siemens and AES. The company was launched in 2018.[82] Fluence provides grid-scale and industrial-strength energy storage solutions, with scalable energy capability ranging from 2 MW to >500 MW and discharge duration of 6+ hours. Their advanced lithium ion sealed cells come in modular packaging, pre-installed with the necessary battery racks and modules, heating and cooling system, power supply, controllers, and safety components.[83] Fluence offers both short- and long-duration units ("cubes") that can be configured and combined on a site; a short-duration cube is approximately 2.5 x 2.5 x 2.2 m, while a long-duration cube is 2.5 m x 2.5 m x 2.1 m.[84]

[78] MIT (2022) The Future of Energy Storage. p. 35. [32]
[79] MIT (2022) The Future of Energy Storage. p. 37. [32]
[80] MIT (2022) The Future of Energy Storage. p. 35-36. [32]
[81] MIT (2022) The Future of Energy Storage. p. 36-37. [32]
[82] Fluence (no date) Fluence Energy. [21]
[83] Fluence (2022) Gridstack - Technical Specifications. [22]
[84] Fluence (2022) Gridstack - Technical Specifications. [22]

Heat Storage: Rondo Energy, Alameda, California

Rondo Energy converts wind and solar energy—either directly from the source or indirectly through the grid—into heat energy that can be stored and deployed as needed (see Figure 7.4).[85] This is an example of a sensible thermal energy system. When wind or solar energy is available, either through the grid or in an off-grid system, Rondo's process uses electric heating elements (called Joule heaters) to turn that electrical energy into high-temperature heat energy. The heating elements are placed near bricks, warming them to temperatures up to 1500°C (~2730°F). These bricks can store heat very effectively for long periods, with thermal losses of less than 1% per day. To release the heat for use, air is directed through the heated bricks, where it rises to temperatures over 1000°C (~1830°F)—the release of heat into the system can be easily adjusted by controlling the air flow out of the brick stack. This heat can then be delivered to a facility as superheated air or superheated steam, with temperatures, pressures, and heat medium (air or water) optimized to meet a facility's specific needs.[86]

7.1.3 Operational Needs

7.1.3.1 Physical footprint

Most energy storage sites report their size in terms of megawatt (MW) capacity, rather than a physical footprint. A good rule of thumb in the field is that per megawatt hour (MWh), the estimated land use for battery storage is 1,000 square feet.[87] The size will scale accordingly. Most energy storage applications require less than 10 acres of total land use.[88]

A battery storage facility called Saticoy, opened by Averon Asset Management in Ventura County in 2021, represents what a typical battery storage site in southern California would look like (Figure 7.5). It houses a 100 MW (or 400 MWh) energy storage system, enough to power the entirety of Ventura County for half an hour or the city of Oxnard for four hours.[89] The system is made up of 142 Megapacks, Tesla's utility-scale battery units, with performance management software from Power Factors.[90]

Another facility, Crimson Storage, is located on 2,000 acres of Bureau of Land Management (BLM) land in Riverside County, California (Figure 7.6).[91] As of the writing of this report, it

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[85] Rondo Energy (no date) The Rondo Heat Battery. [50]

[86] Rondo Energy (no date) The Rondo Heat Battery. [50]

[87] Convergent (no date) Landowner Partnerships. [12]

[88] Merritt (no date) Energy Storage Investment Opportunities. [34]

[89] Wagman (June 29, 2021) Averon opens 100 MW/400 MWh battery energy storage facility in California. [60] Note: For reference, Ventura County, California has a population of about 843,000 people, according to the U.S. Census Bureau's 2020 Census figures. Oxnard, California has a population of about 202,000 people, according to the U.S. Census Bureau's 2020 Census figures.

[90] Wagman (June 29, 2021) Averon opens 100 MW/400 MWh battery energy storage facility in California. [60]

[91] Lewis (October 19, 2022) The world's largest single-phase battery. [30]

is the largest single-phase battery storage facility, and the second largest operating energy storage facility, in the world, with a capacity of 350 MW or 1400 MWh.[92]



Figure 7.5. Saticoy 100 MW battery storage facility, Ventura County, California. Image credit: Averon Asset Management.[93]



Figure 7.6. Crimson Storage 350 MW battery storage facility, Riverside County, California. Image credit: Bureau of Land Management.

[92] Lewis (October 19, 2022) The world's largest single-phase battery. [30]

[93] Wagman (June 29, 2021) Averon opens 100 MW/400 MWh battery energy storage facility in California. [60]

The world's largest energy storage facility is Vistra Energy's Moss Landing Energy Storage Facility, with a capacity of 400 MW or 1600 MWh, also located in California (Monterey County).[94] In this project, battery units were stacked into a retrofitted turbine building in an old power plant that is approximately three football fields long.[95] Moss Landing is an interesting example of reusing existing energy infrastructure to meet new needs and the ability to stack battery units to reduce the land footprint of these facilities, both features that could inform the development of new energy storage projects.

7.1.3.2 Energy requirements

When assessing energy requirements for energy storage, the necessary metric to consider is round-trip efficiency. Not all of the energy that is stored in a battery can be used later—some amount of the energy is lost in the process. Depending on type of battery storage, the round-trip efficiency varies between 40-90% (Table 7.1), meaning that somewhere between 40% and 90% of the energy put into the battery can be withdrawn later for use.[96] Efficiencies can also alter over time for the same system. Aging systems generally have lower efficiencies due to degradation of the battery itself.[97] Systems can also decline in efficiency depending on the length of time that energy is stored in a particular medium before it is discharged; for example, molten salt batteries lose an estimated 1% of their stored energy every day.[98] For relatively short-term storage needs, molten salt could be incredibly efficient, but meeting longer-term needs could require other battery types or trying novel ideas, like freezing the entire molten salt system to hold the energy.[99] Thus, intended usage needs to be a determining factor for the type of storage chosen—large-scale battery storage systems are designed differently to meet short-term needs as opposed to long-term ones.

The storage duration – or how long an energy storage solution can supply energy to the user – depends upon the system's rated power capacity and the energy capacity. Most sites describe themselves in terms of rated power capacity, or the maximum rate of power discharge that a battery system can attain from a full charge expressed in kilowatts (kW) or megawatts (MW).[100] However, the total amount of power that can be stored by a battery system is the energy capacity, which is expressed in kilowatt-hours (kWh) or megawatt-hours (MWh). For a system rated 1 MW of power capacity storing 4 MWh of usable energy capacity (i.e. holding 4 MWh that can be released from the system with its efficiency), the

[94] Colthorpe (October 18, 2022) Crimson Energy Storage 350MW/1,400MWh battery storage plant. [11]
[95] Patel (January 14, 2021) Vistra Energizes Massive 1.2-GWh Battery System at California Gas Plant. [46]
[96] Roberts (July 21, 2018) Batteries have a dirty secret. [49]
[97] NREL (no date) Battery Lifespan. [37]
[98] MIT (2022) The Future of Energy Storage. p. 122. [32]
[99] Blaustein (May 6, 2022) Rechargeable Molten Salt Battery. [2]
[100] Greening the Grid (September 2019] Grid-Scale Battery Storage. p. 2. [24]

storage duration of the system would be 4 hours.[101,102] Determining the correct battery storage system for different applications will rely on matching up typical energy usage with battery characteristics in terms of the rated power capacity and the energy capacity.

7.1.3.2 Other operational requirements

Waste disposal requirements

Day-to-day, waste disposal requirements are generally not needed for energy storage systems. Most systems can run and rerun using the same materials thousands or tens of thousands of times (Table 7.1). The end-of-life disposal for these systems is often opaque, though. For example, utility-scale use of lithium-ion batteries has been growing rapidly, but there are no standardized disposal guidelines for these batteries, which only have a 15-20 year lifetime.[103] These batteries also cannot be disposed of in traditional landfills; not only would it be wasteful of expensive and finite materials, but elements within the battery like cobalt, manganese, and nickel can harm soil and groundwater.[104] Battery recycling is not as advanced as battery production, but it is quickly growing into a large scale industry of itself, as demand for the critical materials that compose batteries increases. For example, in 2023, the U.S. Department of Energy granted Redwood Materials, a lithium-ion battery recycling company based in Carson City, Nevada, a conditional $2 billion USD loan to build out its battery recycling campus. The expansion is expected to 1,600 full-time employees and support the production of more than 1 million electric vehicles per year.[105]

Warehousing requirements

Energy storage technologies are essentially warehouses for electricity and/or heat. Some forms of energy storage may benefit from (or require) housing within a building, but as the only feedstock and product is energy, the need for ancillary on-site warehousing is highly unlikely.

Transportation requirements

Transportation requirements for battery energy storage systems should involve the transfer of electricity from a power source (e.g. wind or solar), and when needed, to an electricity or heat user. Electricity will be transported in the form of power lines. Heat can be transported as steam or hot air. The length of these transport lines is minimized the closer energy source, storage system, and end user are sited together, which is one of the key benefits of Kern County for carbon management industry development. High efficiency renewable energy and storage systems could be sited adjacent to a large-scale business park, reducing technical hurdles and costs of energy transfer.

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[101] Greening the Grid (September 2019] Grid-Scale Battery Storage. p. 2. [24]
[102] NREL (2022) Utility-Scale Battery Storage. [38]
[103] Semeniuk (October 12, 2020) The Future of Energy Storage Needs a Disposal Plan. [52]
[104] Semeniuk (October 12, 2020) The Future of Energy Storage Needs a Disposal Plan. [52]
[105] LPO (February 9, 2023) LPO offers conditional commitment to Redwood Materials. [31]

7.1.3 Carbon Capture Potential

Energy storage systems do not capture or sequester carbon dioxide emissions. However, these technologies are expected to play a key role in transitioning from carbon-intensive energy sources—like coal, oil, and natural gas—to lower-carbon renewables like wind and solar. This is because traditional fossil fuel energy infrastructure can operate continuously and consistently, but renewable sources like wind and solar can be more intermittent in their supplies. To ensure reliable operation of any technology requiring heat or electricity, battery storage is required alongside renewables to sustain continuous or on-demand operations.

It is worth noting that battery storage is not inherently carbon-neutral, and over its life-cycle (manufacture to end-of-life) can emit CO_2 and other greenhouse gasses. How much it emits depends on the *indirect* emissions that occur during production of the energy that it stores (batteries can store energy indiscriminately of the source). If it's cheapest to store and then deploy energy that originates from a fossil fuel facility, then batteries will actually enable a very carbon-intensive energy mix. Currently, most incentives for battery storage expansion do not require the energy to be sourced from renewable resources, meaning that battery storage deployment has actually *increased* carbon emissions relative to a national grid with no storage.[106]

This is relevant to a carbon management industry that uses CO_2 credits (either from public incentives like the federal 45Q tax credit, or from the private carbon credit market) for revenue, because they can only receive income for the *net* CO_2 that they remove from the atmosphere (or prevent from being emitted). If their energy source is carbon-emissions-intensive, that will reduce the viability of their business model. Thus, battery storage needs to be coupled with low-carbon energy sources—sources that are much less carbon-intensive than existing energy sources—to produce maximum revenue potential as well as maximum climate benefits.[107]

7.2 Societal Impacts

7.2.1 Job creation potential

7.2.1.1 Number and types of jobs

By 2050, it is estimated that between research and development, manufacturing, installation, and operation and maintenance, the energy storage industry is expected to create 370,000-450,000 jobs in North America, or nearly 2,000 jobs for every GW of storage capacity installed.[108] Of these roles, only installation and maintenance jobs will be

[106] Roberts (July 21, 2018) Batteries have a dirty secret. [49]
[107] Roberts (July 21, 2018) Batteries have a dirty secret. [49]
[108] ACPA (2021) Clean Energy Labor Supply. p. 18. [1]

necessarily sited at energy storage facilities, and only maintenance jobs will be permanent, long-term, on-site roles. Given that a primary design goal for energy storage is high durability, and low maintenance, there would likely be very few permanent maintenance jobs created.

In terms of installation jobs, the Crimson Energy Storage Project - a 350MW battery storage facility in Riverside County (Figure 7.6) created 140 jobs during peak construction.[109] A 45MW energy storage facility planned in Massac County, Texas, anticipates the creation of 100 short-term jobs during construction.[110]

Sectors of the energy storage industry that have the largest growth potential are manufacturing (38% of all industry job growth) and project development (25%), which includes services like consulting, finance, research, legal support, architecture, engineering, and other specialized design services.[111] Battery recycling is also likely to experience significant growth (see Section 7.1.3.2). While project development jobs could locate onsite, local policies that incentivize or mandate energy storage companies to hire local workers to fill as many roles as possible is a strong driver for expanding the community benefits of these kinds of projects.[112] Manufacturing and recycling do not need to be co-located with installation sites, but given their job growth potential, an assessment of the benefits and risks of encouraging these types of facilities to locate in the region warrants further investigation.

7.2.2.2 Training pipelines

A training needs assessment for energy workforce development conducted by the New York State Energy Research and Development Authority (NYSERDA), identified a suite of thirteen technical, business, manufacturing, and general training needs to create a strong workforce in the energy storage sector.[113] Most of these needs, such as fundamental knowledge of energy storage technology, technical skills training for installation and maintenance, electrician training, regulatory and permitting processes, advanced manufacturing skills, interconnection processes, and safety training, can be learned through on-the-job training, apprenticeships, professional association training programs, or trade schools. Some skills such as engineering, system design expertise, and business and finance modeling, will require advanced post-secondary degrees.

An assessment of job growth potential across the entire clean energy sector (wind, solar and storage) by the American Clean Power Association reported average wages for clean energy occupations to range from $33,710-$158,100 (in 2020 USD), with higher paying

[109] Denos (October 18, 2022) BLM announces completion of Crimson Energy Storage Project. [13]
[110] Vistra (April 6, 2021) Joppa power plant to close in 2022. [58]
[111] ACPA (2021) Clean Energy Labor Supply. p. 18. [1]
[112] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[113] NYSERDA (2021) Energy Storage Workforce Development. [39]

positions requiring advanced degrees.[114] They projected that 65% of job-years created across these occupations would have an annual average wage higher than the national average of $56,310 (in 2020 USD).[115]

7.2.2 Quality of Life

7.2.2.1 Location

Battery storage facilities can be beneficial to communities, especially ones that are heavily reliant on variable energy sources, prone to extreme weather conditions, and/or suffer from transmission issues or grid unreliability. Battery storage facilities can replace "peaker plants"—typically fossil fuel-reliant power plants that run intermittently to meet peak demand on the grid.[116] Peaker plants are frequently located in disadvantaged communities, where they release greenhouse gasses and other emissions, some of which harm human health. Energy storage facilities can also replace aging facilities on the grid in need of decommissioning (such as the Moss Landing Energy Storage Facility, Section 7.1.3.1), which reduces the burden for ratepayers on paying for necessary infrastructure updates.[117] Because battery storage solutions can meet multiple needs, be deployed at a variety of scales, and utilize different storage technologies, there is a good deal of flexibility in ensuring the benefits of storage are realized by local communities.

Battery storage facilities do not locally emit any pollutants that cause harm to human health.[118] This is part of why battery storage solutions generally make a favorable replacement to traditional peaker plants—they can help meet periods of high energy demand without emitting harmful pollutants into local communities.

In general, battery storage systems are described as being "no louder than the average residential home air conditioning system."[119] The noise is derived from inverters, transformers, and fans needed to keep the equipment running,[120] though the exact equipment parts and their noise levels will differ between types of battery storage systems. With a planned 56 inverters, 56 transformers, and 40 HVAC units, the total noise level at a 1,000-foot distance from a 125MW facility operating at maximum sound level was 59.2 dB,[121] about as loud as normal conversational voices when people are standing about 3 feet apart.[122]

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[114] ACPA (2021) Clean Energy Labor Supply. p. 27-29. [1]
[115] ACPA (2021) Clean Energy Labor Supply. p. 24. [1]
[116] PNNL (no date) Energy Storage for Social Equity Initiative. [45]
[117] PNNL (no date) Energy Storage for Social Equity Initiative. [45]
[118] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[119] Convergent (no date) Landowner Partnerships. [12]
[120] Burns & McDonnell (2019) Battery Energy Storage System Sound Study. p. 23. [3]
[121] Burns & McDonnell (2019) Battery Energy Storage System Sound Study. p. 23. [3]
[122] OSHA (no date) Occupational Noise Exposure. [40]

Light pollution is uncommon for battery storage sites, but is something that would need to be evaluated based on the site-specific needs and the facility type.

Battery storage does come with some risks that will impact both on-site workers and, to a lesser extent, quality of life for nearby residents. Utility-scale battery storage sites can be a fire and explosion risk.[123] For example, with lithium-ion batteries, there is the risk of *thermal runaway*, wherein one battery pack overheats, leading to a domino effect causing other units to overheat, which can create a fire or explosion within or across battery packs. If the battery packs catch fire, toxic gasses including carbon monoxide, hydrogen fluoride, and hydrogen chlorine can be released. If batteries are damaged during disposal, they can have similar hazards. With diligent on-site management and strong federal and state regulation, these hazards can be minimized to protect workers and nearby communities.[124]

7.2.2.2 Multi-use potential

Most battery storage systems can be easily co-located with other facilities, as exemplified by the diversity of sites upon which they already exist in urban, residential and remote environments, including private homes. One multi-use example comes from Duke Energy, which is planning to build a solar microgrid and battery storage facility next to Johns Hopkins Middle School in Pinellas County, Florida.[125] The 2.5 MW battery is designed to store energy from the solar microgrid to be deployed to support the school, which also acts as a hurricane shelter, or to the local power grid.

7.3 Environmental Impacts

7.3.1 Water requirements

7.3.1.1 Minimum volume requirements

Water intake amounts vary across battery types, and the relationship between water use (by volume) and capacity to store and release energy is not well reported, to the best of our knowledge, for any industry other than pumped hydropower storage facilities that rely on water from a nearby river being moved into a reservoir with a power station and then released back into the river (in this case, the net water use is very small).[126]

Many energy storage systems require water as a solution medium—redox flow batteries rely on aqueous (water-based) solutions to store the salts needed to generate electricity,[127] but the extent to which that water needs to be replenished (and thus the water demand of

[123] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[124] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[125] Duke Energy (August 25, 2020) Three new battery storage sites. [15]
[126] Casey (November 30, 2022) Underground Water Battery. [6]
[127] MIT (2022) The Future of Energy Storage. p. 29. [32]

such batteries over time) is not well reported. CAES facilities often need water to be pumped underground to dissolve the salts in underground storage caverns, which become a reservoir to store the compressed air for the system.[128] This generates brackish water that needs to be removed from the ground and treated before reuse (see Section 8 on water treatment techniques).[129]

Current lithium-ion batteries do not require water—in fact, most perform better in very dry conditions—but some teams are working on new lithium-ion batteries that can absorb water or use liquid materials instead of being a 'dry-cell' battery.[130]

7.3.2 Other potential impacts

For an industry as diverse as this, it is not possible to clearly outline all potential environmental impacts (positive or negative) in a region that develops utility scale storage. Even within the same category, different battery types do not carry same risks or potential environmental impacts.

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

Two general points, however, can be made. First, battery and other energy storage systems do not generate criteria air pollutants.[131] In fact, because battery storage facilities often replace emergency generators or traditional power plants that run on fossil fuels, battery storage can serve to improve local air quality by replacing energy facilities that do emit pollutants.[132] Second, on a more global scale, battery production does have environmental impacts resulting from the extraction of critical materials (like lithium and cobalt) used to manufacture batteries, and from their disposal. As energy storage technologies scale up, a significant focus of research and development is on optimizing battery longevity and efficiency, and on improving mining practices and identifying raw materials that can replace critical minerals whose sourcing is often unsustainable and/or ethically fraught.[133]

[128] MIT (2022) The Future of Energy Storage. p. 94. [32]
[129] MIT (2022) The Future of Energy Storage. p. 94. [32]
[130] Sagoff (May 2, 2022) Water containing battery electrolyte. [51]
[131] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[132] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[133] Le (August 4, 2020) Flow Batteries. [29]

7.4 Economic Impacts

7.4.1 Business Model

The global energy storage market size is currently valued at $59 billion, and is anticipated to grow by at least 900% by 2035.[134] This is due primarily to the dramatic increase expected in our reliance on variable renewable energy (VRE) sources like wind and solar. In 2020, VREs provided 9% of global energy supplies. It is projected to rise to almost 70% of global energy supplies by 2050,[135] due both to commitments by nations and municipalities to reduce their carbon emissions, and to the fact that since 2020, onshore wind and solar power have been the least expensive forms of energy generation to build.[136]

Business models for utility-scale battery storage typically relies on the mismatch between energy supply and demand. With variable renewable electricity (VRE) sources like wind and solar, energy production highs and lows are based on the weather. Battery facilities buy electricity during periods of high VRE availability, when electricity is the cheapest, and then sell and distribute the electricity when VRE availability is low for a higher price.[137] This system enables battery facilities to generate consistent profits, while also providing a few co-benefits. First, implementing battery storage reduces demand for peaker plants, which are typically sustained using fossil fuels, to meet peak periods of electricity demand, thereby reducing CO_2 and other types of emissions. Second, it levels out energy costs for ratepayers from industrial to household scale. In California, as more battery facilities have come online, the variability between minimum and maximum energy prices has decreased, introducing greater consistency to energy pricing (Figure 7.7).[138]

The build-out of energy storage systems is not always driven by pure economics—rebates and other government incentives can drive additional uptake by making the economics more favorable, and mandates can ensure broad uptake, even when the economics are unfavorable. For example, in 2018, the Federal Energy Regulatory Commission (FERC) mandated that regional transmission organizations (RTOs) begin to adopt energy storage practices and that energy storage facilities are classed as "generation facilities."[139] In December 2020, the U.S. Congress passed the Better Energy Storage Technology Act, authorizing over USD 1 billion over five years to support the research and commercialisation of a range of storage technologies, with a focus on multi-hour distribution (balancing daily variation in VRE availability, and long-duration storage, that addresses seasonal VRE variability.[140] Although more regulatory changes will be necessary

[134] Le (August 4, 2020) Flow Batteries. [29]
[135] MIT (2022) The Future of Energy Storage. p. 271. [32]
[136] Lazard (2021) Levelized cost of energy. [28]
[137] CEC (November 2021) Buy Low, Sell High. [4]
[138] CEC (November 2021) Buy Low, Sell High. [4]
[139] Shim (November 13, 2018) Enthusiasm for Energy Storage. [54]
[140] St. John (December 22, 2020) Congress passes spending bill. [55]

to keep pace with expected changes in the energy grid, these policies offer a promising groundwork to remove unnecessary regulatory barriers and encourage greater participation of energy storage in the national electricity market.[141]



Figure 7.7. As more batteries have entered the California energy market, the highest and lowest energy prices have both moderated. Image credit: California Energy Commission.[142]

7.4.2 Business Costs

7.4.2.1 Cost of energy: Installed cost of storage

When considering the cost of energy storage, there are a few key takeaways:

1. Storage cost is dependent on the storage technology and energy capacity.
2. The price of energy has dropped significantly in the last few decades, and is expected to continue dropping.
3. The capital and operational costs associated with storage development do not translate to a levelized cost of energy in the same way that other energy commodities do, because energy storage is not a stand alone energy provider - it only operates in conjunction with an energy source.

We will unpack these takeaways in this, and the following section.

[141] Shim (November 13, 2018) Enthusiasm for Energy Storage. [54]
[142] CEC (November 2021) Buy Low, Sell High. [4]

Determinants of installed cost of storage

A 2022 study undertaken by the Pacific Northwest National Laboratory (PNNL)[143] examined commercially available energy storage technologies, with the aim of assessing how their costs varied as a function of power capacity (the amount of energy they can provide at a given time, in MW or kW) and energy capacity (the total amount of energy they can store on a single charge, in MWh or kWh), and how these costs are likely to evolve by 2030. Their comparison was across two variables: installed cost and levelized cost of storage (LCOS). Installed cost is addressed here, and LCOS is discussed in Section 7.4.2.2.

Table 7.3. Installed cost of energy storage in 2021.[144]

Battery Type[a]	Power Capacity Range (MW)	Installed Cost ($/kWh)	Installed Cost ($/kW)	Operating Costs ($/kW-yr)	Decommis-sioning Costs ($/kWh)
Lithium-Ion (LFP)[b]	1-10	$360-519	$922-9,128	$2.79-23.30	$2.65
Lithium-ion (NMC)[c]	1-10	$410-576	$1,031-10,405	$6.18-29.59	--
Lead Acid	1-10	$412-607	$1,090-10,457	$4.05-31.46	$16.89-33.28
Vanadium Redox Flow	1-10	$356-836	$1,522-$9,054	$4.85-26.48	$22.95-59.27
Zinc	1-10	$440-631	$1,172-10,798	$10.56-27.65	--
CAES	100-1,000	$16-295	$1,087-1,784	$9.82-18.56	--
Pumped storage hydropower	100-1,000	$221-511	$1,716-2,625	$15.58-28.19	--
Gravitational	100-1,000	$190-731	$1,706-7,600	$14.28-34.37	--
Thermal	100-1,000	$130-595	$1,568-3,944	$6.95-42.77	--
Hydrogen	100-1,000	$126-295	$2,949-3,033	$16.89-23.90	--

a. The most commonly utilized battery types are described in this report. For details on all battery types, see Viswanathan et al. (2022) PNNL energy storage cost assessment.
b. Lithium-ferrophosphate
c. Nickel-manganese-cobalt

Installed costs comprise the net of capital expenses (raw materials, project development, engineering, procurement, construction and grid integration). These costs are detailed in Table 7.3, along with operating costs (fixed operations and maintenance, losses associated with round-trip efficiency (RTE),[145] and in some cases a warranty) and decommissioning costs (disconnection, removal, site remediation and recycling/disposal), and are given as

[143] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. [59]

[144] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. [59]

[145] Note: round-trip efficiency (RTE) is the percentage of the energy used to charge a storage system that is released during discharge. See Table 7.1 for typical RTEs by battery type.

ranges that reflect cost variation as function of power capacity (specified by storage type) and storage duration, in hours.

For any of these technologies, installation costs in terms of energy capacity ($/kWh) decrease with increasing storage duration (see Figure 7.8), but in terms of power capacity ($/kW) and operating costs, they increase with storage duration.[146] Installation costs also decrease with increasing power capacity, due to economies of scale.[147]

Projected decreases in battery costs

The outlook for rapidly decreasing costs for energy storage is quite promising, on the basis of historical trends. Since 1991, the price of lithium-ion batteries has decreased 97%.[148] Like other technological innovations (such as solar and wind power), economies of scale and learning by doing have driven significant, systematic decreases in the cost of production with every doubling of installed capacity. For lithium-ion batteries, this 'learning rate' has been a price decline of about 18.9% for every cumulative capacity doubling.[149] Using this learning rate, as well as anticipated growth in energy storage installation capacity, it is possible to make projected estimates of what costs will be in the future. A cost analysis from MIT estimated that by 2050, lithium ion batteries may have decreased an additional 37-74% in price, while less developed technologies could see even greater cost decreases (up to 91% for flow batteries and up to 97% for metal-air batteries).[150]

7.4.2.2 Cost of energy storage: Levelized cost of storage

The cost of energy is often assessed as a levelized cost, that is incorporating capital, operational, labor and feedstock costs, what is the total cost of producing energy ($/kWh or $/MWh) for a given facility, over the lifetime of that facility?[151] Assessing the levelized cost of storage is slightly more complicated, as it requires not only consideration of the above factors, but also how much the storage system would be used annually (annual hours discharged), the cost of energy needed to charge the energy storage system and the round-trip efficiency (RTE). These variables are combined to calculate the levelized cost of storage (LCOS) as follows:

$$LCOS = [(fcr \times CapEx) + O\&M_{fixed})/AH + ECC, \quad \text{(E7.1)}$$

where fcr = the fixed charge rate (%), CapEx is the present value of capital expenditures, $O\&M_{fixed}$ are fixed operating and maintenance costs, AH is the annual hours discharged, and ECC is the electricity charging cost (purchased energy [$/kWh] divided by RTE [%]).[152]

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[146] NREL (2022) Utility-Scale Battery Storage. [38]

[147] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. f.ex. p. 24-25. [59]

[148] Ritchie (2021) Price of batteries has declined by 97%. [48]

[149] Ritchie (2021) Price of batteries has declined by 97%. [48]

[150] MIT (2022) The Future of Energy Storage. p. 19. [32]

[151] Lazard (2021) Levelized cost of energy. [28]

[152] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. p. 120-121. [59]

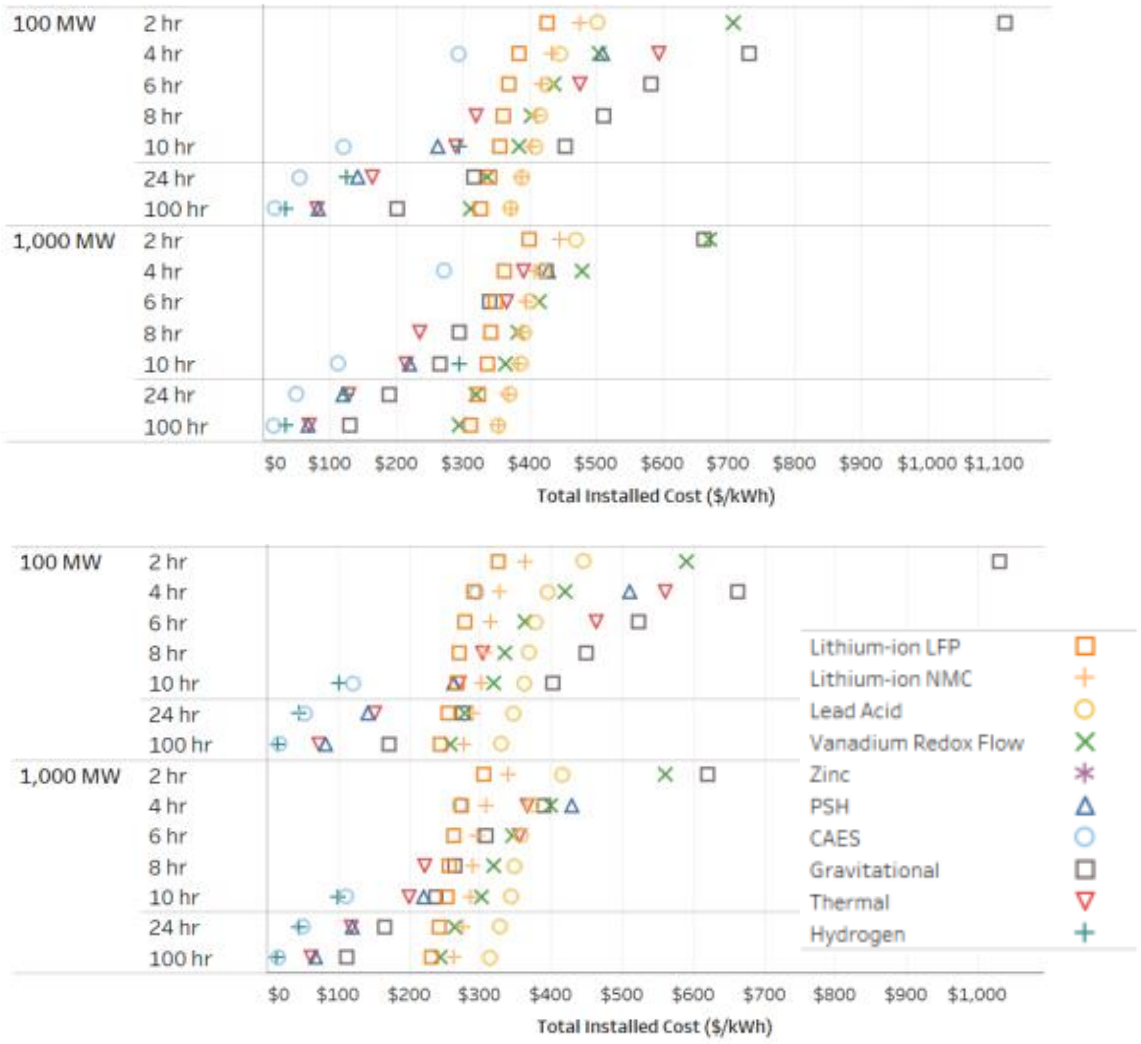

Figure 7.8. Total installed cost of energy solutions, as a function of storage duration and power capacity, showing estimated 2021 values (a) and projected 2030 values (b). Values are shown for power capacities of 100 and 1,000 MW. Data and image credit: Pacific Northwest National Laboratory.[153]

The energy system cost assessment from PNNL (2022) included an LCOS analysis of all studied energy storage systems, and found that levelized costs ranged from about $0.10-1.30 USD/kWh for large (100-1,000 MW) storage systems, with most costs falling between $0.10 and $0.40 (the higher costs were associated with systems that had 100 hr storage duration).[154] For comparison, grid electricity in California is about $0.12-0.65 USD/kWh.[155] It is also important to note that battery storage does not work alone - it operates in tandem with an energy source, like wind or solar - with the direct energy source supplying power sometimes (to the grid and the storage system) and the energy storage system supplying

[153] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. p. ix-x. [59]
[154] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. p. 130. [59]
[155] EIA (February 2023) Average price of electricity. [16]

power other times. Therefore it is most useful to think of how energy storage adds to the levelized cost of energy production from wind or solar, which is about $0.03-0.05 USD/kWh.[156]

The National Renewable Energy Laboratory reports added costs per MWh (= 1,000 x kWh) of $5-39 for energy storage (from their own models and the published literature), with much of the range reflecting the inclusion or omission of tax credits. In a practical example, during a 2018 bidding war for new energy capacity for electricity provider Xcel Energy in Colorado, the median price for energy storage and wind was $21/MWh, and it was $36/MWh for solar and storage. This compares to $18/MWh and $29.50/MWh, respectively, for wind and solar solutions without storage.[157]

7.4.3 Regional benefits

California leads the nation in energy storage, with 215 operational projects providing ~4,200 MW of energy,[158] and plans to grow. Among utility-scale facilities, about 75% of planned development between 2022 and 2025 is concentrated in California and Texas.[159] As such, there are already companies active in the energy storage space with a sizable presence in the California market.

Local laws and regulations in California also make it an attractive location for utility-scale energy storage projects. The California Energy Commission (CEC) predicts that to meet the requirement of Senate Bill 100 for a carbon-free electricity system by 2045, 49,000 MW of battery storage capacity will need to be integrated into the electricity grid.[160] To reach these goals, new state legislation has removed some of the subdivision and zoning requirements that extended project timelines, making it more straightforward to develop a battery energy storage facility in California.[161]

7.4.3.1 Proximate feedstocks

Battery storage systems have minimal feedstocks in the traditional sense. These systems need inputs and catalysts to fuel the redox reactions that support most electrical storage, but these materials can often be reused for many charge/discharge cycles. Thus, having local supplies of materials to meet this need is not a major concern—depending on the battery type, replacement of component chemicals may not be necessary for a decade or longer.

Depending on the system type, water intake will be the most important feedstock consideration. For aqueous systems like redox flow batteries, water is necessary for

[156] Lazard (2021) Levelized cost of energy. p. 9. [28]
[157] Svaldi (January 16, 2018) Xcel Energy receives shockingly low bids. [56]
[158] University of Michigan (no date) U.S. grid energy storage factsheet. [57]
[159] EIA (December 8, 2022) U.S. battery storage capacity will increase significantly by 2025. [17]
[160] CEC (November 2021) Buy Low, Sell High. [4]
[161] Colthorpe (August 31, 2022) California zoning exemption granted. [10]

sustained operation. However, some forms of redox flow batteries have optimized reuse of the liquid electrolyte solutions, with vanadium redox flow batteries having a liquid electrolyte with near-100% recyclability.[162] As a result, this water requirement can vary greatly, even within the same family of batteries, due to the material differences between electrolyte solutions, catalysts, and other components.

Other battery types—like standard dry-cell lithium-ion batteries—are corroded by water,[163] so locating them in arid regions, a common feature in Kern County, could be a great locational fit based on the region's climate and the battery's optimal operating conditions.

7.4.3.2 Proximate consumers

Battery storage has multiple benefits for carbon management and clean energy industries. Many of these processes require energy input to capture carbon or generate other products, but given the goals of the carbon management park, would need to find ways to meet this energy demand while minimizing their operational carbon output. Battery storage can serve to smooth out energy supply availability by storing solar energy during peak production periods and releasing it while the solar supply is negligible (i.e. at night), so facilities can maintain continuous operation. Thermal batteries can also convert renewable energy solar and wind energy into high temperature heat, which is needed in some carbon management industries, particularly L-DAC (Section 3) and steel (Section 5).

7.4.3.3 Co-location advantages

There will already be a large amount of renewable energy resources around to support the carbon management and clean energy industries on-site; batteries bridge the gap between supply and need imbalances.

If the system is entirely off-grid, a battery storage provider could secure procurement agreements directly with park facilities. If the system has a grid connection, the battery storage provider could also secure procurement agreements with local utility companies.

[162] Ondrey (April 1, 2021) Recycling electrolyte from vanadium RFBs. [43]
[163] Sagoff (May 2, 2022) Water containing battery electrolyte. [51]

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58. Vistra. Joppa power plant to close in 2022 as company transitions to a cleaner future. Published online April 6, 2021. Accessed May 12, 2023 from https://investor.vistracorp.com/2021-04-06-Joppa-Power-Plant-to- Close-in-2022-as-Company-Transitions-to-a-Cleaner-Future.

59. Viswanathan, V., *et al.* (2022) 2022 grid energy storage technology cost and performance assessment. Pacific Northwest National Laboratory (PNNL), Technical Report PNNL-33283, 174p. https://www.pnnl.gov/sitesdefault/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf.

60. Wagman, D. Sunrise brief: Arevon opens 100 MW/400 MWh battery energy storage facility in California. *PV Magazine*. Published online June 29, 2021. Accessed March 9, 2023 from https://pv-magazine-usa.com/2021/06/29/sunrise-brief-arevon-opens-100-mw-400-mwh-battery-energy-storage-facility-in-california/.

61. Xiaotao, C., S. Jie, L. Lixiao, *et al.* (2017) Performance Study of Salt Cavern Air Storage Based Non-Supplementary Fired Compressed Air Energy Storage System. *IOP Conf.*

Series: Materials Science and Engineering, 248, 012007. doi.org/10.1088/1757-899X/248/1/012007.

62. Zhang, W., Y. H. Hu. Progress in proton-conducting oxides as electrolytes for low-temperature solid oxide fuel cells: From materials to devices. *Energy Science & Engineering*, 9(7), 984-1011. https://doi.org/10.1002/ese3.886.

8. Water Treatment

TECHNOLOGY AT A GLANCE

- Industry has wide-scale public implementation: globally, 48% of wastewater is treated, with 11% destined for reuse.[1] In the U.S., an estimated 91.1% of wastewater is safely treated.[2]
- Water treatment is energy-intensive[3] and varies in size and complexity based on the amount and quality of water received and the necessary quality for use after treatment.[4]
- Key advantages of this technology in Kern County: regional water supply is already overallocated[5] and subject to frequent drought conditions.[6] Water reclamation and reuse could support new industries while minimizing impacts on existing agricultural and residential water use.
- Key concerns of this technology in Kern County: Water treatment is well-understood and highly regulated for safety. Facilities should be sited where odors, light, and noise pollution will not bother communities and implemented in the context of a sustainable regional water use plan.

[1] Utrecht University (February 8, 2021) Half of global wastewater treated. [79]
[2] Alabaster *et al.* (2021) Progress on Wastewater Treatment. p. 92. [1]
[3] Lund (September 2017) Plant Earns LEED Recognition. [55]
[4] CDC (no date) Water Treatment. [16]
[5] Grantham, Viers (2014) California's water rights system. p. 5. [41]
[6] NDMC (October 13, 2022) Kern County, California. [57]

8.1 Technology Summary

Water use is a critical consideration in the design of any new industrial center, especially in California, which is in the midst of a multi-decadal megadrought.[7] State policies require restoration of the groundwater aquifers[8] that have been traditionally relied upon to compensate for shortages in surface water resources, further exacerbating the need for water conservation.[9] In Kern County, industries requiring abundant fresh water would directly compete with regional agriculture, municipalities and existing industries. However, the state of California produces more than 3.4 million acre-feet of wastewater annually[10] (see below for definitions) that has the potential to be remediated and repurposed for industrial use. The viability of such an option is dependent upon interest, cost, and needs of the envisioned park, which will vary depending upon the types of industries that choose to locate on-site. In this section, we provide a general overview of water treatment facilities, and how they differ as a function of the purity needs of treated water. For readers unfamiliar with industrial scale water treatment and use, relevant key terms and policies are outlined here.

Acre-foot is a standard measurement for large volumes, representing the amount of water needed to cover one acre of land with one foot of water. One acre-foot is equivalent to 326,000 gallons of water.[11] For reference, it would take the average household in California between six months and two years to use this volume of water.[12]

Alternative water is a catch-all term for water sources that are not surface or standard groundwater collection. According to the U.S. Department of Energy (DOE), this includes "Harvested rainwater, stormwater, sump-pump (foundation) water; Graywater [also spelled greywater or grey water]; Air-cooling condensate; Rejected water from water purification systems; Reclaimed wastewater; [and] Water derived from other water reuse strategies."[13] Graywater and reclaimed wastewater are of particular interest here. **Graywater** constitutes water lightly used for domestic or industrial use aside from toilets, and typically requires less processing than wastewater.[14] **Wastewater** is a broader category, including sewage, water used in heavier industrial processes, and stormwater as

[7] James (February 14, 2022) Western megadrought is worst in 1,200 years. [48]

[8] Escriva-Bou *et al*. (2021) Groundwater recharge in California. [33]

[9] Chappelle *et al*. (2017) Groundwater in California. [17]

[10] California Water Boards (no date) Volumetric annual reporting of waste water and recycled water. [15]

[11] Bland (August 4, 2021) Water is life. [9]

[12] Bland (August 4, 2021) Water is life. [9]

[13] EERE (no date) Net Zero Water Building Strategies. [58]

[14] Ghaly *et al*. (2021) Greywater Sources, Characteristics, Utilization and Management Guidelines. p. 128. [39]

well as graywater; it can contain a wider range of pollutants and thus requires more processing, depending on the quality necessary for reuse.[15]

Influent refers to the water entering a treatment plant, and **effluent** refers to the same water after it has undergone treatment and is leaving a treatment plant.[16] The quality and volume of influent and effluent will vary across facilities.

8.1.1 Description: How it Works

Wastewater processing works utilizing a well-established model, though the steps may differ based on the quality of the influent, amount of water processed, and age of the facility. There are a few consistent steps across models, however, with one exception that distinguishes the two primary types of plants: conventional treatment, in which a sedimentation tank is part of the treatment process, or direct filtration, which does not use a sedimentation step.[17] The list below describes **primary treatment**, typical for all wastewater treatment plants. Depending on the quality of the influent water and the necessary quality of effluent flow, secondary or tertiary systems can be implemented to further clean the supply.

- **Preliminary treatment**: influent water passes through coarse screening and grit removal processes to remove large materials, like manmade objects, rocks, or gravel.[18]
- **Coagulation**: chemicals are added to the water to "stick" small particulates together.[19]
- **Flocculation**: as particulates begin to clump together, water is added to large tanks with slowly-mixing paddles, which bring particles together to form floc.[20]
- **Sedimentation**: the water slowly passes through a sedimentation tank, where the floc settles at the bottom of the tank to be pumped out while the water moves out of the tank.[21,22] Direct filtration systems skip this step.[23]
- **Filtration**: the water enters a filter, typically a concrete box with sand and gravel supported on an underdrain structure, which removes remaining suspended particles.[24]

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[15] DES – Queensland (no date) Wastewater. [24]
[16] Pulsar Measurement (no date) Influent and Effluent Flow Monitoring. [61]
[17] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[18] Pescod (1992) Wastewater treatment. [60]
[19] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[20] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[21] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[22] EPA (1998) How Wastewater Treatment Works. p. 3. [29]
[23] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[24] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]

- **Disinfection**: prior to discharge, water is often treated with chlorine gas or a mix of chlorine and ammonia in a process called chloramination to kill microorganisms.[25] The maximum residual disinfectant level (MRDL) for effluent water leaving the plant is 4.0mg/L, and most effluent averages free and total chlorine concentrations "between 2.5 and 3.5 mg/L" when leaving a treatment facility.[26]

While these steps are common to nearly all water treatment facilities, some can be removed or other steps can be introduced, depending on the water quality and planned destination for effluent flow. The flowchart in Figure 8.1 provides an example, demonstrating the water treatment process used at the Granollers Wastewater Treatment Plant, built in Spain in 1992.[27] This system includes far more intermediary steps to clean its water before discharge. The figure also details the steps necessary to process sludge (raw primary biosolids), a byproduct of water treatment.[28]

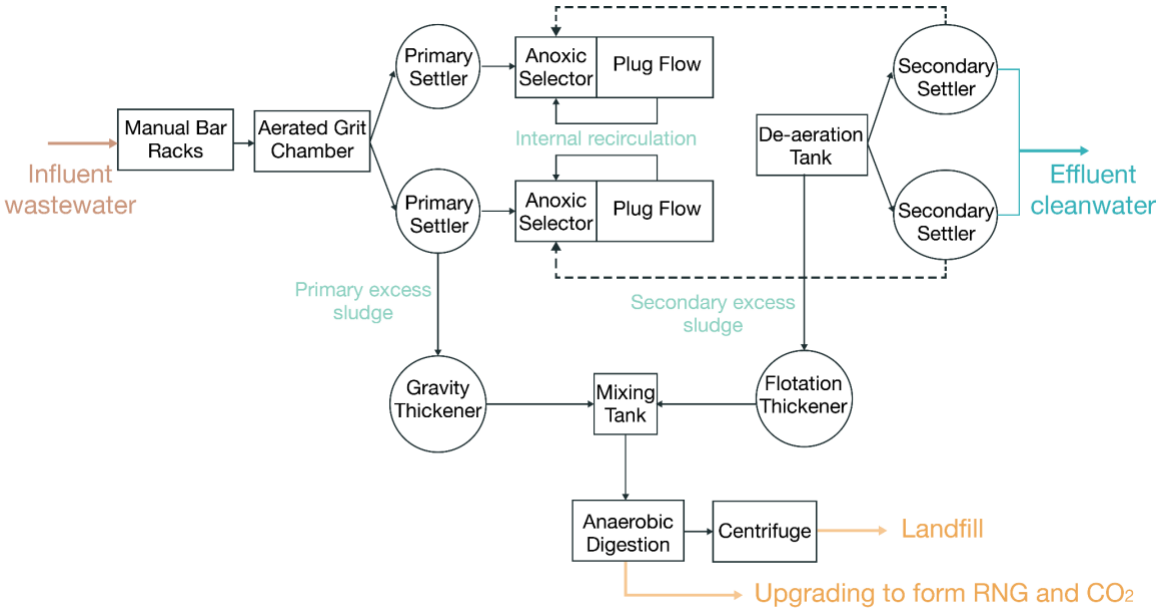

Figure 8.1. Flow chart demonstrating some typical steps of a wastewater treatment process; adapted from Vidal et al. (2002) and other sources.[29]

Cleaning water for industrial use may be less intensive than is required for a wastewater treatment plant producing drinking water quality effluent. The European Union's guidelines for water reuse, which draws on existing best practice, outlines that "industrial water reuse

[25] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[26] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[27] Vidal *et al.* (2002) Design of Wastewater Treatment Plants. p. 4994. [81]
[28] EPA (1998) How Wastewater Treatment Works. p. 3. [29]
[29] Vidal *et al.* (2002) Design of Wastewater Treatment Plants. p. 4994. [81]

is highly determined by the exact quality needs of the individual industrial process and/or product as well as the costs of producing water of the required quality compared to other suitable sources."[30] Thus, there are few 'industry standards' that can be used to define the necessary processes (and costs) of industrial water reuse—it will depend on the types of industries that could be located within the park and the water volume and quality necessary to operate a given facility.

Another freshwater alternative for industrial water (or drinking or irrigation water) is desalination, which is the process of stripping dissolved salts from seawater or other brines. As Kern County is within 100 miles of the Pacific Ocean, desalination of seawater would provide an effectively limitless volume of water for industrial development, albeit at a high price. Desalination is up to four or five times the cost per gallon for treatment, when compared to graywater or wastewater treatment plants.[31] It is considered in this study for the purpose of comparison with treatment of graywater or wastewater, and as a point of consideration for future development in the region, given that freshwater resources are anticipated to become ever more scarce with climate change.[32]

There are two main techniques for desalination, each reviewed briefly here. In reverse osmosis (RO), influent is passed through a series of semi-permeable membranes in order to remove the salts and other impurities found in seawater, as shown schematically in Figure 8.2.[33,34]

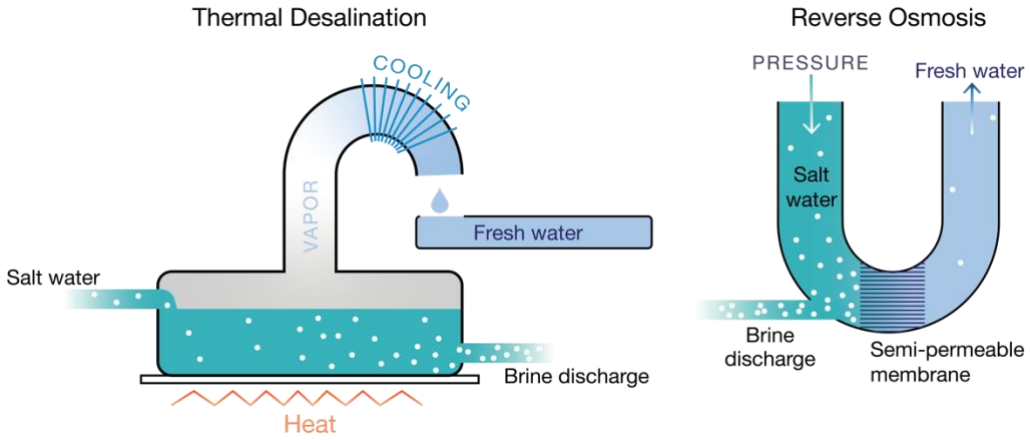

Figure 8.2. Thermal desalination and reverse osmosis are two techniques for producing fresh water from saline waters like seawater or brines. Adapted from the Texas Comptroller of Public Accounts.[35]

[30] EU Water Directors (no date) Common Implementation Strategy. p. 24. [35]
[31] Climate Now (April 19, 2022) Solve the Global Water Crisis? 6:30-6:42. [20]
[32] Hanak (January 9, 2023) Adapting to a Water-Scarce California. [44]
[33] IDE Technologies (no date) What is Desalination? [46]
[34] Ang *et al.* (2015) Integrated/Hybrid Membrane Processes. [3]
[35] Texas Comptroller of Public Accounts (no date) Texas Water Tour: Desalination. [73]

In thermal desalination, heat is used to evaporate seawater, creating pure water vapor and a briny residue. The vapor is subsequently condensed into fresh liquid water. Waste heat from power plants or refineries is often used to supply the heat source.[36] Thermal desalination can be accomplished through vapor compression (VC), in which heat derived from mechanically compressed vapor is used to drive evaporation of the seawater influent. Alternatively, multi-stage flash distillation (MSF) and multi-effect distillation (MED) employ multi-step evaporation/condensation processes, taking advantage of how the boiling point of water varies as a function of salinity to optimize energy efficiency. Steam or the seawater influent itself is used as the carrying agent for the heat, which boils seawater in a series of vessels (or "effects"), producing vapor and a more salty brine. The brine is moved to the next vessel, which induces boiling at a higher temperature, producing more vapor and a saltier brine, that is transferred to the next vessel, and so forth, iterating as many times as is desired.[37,38]

8.1.2 State of Development

Water treatment and transport has been employed for centuries,[39] and are a common feature of public drinking water systems throughout the United States[40] (and the world). But new technologies that are particularly important in water-scarce regions like Kern County, such as desalination of seawater or wastewater treatment that provides water effluent that is clean enough for irrigation or drinking purposes, are not yet widely used on a commercial scale in the United States. Only about 1% of water is recycled in the U.S.,[41,42] and less than 3 gallons of every 1 million gallons of water used each day in the U.S. comes from desalination.[43]

For the purposes of this investigation, we have examined two water treatment facilities that are typical for water reuse in irrigation or landscaping, and a small set of facilities across the nation that fall within the 1% of plants that are designed to generate usable water to directly meet local needs and increase water circularity. Water treatment facilities specifically designed to meet the needs of an industrial park are not well-covered in the literature, given the vast diversity of requirements that might entail. However, lessons gleaned from existing facilities can provide a general sense of the parameters, needs, impacts and benefits of a water treatment or desalination facility to nearby industries or communities.

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[36] IDE Technologies (no date) What is Desalination? [46]
[37] IDE Technologies (no date) What is Desalination? [46]
[38] Tzen (no date) Desalination Technologies (I). [75]
[39] EPA (2000) The history of drinking water. [31]
[40] CDC (no date) Water treatment. [16]
[41] WaterReuse.org (no date) Water Reuse 101. [84]
[42] USGS (no date) How much water is used by people in the United States? [77]
[43] Tonner (November 2, 2021) Desalination in America. [74]

8.1.2.1 Example projects

Bee Ridge Water Reclamation Facility, Sarasota County, Florida[44]

This facility in Sarasota County has a capacity of 12 million gallons per day (GPD), making it the largest of the county's water treatment plants. Wastewater is moved to the site through a series of underground pumps and lifting stations. Once at the site, the influent water goes through four major cleaning steps: screening for inorganic materials, biological processing, filtration, and disinfection. Biosolids removed during the treatment process are separated out and composted.

Effluent water that leaves the Bee Ridge facility after processing is reclaimed water that is suitable to meet commercial and residential needs for landscaping and irrigation. This reduces the demand to use potable water—which could be used in homes for cooking and cleaning—for outdoor use.

Lancaster Water Reclamation Plant, Lancaster, California[45]

This facility in Lancaster, just south of Kern County, has a capacity of 18 million GPD. It employs primary, secondary, and tertiary processing, so the facility can generate reclaimed water suitable for agricultural, municipal, industrial, and parkland uses, including maintenance of water levels in regional parks and migratory bird ponds. An estimated 12.6 million gallons per day of reclaimed water is used from the Lancaster facility every day.

The Lancaster facility also saves its byproducts; biosolids are dried and can be used for compost or soil additives. The methane (biogas) generated on-site from processing wastewater is used to meet the heat requirements of the anaerobic digesters.

Direct potable reuse (DPR) water treatment demonstration facilities, United States

Although it is possible to generate reused water at the quality necessary for safe drinking water, few states allow treated wastewater to be pumped directly into homes—currently, only Texas and (on a case-by-case basis) Arizona allow direct distribution of treated water as potable tap water (direct potable reuse, or DPR).[46] Both Big Spring and Wichita Falls, in Texas, have used DPR to support local water supplies, with Wichita Falls relying on the practice to generate 5 million gallons of treated water per day to support the city during the end of a 5-year drought.[47]

In California, cities like San Diego and Los Angeles have begun to consider the implementation of DPR to diversify their own water supplies.[48] The State Water Control Resources Board is expected to release updated regulations this year that would allow DPR

[44] Sarasota County (no date) Bee Ridge Water Reclamation Facility. [68]
[45] LACSD (no date) Lancaster Water Reclamation Plant. [54]
[46] Constantino (August 19, 2022) What's in your drinking water? [23]
[47] Constantino (August 19, 2022) What's in your drinking water? [23]
[48] Constantino (August 19, 2022) What's in your drinking water? [23]

in the state.[49] To prove the viability and safety of DPR to the public, San Diego ran a demonstration advanced purification facility from 2009 to 2013 allowing the public to tour the plant and try the water, but avoided any legal trouble by not sending any of the DPR water to taps.[50] Los Angeles plans to undertake a similar demonstration facility in 2024 to act as "proof of concept" for city residents about the safety of DPR.[51] Experts estimate that California has the potential to triple its current water reuse rate to 2.8 million acre-feet annually.[52]

8.1.3 Operational Needs

8.1.3.1 Land use requirements

Water treatment plants can have large land use requirements. The physical footprint of a facility can comprise a series of open ponds and/or buildings, depending on facility scale and local regulations.[53] Quality of the influent and effluent can also shape facility size—more intensive treatment can introduce additional filtration steps requiring extra equipment or ponds—and facilities often locate, when possible, on larger sites than needed to both leave room for future expansion and avoid bothering nearby communities with any noise, light, or odor pollution from the treatment plant.[54]

It is important to note that facility acreage and facility capacity (the amount of water a treatment plant can process) are not strongly correlated. In the United States, the largest treatment plants by capacity have maximum physical footprints of about one square kilometer (~247 acres), with an average size of around 0.6 square kilometers (~148 acres).[55] For a regionally representative example, the Bakersfield Wastewater Treatment Plant No. 2, processing 13.7 million gallons per day or about 15,345 acre-feet of water per year,[56] occupies ~645 acres of land.[57]

Design plans also differ considerably, depending on how much of the processing equipment is visible from the outside of the facility. An advantage of water treatment facilities relative to other industries included in this report, is the wide potential for alternative uses, including natural or open spaces, or public use spaces (see Section 8.2.2). An image demonstrating the potential appeal in the landscape and for nearby residents is shown in Figure 8.3.

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[49] Water Education Foundation (no date) Water Recycling. [83]
[50] Constantino (August 19, 2022) What's in your drinking water? [23]
[51] Constantino (August 19, 2022) What's in your drinking water? [23]
[52] Water Education Foundation (no date) Water Recycling. [83]
[53] USA SHADE (no date) Water Treatment Facility Design Guide. [76]
[54] USA SHADE (no date) Water Treatment Facility Design Guide. [76]
[55] Wikipedia (August 2, 2022) List of largest wastewater treatment plants. [86]
[56] City of Bakersfield (no date) Wastewater Treatment Plants. [18]
[57] Measured via Google Earth.



Figure 8.3. The Newtown Creek Wastewater Treatment Plant in is located on a 52-acre site and has been designed to exist alongside residential development.[58] Blue and white lighting at the plant seek to provide enough light to work safely at night, without constituting an ecological or community hazard of light pollution.[59] Image credit: Victoria Belanger / Flickr

8.1.3.2 Energy requirements

Water treatment is an extremely energy-intensive process, using approximately 650 MWh per acre-foot of treated water.[60] Electricity costs alone can account for 25% to 40% of a water treatment facility's annual operating budget,[61] and within most municipal areas, wastewater treatment facilities are the largest single electricity consumer.[62] Energy requirements for water treatment depend on the quality of influent water being processed, considering both the type of contaminants involved, and their concentration in the influent. These factors determine the technologies and methods used to treat the water and are thus highly correlated with energy consumption.[63] The most energy intensive practices are generally also the most expensive, with seawater desalination requiring more electricity than cleaning wastewater or graywater.[64]

Aside from treatment facilities themselves, transporting water before or after treatment also requires a great deal of energy, simply because water is heavy to move. For reference, one acre-foot of water weighs 1,360 U.S. tons (~1,233 metric tons).[65] In California, the State Water Project – a suite of canals, pipelines, reservoirs, and hydroelectric power facilities that serve as a freshwater delivery system across the state[66] – is "the state's single largest user of electricity" as the infrastructure needed to support pumping water between regions is highly energy intensive.[67]

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[58] L'Observatoire International (no date) Newtown Creek. [53]
[59] L'Observatoire International (no date) Newtown Creek. [53]
[60] Hamilton *et al.* (2009) Driving energy efficiency in the U.S. water & wastewater industry. [43]
[61] Lemar, de Fontaine (2017) Energy Data Management Manual. p. 2. [51]
[62] Lemar, de Fontaine (2017) Energy Data Management Manual. p. 5. [51]
[63] Energy Star (no date) Energy Use in Wastewater Treatment Plants. p. 2. [26]
[64] Fort, Nelson (2012) Pipe Dreams. p. 21. [36]
[65] Fort, Nelson (2012) Pipe Dreams. p. 3. [36]
[66] California Department of Water Resources (no date) State Water Project. [14]
[67] Fort, Nelson (2012) Pipe Dreams. p. 3. [36]

Innovative state and federal programs are helping facilities to reduce their energy consumption through improvements in energy recovery, benchmarking usage, and efficiency upgrades to onsite equipment.[68] Scientists and engineers are even optimistic that ambitious wastewater treatment plants could become net energy creators, rather than users, in the future.[69] This is primarily due to their ability to use the biogas and thermal heat produced on-site more efficiently with measures like co-digestion and fuel cell systems.[70] However, given the present average energy requirements of water treatment facilities (650 MWh/acre-foot), approximately 1.6 acres of solar energy would be required to treat an acre-foot of water.* Water needs from the various carbon management systems explored in this report range from less than 0 acre-feet per million metric tons of CO_2 captured (S-DAC and some forms of BiCRS), to as much as ~16,000 acre-feet of water needed per million tons CO_2 (L-DAC, see Figure 8.4). The high-end estimate translates to about 25,312 acres of solar panels needed to support sufficient water treatment.

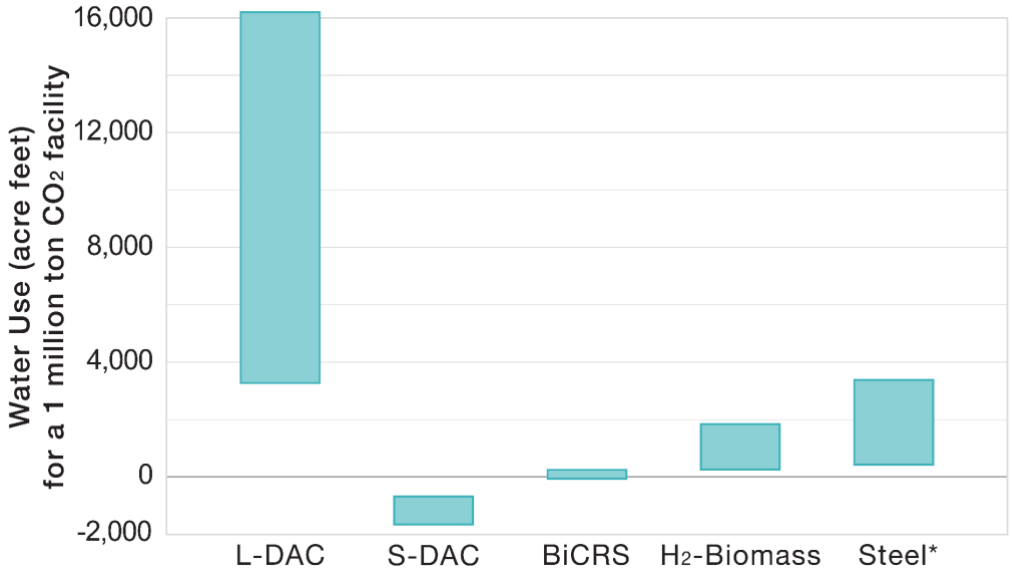

Figure 8.4. Water use across carbon management industries, based on this study (see Sections 3, 4 and 5). Hydrogen production via biomass, steel and particularly L-DAC technologies are water-intensive practices, using as much as 16,200 acre-feet of water annually, that could be sourced from treated graywater or (less economically) desalinated seawater.

[68] Lemar, de Fontaine (2017) Energy Data Management Manual. p. 4. [51]

[69] Gandiglio *et al.* (2017) Enhancing the Energy Efficiency of Wastewater Treatment. p. 1. [38]

[70] Gandiglio *et al.* (2017) Enhancing the Energy Efficiency of Wastewater Treatment. p. 1-2. [38]

* Please see Section 3.1.3.2 of this report to see the equation and solar capacity factor used to derive this estimate.

8.1.3.3 Other operational needs

Waste disposal requirements

Wastewater treatment plants generate bio-solids and methane gas as byproducts of the water purification process.[71] According to the EPA, the methane produced on-site is frequently used by water treatment plants as fuel, rather than being disposed of or sold.[72] However, the methane produced can be sold as renewable natural gas (RNG) to other firms as long as its production and storage meets necessary federal and state standards.[73] This could encourage circularity within a water treatment plant or within a carbon management industrial park at large, particularly given the potential for generating electricity plus CO_2, or hydrogen fuel plus CO_2, through oxy-fuel combustion or methane steam reforming, respectively (see Sections 4 and 6).

Biosolids are another byproduct that are produced by physically and chemically treating the solids separated out during the water purification process to generate a nutrient-rich, semisolid product.[74] These solids can be used productively on agricultural and mining sites to improve soil structure, add nutrients, and improve water reuse, with secondary benefits including reduced landfilling and reduced use of synthetic fertilizers.[75] If not reused, biosolids must be disposed of by surface disposal methods, such as landfilling or incineration.[76]

Warehousing requirements

To store influent prior to treatment and effluent before it is sent to customers, water treatment facilities typically require a large amount of onsite storage. Water awaiting treatment is often held in ground lakes or pools.[77]

Because treated water is also often stored onsite until it can be transported to a customer, facilities can require millions of gallons worth of space to store cleaned water.[78] Onsite storage helps to regulate water supply to align with demand, both of which can vary seasonally.[79] Furthermore, onsite storage serves to further reduce the amount of nitrogen, microorganisms, and suspended solids present in treated water, so water leaving storage can also be cleaner than when it first leaves the treatment plant.[80] Depending on the

[71] City of Bakersfield (no date) Wastewater Treatment Plants. [18]
[72] EPA (no date) Methane Generated on Site. [30]
[73] EPA (no date) Methane Generated on Site. [30]
[74] EPA (no date) Basic Information about Biosolids. [28]
[75] EPA (no date) Basic Information about Biosolids. [28]
[76] EPA (no date) Basic Information about Biosolids. [28]
[77] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[78] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[79] Pescod (1992) Wastewater treatment. [60]
[80] Pescod (1992) Wastewater treatment. [60]

location and quality, effluent can be directly discharged into 'receiving waters' such as nearby rivers or streams, removing the need to store effluent flow for distribution.[81]

Transportation requirements

The influent and effluent from any water treatment plant would need to move between potential sources – agricultural fields, commercial or industrial facilities, or the ocean – to the plant, and then into the carbon management park. Depending on the yield of the plant and the park's water usage, additional infrastructure may be necessary to transport water to alternate consumers or to nearby aquifers in need of replenishment.

In California, water is typically transported using open canals, aqueducts, or pipelines.[82] The size of this equipment, as well as its operating needs and costs, will depend on the anticipated load.[83] Moving water can be energy-intensive over any topographical features, as pumps will be necessary to accommodate any increases in altitude along the route; as a result, the most efficient pipelines would move water near flat or declining geography to benefit from gravity.[84] A good example of this type of infrastructure operating without energy-intensive pumps is the nearby Los Angeles aqueduct, which runs through the eastern portion of Kern County.[85, 86]

Pipeline requirements

Pipeline requirements would depend upon a facility's size and anticipated influent and effluent flows. A low intensity project may only require polyvinyl chloride (PVC) pipes, while larger projects would require steel pipes.[87] Investing in durable and easily-repairable equipment is generally the most cost-effective option in the long run by minimizing future repair and maintenance costs.[88]

8.1.4 Local Context - Current Water Use

Given the overall focus of this report on the potential development of a carbon management industrial park, an entire segment on water use—including the viability of on-site water treatment options—may appear to be out of scope. However, water is often critical to ensuring sustained and successful facility operations, thus the local context of water availability in Kern County is worth examining.

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[81] EPA (1998) How Wastewater Treatment Works. p. 4-5. [29]

[82] Bland (August 4, 2021) Water is life. [9]

[83] Resourcefulness (no date) Transporting Water. [64]

[84] Resourcefulness (no date) Transporting Water. [64]

[85] Fort, Nelson (2012) Pipe Dreams. p. 23. [36]

[86] Library of Congress (1908) Topographic map of the Los Angeles aqueduct and adjacent territory. [52]

[87] Frankel (November 10, 2021) Wastewater Treatment System Cost? [37]

[88] Frankel (November 10, 2021) Wastewater Treatment System Cost? [37]

California is in a state of drought, having experienced a series of such dry years since at least 2000, that the few wet years in between have not been enough to replenish groundwater or support plant regeneration.[89] Currently, over 80% of Kern County is experiencing 'exceptional drought' conditions.[90]

In Kern County, precipitation is low due to the arid climate—the county seat of Bakersfield receives an average of 6.49 inches of rain per year.[91] Yet the area uses water to support a diverse range of communities, industries, and farms; in an average year, agriculture receives 2,294,000 acre-feet of water and municipalities and industry receive 166,000 acre-feet of water across Kern County.[92] Only about one-quarter of the water used originates from local surface sources, like the Kern River or smaller streams.[93] Most of the region's water is derived from underground reservoirs or is brought in from the State Water Project (via the California Aqueduct) or the federal Central Valley Project (via the Friant-Kern Canal).[94]

Water is overallocated across California when compared to supply, with a 2014 study from University of California researchers finding that "[in] the state's major river basins, water rights account for up to 1000% of natural surface water supplies."[95] For the Kern River, this figure stood at 631%.[96] Additionally, overpumping of underground aquifers as an alternative water source has led to land subsidence, with approximately half the land in the San Joaquin Valley experiencing significant land subsidence (over one foot in surface ground level change) by 1970.[97] In this context, land subsidence occurs when water is removed from under the ground and the land at the surface drops down as a result.[98] These environmental changes have caused significant concern, and the state has sought to resolve these impacts of reduced aquifer replenishment and land subsidence with laws like the Sustainable Groundwater Management Act (SGMA) of 2014.[99]

Given this regional context, any ways in which newly developing industries in Kern County can make use of non-freshwater sources, like treated graywater or desalinated seawater, or in which industries that produce water as a byproduct of carbon management (S-DAC and some forms of BiCRS) could co-locate with more water intensive industries, warrant examination.

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[89] Wigglesworth (April 18, 2021) Is California suffering a decades-long megadrought? [85]
[90] NDMC (October 13, 2022) Kern County, California. [57]
[91] WAKC (no date) Water in Kern County. [82]
[92] WAKC (no date) Water in Kern County. [82]
[93] WAKC (no date) Water in Kern County. [82]
[94] WAKC (no date) Water in Kern County. [82]
[95] Grantham, Viers (2014) California's water rights system. p. 1. [41]
[96] Grantham, Viers (2014) California's water rights system. p. 5. [41]
[97] USGS (October 17, 2018) Land Subsidence. [78]
[98] USGS (October 17, 2018) Land Subsidence. [78]
[99] SWRCB (no date) The Sustainable Groundwater Management Act. [71]



Figure 8.5. Image of the Los Angeles Aqueduct, which does not require energy for pumping, demonstrating what large-scale water pipelines look like in the local environment. Image credit: Mavens Notebook / Flickr.

8.2 Societal Impacts

8.2.1 Job creation potential

8.2.1.1 Number and types of jobs

Water management will likely generate relatively few jobs past any necessary construction phases; however, the initial construction of any treatment facilities or canals would be labor-intensive endeavors.[100]

California's water supply is heavily monitored and managed by existing staff attempting to balance demands from industry, agriculture, and power generators, in addition to communities and natural habitats.[101] Any additional permanent jobs created in this sector will likely be skilled jobs to remotely manage flows, supplies, and make executive decisions during periods of drought.[102]

There could be some full-time, on-site jobs generated by a water treatment facility. The majority of these would likely require vocational training, but would not require extensive secondary education, as 85% of national water-related occupations are filled by workers

[100] Kane, Tomer (2018) Renewing the water workforce. p. 17. [50]
[101] Escriva-Bou, A. *et al.* (2019) Dams in California. p. 1. [34]
[102] California Department of Water Resources (no date) Careers. [13]

who have less than a bachelors degree.[103,104] Furthermore, water infrastructure jobs are generally good jobs, with an average wage that exceeds the national average and equates to a livable wage in most of the country.[105]

For a large water treatment facility, staffing needs would likely be around a few dozen employees. For reference, Bakersfield's Wastewater Treatment Plants 2 and 3, processing 13.7 and 17.3 million gallons per day of influent water (or approximately 15,346 and 19,378 acre-feet per year), support 11 and 19 jobs, respectively.[106]

8.2.2.2 Training pipelines

Anyone with a high school diploma or GED with appropriate experience can become certified to fill most water treatment roles.[107] All states set their own guidelines for certification for water operators.[108]

Most training for working with water infrastructure relies on developing skills and knowledge through applied learning, rather than emphasizing traditional postsecondary education.[109] Some specialized jobs within the water workforce—including architects, environmental engineers, and computer systems managers—typically require a postsecondary degree and earn higher pay.[110]

8.2.2 Quality of Life

8.2.2.1 Location

Light pollution is a frequent complaint regarding water treatment sites close to communities.[111] Since the facilities process water continuously, the site must be well-lit at all hours of the day for the safety of its employees, who are walking around and operating large equipment. Newly-designed plants have taken on a variety of innovative features to try and address light pollution concerns. The Newtown Creek plant (seen in Figure 8.3) has used a mixture of blue and white lighting to provide both an artistic and safe amount of light without disturbing residents.[112] A LEED-certified wastewater treatment plant located in Dryden, Ontario optimized their design to use the lowest possible light levels whilst still

[103] Bureau of Labor Statistics (October 4, 2022) Water and Wastewater Treatment Plant. [12]
[104] Kane, Tomer (2018) Renewing the water workforce. p. 21. [50]
[105] Kane, Tomer (2018) Renewing the water workforce. p. 19-20. [50]
[106] City of Bakersfield (no date) Wastewater Treatment Plants. [18]
[107] AWWA (no date) Water Operator Certification Explained. p. 13. [2]
[108] AWWA (no date) Water Operator Certification Explained. p. 13-14. [2]
[109] Kane, Tomer (2018) Renewing the water workforce. p. 22. [50]
[110] Kane, Tomer (2018) Renewing the water workforce. p. 20. [50]
[111] ACE (2005) Washington Aqueduct: Environmental Impact Statement. p. 5-13. [4]
[112] L'Observatoire International (no date) Newtown Creek. [53]

meeting security requirements.[113] Another facility in Adelaide, Australia is using infrared lighting to monitor all the external features and security gates of their water plant, so only the inside of buildings require visible lighting for operation.[114] Although light pollution is a serious concern, there are innovative options available to protect worker safety and reduce light pollution for any nearby residents.

Noise complaints are another frequent issue with locating water treatment plants close to residential areas.[115] Given the fans, motors, pumps, and compressors needed to run the plant, noise can build up.[116] The most common problem is not just an increase in ambient noise, but different parts of equipment that produce unique but similar tones, creating a 'pulsating' effect for human ears that can be perceived as doubling the sound coming from the plant.[117] Designing the plant to accommodate for noise can resolve most of these problems. Construction plans should locate large equipment away from residential areas, minimize the potential openings in the building for sound to escape, and include necessary sound-dampening materials like acoustical louvers and HVAC duct silencers.[118] Recent software developments, namely variable frequency drives (VFD), can adjust the speed of rotation for devices based upon the required load, which can dramatically lower the sound pressure generated.[119]

If the water being processed involves any raw sewage, as is true of most wastewater plants, odor becomes another concern for the plant. Depending on the chemicals and processes used to cope with biological waste, the resulting biosolids may also release a noticeable smell, typically due to "ammonia, amines, and reduced sulfur-containing compounds" present in the biosolids.[120] Odors can be mitigated with intentional design. At the Dryden plant (Figure 8.4), a fan is placed over the influent flow entrance to draw off air into a set of biofilters and charcoal, leaving most of the facility odor-free to house offices and other space for workers.[121]

8.2.2.2 Multi-use potential

Multi-use projects with water treatment plants are rare, likely due to their size and high potential for noise pollution. Although plants like the Newtown Creek treatment facility have been designed with unique tanks, lighting, and glass walkways to draw visual interest

[113] Lund (September 2017) Plant Earns LEED Recognition. [55]
[114] Raytec (July 14, 2014) RAYMAX IR Protects Australian Water Plant. [63]
[115] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[116] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[117] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[118] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[119] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[120] EPA (no date) Basic Information about Biosolids. [28]
[121] Lund (September 2017) Plant Earns LEED Recognition. [55]

from passersby, akin to an art exhibit, these designs are uncommon and do not involve any nontraditional users on the actual site.

There are some unique water treatment facilities that have evolved for multi-use purposes. The R.C. Harris Water Treatment Plant in Toronto, Ontario processes about 30% of the city's drinking water, but also is a notable Art Deco building with public access to the grounds and has served as a frequent filming location for TV and movies.[122] The plant used to be fully open for public access until security concerns arose in the early 2000s, but still allows some public access for special events.[123] Similarly, water treatment plants in China and the United States have managed to incorporate both indoor and outdoor botanical gardens for public enjoyment.[124,125]

8.3 Environmental Impacts

8.3.1 Water requirements

8.3.1.1 Minimum volume requirements

For graywater and wastewater treatment plants, the volume of influent and effluent hardly differs. By weight, wastewater is 99.9% water, with only the remaining 0.1% of organic and inorganic compounds, as well as microorganisms, being removed by the filtration process.[126] Thus the yield of water that will be released as effluent is quite high. There is no minimum volume requirement to operate a water treatment plant, though efficiency varies—both in terms of maximizing water reuse and equipment lifetime—if the plant is processing much more or much less water than it was designed to handle.[127]

For desalination specifically, the technology used to remove salts from seawater will determine the minimum volume requirements necessary. Using reverse osmosis (RO), approximately half of the initial volume of water run through the process can be desalinated—the remainder is returned to the water source.[128] This is considered a relatively good yield for desalination processes.

The salient question for volume requirements—what will the average daily water needs of the carbon management park look like—is also the most difficult to answer, as different technologies exhibit a vast range of water consumption patterns. For biomass-based

[122] City of Toronto (no date) Fast Facts about the City's Water Treatment Plants. [19]
[123] Mok (no date) The historic R.C. Harris Water Treatment Plant. [56]
[124] Engineering News-Record (September 25, 2019) Wusong Wastewater Plant Upgrade - Botanical Garden. [27]
[125] Smith (June 2019) Landscape With a Purpose. [69]
[126] Buchanan, J. R. (no date) Wastewater Basics 101. [11]
[127] Tchobanoglous, G. *et al.* (2021) Rationale for constant flow to optimize wastewater treatment. p. 1238-1239. [72]
[128] Beswick *et al.* (2021) Does the Green Hydrogen Economy Have a Water Problem? p. 3168. [8]

processes (BiCRS and BECCS), facilities can typically run close to neutral on water use. Some processes are even net-positive on water and can generate water as a reaction byproduct at a quality suitable for agricultural use.[129] Other technologies, like hydrogen production via electrolysis, require water to generate any output. 9 kg of water must be used to generate a single kg of hydrogen fuel (Section 6), with some companies reporting that in the field, the best estimate is 12 kg per kg of hydrogen produced due to water vapor loss.[130, 131]

8.3.1.2 Minimum quality requirements

Water quality needs are dependent on the intended use of the treated water. For agricultural uses or industrial cooling needs, water can typically be less filtered than would be necessary for drinking water. To use water in chemical processes like electrolysis, the water must meet high standards of purity (i.e. be distilled and/or deionized) to preserve the efficiency and lifetime of the equipment.[132] Membrane-based electrolyzers require water to be of type II purity, though operate better with water of type I purity, which is even more filtered.[133]

8.3.3 Other potential impacts

Redirecting water use in any way may impact existing usage covenants, or harm the well-being of local communities, farms, or wildlife. Given the exceptional drought conditions in Kern County discussed in Section 8.1.4, directing already-purified water for industrial use from existing sources that are already stretched for existing and new housing would be difficult.

In terms of environmental impact, generating more usable water for the park from otherwise undesirable sources, including graywater, stormwater, seawater, or wastewater, can be construed as a net positive. If a water treatment facility can purify otherwise unusable water to be clean enough for industrial, agricultural, or residential uses, and in excess of the quantities needed by members of the carbon management park, this water can help alleviate shortages in the county's current supplies. Excess purified water could be traded through California's water markets to help keep agricultural producers in business during dry years. It could even be stored in the area's underground aquifers to replenish the over-drained supply and prevent continued land subsidence in the southern San Joaquin Valley. Further, excess energy generation from other industries (such as electricity from oxyfuel combustion of biomass, or waste heat from BiCRS or steel

[129] San Joaquin Renewables (no date) The Project. [67]

[130] Beswick *et al.* (2021) Does the Green Hydrogen Economy Have a Water Problem? p. 3167. [8]

[131] Valdez (August 11, 2022) Electrolyzers and Water. [80]

[132] Spiegel (October 18, 2022) Introduction to Electrolyzers. [70]
Note: this information derives from a response provided in the comment section by the Fuel Cell Store account.

[133] Jonsson, Mässgård (2021) An Industrial Perspective on Ultrapure Water Production. p. 17. [49]

industries) could be used as a cost-effective and carbon-free energy source for treating alternative waters for regional use.

8.4 Economic Impacts

8.4.1 Business Model

The profitability of water is a complex question due to the array of existing regulations and allocations involved and the unusually low price of water.[134] Low tariffs on water use are intended to protect economically vulnerable residential consumers, but also effectively undercharge all users—including those in industry and agriculture—for their current water use.[135] This system means that despite scarcity, water is generally undervalued, and thus rarely conserved or reused.[136] At the macro scale, investing in large facilities for generating more clean water from less pure sources is seen as an expensive and unnecessary investment when water access is currently cheap in monetary terms. However, as scarcity increases, there is a "huge opportunity" to adopt reuse and recycling practices for industrial water that will mitigate risks associated with climate change as the American West becomes more arid.[137]

Because of the high costs associated with these projects, the federal government offers a range of funds, loan guarantees, and grant programs that can provide funding for projects aiming to increase water reuse, reclamation, and efficiency.[138] Most programs emphasize community or local government leadership, and may be ineffective options for an industrial park—more research would be needed to determine the viability of pursuing federal water reuse funding for a specific project. Likely, policy intervention or necessity due to scarcity will be the levers that encourage more widespread adoption of water conservation, reuse, and desalination within California.[139]

Finally, under California law, water is a public resource, although its use can be subject to private rights.[140] Presumably, the revenue potential of a water treatment facility within a carbon management industrial park would depend on how projects were permitted and funded. If the County itself owned a water treatment plant, it could presumably sell the water (within the park or outside of it) or store it in aquifers. It is less clear whether there is a profitable model for a privately owned and operated water treatment plant. California does operate a water market where a purifier could recuperate costs by selling water,

[134] Climate Now (November 16, 2021) Water Strategy. 9:25-9:55. [21]
[135] Climate Now (November 16, 2021) Water Strategy. 11:07-11:58. [21]
[136] Climate Now (November 16, 2021) Water Strategy. 11:07-11:58. [21]
[137] Climate Now (2022) Solve the Global Water Crisis? 4:42-6:10. [20]
[138] EPA (no date) Water Reuse Infrastructure Funding Programs. [32]
[139] James (August 11, 2022) California expected to lose 10% of its water within 20 years. [48]
[140] Green (no date) A Primer on California's Water Issues. [42]

though most of the water traded in California originates from surface sources.[141] 46% of all water traded in California is done between buyers and sellers in the same county.[142] In the last decade, farmers in the San Joaquin Valley and cities have been the largest buyers in the water trading market, so it is likely that there would be substantial interest in Kern County around purchasing any water generated from industrial park activity or from treatment of alternative waters, not to mention the potential of selling to industrial players within the park to support their operations.[143]

8.4.2 Business Costs

Capital and operational costs for water treatment can be difficult to ascertain. First, there is currently no federal or non-federal standard for what factors should be included or excluded when reporting estimated capital or operating expenses.[144] Furthermore, both the capital and operational costs are dependent upon changeable factors; for example, for capital costs, this includes the volume and quality of the influent water and for operating costs, this includes the costs of labor and electricity.

8.4.2.1 Cost to build (upfront costs)

Costs to build a facility depend upon its capacity (usually measured in gallons per day, hereafter GPD) and purity of the influent. Wastewater treatment centers capable of processing 150,000 GPD for industrial use typically cost $500,000 to $1.5 million upfront.[145] For reference, 150,000 GPD is equivalent to 168 acre-feet of water treated per year, and water-intensive carbon management facilities investigated in this report could require up to 16,200 acre-feet per million tons of CO_2 captured (Figure 8.4).

Depending on the other technologies needed to filter and process the water and the level of purity required for the effluent, costs can grow significantly—up to many millions in additional upfront costs. Reverse osmosis (RO), a desalination process, and ion exchange (IX), which can remove minerals and ions to generate deionized water for chemical processes like electrolysis,[146] both would add an estimated capital cost of under $5 million for smaller GPD systems.[147] Complete distillation and purification via zero liquid discharge (ZLD)—essentially, a water treatment plant that does not release water with any solid or liquid contaminants into the natural environment, like streams or groundwater, instead

[141] Hanak *et al*. (2021) California's Water Market. p. 1. [45]
[142] Hanak *et al*. (2021) California's Water Market. p. 1. [45]
[143] Hanak *et al*. (2021) California's Water Market. p. 2. [45]
[144] Dundorf *et al*. (2017) Quantifying the Cost of Water Treatment. [25]
[145] SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]
[146] Atlas Scientific (October 31, 2022) Ion Exchange in Water Treatment. [5]
[147] SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]

recycling the water routinely on-site[148]—would be considerably more expensive, running up to $10 million for systems capable of handling GPD in the thousands.[149]

8.4.2.2 Operational costs

Operational costs for water treatment vary considerably based upon influent quality,[150] and are dependent upon material costs, electricity costs, labor costs, and costs from third-party services.[151]

Treating graywater and other wastewater is less cost-intensive than treating seawater or other brackish water via desalination. To generate the same quantity of usable water, the costs of operation for desalination are typically two to four times higher than for wastewater treatment.[152] In a study of treatments to recycle irrigation water for greenhouses, researchers found that the costs ranged from $0.07 to $1.00 to treat 1,000 gallons of water, depending on the treatment method,[153] equating to between $38,325 and $547,500 per year for a 150,000 GPD facility. That's over a tenfold increase between the lowest and highest cost treatment option, and irrigation water generally has less impurities requiring treatment compared to wastewater or seawater, suggesting operational costs would be higher for a wastewater treatment facility or desalination plant.

8.4.3 Regional benefits

With population increases and a decades-long cycle of droughts afflicting the American West, innovative projects to generate more usable water should be drawn to locations like Kern County, with its abundance of open land to locate a facility and steady mix of agricultural, industrial, and residential water consumers.

8.4.3.1 Proximate feedstocks

Within Kern County, the largest water users are in the agricultural sector.[154] Agriculture produces substantial runoff of graywater, as up to half of the water used in crop irrigation evaporates or becomes runoff.[155] If captured and reused, this graywater would constitute an existing and accessible source of water for the carbon management park.

The western edge of Kern County is located less than 100 miles from the Pacific coastline, making it a potential site for desalination projects. A desalination facility could also be

[148] Saltworks (January 15, 2018) What is Zero Liquid Discharge & Why is it Important? [65]
[149] SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]
[150] Frankel (November 10, 2021) Wastewater Treatment System Cost? [37]
[151] Bluefield Research (October 9, 2018) Operating Expenditures. [10]
[152] Climate Now (April 19, 2022) Solve the Global Water Crisis? 6:30-6:42. [20]
[153] Raudales *et al.* (2017) How much does it cost to sanitize your water? [62]
[154] WAKC (no date) Water in Kern County. [82]
[155] Balsom (September 28, 2020) Water Usage In The Agricultural Industry. [7]

located on the coast and utilize pipelines or canals to transport water into Kern County for industrial or agricultural uses.

8.4.3.2 Proximate consumers

In addition to potential users within a carbon management industrial park, treated water could be utilized by residents as drinking water or for agricultural use, depending on the quality of water available and the amount produced in excess of the carbon management park's needs. For water that is not purified to drinking water standards, underground storage to replenish regional aquifers would be an option. As groundwater, the water would be purified further within the aquifers, making it usable to consumers above the surface in the future.[156]

8.4.3.3 Co-location advantages

Kern's existing supply of clean energy from wind and solar—amounting to over half of California's total renewable energy supply—may be appealing for water treatment plants, which are energy-intensive operations.[157] Similarly, depending on the energy and heating needs of a facility, locating on-site in the carbon management park may be a good way to reuse heat or energy that would otherwise be lost from other processes, like converting biomass or steel production.

[156] Balke, Zhu (2008) Natural water purification and water management by artificial groundwater recharge. [6]
[157] Oviatt (July 15, 2022) Why is California punishing our alternative energy leader? [59]

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9. Carbon Dioxide Transport

TECHNOLOGY AT A GLANCE

- Industry is well established: CO_2 pipelines have been in operation in the U.S. for more than 50 years.[1]
- Pipelines are typically the most cost-effective option for overland transport of CO_2. Average levelized cost for pipeline transport is $10-20 per metric ton CO_2, but values can be higher or lower depending on length of pipeline, pipeline capacity, and siting logistics (terrain, securing rights-of-way, urbanization, etc.).
- CO_2 pipelines are typically constructed ~3 feet below the surface, so they do not create a visual or sound impact at the surface, and can co-locate with other land uses.
- Key advantages of this technology in Kern County: Would provide a cost-effective solution for transporting CO_2 between producer(s) in the region and sites that are permitted for injecting CO_2 underground for the purpose of permanent geologic storage.
- Key concerns for this technology in Kern County: Safety hazards related to leaks or ruptures of pipelines are exceedingly rare, but if a large rupture occurs, CO_2 can pose a health risk in the immediate vicinity. Siting pipelines in remote areas and following all federal and state regulations regarding monitoring and emergency response protocols in event of a leak are critical. Additionally, regulatory

[1] Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

frameworks for construction of CO_2 pipelines in California are not yet well-established.

9.1 Technology Summary

Between any potential carbon dioxide source or production and sequestration, safe transport is required. Pipelines, rail cars, trucks, and ships are all available forms of transport for carbon dioxide. In most cases, pipelines are the most cost-efficient choice,[2] especially for moving long or routine distances over land. These pipelines compress the carbon dioxide into a single phase (it can be gaseous, liquid, dense-phase or supercritical, depending on pipeline specifications) and then maintain controlled temperature and pressure conditions to safely deliver the carbon dioxide to its end use.[3] For the carbon management industrial park being examined here, that end use would be permanent geologic storage, taking place deep underground in nearby sequestration sites that have been appropriately permitted for such use, with the possible exception of some CO_2 utilized by other co-located industries (see Section 10).

9.1.1 Description: How It Works

Pipelines are the standard transportation choice for moving large volumes of carbon dioxide for extended distances (on the order of hundreds to thousands of miles) along overland routes,[4] especially when the sources and sinks are located at fixed points, as they are intended to be for proposed projects in Kern County. CO_2 pipelines are made from externally coated steel line pipe[5] and operate at high pressures to transport carbon dioxide between sources and sequestration sites.[6] There is also an external cathodic protection applied to prevent corrosion on the outside of the pipe.[7]

Because impure CO_2 streams (containing traces of NO_x, SO_x, O_2 or H_2O) can have corrosive effects on alloys and polymers,[8] non-steel or composite metal pipelines are not permissible to transport carbon dioxide under California law without an exemption approved by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA).[9] Pipelines are more complex than a single steel tube, though. They have a range of parts, including "valves, compressors, booster pumps, pig launchers and receivers, batching stations and instrumentation, metering stations, and Supervisory Control and Data Acquisition (SCADA)

[2] Roussanaly *et al.* (2021) Comparison of CO_2 shipping options. p. 20-22. [31]
[3] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 5-6. [19]
[4] Roussanaly *et al.* (2021) Comparison of CO_2 shipping options. p. 20-22. [31]
[5] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[6] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 7. [19]
[7] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[8] Paul *et al.* (2012) Selection of materials for high pressure CO2 transport. [23]
[9] PSD (June 8, 2022) Carbon Dioxide Pipeline FAQs. [28]

systems."[10] The number and complexity of these constituent parts is dependent on the pipeline's length, topography of the pipeline route, the need to adjust for pressure along-route pressure variability, and safety monitoring requirements.

Before pipeline transport, carbon dioxide must be dehydrated and not surpass certain oxygen or hydrogen sulfide (H_2S) concentrations to avoid internal corrosion of the pipeline or constituent parts, or cause stress cracking in the steel.[11] When necessary, there are coatings designed for the inside of pipelines in addition to the standard external coating.[12] Theoretically, corrosion-resistant pipeline could be designed that allowed for the transportation of carbon dioxide with higher concentrations of water or H_2S present.[13] However, given the high risks of H_2S to human health if a pipeline were to rupture or leak, purifying the carbon dioxide prior to transport is likely to remain a necessity.[14]



Figure 9.1. Installation of the Cortez Pipeline, a 30" diameter carbon dioxide pipeline located in New Mexico, during a maintenance upgrade conducted and documented by STATS Group. Image credit: STATS Group.

Finally, carbon dioxide needs to be condensed prior to transport, which requires specialized compressors.[15] Although similar compressors have been utilized in the natural gas industry, the unique properties of carbon dioxide require some design, material and sizing modifications.[16] Once compressed, carbon dioxide can be transported as a gas, liquid,

[10] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[11] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[12] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[13] Doctor *et al*. (2018) Transport of CO_2. p. 181. [6]
[14] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 4. [29]
[15] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[16] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

solid, dense phase substance, or supercritical fluid (Figure 9.2), depending on the pipeline length, requirements, and location.[17] The most common pipelines constructed in the United States are intended for liquid or dense phase carbon dioxide transport, with liquid being more common near population centers and dense phase more common in sparsely populated regions.[18] Although it can be transported in a variety of physical states, for a given pipeline, operators need to keep the carbon dioxide in the same state for all steps of transportation, as two-phase flows can interfere with compressors or other key equipment, increasing the odds of pipeline failure.[19] Optimizing CO_2 pipeline transport relies upon reducing impurities and controlling temperature and pressure to avoid unexpected pressure drops.[20] Since carbon dioxide exhibits nonlinear patterns of compressibility and density, pipeline operators typically develop point-by-point estimations of fluid properties along the pipeline's length using computational modeling.[21]

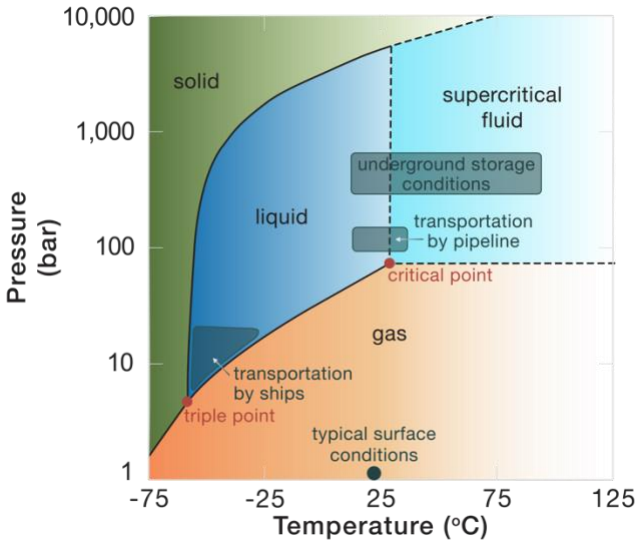

Figure 9.2. CO_2 is a gas at standard surface temperatures and pressures. When transported for permanent underground storage via pipeline, pipeline pressure and temperature is controlled to keep CO_2 in a denser phase. Dense phase liquids and supercritical fluids demonstrate properties of both a fluid and a gas - they can flow easily like a gas, but their high density allows for high flow capacity. Adapted from Paul et al. (2012).[22]

Commercial carbon dioxide pipelines, in which CO_2 is in a dense liquid phase or supercritical fluid phase for the entire journey, typically operate at pressures between 1,200 pounds per square inch gauge (psig) and 2,200 psig (83-152 bar), though some pipelines have higher maximum pressures in the 2,500 to 2,800 psig (172-193 bar) range.[23] These higher pressures allow the operator to minimize costs by increasing flow capacity for the

[17] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 5. [19]

[18] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 6. [19]

[19] Forbes *et al*. (2008) CCS Guidelines. p. 44. [12]

*For reference, a *two-phase flow* occurs when the carbon dioxide in the pipeline exists at two physical states simultaneously (ex. liquid and gas).

[20] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 5. [19]

[21] Forbes *et al*. (2008) CCS Guidelines. p. 45. [12]

[22] Paul *et al*. (2012) Selection of materials for high pressure CO2 transport. [23]

[23] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

pipeline.[24] To ensure that the CO_2 remains in a dense phase state along the entire pipeline length, pumps are used to recover any pressure losses that can occur due to friction of elevation changes.[25] The allowable temperature range for the pipeline will differ between projects, with the minimum set based upon the winter ground temperature and the maximum set by the compressor-station output temperature and any temperature limits imposed by the pipeline coating composition.[26] A standard temperature range for carbon dioxide pipeline operation falls between 55 and 110°F.[27]

Pressure and temperature are not the only factors which impact carbon dioxide behavior. For example, the fluid flow rate responds to changes in pipeline diameter—for larger pipeline diameters, the fluid flow rate decreases, which should result in fewer pressure drops within the pipeline.[28] Extensive modeling is required to determine the most efficient and cost-effective balance of pipeline size, number of compressors, and route design.[29]

In general, CO_2 pipelines will need to be purpose-built to handle carbon dioxide, especially when intended for transporting large quantities of carbon dioxide or covering long distances. Pipelines designed to transport natural gas, for example, are in a different class according to the American National Standards Institute (ANSI)—they are not built to the same maximum pressure rating necessary for transporting carbon dioxide.[30] Some pipelines built for other energy purposes have been retooled to transport carbon dioxide at lower flow rates and/or for distances shorter than 100 miles.[31] Federal requirements for pipeline construction are set by PHMSA and are covered at greater length in Section 9.1.4.

9.1.2 State of Development

Carbon dioxide pipelines already constitute a small but growing industry. The United States is a global leader in the area, having established some of the first carbon pipelines in the 1970s.[32] As of 2015, the U.S. had over 4,400 miles of active carbon dioxide pipelines, with that figure growing every year.[33]

The vast majority of carbon dioxide pipeline projects support enhanced oil recovery (EOR) in Texas and the American West; the number currently deployed for sequestration is

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[24] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[25] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[26] Forbes *et al*. (2008) CCS Guidelines. p. 44. [12]
[27] Forbes *et al*. (2008) CCS Guidelines. p. 44. [12]
[28] Forbes *et al*. (2008) CCS Guidelines. p. 45. [12]
[29] Forbes *et al*. (2008) CCS Guidelines. p. 45. [12]
[30] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[31] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[32] Doctor *et al*. (2018) Transport of CO_2. p. 182. [6]
[33] Peletiri *et a*l. (2018) CO_2 Pipeline Design. p. 3. [24]
** This figure has been converted to miles; in Peletiri et al., this figure is given as 7200 kilometers.*

smaller.[34] However, because the technical and regulatory requirements for safely and efficiently moving carbon dioxide are the same regardless of end use, pipelines developed for EOR can be used as a case study for new pipeline systems being constructed for permanent CO_2 sequestration.

9.1.2.1 Example projects

Pipeline companies: Kinder Morgan, Houston, TX and Trimeric, Buda, TX

Installation of pipelines are typically performed by third parties, rather than carbon management companies, sequestration companies, or even pipeline operators.[35] Kinder Morgan is the largest transporter of carbon dioxide in North America, although they also operate many of their pipeline systems. They have capacity to transport as much as 1.5 billion cubic feet (>77,000 metric tons) of CO_2 daily.[36] Although their operations are mostly sourcing CO_2 from natural source fields and delivering it to oil and gas operations for the purpose of enhanced oil recovery, the logistics of pipeline transport are the same for CO_2 sourced from capture industries and transported for the purpose of injection and permanent storage. Kinder Morgan's largest pipeline is 500 miles long and spans from Colorado to Texas.

Trimeric is another example of a third party company that could support pipeline development. They design CO_2 purification and compression facilities, and their company has served as technical experts and design engineers on a wide range of research programs supported by the U.S. Department of Energy, and for carbon dioxide pipeline projects in the United States.[37] Their process engineers have worked on all stages of the CO_2 transportation and storage process, including dehydration, cooling, pumping, liquefaction, compression, purification, and sequestration pumping.[38]

South West Hub Project, Western Australia

The South West Hub project, which broke ground in 2012, is designed to connect point source carbon emissions in industrial centers south of Perth to sequestration sites underneath the Lesueur sandstone formation in saline aquifers.[39] Publicly available video and conference papers largely emphasize the research conducted on validating Lesueur's feasibility as a sequestration site—the pipeline infrastructure needed for the project is less emphasized.[40] However, its overall model matches well with Kern's potential projects, where a number of known carbon producing or capturing sites within a carbon

[34] Jones, Lawson (2022) Carbon Capture and Sequestration (CCS) in the United States. p. 8. [16]
[35] George Peridas (LLNL) personal communication, July 6, 2022.
[36] Kinder Morgan (no date) CO_2 operations overview. [18]
[37] Trimeric (no date) CO_2 Capabilities. [38]
[38] Trimeric (no date) CO_2 Capabilities. [38]
[39] Sharma, Van Gent (2018) The Australian South West Hub Project. p. 2. [32]
[40] Sharma, Van Gent (2018) The Australian South West Hub Project. p. 12-14. [32]

management park will be directly connected with a sequestration site using the same pipeline infrastructure.

The South West Hub also presents an interesting form of management, as the project originated as a collaboration between the Western Australia Department of Mines, Industry Regulation and Safety, acting as the project lead, and industrial producers in the energy and chemicals space.[41] This project may be valuable as a type example for private-public partnership in carbon management projects.

9.1.3 Operational Needs

9.1.3.1 Land use requirement

Most carbon dioxide pipelines are relatively small, ranging from 12-28 inches in diameter,[42] and operate similarly to pipelines used for decades in the oil and natural gas industries, though they often operate at higher pressures.[43] On land, pipelines are typically buried 3 to 4 feet beneath ground level—thus at surface level, the physical footprint of the pipeline is invisible, except at metering or pumping stations.[44]

The siting of a pipeline is determined by state authorities; federal authorities are only implicated if a project crosses federal lands, uses federal funding, or if a project sought federal intervention to grant eminent domain.[45] Pipeline operators who operate as public utilities or common carriers may have greater flexibility over their siting options, as state and federal authorities can grant the powers of eminent domain to these projects to acquire land,[46] and because of existing rights-of-way utilities possess for other pipeline systems, like natural gas.[47] In lengthy pipeline projects, it is near impossible to site a project without exercising eminent domain.[48]

9.1.3.2 Energy requirements

Condensing the carbon dioxide gas into a dense state for transport requires a large energy input to reach appropriate pressurization, ranging from 90-120 kWh per metric ton of CO_2,[49] about the same amount of energy needed to power a home for 3-4 days.[50] CO_2 compressors can be fueled by "electricity, natural gas or diesel engines, steam, or a combination of

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[41] Department of Mines, Industry Regulation, and Safety (no date) South West Hub Project. [5]

[42] Molag, Dam (2011) Modelling accidental CO_2 pipeline release. p. 2301. [21]

[43] EEIA (no date) Key Excerpts on CO2 Transport. p. 3-4. [7]

[44] Forbes *et al.* (2008) CCS Guidelines. p. 46. [12]

[45] DOE (2017) Siting and Regulating Carbon Capture. p. 31. [4]

[46] Forbes *et al.* (2008) CCS Guidelines. p. 49. [12]

[47] Industry representative, personal communication, February 10, 2023.

[48] Fish, Martin (2010) California Carbon Capture and Storage Review Panel. p. 2. [11]

[49] Jackson, Brodal (2018) A comparison of the energy consumption for CO_2 compression process alternatives. p. 1. [15]

[50] EIA (October 12, 2022) How much electricity does an American home use? [8]

these,"[51] and could be the responsibility of either the pipeline operator or the capturing industry. For industries like DAC and steel, compression represents between 25% and <1% of the energy needs for CO_2 capture.[52]

Maintaining constant pressure and flow specifications along the length of the pipeline also requires energy input (using compression or pumps), although it is a small fraction of the energy needed for compression, and can be minimized through intentional route designs that take advantage of gravity to maintain flow through the pipeline.[53,54] Choosing between compressors or pumps to maintain constant pressure conditions within the pipeline depends on the intended physical state for transport—compressors are needed for gas, whereas pumps can be used for liquid or dense phase carbon dioxide.[55,56] Given the park's goal of carbon management, using low-carbon energy sources to power initial CO_2 compression and any additional pumps or compressors along the length of the pipeline should be a priority.

9.1.3.3 Other operational needs

Waste disposal requirements

There should be no waste disposal requirements for regular operation and maintenance of CO_2 pipelines, unless the pipeline or monitoring equipment requires replacement. Then, the old equipment would need to be disposed of or recycled accordingly.

The carbon dioxide itself often needs to be dehydrated and treated to reach a certain purity percentage (generally 95%) for efficient and safe transport, so preparing CO_2 for transport will likely produce some byproducts to dispose or reuse, like water and hydrogen sulfide (H_2S).[57] It is important to remove water from CO_2 streams because it can react with carbon dioxide to form carbonic acid (H_2CO_3) in the pipeline, which can cause corrosion. Similarly, hydrogen sulfide can interact with any remaining water to form sulfuric acid, another corrosive compound. Additionally, because H_2S is toxic to humans at any concentration exceeding 200 parts per million (ppm), for the safety of any communities located near a CO_2 pipeline, both water and H_2S should be restricted to reduce the likelihood and resulting risk of a pipeline rupture.[58] Water could be filtered and reused onsite in the industrial park (see Section 8). The most common disposal method for hydrogen sulfide is injection into deep geologic storage, as surface storage of sulfur generally constitutes a liability for the

[51] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[52] Appendix D
[53] Suter *et al.* (2022) Carbon Capture, Transport, & Storage. p. 21. [35]
[54] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[55] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 6. [19]
[56] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 5. [19]
[57] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 4. [29]
[58] Forbes *et al.* (2008) CCS Guidelines. p. 43. [12]

producer.[59] However, this purification process would likely be the responsibility of a different party—i.e. the company capturing or generating carbon dioxide within the carbon management park—rather than the pipeline operator, and for many types of CO_2 capture explored in this report (BiCRS, DAC, oxy-fuel combustion), H_2S is not known to be a significant contaminant.

Warehousing requirements

There are no inherent warehousing requirements for transporting carbon dioxide, but the value of housing some carbon outside of the pipeline to maintain a constant supply, and therefore pressure, is likely advantageous.

9.2 Societal Impacts

9.2.1 Job creation potential

9.2.1.1 Number and types of jobs

Monitoring and upkeep of a local pipeline network will likely create between 8-20 high-wage permanent jobs.[60] CCS initiatives are also projected to generate indirect employment, as new pipeline manufacturing projects and administrative staff will be necessary in addition to jobs created on-site.[61] These indirect jobs may not be locally concentrated, however.

9.2.1.2 Training pipelines

Jobs in CO_2 transport require a mix of skill levels but overlap considerably with skills in other pipeline management or engineering jobs (like those in the oil and gas industry) and other heavy industries.[62]

9.2.2 Quality of Life

9.2.2.1 Location

Unlike transport via rail, truck, or ship, there is no noise or light pollution from a pipeline that would disturb nearby communities. Additionally, because CO_2 pipelines are buried, they produce no significant visual disturbances to the landscape. The primary issue relevant to locational justice is both the real and perceived risks of a pipeline leak or rupture.

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[59] Forbes *et al*. (2008) CCS Guidelines. p. 43. [12]

[60] Carbon Capture Coalition (no date) Jobs and Project Development Status. p. 4. [3]

[61] Townsend *et al*. (2020) Thought Leadership. p. 15. [37]

[62] Carbon Capture Coalition (no date) Jobs and Project Development Status. p. 4. [3]

We explore this issue here, first in the context of general public's attitudes towards pipeline safety, and then with a focus on the actual risks associated with transporting CO_2.

Pipelines related to the energy sector have a long history of generating locational justice concerns, primarily for the environmental, health and safety hazards that they can bring. Some key examples from the oil and gas sector where locational justice has become a widespread public concern because of risk to local ecosystems, water resources and safety include the Dakota Access Pipeline,[63] Enbridge's Line 3,[64] and the Coastal GasLink project in Canada.[65] Given the historically large public debates around these major pipeline projects, the idea of placing any new pipelines in or near a community could drive resistance among local residents and environmental groups, even though piping carbon dioxide has a different purpose, and carries different risks (and safety mitigation measures) than piping oil or natural gas. For example, regional chapters of environmental organizations are already organizing against the construction of new carbon dioxide pipelines in other parts of the country. The Iowa chapter of the Sierra Club has been resisting three proposed pipelines primarily because the carbon transported has an unclear end-of-life—there has been varied messaging about whether it will be sequestered or used for EOR.[66]

Addressing the general public's hesitancy or resistance to development of pipeline networks requires open communication and education about the real hazards associated with CO_2 pipelines, how they differ from other types of pipelines, what mitigation strategies ensure low safety risks associated with these kinds of pipeline, and the current and developing regulatory frameworks that are designed to assess and monitor pipeline safety standards.

Safety risks associated with CO_2 pipelines

Unlike natural gas and other fossil fuels, carbon dioxide is not flammable or explosive, and if leaked in small quantities, will dissipate into the air without creating a hazardous situation.[67] But, in large quantities (over 40,000 ppm, or comprising more than 4% of inhaled air) it acts as an asphyxiant,[68] and if released quickly from the pressurized conditions of a dense phase or supercritical phase pipeline, can cause flash freezing - producing temperatures immediately around a pipeline rupture that are well below freezing, which can cause brittle failure of the remaining pipeline and exacerbate further

[63] Environmental & Energy Law Program (no date) The Dakota Access Pipeline (DAPL). [9]
[64] MPR News (October 1, 2021) The Line 3 oil pipeline project: What you need to know. [20]
[65] Simmons (November 8, 2022) 'You will be arrested'. [34]
[66] Sierra Club Iowa Chapter (no date) Carbon Dioxide Pipelines - Say NO to CO2 pipeline projects. [33]
[67] Thomley, Kammer (2023) CO_2 pipeline safety. [36]
[68] FSIS (2020) Carbon dioxide health hazard information sheet. [13]

rupturing.[69] This means that small leaks present little health or safety risk,[70] and in fact, over the 50 years that CO_2 pipelines have operated in the U.S. there has been only one reported injury and no deaths related to pipeline operation.[71,72] A significant pipeline rupture, however, could pose a safety hazard. If a breach were to occur, carbon dioxide could be released into the atmosphere in high concentrations; because CO_2 is more dense than ambient air, rather than dissipating as it is released, it can concentrate in low-lying areas, risking the health of any residents in the area.[73]

Although leaks are uncommon, a significant event did occur near a population center in 2020. That year, a carbon dioxide pipeline ruptured near Satartia, Mississippi, sending 49 residents to the hospital. Residents reported seeing an eerie green cloud that left them "nauseated and dazed."[74] Carbon dioxide itself is odorless and colorless—the green shade of the gas reported in Satartia is thought to be due to high amounts of hydrogen sulfide in the supply, which likely worsened the health impacts on residents.[75] The Satartia rupture is thought to be the first outdoor CO_2 mass exposure event resulting from a pipeline failure globally.[76] However, as pipeline mileage increases in the future, potential for these types of accidents could grow. The federal Pipeline and Hazardous Materials Safety Administration, or PHMSA (responsible for pipeline safety and monitoring), has responded to the Satartia leak by promising additional regulations for CO_2 pipeline safety, with a focus on emergency preparedness.[77]

Mitigation options for CO_2 pipelines

To reduce public concerns about pipelines in general, other hazardous materials transported via pipeline – like natural gas – are typically odorized, so residents can identify a gas leak and evacuate. In theory, the same practice is possible for carbon dioxide moved through pipelines, although there are currently no requirements in place to odorize carbon dioxide prior to transport for the purpose of public safety.[78] There are some promising contenders for odorants, like disulfides or thioethers, although they increase pipeline operation costs and dilute the purity of the carbon dioxide stream.[79]

Compared to other types of pipelines, carbon dioxide pipelines are more susceptible to longitudinal running fractures, which can be a brittle or ductile weakness in the pipeline,

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[69] Vree *et al.* (2015) Rapid depressurization of a CO_2 pipeline. [39]
[70] Forbes *et al.* (2008) CCS Guidelines. p. 48-49. [12]
[71] Thomley, Kammer (2023) CO_2 pipeline safety. [36]
[72] Doctor *et al.* (2018) Transport of CO_2. p. 182. [6]
[73] Doctor *et al.* (2018) Transport of CO_2. p. 188. [6]
[74] Zegart (August 26, 2021) Gassing Satartia. [40]
[75] Zegart (August 26, 2021) Gassing Satartia. [40]
[76] Zegart (August 26, 2021) Gassing Satartia. [40]
[77] PHMSA (May 26, 2022) New Safety Measures. [27]
[78] Doctor *et al.* (2018) Transport of CO_2. p. 190. [6]
[79] Forbes *et al.* (2008) CCS Guidelines. p. 48. [12]

causing it to "unzip" several hundred meters.[80] To mitigate the severity of a potential rupture, propagation of these kinds of fractures can be inhibited with the placement of fracture arrestors along the pipeline. The arrestors are typically placed every 500 meters (545 yards) along the length of the pipeline, minimizing the distance a fracture can spread.[81,82]

Additionally, a variety of monitoring fixtures, both internal and external, can be used to ensure the pipeline is secure, or provide warning for emergency response if a rupture occurs. Meters can be placed along the pipeline to conduct computational pipeline monitoring (CPM) leak-detection, though this is not yet a regulatory requirement as it can be technically difficult to implement.[83] Other types of monitoring—including pressure point analysis or aerial and visual surveys—can also be used to identify potential leaks.[84]

Finally, the most effective safety measure for CO_2 pipelines is siting them far from urban or residential areas. Because CO_2 settles rather than dissipates, any impact from a pipeline leak will occur in the vicinity of the pipeline, although determination of safe distances from pipelines that experience an accidental rupture remains ongoing.[85]

Regulatory authority and monitoring

The Occupational Health and Safety Administration (OSHA) imposes safety regulations that impact carbon dioxide pipeline operators, including workplace safety laws that ban carbon dioxide exposure exceeding 5,000 ppm.[86] Requirements for pipeline construction and management have also been standardized by PHMSA within the U.S. Department of Transportation,[87] and operators that fail to meet standards of environmental safety can be issued with notices and fined.[88]

In response to the Satartia pipeline rupture, PHMSA initiated new rulemaking processes to strengthen regulations on carbon dioxide pipeline safety, including updating standards on emergency preparations and response, that may impose new requirements for the safe construction, maintenance, and operation of future pipelines.[89] As of the writing of this report, PHMSA has not released any new regulations determined from this rulemaking process. Currently, PHMSA regulations only apply to pipelines transporting supercritical carbon dioxide at a minimum of 90% purity. Projects where the carbon dioxide is in a liquid

[80] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 4. [19]
[81] Doctor et al. (2018) Transport of CO_2. p. 184. [6]
[82] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[83] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[84] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[85] Molag, Dam (2011) Modelling accidental CO_2 pipeline release. p. 2301. [21]
[86] Forbes *et al*. (2008) CCS Guidelines. p. 47. [12]
[87] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[88] PHMSA (May 26, 2022) New Safety Measures. [27]
[89] PHMSA (May 26, 2022) New Safety Measures. [27]

or gas state, as well as lower-purity pipelines, remain less regulated.[90] Furthermore, PHMSA's current guidelines do not regulate maximum concentrations of water or hydrogen sulfide contaminants in CO_2,[91] despite their presence making pipelines more susceptible to corrosion and failure, and the added health risk of H_2S if a leak occurs.

In the state of California, the Pipeline Safety Division (PSD) of the Office of State Fire Marshal regulates supercritical and hazardous liquid pipelines (including CO_2 pipelines) following the 49 Code of Federal Regulation (CFR), Part 195 and the Elder California Pipeline Safety of 1981.[92] However, in 2022, the California state legislature passed law SB-905, stating that no new CO_2 pipelines can be built until the federal government updates its CO_2 pipeline policies with stronger safety regulations, or until state lawmakers can develop their own pipeline standards, based on recommendations from the California Natural Resources Agency (CNRA).[93] To this end, CNRA submitted a proposal to the California legislature in March 2023 for establishing a state framework and standards for intrastate CO_2 pipelines, which is now being considered.[94] Such a framework is critical not only for ensuring the safe handling and transportation of CO_2 for permanent sequestration, but also for ensuring public acceptance of nascent carbon management industries.

9.2.2.2 Multi-use potential

Since onshore pipelines are typically beneath the surface once installed, the land surface above a pipeline can still be used for a variety of purposes. Some forms of agriculture that require ample underground space for plant roots may be inappropriate, but myriad other applications should be sustainable on overlapping land, while keeping in mind the advantage of siting CO_2 far from human activity for safety reasons.

9.3 Environmental Impacts

9.3.1 Water requirements

No references were found identifying any water requirements for the operation of CO_2 pipelines. Given the technology, it is unlikely that water is necessary for operation beyond that generally required for construction.

[90] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 2. [29]
[91] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 5. [29]
[92] OSFM (no date) Carbon Dioxide Pipeline. [22]
[93] Phillis, Ronayne (February 23, 2023) Pipeline debate at center of California carbon capture plans. [25]
[94] CNRA (2023) Proposal for CO_2 pipeline state policy framework. [2]

9.3.2 Other potential impacts

California's Central Valley is naturally susceptible to seismic activity, and small earthquakes in the region are common and larger-scale seismic events are possible. This environmental stressor will exacerbate external pressure on any pipelines constructed and will need to be accounted for in construction and operational monitoring plans, as is done for all pipeline systems in the region.

9.4 Economic Impacts

9.4.1 Business Model

Business models for the operation of carbon dioxide pipelines can be flexible from project to project, based upon the operator's structure. For example, the owner or operator of the transport infrastructure could charge either CO_2 suppliers or CO_2 purchasers a tariff for using the pipeline network.[95] Given the proposed setup of a carbon management park as a putative CO_2 source and a sequestration well operator as a CO_2 "purchaser," both avenues of tariffs seem possible—either charging a tariff to members of the park to sequester their carbon dioxide off-site, or a transport tariff being covered as part of a carbon offset payment or other arrangement where an external company would act as a carbon purchaser.

Under either scheme, the pipeline operator can choose between different tariff calculation models. The two most common options are charging based upon the distance moved, by summing the specific costs per segment of pipeline traveled, or determining a system average cost to charge all users of the network (i.e. a flat rate per ton CO_2).[96] Based upon the current end-to-end structure of the pipeline that would be built for this project (modeled as a single business park producing CO_2 and supplying it to a single site for sequestration), a system average cost and total distance traveled would likely come out to near-identical tariffs. However, if the carbon management park model proves successful, there could be multiple parks in different locations, sharing a single pipeline system, in which case a preferred tariff model would have to be determined across parties.

The time horizon for profitability of a CO_2 pipeline network will depend upon the tariff rate and the total capital cost—without external incentives, it would likely take a few years before tariffs offset the millions spent on permitting, construction, and monitoring.

[95] Abramson *et al.* (2020) Transport Infrastructure for CCS. p. 31. [1]

[96] Abramson *et al.* (2020) Transport Infrastructure for CCS. p. 31. [1]

9.4.2 Business Costs

9.4.2.1 Cost to build (upfront costs)

Upfront costs are a substantial hurdle to constructing CO_2 pipelines. In general, costs depend on the terrain, environment, and existing regulations around right-of-way.[97] Shorter pipelines requiring few bends and avoiding existing features in the built environment constitute the cheapest conditions for pipeline construction,[98] as does avoiding heavily built areas like cities and suburbs. The Greencore Pipeline in Montana, which spans private ranches as well as state and federal public lands was built for $68,635 per diameter inch mile; meanwhile, the Webster Pipeline built in the industrial and suburban districts south of Houston, Texas cost $199,176 per diameter inch mile to construct.[99] According to a 2018 IPCC report, population density and terrain are the largest determinants of cost: "Onshore pipeline costs may increase by 50 to 100% or more when the pipeline route is congested and heavily populated. Costs also increase in mountains, in nature reserve areas, in areas with obstacles such as rivers and freeways, and in heavily urbanized areas because of accessibility to construction and additional required safety measures."[100] Pipeline right-of-ways can amount to 4%-25% of the overall pipeline construction costs, with estimates at the lower end of this range in rural areas and higher end of this range in suburban or urban areas.[101]

In 2020, the Great Plains Institute developed a techno-economic analysis of building national CO_2 transport infrastructure to support near- and medium-term carbon capture and storage capacity at a national scale. They modeled how much of a variety of pipelines (distinguished by diameter, and therefore CO_2 flow rate capacity) would be necessary to capture CO_2 from the most economically feasible point sources of carbon dioxide existing today, and determined capital, labor and operation and maintenance costs of pipeline infrastructure as a function of pipe diameter and length. A summary of their analysis is detailed in Table 9.1, for the purpose of illustrating a few key points.

First, reducing the pipeline's length by siting the carbon source (like a carbon management park) and sequestration well projects close together, drastically lowers all costs (capital, labor and maintenance) for the pipeline operator.[102] Second, while smaller pipe diameters do result in lower costs per mile, due to lower material costs, large diameter pipelines are ultimately more cost efficient, as long as they are operating at capacity. The more CO_2 that is transported through the pipeline systems, the lower the effective cost per ton of CO_2.[103] The calculated costs of CO_2 transport per ton-mile (how much it costs to move one ton of

[97] Doctor *et al*. (2018) Transport of CO_2. p. 189-190. [6]
[98] Peletiri *et al*. (2018) CO_2 Pipeline Design. p. 4. [24]
[99] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[100] Doctor *et al*. (2018) Transport of CO_2. p. 190. [6]
[101] Peletiri *et a*l. (2018) CO_2 Pipeline Design. p. 4. [24]
[102] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 23. [1]
[103] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 29. [1]

CO_2 one mile) is lower than most summative estimates of the levelized cost of CO_2 transport (usually ~ $10-20 per ton of CO_2 from source to sink, see below), because most point sources of carbon would be unable to provide enough CO_2 for the pipeline to operate at capacity. For example, the calculations in Table 9.1 indicate that a 100 mile, 24" pipeline operating at full capacity would cost $1 per ton of CO_2 transported. However, that requires that the pipeline is transporting 25 million tons of CO_2 annually. The largest facility capturing CO_2 for the purpose of sequestration (not EOR) in the US today is the Illinois Industrial ethanol plant (operated by Archer Daniels Midland Co.),[104] which is capturing CO_2 at a rate of about 500,000 tons annually.[105] At that rate, it would cost over $50 per ton of CO_2 to pipe it for 100 miles in a 24" pipeline, and $15 per ton of CO_2 in an 8" pipeline. Such sensitivity to CO_2 capacity demonstrates the value of developing concentrated sources for large amounts of CO_2, such as could be achieved by co-locating CO_2-emitting industries and/or carbon removal industries like DAC or BiCRS/BECCS in a single business park.

Table 9.1. Capital and operating costs of CO_2 pipelines as a function of pipe diameter and segment length[106]

Pipe diameter	Segment capacity	Segment length	Capital costs	Labor costs	Annual O&M costs	Cost per Mile[a]	Cost per tCO_2-mile[b]
(inches)	($MtCO_2$/yr)	(miles)	(million USD)			(million USD)	(US cents)
8"	<5	8,560	$3,436	$3,672	$72.6	$1.1	1.8 ¢
12"	3-7	5,834	$4,195	$2.928	$49.5	$1.5	1.6 ¢
16"	6-11	2,675	$2,888	$1,777	$22.7	$2.0	1.5 ¢
20"	10-16	1,790	$2,704	$1,498	$15.2	$2.6	1.4 ¢
24"	15-25	59	$99	$63	$0.5	$3.0	1.0 ¢
30"	24-33	16	$34	$23	$0.1	$3.8	0.97 ¢

a. The sum of capital, labor and annual O&M costs (assuming a 30 year lifespan), divided by segment length.
b. The sum of labor and annual O&M costs normalized to maximum segment capacity and pipeline lifespan with the levelized capital cost, divided by the segment length. (Modeled for a 30 year lifespan and capital recovery factor of 12.5%.)

Another report which performed cost-benefit analyses of nation-wide decarbonization plans - Princeton's Net-Zero America report - calculated regionally specific building costs for CO_2 pipeline networks. To build a main CO_2 pipeline fully across the region of southern California, the report estimates a cost of $1.2 billion for 239 miles[107] of a 36" diameter

[104] Rassool *et al.* (2021) CCS in the circular carbon economy. [30]
[105] EPA (no date) Archer Daniels Midland Co. Emissions Data. [10]
[106] Data from Abramson et al. (2020) Transport Infrastructure for CCS. p. 23, 29. [1]
[107] Email correspondence with Chris Greig and Andrew Pascale, January 24-25, 2023.

pipeline, or $139,470 per diameter inch mile.[108,109] The cost per user (whether CO_2 supplier or buyer) for this pipeline could be reduced by incorporating other carbon dioxide pipelines into this system, creating a regional network in southern California to connect carbon producers or capture sites to sequestration sites in Kern County. The best layout for a hypothetical hub system to connect multiple sources with a single sink—whether it be "tree with branches" or "hub and spoke" (Figure 9.3)—would depend upon angles the pipelines from the sources are placed at relative to each other.[110]

Innovative financing could also reduce the overall capital needed to sustain regional scale pipeline networks. Financing options, including private activity bonds (PAB) or master limited partnerships (MLP), should be explored by any potential operator to reduce the direct capital required to start up operations.[111]

In addition to construction costs, it is also critical to consider the time needed for an onshore pipeline to go from development to deployment – estimated at four to six years.[112] Opening of a pipeline this decade, for instance, would require setting an ambitious project timeline now to be able to clear all the regulatory requirements needed, complete construction, and pass safety and environmental quality checks prior to deployment.

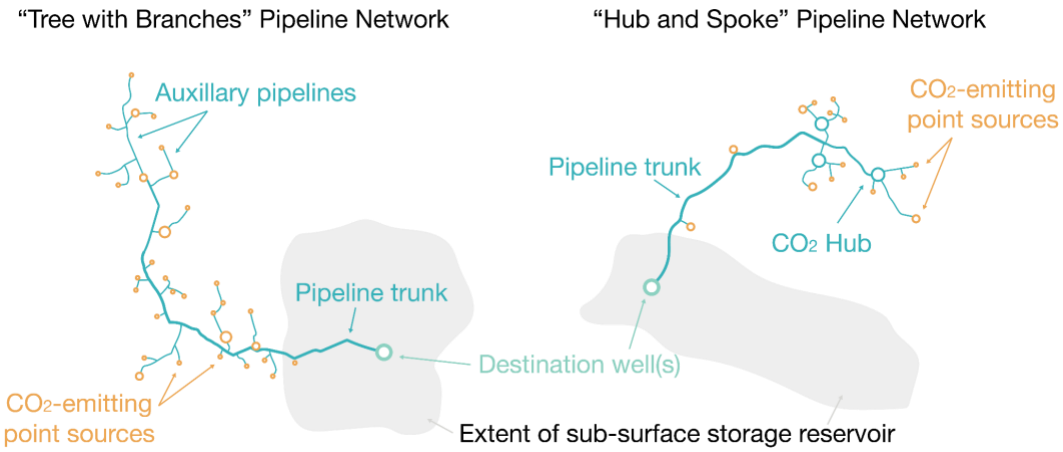

Figure 9.3. CO_2 transport pipelines are most cost-effective when built as a network, connecting multiple CO_2 sources to an underground storage site. The two most common pipeline network designs are a 'tree with branches' model, which has a single main line with many small, single-input offshoots, and a 'hub and spoke' model, where CO_2 sourced from several small facilities ('spokes') are combined in a 'hub' before being joined to a main pipeline.

[108] Greig, Pascale, Wagner (2021) Net-Zero America Annex I. p. 25-26. [14]

[109] The conversion to diameter inch miles was possible due to additional information provided by the primary authors on Net-Zero America Annex I via email on January 25, 2023.

[110] Peletiri *et al*. (2018) CO_2 Pipeline Design. p. 6. [24]

[111] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 29. [1]

[112] ZEP (no date) The Costs of CO2 Transport. [41]

Finally, it is worth noting that the expense of building and maintaining a CO_2 pipeline is not typically a significant portion of the cost of carbon capture and storage projects. Up to 90% of carbon management project costs come from the capture process itself, and the energy needed for CO_2 compression.[113] Transport is a relatively small portion of the overall cost of capturing CO_2 for the purpose of permanent underground storage.

9.4.2.2 Operational costs

Operation and management (O&M) costs of a pipeline vary by industry, as they are dependent on the required maintenance and monitoring technology. One estimate of O&M and labor costs – from the Great Plains Institute[114] – is given in Table 9.1. Such costs are often estimated to be between 4 and 7% of the original capital cost.[115] In scenarios explored by Princeton's Net-Zero America study, which looked at potential paths to get to net-zero nationwide by 2050, the estimated average cost to move a ton of CO_2 – considering capital as well as O&M costs – would range between $10-20, depending on the location.[116] For long distances or CO_2 derived from low-capacity sources (see Section 9.4.2.1), the cost would increase, but approximately 90% of carbon dioxide moved throughout this hypothetical national network could be moved for under $20/ton CO_2.[117]

As discussed above, there are additional safety considerations for an operator with locating pipelines near population centers, thus siting pipelines too close to communities can result in both higher upfront and heavier monitoring costs for operators.

9.4.3 Regional benefits

Any carbon management business park of the form considered in this study would likely find pipelines to be the most cost-effective form of CO_2 transport to locations suited for permanent underground storage. Additionally, regions like Kern County, where there is suitable geology and growing industry interest in developing CO_2 sequestration sites (as of the writing of this report, three companies have applied for permits from the EPA to construct Class VI wells for the purpose of CO_2 sequestration), development of a pipeline network is crucial. If a large carbon management park was developed within Kern County to act as the primary CO_2 source, pipeline distances could be exceptionally short by industry terms, requiring tens to a few hundred miles of pipeline, rather than hundreds to thousands (the county is 180 miles across at its widest point). Not only would short distances reduce the costs of construction and maintenance, but all of construction, monitoring, and taxation would fall under the same set of state and county regulations for the entire length of the pipeline, reducing regulatory or bureaucratic hurdles.

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[113] Peletiri *et al*. (2018) CO_2 Pipeline Design. p. 2. [24]

[114] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 23. [1]

[115] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. A6. [1]

[116] Greig, Pascale, Wagner (2021) Net-Zero America Annex I. p. 34. [14]

[117] Greig, Pascale, Wagner (2021) Net-Zero America Annex I. p. 33-34. [14]

9.4.3.1 Proximate consumers

As Kern County is already pursuing permits for a sequestration site and investigating the feasibility of a carbon management park, transport of carbon dioxide will be necessary to link these two distinct projects to fulfill their potential.

When applying for LCFS (Low Carbon Fuel Standard) or CARB (California Air Resources Board offset) credits, there will need to be a new legal arrangement drawn up between the supplier, the sequesterer, and the transporter about who will claim the credits and how they will be divided amongst parties within this relationship.[118]

9.4.3.2 Co-location advantages

The primary advantage of a carbon management park that can act as a 'hub' is particularly evident when dealing with transport. Pipelines are time-consuming to design and permit, expensive to safely build and monitor, and require meeting a range of regulations and environmental quality checks. Any company developing a pipeline project would want to ensure that there would be steady interest in carbon dioxide transport; the occupants of a carbon management park, who are either generating or capturing carbon dioxide, would be of substantial appeal because they would constitute a reliable source of carbon to transport. As for members of the industrial park, having another player provide the pipeline infrastructure can reduce overall costs and risks of their operation, as they can focus on the carbon capture and purification, but leave the transportation and sequestration portion to other companies. Thus co-locating has the appeal of distributing risk across a set of players.

9.4.3.3 Other

Although technically tricky to accomplish due to the differences between the material and safety requirements of oil pipelines versus carbon dioxide pipelines, there are operational projects that have retrofitted existing oil pipelines to transport carbon dioxide. In the Netherlands, the OCAP pipeline has been transporting carbon dioxide since 2004 using a retrofitted oil pipeline that had been out of commission for 25 years.[119] The right pipeline operator may be able to reuse existing oil and natural gas pipelines[120] in Kern County by upgrading them to the necessary specifications to safely move carbon dioxide, which could be less costly than constructing a new pipeline and reduce the burdens of permitting and obtaining right-of-ways. If such re-purposing is deemed unsafe for CO_2 transport be the ongoing assessment of state safety regulations,[121] it is worth investigating whether existing right-of-ways for these pipeline systems could be used for CO_2 transport as well, minimizing the time and expense of identifying and purchasing rights to new right-of-ways.

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[118] Internal conversation with DOE Technical Team, August 29, 2022.

[119] Kenton, Silton (no date) Repurposing Natural Gas Lines. [17]

[120] PHMSA (no date) National Pipeline Mapping System. [26]

[121] CNRA (2023) Proposal for CO_2 pipeline state policy framework. [2]

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10. Carbon Dioxide Utilizing Industries

TECHNOLOGY AT A GLANCE

- There are a diverse suite of industries that can incorporate CO_2 into their production process or their final products. Most industries are in pilot or early demonstration phases of CO_2 integration. The exception is the food and beverage industry, which uses about 15 million tons of CO_2 annually.[1]
- The most promising industries for scaling up CO_2 utilization to the million-ton scale are in cement and concrete manufacturing, building materials manufacturing, synthetic carbon fuels, and plastics, polymers and other chemical manufacturing.
- Significant investment in research and development (± policy incentives) will be needed to bring costs down relative to competing, non-CO_2 utilizing products.
- Key advantages of these technologies to Kern County: co-location within a carbon management industrial park and near abundant clean solar and wind power will reduce operational costs and make CO_2-utilizing products more economically viable.
- Key concerns for this technology in Kern County: each CO_2-utilizing industry has its own suite of impacts and benefits, which warrant further investigation. Additionally, most CO_2-utilizing industries do not permanently store CO_2; it is (re)-released to the atmosphere on the order of months to years. Case by case life cycle analyses of the carbon removal benefit of a CO_2-utilizing practice will be necessary to understand whether it provides any climate benefit, and whether it is eligible for state or federal carbon removal incentives.

[1] Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

10.1 Technology Summary

Interest from governments,[2] companies[3] and scientists[4] around the growth of the carbon management industry is primarily for the purpose of carbon dioxide removal: pulling CO_2 from the atmosphere (through processes like DAC or BiCRS) or preventing CO_2 emissions from point sources (like steel mills), and storing that CO_2 permanently and safely underground to reduce the impacts and mitigate the costs of climate change. However, until the U.S. Inflation Reduction Act that passed in 2022 increased financial incentives for carbon sequestration, carbon capture for the purpose of permanent storage was, for the most part, not financially feasible.[5] As an alternative, several researchers and companies have explored options for using CO_2 in products, in ways that would either remove it from the atmosphere on timescales of decades to centuries, or replace products or feedstocks that would otherwise produce more greenhouse gas emissions.[6]

Even with the increased cost effectiveness of carbon management for the purpose of removal and storage, the research and innovations of recent decades in CO_2 utilization has seeded or expanded potential commercial markets for CO_2 that could complement sequestration programs, and those markets could grow in scale to using as much as tens of millions of tons of CO_2 annually by mid-century.[7]

The primary industries expected to use CO_2 are food & beverages, concrete & other building materials, fuels, and chemical manufacturing opportunities, and in this section, we provide a review of each of these sectors and how CO_2-utilization can be integrated into their products or supply chains. Because this section is an examination of several different nascent industries, and detailed evaluation of each is beyond the scope of this report, rather than presenting CO_2-utilizing industries in the format common to other industries examined here (through technological, societal, environmental and economic lenses), we will provide brief descriptions of each category of CO_2-utilizing industries, examining their state of development and describing example projects (Section 10.1), and then will consider the potential of these industries from a business model standpoint (Sections 10.2 and 10.3).

Note that the industries described in this section are not necessarily exhaustive examples of uses for CO_2. For example, it can be used to increase agricultural productivity or in cleaning or medical processes – but these uses are either addressed in other sections of the larger report or are negligible in the context of how much CO_2 they would utilize. As such, these uses are not explored in this section. Finally, one application of CO_2-utilization

[2] WRI (December 22, 2022) Carbon removal in the BIL and IRA. [57]

[3] Brigham (June 28, 2022) Why Big Tech is pouring money into carbon removal. [5]

[4] Harvey (April 5, 2022) Carbon removal 'unavoidable' as climate dangers grow, new IPCC report says. [26]

[5] Climate Now (February 18, 2022) How to scale up carbon capture and storage with Sheila Olmstead. [18]

[6] IEA (2019) Putting CO_2 to Use. [34]

[7] IEA (2019) Putting CO_2 to Use. p. 1. [34]

is not addressed in this section at all: Enhanced Oil Recovery, or EOR. While globally, EOR is by far the largest market for CO_2, it is not a relevant market to consider for the purpose of a carbon management business park in Kern County, given that state law SB-905 prohibits operators from injecting CO_2 produced in a carbon management project into the subsurface for the purpose of enhanced oil recovery.[8]

10.1.1 Types of Industries

CO_2 can be used in its pure state for several purposes – an example many are familiar with is beverage carbonation. Currently, most commercial processes that rely on CO_2 use it directly.[9] However, if the goal of CO_2 utilization is to create a measurable impact in the reduction of atmospheric greenhouse gases, it will have to be adopted by industries that would use tens or hundreds of millions of tons of CO_2 annually. These types of industries – concrete, fuels, plastics and polymers, and other chemicals – require chemical or biological conversion of the CO_2 into usable products, which can be technologically complex and energy intensive. A summary of the wide range of industrial applications for CO_2 is shown in Figure 10.1, adapted from a comprehensive report on CO_2 utilization from the International Energy Agency (IEA),[10] to which the reader is referred for further information on the topic.

The CO_2 utilization market is relatively small (currently, about 25-35 million tons of CO_2 are used in non-EOR industries),[11,12] and likely to remain so in the short term, as carbon management companies that could cost-effectively source CO_2 are still in nascent stages of development, and the markets most likely to be large consumers of CO_2 (building materials and fuels) will require years of testing to ensure they meet regulatory and safety standards.[13] Additionally, adoption of CO_2 utilization practices will require either 1) a clear economic benefit compared to current techniques for an industrial activity or product development, or 2) a clear and measurable climate benefit to the utilization of CO_2 that adds enough value to its use that additional costs can be offset. For most CO_2-utilizing industries, neither of these goals has been clearly achieved yet – more expansive and improved methods to analyze the life-cycle emissions of CO_2-utilizing products will be necessary to inform the best policy and investment decisions for the future.[14] In the following sections, we provide a brief summary of the state of the art for CO_2 utilization in the food and beverage, concrete, building material, fuel, plastic & polymer, and chemical industries.

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[8] OpenStates (no date) SB 905. [48]

[9] IEA (2019) Putting CO_2 to Use. p. 3. [34]

[10] IEA (2019) Putting CO_2 to Use. [34]

[11] IEA (2020) CCUS in Clean Energy Transitions. p. 109. [36]

[12] Note: About 70-80 million tons of CO_2 is used for EOR, and ~125 $MtCO_2$/yr is used by the fertilizer industry. However, fertilizer facilities produce and use their own CO_2, so they do not need to buy it externally. (IEA (2020) CCUS in Clean Energy Transitions. [36])

[13] IEA (2019) Putting CO_2 to Use. p. 1. [34]

[14] IEA (2019) Putting CO_2 to Use. p. 2. [34]

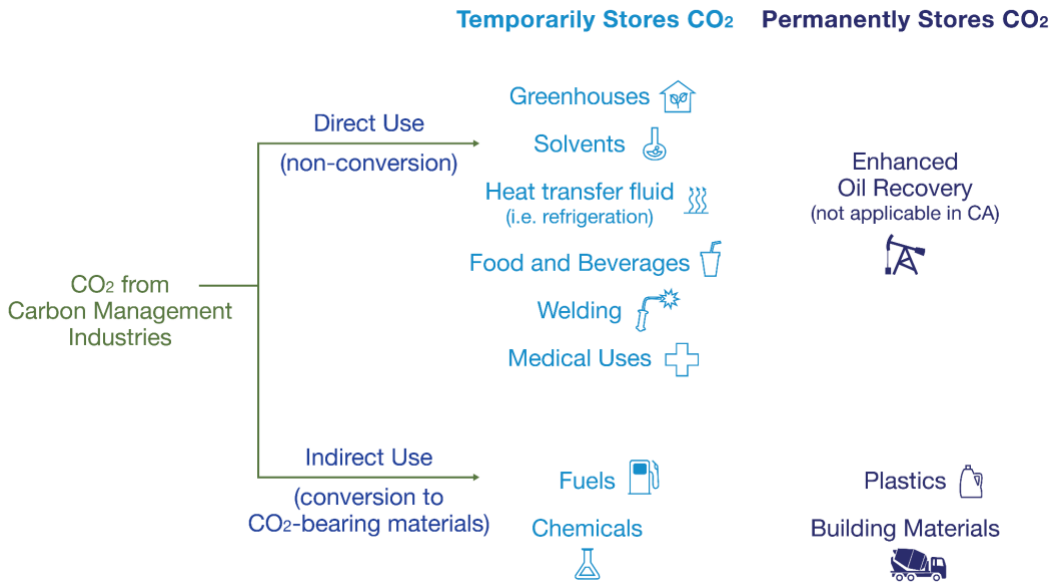

Figure 1. A summary of direct uses of CO_2 (including in greenhouses, in food and beverages and solvents) and indirect uses of CO_2 (including fuels, plastics, and building materials). Adapted from IEA (2019).[15]

10.1.1.1 Food & Beverages

Currently, the largest industry for CO_2 utilization (excluding EOR and fertilizers, see notes above) is the food and beverage industry, which purchases about half of the CO_2 on the market – approximately 15 million tons in 2015.[16,17] Carbonated beverages comprise about half of the use in the food and beverage industry,[18] but CO_2 is also used as a produce preservative, a freezing agent for meat, or to keep food items cold in transport as dry ice.[19] Food and beverage opportunities for CO_2 utilization are among the least useful in terms of atmospheric carbon dioxide removal; the CO_2 that is utilized will only be stored temporarily in the product before returning to the atmosphere.[20] However, it is one of the more well-established CO_2-utilization industries, with captured CO_2 already used on a commercial scale.

Another promising avenue of food and beverage applications is associated with chemical manufacturing opportunities. For example, sodium bicarbonate, or baking soda, can be formed through the chemical conversion of CO_2 (its chemical formula is Na_2CO_3). Baking soda is both widely used in commercial baked goods and sold directly to consumers.[21]

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[15] IEA (2019) Putting CO_2 to Use. p. 7-8. [34]
[16] GlobalNewsWire (January 7, 2021) The Largest User Of The Carbon Dioxide Market. [25]
[17] IEA (2019) Putting CO_2 to Use. p. 6. [34]
[18] IEA (2019) Putting CO_2 to Use. p. 6. [34]
[19] nexAir (no date) Carbon Dioxide in Food and Beverage. [44]
[20] Budinis (January 31, 2020) Going carbon negative. [6]
[21] IEA (2019) Putting CO_2 to Use. p. 49. [34]

Chemical compounds formed by converting CO_2 are explored at large in Section 10.1.1.6 on chemical manufacturing.

Example Project: Coca-Cola HBC Switzerland, Switzerland

A Coca-Cola franchised bottler in Switzerland purchased captured CO_2 from the first commercially operating DAC facility in the world for use in beverage carbonation for its Valser sparkling water.[22] Climeworks' first generation Hinwil DAC facility supplied CO_2 to the bottling company from 2017 until the retirement of the facility in January 2023.[23] Presently, Coca-Cola is considering ways to expand its use of captured CO_2 across its products and Climeworks is looking to expand their CO_2 utilization offerings beyond Switzerland as their operations grow.[24, 25]

Example Project: Air Company, New York, New York

Air Company is a carbon utilization company that uses CO_2 conversion technology to produce carbon negative alcohol products, such as vodka, as well as personal care products including perfume and hand sanitizer.[26] Air Company's technology obtains CO_2 from point-source capture sources, then combines that CO_2 with green hydrogen (hydrogen via electrolysis) to create an alcohol mixture that is distilled and forms the basis for their product offerings.[27] They also rely wholly on clean energy (wind and solar) to support their processes.[28]

Air Company is planning to add fuel products to their commercial-scale offerings, namely sustainable aviation fuels, ethanol, and methanol (see Section 10.1.1.4).[29] Their aviation fuels have been successfully used by the U.S. Air Force in pilot-scale tests, and the company is currently in the process of scaling their operation to a commercial demonstration phase.[30] If expanded to all potential areas of business that Air Company has scoped (food, personal care and fuels), they anticipate their technology "could avoid 10.8% of global CO_2 emissions, the equivalent of more than 4.6 billion tons of CO_2 annually."[31]

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[22] Johnston (September 6, 2021) Inside the Facility. [37]

[23] Climeworks (January 24, 2023) Climeworks completes the commercial operation of its 1st gen technology. [20]

[24] Johnston (September 6, 2021) Inside the Facility. [37]

[25] Kotecki (January 15, 2019) Sparkling water made with carbon dioxide captured from the atmosphere. [39]

[26] Air Company (no date) Transforming CO_2. [3]

[27] Air Company (no date) AIR Eau de Parfum. [1]

[28] Air Company (no date) AIR Eau de Parfum. [1]

[29] Air Company (no date) Transforming CO_2. [3]

[30] Air Company (no date) AIRMADE™ SAF. [2]

[31] Air Company (no date) Transforming CO_2. [3]

10.1.1.2 Concrete

Concrete production is very carbon-intensive, accounting for at least 8% of global CO2 emissions.[32] Moreover, concrete demand is quickly accelerating—we use three times more concrete than we did 40 years ago, and as more nations industrialize, demand growth is expected to continue.[33] Thus decarbonizing concrete production has a clear positive impact on reducing global greenhouse gas emissions. There are already small-scale manufacturing facilities developing lower-carbon concrete, but it will require immense scaling and regulatory reforms before these products can replace traditional concrete.[34]

In general, CO_2 utilization in concrete production falls into two categories: 1) replacing water for curing, or 2) as a raw material within the concrete mixture. Both uses represent examples of CO_2 utilization that provide sequestration on the order of decades, so could benefit from carbon offset marketplaces or regulatory incentives for CO_2 storage.[35] CO_2 curing is both a mature and particularly promising avenue for CO_2 use, as it provides the co-benefits of decreasing water use, decreasing the production time for curing, and producing a higher-strength concrete. Additionally, the amount of CO_2 necessary for concrete curing is relatively minimal, so does not add significant manufacturing costs to cement production, even with the still relatively high costs of capture CO_2. Meanwhile, using CO_2 directly in the production process is a developing area of technology. Injecting CO_2 directly into concrete changes its material composition and could affect its properties—at this early stage of development, it is not yet clear to what degree. CO_2-rich concrete could have material properties that are essentially the same – or better – than conventional concrete.[36]

In terms of market readiness, barriers for CO_2-rich concrete are cost- and policy-related. One way to keep costs low while the industry (and availability of CO_2) evolves, is by injecting CO_2 into precast concrete materials, like concrete bricks, at a central facility rather than incorporating captured CO_2 into onsite concrete mixing or curing of concrete at building sites (see example projects below).[37]

In terms of policy barriers, all types of concrete are highly regulated for safety reasons. As such, extensive testing and regulatory reforms are necessary before any CO_2-utilizing concrete could be used for high-stability purposes. Thus, early market opportunities will likely rely on less-intensive concrete uses, like paving roads or poured concrete floors.[38]

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[32] *Nature* (September 28, 2021) Concrete's colossal carbon footprint. [43]

[33] *Nature* (September 28, 2021) Concrete's colossal carbon footprint. [43]

[34] IEA (2019) Putting CO_2 to Use. p. 12. [34]

[35] The federal tax credits 45Q provides a reduced tax-credit for industrial uses of CO_2 (compared to permanent storage) as long as emissions reductions can be clearly demonstrated. From: IEA (November 4, 2022) Section 45Q credit for carbon oxide sequestration. [35]

[36] IEA (2019) Putting CO_2 to Use. p. 12, 54-55. [34]

[37] IEA (2019) Putting CO_2 to Use. p. 55-56. [34]

[38] IEA (2019) Putting CO_2 to Use. p. 12. [34]

Although developers are working on promising new industrial processes in this field, experts anticipate that the hurdles in scaling and deploying CO_2-utilizing concrete will be regulatory, rather than technical, in nature.[39]

Example Project: Carbicrete, Montreal, Quebec

Canadian company Carbicrete has developed a new process to reduce their carbon emissions that both changes the constituent parts of the concrete to be less carbon intensive and relies on CO_2 to cure its final concrete product.[40] Rather than mixing cement with aggregates and water to generate their concrete, they replace the cement with steel slag, which is incorporated into the mixture on industry standard equipment—removing the requirement for cement altogether.[41] Then, they mold precast concrete blocks that are cured with CO_2 in a specialized chamber, taking 24 hours to reach their full strength.[42] In testing, they have found their concrete has up to 30% higher compressive strength, improved freezing and thawing resistance, and the same water absorption properties of traditional concrete.[43]

Across Carbicrete's production process, more CO_2 is absorbed in the concrete than is emitted in manufacturing, making their concrete production carbon negative.[44] Currently, Carbicrete relies on captured industrial point-source emissions for its CO_2, but it is hoping to move to using CO_2 from Direct Air Capture (DAC) facilities in the future so they are actively removing existing CO_2 from the atmosphere.[45]

Example Project: CarbonCure, Halifax, Nova Scotia

CarbonCure's process relies on incorporating CO_2 directly into the concrete mix, where the CO_2 reacts with calcium ions within the cement (composed primarily of lime, or CaO and $Ca(OH)_2$) in order to form calcium carbonate ($CaCO_3$).[46] They market a range of products from their technology, including ready concrete mix, concrete bricks, precast concrete, and reclaimed water.[47] Their technology decreases both the water and carbon intensity of their concrete in comparison to traditional concrete.[48]

It's expected that over the next 30 years, about half of the emissions from new construction will come from embodied carbon, which is the carbon emitted during the manufacture of

[39] IEA (2019) Putting CO_2 to Use. p. 58. [34]
[40] Carbicrete (no date) Technology. [11]
[41] Carbicrete (no date) Technology. [11]
[42] Carbicrete (no date) Technology. [11]
[43] Carbicrete (no date) End Users. [10]
[44] Carbicrete (no date) Carbicrete - About the Process Video. 0:31-0:36. [9]
[45] Fairs (June 27, 2021) Carbon Revolution. [24]
[46] CarbonCure (no date) Innovative CO_2 Technologies. [14]
[47] CarbonCure (no date) Innovative CO_2 Technologies. [14]
[48] CarbonCure (no date) Innovative CO_2 Technologies. [14]

building materials.[49] CarbonCure's goal is that with their associated products, they could remove 500 million metric tons of embodied CO_2 from the environment by 2030, equivalent to taking 100 million cars off the road.[50]

Example Project: Solidia Technologies, San Antonio, Texas

Solidia Technologies is developing two processes for reducing CO_2 emissions associated with concrete production: one is to adjust the chemistry of the cement mix and the other - like other companies - is to use a CO_2 curing process.[51] Their cement formula is more silica-rich and less lime-rich than the most common cement recipe, Portland cement. Because lime production (converting limestone rock ($CaCO_3$) to lime (CaO and $Ca(OH)_2$) is an energy intensive process that releases CO_2 in the atmosphere, a cement chemistry with less lime has the effect of lowering the CO_2 emissions, energy requirements, and raw materials intensity of the cement and subsequent concrete products.[52]

The lime-poor cement is combined with sand granules to generate their concrete, which undergoes CO_2 curing. In the CO_2 curing process, the CO_2 reacts with the cement in the concrete to form calcium carbonate ($CaCO_3$), strengthening the material and chemically trapping the CO_2.[53] This process makes the concrete higher performing, reduces production costs, and drastically reduces the curing time to less than 24 hours, compared to a full 4 weeks for traditional concrete.[54]

If implemented globally, Solidia anticipates that their technologies could reduce carbon emissions from concrete production by up to 70%.[55]

10.1.1.3 Building Materials

CO_2 can be utilized for building materials other than concrete as well, with most applications involving the remediation of metal waste materials into carbonates that can be used as aggregates in construction.[56] Fly ash and steel slag are two examples of alkaline wastes - materials that have high concentrations of reactive metals like calcium and magnesium. These kinds of metals chemically bond with CO_2 to form solid carbonate materials ($CaCO_3$ and $MgCO_3$) that permanently bind the carbon. Carbonation of 1 ton of fly ash can sequester about 0.07-0.25 tons CO_2, and carbonation of 1 ton of blast furnace slag from steel operations requires about 0.26-0.38 tons CO_2. Not all of the CO_2 used is bound up in the product, but the cost of CO_2 input encourages recycling the CO_2 such that the majority of the CO_2 input will be sequestered. Producing carbonates from metal waste is a

[49] CarbonCure (no date) 500 Million Tonne CO_2 Reduction. [13]
[50] CarbonCure (no date) 500 Million Tonne CO_2 Reduction. [13]
[51] Solidia Technologies (no date) Solutions. [52]
[52] Solidia Technologies (May 2021) The Science Behind Solidia. [53]
[53] Solidia Technologies (no date) Solutions. [52]
[54] Solidia Technologies (no date) Solutions. [52]
[55] Solidia Technologies (no date) Impact. [51]
[56] IEA (2019) Putting CO_2 to Use. p. 59. [34]

relatively new industry, and life-cycle assessments of the CO_2-reduction potential of carbonated waste products are limited and often not transparent – substantial analytical work is still needed to establish the climate benefits possible from these processes.[57]

However, a co-benefit of metal-waste carbonation is that it binds harmful metals that could leach into the environment and cause harm, and it helps eliminate the costs of tailings or hazardous waste disposal in mining and industrial applications.[58] Thus, these practices have the potential to reduce the environmental impact of existing industrial sites requiring remediation and protect industrial communities from future environmental harm.

Carbonation of metallic wastes for construction aggregates does face economic hurdles before significant scaling can take place. Since building materials are readily and cheaply available, it is difficult for materials generated from waste to be economically competitive in the marketplace.[59] As a result, early markets are likely to appear only where there are large amounts of waste to process and tightening regulations incentivize safe remediation of that waste. Examples include regions around the world that are increasing regulations around disposing bauxite residue (informally called "red mud") from aluminum production,[60] and regions where industrial waste disposal is expensive, like the European Union (EU).[61] Regulations can also present hurdles, however; for example, EU law currently prohibits the integration of waste into commercial products, which could present challenges for bringing a carbonated aggregate generated from waste into the European market.[62]

Example Project: Carbon8, United Kingdom

In the UK, Carbon8 works to capture CO_2 from industrial sources and then, at the same site, react that CO_2 with residues and byproducts that would otherwise be destined for landfilling.[63] Once formed, these carbonated materials can be used for "a variety of applications including in cement blocks, road filler and green roofing substrate."[64] Carbon8's technology is notable because it can sequester CO_2 for long periods and has a relatively short production time, with an estimated time for its carbon capture and storage process of 20 minutes.[65]

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[57] IEA (2019) Putting CO_2 to Use. p. 59-62. [34]
[58] IEA (2019) Putting CO_2 to Use. p. 59. [34]
[59] IEA (2019) Putting CO_2 to Use. p. 60. [34]
[60] Srivastava *et al.* (2023) Challenges, regulations, and case studies on sustainable management. [54]
[61] IEA (2019) Putting CO_2 to Use. p. 61. [34]
[62] IEA (2019) Putting CO_2 to Use. p. 62. [34]
[63] Carbon8 (no date) Our Solution. [12]
[64] Carbon8 (no date) Our Solution. [12]
[65] Carbon8 (no date) Our Solution. [12]

10.1.1.4 Synthetic Carbon Fuels

Another budding industrial opportunity for CO_2 use is to incorporate captured CO_2 into new carbon fuels. These fuels could replace conventional fuels in use today, including gasoline, aviation fuels, methane, and methanol.[66] This prospect has clear potential: by volume, synthetic carbon fuels rank as the biggest use potential for CO_2, with the ability to provide a lower-carbon fuel option for industries with few non-carbon fuel alternatives, like the aviation industry, or by replacing fossil fuels with an option that is simpler to use and store than pure hydrogen fuels. However, synthetic carbon fuels come with challenges as well: generating fuels from CO_2 is very energy-intensive, and existing fuel standards may be difficult to meet with synthetic CO_2-derived fuels. Additionally, upon combustion of these fuels, CO_2 will be re-released into the atmosphere, and so these products are not pathways for permanent CO_2 removal and storage, and thus not eligible for carbon credits, or policies that incentivize carbon removal.[67]

Production of synthetic carbon fuels can be carried out through one of two pathways, either direct or indirect.[68] Both pathways involve combining CO_2 and H_2 for chemical conversion, summarized by this simplified reaction:

$$CO_2 + H_2 \text{ (or } H_2O) + \text{energy} \rightarrow \text{Hydrocarbon fuel} + O_2 \qquad \text{(R10.1)}$$

The direct pathway relies on hydrogenation, and the indirect pathway on a reverse gas-water shift process followed either by a Fischer-Tropsch (FT) or methanol synthesis process. Not all of these processes are equally ready for commercial deployment. Hydrogenation, FT, and methanol synthesis are all mature processes, but the reverse water-gas shift is still at the demonstration scale.[69] Other processes that develop CO_2-derived fuels via chemical or biological pathways are still in the research and development phase.[70]

Regardless of production pathway, producing synthetic carbon fuels is an energy intensive process, which significantly contributes to their high cost relative to fossil fuels. For example, in creating CO_2-derived methane and methanol, electricity accounts for 40-70% of production costs and is the primary reason that production costs exceed traditional methane and methanol by 2 to 7 times.[71] With improvement, CO_2-derived methanol may become price-competitive in the marketplace, but other fuels produced from CO_2 – methane, diesel, gasoline, and aviation fuel – are expected to require policy interventions

[66] IEA (2019) Putting CO_2 to Use. p. 9. [34]
[67] IEA (2019) Putting CO_2 to Use. p. 7-10. [34]
[68] IEA (2019) Putting CO_2 to Use. p. 10. [34]
[69] IEA (2019) Putting CO_2 to Use. p. 18. [34]
[70] IEA (2019) Putting CO_2 to Use. p. 9. [34]
[71] IEA (2019) Putting CO_2 to Use. p. 10. [34]

to compete with traditional fuels.[72] Some of the policy avenues that could precipitate this change in demand are explored in Section 10.3.2.

The energy demand of synthetic carbon fuels is intuitive - production of these fuels is essentially a reversal of the combustion reaction we use to obtain energy:

$$\text{Hydrocarbon fuel} + O_2 \rightarrow CO_2 + H_2O \text{ (or } H_2\text{)} + \text{energy} \quad \text{(R10.2)}$$

Thus, synthetic carbon fuels will only have value if the energy used to create them produces less CO_2 than would come from simply combusting fossil fuels. For example, using electricity generated from a coal-fired power plant to create synthetic carbon fuel could emit more CO_2 than it avoids. Thus, for any production facility, a full life-cycle analysis would be necessary to examine how beneficial these CO_2-derived fuels are when compared to traditional fuels.

Example Project: Carbon Engineering - Air to Fuels, British Columbia, Canada

Carbon Engineering is one of two leading companies in the development of Direct Air Capture (the other being ClimeWorks, see Section 3), having operated a pilot Liquid Direct Air Capture (L-DAC) facility in Sqamish, British Columbia since 2015.[73] In addition to their work in capturing CO_2 for the purposes of underground sequestration, the company's Air to Fuels program develops synthetic fuels that are drop-in compatible with existing infrastructure and engines. Their process involves reacting CO_2 captured from the air with green hydrogen derived from electrolysis (see Section 6) to create hydrocarbons that can be converted into synthetic gasoline, diesel or jet fuel.[74] In 2019, the reported cost to produce these fuels was ~ $4 USD per gallon.[75]

Example Project: George Olah Renewable Methanol, Svartsengi, Iceland

The George Olah Renewable Methanol facility, located in Svartsengi, Iceland, is the first industrial scale operation converting captured CO_2 to methanol fuel.[76] The facility was commissioned in 2011 and reuses 5,500 metric tons of CO_2 annually. It relies on captured CO_2 from a nearby geothermal power plant (point-source capture) to synthesize methanol via a catalytic reaction with H_2.[77]

Example Project: Air Company, New York, New York

Air Company is developing a variety of products utilizing CO_2, including alternative fuels, and is described in detail in Section 10.1.1.1.

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[72] IEA (2019) Putting CO_2 to Use. p. 10. [34]

[73] Carbon Engineering (no date) Our Story. [16]

[74] Carbon Engineering (no date) Air to Fuels™. [15]

[75] Conca (October 8, 2019) Carbon Engineering – Taking CO_2 right out of the air to make gasoline. [21]

[76] IEA (2019) Putting CO_2 to Use. p. 18. [34]

[77] Carbon Recycling International (no date) George Olah renewable methanol plant. [17]

10.1.1.5 Plastics & Polymers

Today, fossil fuels are not only used for energy production, but are a primary feedstock in the production of a variety of plastics, polymers and their derivatives: materials that are collectively described as the *petrochemical* industry. In the long term, decarbonization efforts would ideally reduce fossil fuel use in petrochemicals in addition to the energy sector, and to this end, plastics and polymer production is an industry with a strong potential for reusing captured CO_2 to create new products.[78]

A clear benefit to incorporating CO_2 into plastics and polymers is that it requires relatively low energy input, making it cost-competitive with many traditional manufacturing practices, and it reduces the raw materials necessary from fossil fuels.[79] However, this is not a fix-all solution—at least currently, CO_2 can only replace part of the raw material from fossil fuels necessary to form plastics or polymers, up to approximately 50% of the final products' mass.[80] Full life-cycle analyses would be necessary to quantify the degree to which CO_2-utilization reduces the emissions associated with polymer production. Additionally, while the longevity of CO_2-derived plastics and polymers could provide an environmental benefit in the form of long-term storage sites for CO_2, the accumulation of non-degradable plastic waste creates a different environmental hazard that needs to be considered.[81]

Example Project: Econic, United Kingdom

UK manufacturer Econic is using CO_2 to produce polyurethane, which is used in foam, coatings, sealants, elastomers and other products.[82] Their process relies on replacing a percentage of the material's polyols—cross-linking agents—with carbon dioxide, which serves not only to bind the CO_2 but also replaces a highly expensive standard polyol material, propylene oxide.[83] As a result, Econic estimates that their process will not only lower carbon emissions, but also save money for manufacturers.[84] Econic products are in development - with full scale production of their polyol technology planned to begin in 2024.[85]

10.1.1.6 Chemical Development

Most of the products discussed in the previous sections involved some form of chemical conversion of CO_2 into a new product. However, there are other ways to chemically convert CO_2 that does not fit clearly into these large, existing industrial sectors, like fuels, building

[78] Vilcinskas (March 2020) Carbon dioxide-based polymers. [56]
[79] IEA (2019) Putting CO_2 to Use. p. 11. [34]
[80] IEA (2019) Putting CO_2 to Use. p. 11. [34]
[81] Parker (June 7, 2019) The world's plastic pollution crisis explained. [49]
[82] Cormier (no date) Turning carbon emissions into plastic. [22]
[83] Cormier (no date) Turning carbon emissions into plastic. [22]
[84] Cormier (no date) Turning carbon emissions into plastic. [22]
[85] Econic (January 12, 2023) Econic Technologies Named on the 2023 Global Cleantech 100. [23]

materials or plastics. This section encompasses products of CO_2-conversion that are outside of the previously described sectors, as well as some processes of chemical conversion that are in early stages of laboratory testing, but could have promising future applications.

Through processes described as biological conversion, CO_2 can be converted into fatty acids, amino acids, and proteins.[86] Synthetic amino acids and proteins can be used in animal feed or, in the future, to generate meat alternative products.[87]

Electrochemical conversion of CO_2 could produce a wide variety of products, including carbon monoxide and carbon nanomaterials.[88] Some products, like methanol and formic acid, can be generated through thermochemical or electrochemical conversion of CO_2.[89] These products are exceedingly versatile and useful. Carbon monoxide is used in the formation of an array of other chemical materials, including long-chain hydrocarbons for fuel and methanol. Carbon nanomaterials, depending on their specific shape and characteristics, can be used in fuel cells, batteries, automotives, and water treatment.

Methanol can be formed with CO_2, CO, and H_2 molecules, and serves as a reactant for forming other chemical compounds, including acetic acid, formaldehyde, and long-chain hydrocarbons. It can also be used as a fuel (see Example Project: George Olah Renewable Methanol in Section 10.1.1.4) – although less energy-dense than gasoline, methanol can be used in some gas-powered engines with minor modifications.[90] Lastly, formic acid can be formed through a multi-step process, but has thus far been rarely commercialized as it relies on an expensive catalyst and can be difficult to separate out at the product end.[91] Formic acid (or CH_2O_2) can be used as a food additive, pesticide (depending on local regulations), in cleaning products, in dyeing or treating fabric and paper products, and as an organic reagent for chemists.[92]

10.2 Growth in CO_2-Utilizing Industries: Obstacles and Opportunities

The International Energy Agency (IEA) has identified four primary factors that will determine the market viability of a CO_2-utilizing technology: scalability, competitiveness, climate benefits, and the policy & regulatory framework in place.[93] The IEA's analysis of

[86] ten Have (December 20, 2022) Don't bury money. [55]
[87] ten Have (December 20, 2022) Don't bury money. [55]
[88] ten Have (December 20, 2022) Don't bury money. [55]
[89] ten Have (December 20, 2022) Don't bury money. [55]
[90] ten Have (December 20, 2022) Don't bury money. [55]
[91] ten Have (December 20, 2022) Don't bury money. [55]
[92] PubChem (no date) Formic Acid (Compound). [50]
[93] IEA (2019) Putting CO_2 to Use. p. 28. [34]

each of these factors are summarized briefly here, with additional focus given to national and state policies and funding opportunities that could impact growth of CO_2-utilizing industries in California.

10.2.1 Scalability

For new technologies, supply chains and infrastructure to produce new products take time to develop. In terms of CO_2-utilizing industries, key supply inputs are CO_2 and clean energy (and in some cases, hydrogen). For projects to grow from R&D testing scale to commercial production, large supplies of these inputs will be necessary, which requires either siting such industries close to input sources, or developing significant infrastructure (100% utility-scale energy and a large CO_2 (± H_2) pipeline networks). While these supply frameworks are in development, it will likely be several decades before such inputs are widely available.[94] Co-locating CO_2-utilizing industries in regions close to points of CO_2 capture, green hydrogen production, and abundant potential for clean, renewable energy, as would be the case in a carbon management business park in Kern County, would be highly advantageous, particularly before the infrastructure to support national supply chains is available.

Another critical determinant to scalability is marketplace demand, which varies widely across the products examined here. For example, demand for some of the sophisticated chemicals made with CO_2 will likely be constrained to chemical engineering firms, specialized labs, and other chemical industries. Meanwhile, demand for a product like concrete has grown exponentially over the last century,[95] and with applications across a wide variety of sectors that grow in tandem with population growth and social-economic development (residential, industrial, municipal, and commercial), is likely to continue such growth. Demand is also not fixed – new technologies may shift what materials are most in demand in ways that have not been considered here – but the ability to project future demand and revenue potential will certainly shape the types of initiatives that are pursued and funded within this early, exploratory phase. The IEA estimates that the five largest potential CO_2-utilization markets (fuels, chemicals, building materials from waste, building materials from minerals – essentially, concrete and cement, and CO_2 to boost plant yields – discussed in Section 11) each have the potential to scale up to tens of millions of tons of CO_2 use annually, on a global scale.[96]

10.2.2 Competitiveness

CO_2-utilizing products that will see success at a commercial scale are those whose use or CO_2-based production pathway can be easily implemented and have the lowest production costs, especially when ranked against alternatives. This will depend on the costs of the technology itself, the market price, and the cost of inputs—material, energy, labor. For

[94] Larson *et al.* Net-Zero America: Final Report Summary. [40]

[95] Andrew (2018) Global CO2 emissions from cement production. [4]

[96] IEA (2019) Putting CO_2 to Use. p. 1. [34]

example, plastics and polymers made with CO_2 reuse are expected to be quite competitive, as there's little additional equipment needed for production, the process can actually save money in material cost for manufacturers, and these products could be sold near the existing average market price for these plastic and polymer products.

In contrast, carbon-based synthetic fuels will need to compete against fossil fuels that have been historically abundant and heavily subsidized.[97] Building materials, like concrete, will need to compete on a global market where profit margins are low, so additional production costs are difficult to absorb without some kind of policy incentives.[98] Both of these types of CO_2-utilizing industries will likely need some kind of policy intervention to support their adoption during early stages of development (see Section 10.2.4).

10.2.3 Climate benefits

Life cycle emissions and other environmental benefits associated with products that utilize captured CO_2 is often difficult to characterize, but will be essential for quantifying the impact and cost-benefit of adopting products that utilize CO_2, as is determining the life cycle emissions of the products they displace. For example, for building aggregates that are developed from combining industrial waste (slag and tailings) with CO_2, there are clear benefits—not only does the construction industry have new aggregates to work with, the technology reduces wastes that could leach harmful metals into the environment. However, for an item like plastics or polymers, addition of CO_2 into the production process does not displace the need for raw materials from fossil fuels to create these products—the impacts are limited as current technologies do not fully displace the reliance on fossil fuels.

Benefits are also enhanced when the necessary energy to complete these processes is reduced through in the CO_2-utilization process compared to traditional methods, and/or if it supplied through clean sources near the production site. Depending on the region, this could include solar, wind, hydropower, geothermal, and/or nuclear energy sources.

Finally, the benefits of CO_2 reuse will be driven by the amount of time that the CO_2 is stored within the product. For building materials and concrete, this is on the order of years or decades; for beverages and fuels, this could be only a few weeks or months. Longer storage of the CO_2 within the product enhances the climate benefits by acting more as a CO_2 removal solution, whereas products with short storage spans only serve to recycle existing atmospheric CO_2, avoiding further CO_2 additions from fossil sources.

10.2.4 Funding Opportunities & Policy Support

To date, most of the investment in CO_2-utilization technologies has come from the private sector. Between 2008 and 2018, private investment in the form of venture capital and

[97] IEA (February 2023) Fossil Fuels Consumption Subsidies 2022. [32]

[98] Khung, Crete (2022) Life cycle assessment (LCA) and cost-benefit analysis for low carbon concrete. [38]

growth equity for start-ups in the CO_2-use space reached nearly $1 billion USD, globally.[99] It is worth noting that level of investment pales in comparison to other clean energy sectors. Global investment in electrified transport topped $139 billion dollars USD in 2020 alone, and $304 billion dollars USD were invested in renewable energy in the same year.[100] However, public funding and policy support is beginning to gain momentum within state and federal governments. The simplest and most direct policy support for CO_2-utilization is the development of incentives, guidelines or policies for using low-carbon products, or requiring products to stay below a maximum carbon-intensity (i.e. limit of how much CO_2 per unit product was emitted).[101] While politically less popular, another effective policy strategy is placing a price on carbon (a carbon tax), that reflects the cost of – and provides revenue for – mitigating climate change, while also encouraging the use of carbon-negative materials over carbon-intensive materials.[102]

As a climate leader within the nation, California has some statewide policies already informing practices in some CO_2 utilization areas. Federally, the United States supported research and development of CO_2 use through a variety of grant programs, and is beginning to develop additional policy incentives.

10.2.4.1 Relevant California State Policies

With a state-wide commitment to be carbon-neutral by 2045,[103] laws are being developed to directly address CO_2-emitting industries, many of which are industries that can use CO_2 (concrete and cement, fuels, plastics and chemicals). For example, California's SB 596, passed in 2021, requires the cement industry to reach net-zero carbon emissions by 2045, are changing the landscape by making climate improvements a necessity.[104,105] However, the high costs of decarbonizing some processes—like creating cement and concrete—have led operators to seek ways to work with the government to lower emissions.[106] California's Air Resources Board (CARB) is scheduled to release a comprehensive strategy to guide the state's cement industry to meet this goal by July 1, 2023, including defining metrics for greenhouse gas intensity, coordinating strategy with other state agencies, and incorporating ways to leverage state and federal incentives and market demand to promote low-carbon cement.[107]

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[99] IEA (2019) Putting CO_2 to Use. p. 25. [34]

[100] Bullard (January 28, 2021) In the race for investment dollars, cars are pulling ahead. [7]

[101] IEA (2019) Putting CO_2 to Use. p. 5. [34]

[102] Climate Now (October 18, 2021) Pricing carbon around the globe. [19]

[103] Office of Governor Gavin Newsom (November 16, 2022) California releases world's first plan. [46]

[104] Office of Governor Gavin Newsom (September 23, 2021) Governor Newsom Signs Climate Action Bills. [47]

[105] Lopez (June 27, 2022) Climate-friendly cement? [41]

[106] Lopez (June 27, 2022) Climate-friendly cement? [41]

[107] CARB (2022) SCOPING PLAN FOR ACHIEVING CARBON NEUTRALITY. p. 48. [8]

California's climate policies have also prevented the use of CO_2 for certain uses. SB 905 (2022) bans the use of captured CO_2 for enhanced oil recovery (EOR),[108] a process where CO_2 is injected into existing oil fields to extract hard-to-reach deposits, thereby extending the lifetime of oil fields.[109] SB 1314 (2022) effectively bans the use of CO_2 injection for EOR, explicitly citing that the state's support of CCUS technologies is driven by a desire to advance towards a carbon-neutral society rather than extending the lifetime of fossil fuel production facilities.[110]

10.2.4.2 Relevant United States Federal Funding Programs and Policies

At the federal level, funding in CO_2 utilization has primarily been in the form of grants for early-phase research and development (R&D). The 2009 American Reinvestment and Recovery Act (ARRA) invested $100 million USD in R&D projects focused on innovative CO_2 conversion projects,[111] notably in the building materials and chemical production industries.[112] From 2012-2017, a portion of the U.S. Department of Energy (DOE)'s Carbon Storage Program (between ~$1 and 10 million USD annually) funded an R&D portfolio of projects specifically in the space of carbon use and reuse.[113] A similar program (the Climate Innovation Research Opportunity investment program) launched in 2021, providing another $100 million USD grant program for low-carbon energy technologies, including those in the field of carbon capture and utilization.[114] The 2020 Energy Act authorized the Department of Energy to allocate nearly $7 billion USD in funds for various carbon management and removal programs, including carbon utilization.[115] Additional funding is planned from the 2021 Infrastructure Investment and Jobs Act, with $12 billion USD earmarked for investments in carbon capture, utilization and storage technology.[116]

Section 45Q in the tax code provides a credit for qualified uses of CO_2, most commonly used for EOR in the oil and gas sector, but other uses can qualify if they fall into certain categories. The language of Section 45Q(f)(5)(A) permits 45Q credits for processes that fix CO_2 via photosynthesis or chemosynthesis or chemical conversion that securely stores carbon, but other uses could become eligible if a commercial market exists and the use of qualified CO_2 is determined to be eligible for 45Q by the Secretary of Energy.[117]

In general, experts agree that governments need to develop more incentive structures to encourage CO_2 utilization, as well as more robust policies in place to quantify reduced or

[108] OpenStates (no date) SB 905. [48]
[109] FECM (no date) Enhanced Oil Recovery. [45]
[110] IEA (November 4, 2022) Enhanced Oil Recovery and CCUS (SB 1314). [31]
[111] IEA (August 24, 2021) American Reinvestment and Recovery Act - CCUS elements. [28]
[112] IEA (August 24, 2021) American Reinvestment and Recovery Act - CCUS elements. [28]
[113] NETL (2017) Carbon use and reuse program overview briefing. [42]
[114] IEA (July 8, 2021) Climate Innovation Research Opportunity investment program. [29]
[115] IEA (March 10, 2022) Energy Act of 2020. [30]
[116] IEA (April 18, 2022) Infrastructure and Jobs act. [33]
[117] IRS (no date) Request for Comments on Credit for Carbon Oxide Sequestration. p. 5-6. [27]

avoided emissions resulting from CO_2-utilizing products or production pathways. Underpinning any policies or incentives with transparent measurement, reporting, and verification standards will be crucial to ensuring that development of CO_2 utilization programs results in meaningful emissions reductions or carbon removal.[118] Although this sounds straightforward, developing these standards is difficult due to the range of products that can be developed utilizing CO_2, and the need to assess the life cycle impacts of CO_2-utilizing products as compared traditional manufacturing methods for those same kinds of products.[119]

Finally, adaptations in existing legislation and regulations will also be required for the widespread adoption of CO_2-utilizing materials, especially in long-lived products like concrete and building materials that, for public health and safety reasons, are highly regulated. Without a clear regulatory pathway to the adoption of CO_2-utilizing materials as replacements for the carbon-intensive products used today, continued development and commercial scaling of these technologies will not be possible.

[118] IEA (2019) Putting CO_2 to Use. p. 67. [34]
[119] IEA (2019) Putting CO_2 to Use. p. 67. [34]

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16. Carbon Engineering. Our Story. Published online (no date). Accessed May 6, 2023 from https://carbonengineering.com/our-story/.

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53. Solidia Technologies (2021) The Science Behind Solidia. Science Backgrounder. 2p. https://www.solidiatech.com/releases.html.

54. Srivastava, R., *et al.* (2023) Challenges, regulations, and case studies on sustainable management of industrial waste. *Minerals*, 13(1), 51. https://doi.org/10.3390/min13010051.

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11. Connections with Regional Agriculture

OPPORTUNITIES AT A GLANCE

- Kern County's agricultural sector emits over 2 million tons of CO_2 annually, 65% of which comes from the degradation of agricultural waste, including livestock waste.[1]
- 482,000 tons of agricultural waste and 625,000 tons of livestock manure are produced in Kern County annually, and could be converted into renewable fuels, pure streams of CO_2, and/or a source of water.
- Conversion of 100% of Kern County's biomass waste could produce over 900 thousand metric tons of CO_2 annually.
- Biochar is a byproduct of BiCRS + BECCS processes, which could serve as a nutrient-adding alternative to fertilizer for regional croplands.
- Additional products of carbon management industries that could be useful to regional agriculture are water (depending on carbon management technology) and CO_2, which can be used to enhance greenhouse production.

[1] Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

11.1 Kern County's Agricultural Sector

Agriculture is a major industry throughout California's Central Valley, a region that produces about a quarter of the nation's food.[2] In Kern County alone, agricultural output is valued at over $8 billion annually,[3] making it the highest producing agricultural county in California by value in 2021.[4] The agriculture sector also leads the county in land use,[5] water use,[6] and employment,[7] providing nearly 1 in 5 county jobs directly, and supporting a variety of indirect jobs (i.e. sales of equipment, fertilizers, feed, and other supplies, or supplying food an beverage processing facilities). As such, understanding the ways in which carbon management and clean energy technologies can enhance, benefit from, or compete with this sector are worth considering.

A full examination of agriculture and its projected development in Kern County is beyond the scope of this report. Rather, in this section we will provide a brief overview of the current state of the industry, highlighting strengths, challenges and potential synergistic pathways between agriculture and the development of one or more carbon management business parks in the region.

11.1.1 The Current Agriculture Industry

Kern County's farmland is expansive, covering 2,295,497 acres of land according to the USDA's 2017 Census of Agriculture.[8] That means that farmland accounts for 44% of Kern county's land area of 5,206,176 acres.[9] Although over 80% of the county's sales are in crops, land use is more evenly distributed between livestock and crops, with 53% of farmland designated as pastureland and 42% of farmland designated as cropland.[10]

Agriculture requires more than land to flourish, though, and the water needed to irrigate Kern County's croplands is in jeopardy. In Kern County today, 2,294,000 million acre-feet of water is devoted to the agriculture industry.[11] That represents 93% of total municipal,

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[2] U.S. Geological Survey (no date) California's Central Valley. [45]

[3] Kern County Department of Agriculture and Measurement Standards (2022) 2021 Kern Agricultural Crop Report. [23]

[4] When compared to other county crop reports from the California Department of Food and Agriculture; accessed March 4, 2023 from https://www.cdfa.ca.gov/exec/county/CountyCropReports.html.

[5] NASS (no date) Agriculture Census: Kern County. [32]

[6] WAKC (no date) Water in Kern County. [47]

[7] State of California EDD (no date) California Labor Market Information Resources and Data. [42]

[8] NASS (no date) Agriculture Census: Kern County. [32]

[9] U.S. Census Bureau (no date) QuickFacts: Kern County, California. [44] (In this source, land area is given in square miles and has been presented here converted to acres.)

[10] NASS (no date) Agriculture Census: Kern County. [32] These percentages do not add to 100% as the Agriculture Census recognizes other categories (woodland, other) that are not discussed here.

[11] WAKC (no date) Water in Kern County. [47]

industrial and agricultural water use in the county. More than 70% of that water is sourced from reservoirs to the north of the county, or from groundwater in subsurface aquifers.[12] With more frequent droughts impacting the region and the implementation of laws like the 2014 Sustainable Groundwater Management Act (SGMA), which requires local water users to achieve sustainable groundwater use by 2040,[13] less water will be available for irrigation from rain and snowfall, and significantly less water will be available from underground aquifers.[14,15] The Public Policy Institute of California estimates the combined impact of climate change and the SGMA could result in as much as 900,000 acres of fallowed farmland in the San Joaquin Valley by 2040. The number can be lessened (but not eliminated) with improved water trading rules, infrastructure investments, and improved agricultural productivity.[16]

Development of carbon management business parks like that considered here, provide a potential revenue-generating alternative to agriculture in fallowed croplands, while carbon management itself directly combats the primary driver of climate change-induced droughts. Below, we explore how principles of carbon management – both in collaboration with some of the carbon management industries described in this report and applied directly to agricultural practices – could help farms transition under these new circumstances.

Table 11.1. Agriculture-related emissions in Kern County and California[a]

Emissions Source	Kern 2005[b]	CA 2005[c]	CA 2020[c]	% Change[d]
Livestock enteric fermentation	633,214	10.5 million	11.0 million	+5%
Livestock manure management	741,173	10.4 million	11.6 million	+12%
Crop growing & harvesting	575,572	8.2 million	6.8 million	-17%
Fuel combustion	74,511	4.6 million	2.3 million	-50%
TOTAL	**2,024,470**	**33.7 million**	**31.7 million**	**-6%**

a. In metric tons CO_2-equivalent.
b. Kern County Planning and Natural Resources Department (2012) Community GHG emission inventory final report.
c. CARB (2022) California greenhouse gas emissions for 2000 to 2020.
d. Relative change in state-wide emissions from 2005 to 2020.

[12] WAKC (no date) Water in Kern County. [47]
[13] Escriva-Bou *et al.* (2023) The future of agriculture in the San Joaquin Valley. [15]
[14] California Department of Water Resources (no date) Climate Change Basics. [9]
[15] Escriva-Bou *et al.* (May 14, 2020) Sinking Lands, Damaged Infrastructure. [16]
[16] Escriva-Bou *et al.* (2023) The future of agriculture in the San Joaquin Valley. [15]

11.1.2 Carbon Capture Potential

In 2012, the Kern County Department of Planning and Community Development created an inventory of community-wide greenhouse gas emissions, estimating the county's sector by sector emissions impact in 2005, in units of metric tons CO_2-equivalent (CO_{2e}). The agriculture sector sequestered ~400,000 metric tons of CO_{2e}, annually, through the process of photosynthesis and plant growth, but released over 2 million tons of CO_{2e} through enteric fermentation (digestive gasses of livestock), manure management, crop growing and harvesting, and fuel combustion (Table 11.1).[17] The report forecasted an ~30% increase in emissions by 2020, but no subsequent studies have been undertaken at the county level. At the state level, livestock related emissions have increased 5-12%, crop-related emissions have decreased 17%, and fuel combustion-related emissions have decreased 50%, with the net effect being very little change in agriculture sector emissions since 2020.[18] Of these emissions, some can be reduced through partnerships with biomass with carbon dioxide removal (BiCRS) technologies, detailed in Section 11.2, while others can be reduced through low carbon farming techniques, which are introduced briefly here. With sustainable practices and low-carbon techniques, farms can reduce their overall impacts on the environment. From low-till farms and crop cover to technical systems equipped to monitor water and nutrient levels, there are a variety of potential avenues to reduce the carbon intensity of farming.

About 28% of Kern County's agricultural emissions come from crop growing and harvesting, which includes fertilizer use, soil preparation and disturbance, and crop residue burning.[19] Many of these emissions can be reduced through the practice of *carbon farming*, a set of farming tactics that sequester carbon or reduce the GHG emissions of agriculture by focusing on the importance of CO_2 drawdown via photosynthesis as a carbon removal strategy.[20] An example is no-till farming practices, in which the topsoil is left undisturbed, preventing it from releasing its stored carbon into the atmosphere.[21] Other practices, like cover cropping, also serve to sequester carbon in soils and keep the ground nutrient-rich for other crops. With cover crops, new roots help feed the soil's ecosystem of fungi, bacteria, and other organisms over time, gradually increasing the soil's carbon levels.[22]

Currently, these practices are not standard for agricultural land in the region—the USDA found that in Kern County, less than 10% of farms are no-till or reduced-till and that only 2% of farms have cover crops.[23] However, interest has been rising in these practices nationally, and many feel there could be economic benefits as well as climate benefits

[17] Kern County Planning and Natural Resources Department (2012) Community GHG emission inventory. [24]
[18] CARB (2022) California greenhouse gas emissions for 2000 to 2020. [5]
[19] CARB (2022) California greenhouse gas emissions for 2000 to 2020. [5]
[20] Carbon Cycle Institute (no date) What is Carbon Farming? [10]
[21] Spears (June 24, 2018) What is No-Till Farming? [41]
[22] Clark (2015) Cover Crops and Carbon Sequestration. [11]
[23] NASS (no date) Agriculture Census: Kern County. [32]

associated with their adoption. Reporting from the USDA indicates that shifting from conventional to continuous no-till farming uses a third of the amount of diesel for farm equipment per acre, saves time in field maintenance, and can save money in future years as the more nutrient-dense soil requires less water and fertilizer to thrive.[24] Agricultural planners in Minnesota have reported that the net profit from farms earning $5.25 per acre with conventional farming can increase up to $112 per acre with a combination of no-till and cover cropping practices.[25]

More technologically driven carbon farming techniques include implementation of advanced monitoring equipment and automated systems, which can also help reduce water and fertilizer usage on agricultural lands. A variety of sensors are available to monitor farmland conditions: temperature sensors, electrochemical sensors for nutrient levels and pH, mechanical sensors to monitor soil compression or displacement, airflow sensors to test soil air penetration, and dielectric sensors for calculating soil moisture levels.[26] These systems can also be equipped to identify environmental threats like drought stress early, giving farmers more time to plan and mitigate such risks to their livelihood. [27]

11.2 Potential Relationships with a Carbon Management Business Park: Feedstocks and Products

11.2.1 Agricultural Waste as Carbon Management Feedstocks

Industries under the carbon management umbrella, though they all aim to sequester carbon, utilize different feedstocks and produce varied byproducts of capture. For biomass with carbon dioxide removal or biomass-to-energy with carbon capture and storage processes (collectively referred to as BiCRS, see Section 4), the feedstock is biomass. From an environmental perspective, the biomass source is ideally waste from existing agriculture or forest management practices. Examples specific to agriculture include plant residues (stalks, pits, shells) from harvest seasons, tree trimmings, or other discarded organic material. Obtaining BiCRS feedstocks from such sources solve two problems: they reduce the potential land and water use impacts of BiCRS that would result from producing dedicated feedstock crops, and they prevent the release of CO_2 that has already been trapped in that biomass material back to the atmosphere. Often, agricultural residues are left to decompose on the cropland,[28] releasing their carbon content as either methane (CH_4)

[24] Creech (August 3, 2021) Saving Money, Time and Soil. [14]
[25] Scharpe (January 11, 2020) Economics of no-till and cover crop; does it really pay off? [39]
[26] GeoPard Agriculture (no date) What types of sensors are used in precision agriculture? [17]
[27] GlobalNewsWire (February 12, 2020) Agricultural Sensors Market To Reach USD 2.56 Billion By 2026. [18]
[28] Lal (2005) World crop residues production and implications of its use as a biofuel. [26]

or CO_2 into the atmosphere, or are they burned.[29] The latter technique, common in orchards and vineyards, also releases air pollutants like SO_2, nitrous oxides, and particulate matter,[30] and are a particular health hazard to the regional community.[31]

In Kern County in 2021, 482,000 tons of almond hulls, almond shells and crop biomass were produced.[32] From 2000-2020, between 200,000 and 1,200,000 tons of agricultural waste were burned in the San Joaquin Valley each year.[33] The variation is due to increasing burn prohibitions from 2003-2011, which were relaxed over the following decade in response to drought-related fallowing of croplands. In 2021, the California Air Resources Board (CARB) renewed their plan to phase out agricultural burning entirely by 2024,[34] meaning disposal alternatives will be required for the region's agricultural waste. Currently, CARB is offering a grant program that incentivizes 'whole orchard recycling' as an alternative to burning.[35,36] Whole orchard recycling involves the chipping and grinding of waste material, which is then re-incorporated into the soil. It has the advantage of restoring soil nutrients, but may still release greenhouse gasses to the atmosphere as it decomposes into the soil. Another disadvantage is that it is a tax-funded program that may not run indefinitely. A more ideal solution to agricultural waste removal is identifying a buyer, for which BiCRS industries would be strong candidates.

Based on the average amount of carbon in organic feedstocks (~49% by mass of the dry tonnage),[37] the agriculture waste in Kern County alone could produce as much as 860,000 metric tons of CO_2 for geologic storage, depending on the BiCRS technique applied. If all of the San Joaquin Valley's agricultural waste were used for carbon management (approximating from the maximum rate of annual burning), as much as 2 million metric tons of CO_2 could be produced for geologic storage.

11.2.2 Renewable Natural Gas (RNG)

Another industry that relies heavily on biomass inputs is the renewable natural gas (RNG) industry. RNG relies on capturing the biomethane released from decomposing biomass, which can then be captured and compressed for use as natural gas.[38] A wide variety of

[29] CARB (2021) San Joaquin Valley agriculture burning assessment. [6]

[30] Andini *et al.* (2018) Impact of crop residue burning on air pollution and climate change. [3]

[31] Vaughan, Klein (September 6, 2022) Smoke from ag burning contributes to long-term health effects. [46]

[32] Kern County Department of Agriculture and Measurement Standards (2022) 2021 Kern Agricultural Crop Report. [23]

[33] CARB (2021) San Joaquin Valley agriculture burning assessment. [6]

[34] CARB (no date) San Joaquin Valley agricultural burning phase down. [7]

[35] Mayer (September 10, 2022) The goal is to end open-field burning by growers. [29]

[36] Klein, Vaughan (September 8, 2021) As air regulators phase out ag burning, what's the alternative? [25]

[37] Baker *et al.* (2020) Getting to Neutral. p. 31. [4]

[38] Murillo (August 8, 2022) A RNG Facility Will Be Opening Soon in Lost Hills. [31]

biomass can be used for RNG—agriculture waste and dairy manure are the most relevant for this section, but waste from food, wastewater, and landfills can also be used for RNG.[39]

Over the last decade, RNG has already been making inroads within Kern County. The CalBioGas cluster in Kern County is a joint venture wherein local dairy farmers use onsite dairy digesters to capture methane (CH_4), which is then shipped to a central upgrading facility run by California BioEnergy and Chevron that converts the methane into RNG.[40] A company described in detail in the BiCRS section of this report (Section 4), San Joaquin Renewables, is planning to site its first waste biomass-to-RNG facility in McFarland and will be producing RNG alongside its plans to capture and sequester CO_2.[41] Once active, their RNG will be transported using pipelines from regional energy provider SoCalGas.[42] SoCalGas has been actively embracing RNG as an energy alternative, with nine RNG projects currently connected to their system.[43] By 2030, SoCalGas is aiming to have 20% RNG in the natural gas supply that it sends to core customers.[44] Given these recent and upcoming projects, it appears that there is substantial interest in future RNG expansion in Kern County.

A significant contribution to the enthusiasm for RNG comes from economic incentives – under California's Low Carbon Fuel Standard (LCFS) program, in effect until at least 2030, RNG can qualify for LCFS credits in any situation where RNG is replacing "conventional transportation fuel in California,"[45] significantly subsidizing the cost of production (see Section 4). But there are carbon management incentives worth considering as well.

Anaerobic digestors, which are a typical first step in the conversion of biomass waste (particularly livestock manure) to RNG, produce *biogas*, which is a mixture of methane, CO_2 and other trace gasses.[46] About 18-27% of livestock manure solids (dry weight) will be converted to biogas.[47] Biogas is then *upgraded* to produce RNG (Figure 11.1),[48] by stripping the CO_2 and other gasses, leaving pure biologically-derived methane that can serve as a drop-in replacement anywhere methane is used. The ratio of CO_2 to CH_4 in the biogas is about 30-40 mol% CO_2 and 60-70 mol% CH_4.[49] That means that for the 625,000 tons of

[39] Murillo (August 8, 2022) A RNG Facility Will Be Opening Soon in Lost Hills. [31]
[40] California Climate Investments (2021) Capturing Methane to Create Renewable Fuels in Kern County. [8]
[41] San Joaquin Renewables (no date) The Project. [38]
[42] San Joaquin Renewables (no date) The Project. [38]
[43] SEMPRA (February 24, 2022) RNG in SoCalGas Pipelines. [40]
[44] SEMPRA (February 24, 2022) RNG in SoCalGas Pipelines. [40]
[45] Psihoules, Toro, Gamache (December 8, 2021) LCFS credit for renewable natural gas. [37]
[46] Yentekakis, Goula (2017) Biogas management. [48]
[47] PennState Extension (March 12, 2012) Biogas from manure. [36] ~15% of livestock manure are solids. Of those, 91% are volatile (can be converted to biogas), and conversion efficacy is 20-30%.
[48] IEA (no date) Introduction to biogas and methane. [21]
[49] Yentekakis, Goula (2017) Biogas management. p. 3. [48]

livestock manure produced by Kern County in 2021,[50] about 150,000 tons of biogas can be produced, which can be separated into about 4 million cubic feet of RNG as well as 85,000 tons of CO_2 for geologic storage.[51]

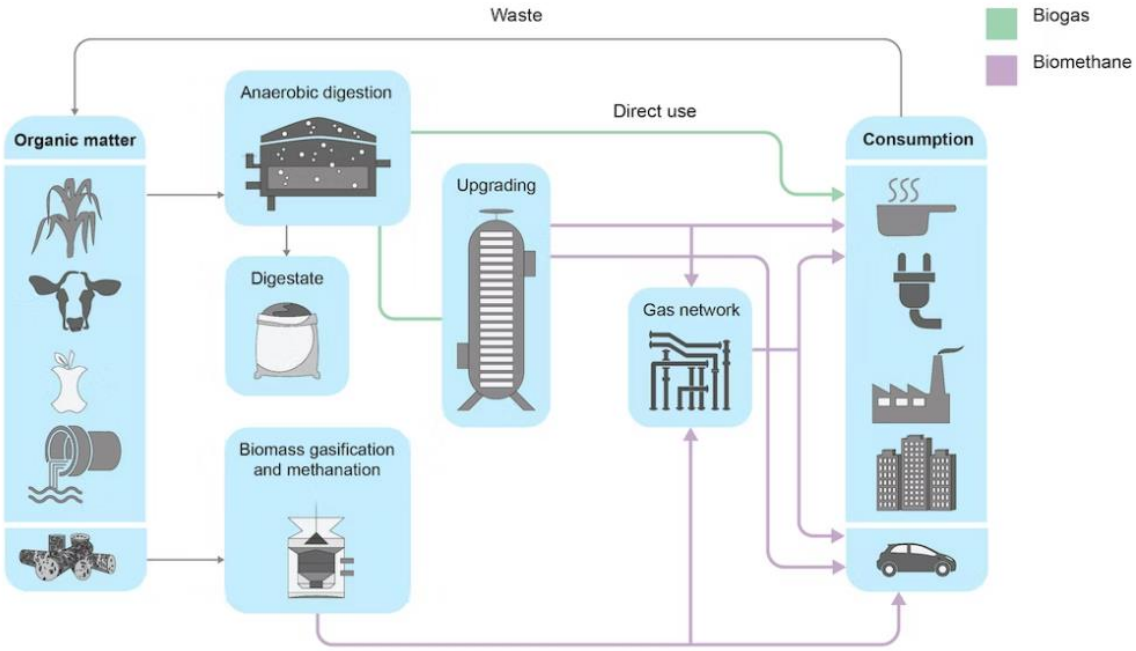

Figure 11.1. Schematic of RNG production. Image credit: International Energy Agency (IEA).[52]

11.2.2 Carbon Management Byproducts as Agricultural Supplements

Some BiCRS process used to convert biomass also generate useful byproducts for agriculture. For example, biomass processed via pyrolysis and gasification produces biochar, a soil additive that can support soil microorganisms, mitigate heavy metal toxicity, and raise soil pH.[53,54] Biochar can often be applied in place of traditional fertilizers, which has downstream benefits for the environment, as it prevents nitrogen runoff into

[50] Kern County Department of Agriculture and Measurement Standards (2022) 2021 Kern Agricultural Crop Report. [23] (Note: we are assuming dry tons. This is not explicitly stated in the report, but is consistent with the fraction of California's livestock farms located in Kern County and the state-wide dairy manure biomass estimate in Baker *et al.* (2020) Getting to Neutral. p. 32., which is listed in bone-dry tons.)

[51] Assumptions made in this calculation: Livestock manure was reported as dry tons, conversion factor to biogas is 25%, molar ratio of CO_2 to CH_4 is 30%:70%, 1 metric ton of methane at atmospheric pressure is 57,800 cubic feet.

[52] IEA (no date) Introduction to biogas and methane. [21]

[53] ARS (no date) What is Pyrolysis? [2]

[54] ARS (no date) Exploring the Benefits of Biochar. [1]

waterways and the release of excess nitrous oxide (N_2O) into the atmosphere—a greenhouse gas that warms the planet 300 times as much as CO_2.[55]

Additionally, some biomass gasification processes and S-DAC facilities generate water as a byproduct. The biomass gasification for San Joaquin Renewables uses local wood waste and nut shells to generate water along with biochar, renewable natural gas (RNG), and CO_2 for sequestration.[56] Clean Energy Systems, which has an existing test facility at Kimberlina in Kern County,[57] and purchased the idle Delano biomass facility, also in Kern, with plans to develop it into a BiCRS facility (still in the pre-permitting and assessment phase),[58] also produces water as a byproduct of their oxy-fuel combustion system (Section 4). Though utilizing an entirely different process, Climeworks' solid direct air capture (S-DAC) system also generates water alongside CO_2, generating 0.8-2 tons of water per ton of CO_2 captured.[59]

11.3 Other Collaborative Opportunities

11.3.1 Multi-Use Potential

Another potential opportunity for symbiosis between regional agriculture and carbon management industries is to share resources—primarily land, but potentially water as well—with local agriculture.

If water resources become increasingly scarce and farmers are being required by new groundwater policies to make decisions to permanently fallow unproductive land, then land could be rented or sold to carbon management companies, who may have large land use requirements to operate facilities (especially if they rely on solar power). In this arrangement, the land would continue to be profitable through the rents paid. Additional funding could be raised if farmers sold water to carbon management industries to operate. Some companies in the green energy and carbon management space are explicitly looking for landowners to partner with to deploy their processes, including NovoHydrogen, a company planning to develop local hydrogen fuels without degrading the land,[60] and InterEarth, looking for sites appropriate for their direct biomass burial method.[61]

Some technologies hold the promise of being able to operate with high mobility or to be decentralized, with nodal facilities spread out over large areas. In terms of high mobility, one example is Charm Industrial—their biomass pyrolyzer equipment can fit in the back of

[55] Manthiram, Gribkoff (July 15, 2021) Explainer - Fertilizer and Climate Change. [28]
[56] San Joaquin Renewables (no date) The Project. [38]
[57] Clean Energy Systems (no date) Site Locations. [12]
[58] Cox (December 4, 2021) Idle biomass plant near Delano would reopen. [13]
[59] Lebling *et al.* (May 2, 2022) 6 Things to Know About Direct Air Capture. [27]
[60] NovoHydrogen (no date) Partner with Us. [33]
[61] InterEarth (no date) For Farmers. [20]

a semi-trailer and can be driven directly to a site, so biomass doesn't have to be transported to a central processing facility.[62] Charm also pays farmers to be able to collect their biomass, and their unit can be temporarily stationed on the edge of a field during harvest season, when there is an abundance of waste biomass, and then offsite the rest of the year.[63] In terms of diffuse land use, direct air capture (DAC) is a prime example of technology that works well spread out across the land. Although DAC contactors can be placed anywhere (see Section 3), there is likely a minimum spacing of several hundred yards between contactors, to ensure the CO_2-free exhaust of one contactor fan does not directly feed into the next.[64] The space between contactors could be used for other land-intensive purposes, like farming or solar panels. However, there are uncertainties about how well crops would handle growing in between units that absorb CO_2 from the atmosphere, as plants also need to absorb CO_2 from the atmosphere to grow successfully.[65] This issue warrants further investigation.

11.3.2 Greenhouses

Greenhouses are experiencing a period of growth in California, driven primarily by drought conditions and an increasing consumer demand for organic and locally-grown produce.[66] This is because greenhouses promote higher productivity, even in less optimal environments: farming can take place on a smaller land footprint with lower water usage while still obtaining high crop yields.[67] Innovations like UC Santa Cruz's solar greenhouse, which uses transparent solar panels to filter light and help offset operational costs, are working towards the development of greenhouses that could be used "in most of California" rather than just along the coast.[68] Although these developments are still in pre-commercial stages, it presents another opportunity for the long-term future of agriculture in Kern County and California at large.

If greenhouses were implemented in Kern County, some of the CO_2 captured by carbon management industries could be supplied to the greenhouses to encourage plant growth. CO_2 must be very pure to not damage the plants,[69] but increasing the CO_2 concentration of the ambient air inside greenhouses can increase yields of some crops by up to 25-30% with CO_2 application.[70] Typically, greenhouses obtain CO_2 from combustion of natural gas, which also serves as a heat source for the facility. A retrofitted oil pipeline in the

[62] Temple (May 26, 2022) Charm Industrial's big bet. [43]
[63] Temple (May 26, 2022) Charm Industrial's big bet. [43]
[64] Herzog (February 4, 2021) Direct air capture: A process engineer's view. 16:05-16:34. [19]
[65] Ontario Ministry of Agriculture, Food, and Rural Affairs (August 2009) Carbon Dioxide in Greenhouses. [35]
[66] Murdock (July 23, 2018) Solar Greenhouse. [30]
[67] Murdock (July 23, 2018) Solar Greenhouse. [30]
[68] Murdock (July 23, 2018) Solar Greenhouse. [30]
[69] IEA (2019) Putting CO_2 to Use. [22]
[70] IEA (2019) Putting CO_2 to Use. [22]

Netherlands spanning over 180 miles demonstrates a viable alternative: the pipeline supplies 500,000 metric tons of CO_2 annually (captured from hydrogen production) to over 600 greenhouses in the region, and without the need of producing CO_2 from natural gas combustion, the greenhouses are able to switch to more sustainable heat sources.[71]

11.3.3 Other Potential Opportunities

This report is not comprehensive. There are other opportunities in the agribusiness space that may work symbiotically with carbon management technologies but were not identified to be good fits for Kern County at this time, and thus were not explored further here, although some examples are discussed in greater detail in other sections of the report. These include developing dedicated biomass crops to sustain BiCRS operations (also addressed in Section 3) or using CO_2 to promote algae growth to generate petroleum substitutes[72] (also addressed in Section 10).

A proposed component of the Carbon Management Business Park is a dedicated Research and Development Incubator, which would be an ideal setting for the exploration of new ways that local agriculture and carbon management industries could serve one another.

[71] OCAP (no date) Factsheet: Pure CO2 for Greenhouses. [34]

[72] IEA (2019) Putting CO_2 to Use. [22]

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Appendices

Appendix A. Existing commercial and industrial power facilities with CCS

Appendix B. Commercial and industrial power facilities with CCS in advanced development

Appendix C. Commercial and industrial power facilities with CCS in early development

Appendices A-C are summarized from the Global CCS Institute (GCCSI) CO_2RE Facilities Database, a list of all historical, active, and developing carbon-capture related projects worldwide. The database is maintained, and updated regularly to reflect status updates and new projects. The lists represented by Appendices A-C represent the status of the global carbon management industry as of the publication of this report. The database was sampled for this report on March 18, 2023.[1]

Appendix D. Comparative analysis of carbon management industries

A primary objective of this report is to provide an accessible resource for cost-benefit analysis of a variety of carbon management technologies that could hypothetically be developed in Kern County. We developed quantitative estimates of 6 key metrics across all 5 carbon management technologies examined in detail (L-DAC, S-DAC, BiCRS, green hydrogen from biomass, and steel with point source carbon capture):

- Land use
- Energy use
- Water use
- Job growth potential
- Cost to build (a proxy for potential county tax revenue)

[1] Global CCS Institute (GCCSI). CO_2RE Facilities Database. Published (no date). Accessed March 18, 2023 from https://co2re.co/FacilityData.

- Cost per ton CO_2 (a reflection of the competitiveness of the industry in the emerging carbon market)

Details of how each estimate was determined is given in the relevant section of the report, but how each industry compares with each other across these six metrics is shown visually in Appendix D across a suite of Figures D.1- D.6. The same figures are provided in the Comparative Analysis section of the companion website, at cmbp.kernplanning.com.

Appendix A. Existing commercial and industrial power facilities with CCS

Facility Name	Country	Operational	Industry
Terrell Natural Gas Processing Plant (formerly Val Verde)	USA	1972	Natural gas processing
Enid Fertilizer	USA	1982	Fertilizer production
Shute Creek Gas Processing Plant	USA	1986	Natural gas processing
MOL Szank field CO2 EOR	Hungary	1992	Natural gas processing
Sleipner CCS Project	Norway	1996	Natural gas processing
Great Plains Synfuels Plant and Wayburn-Midale	USA	2000	Chemical production
Core Energy	USA	2003	Natural gas processing
In Salah CO2 Storage	Algeria	2004	Natural gas processing
Petrobras Santos Basin Pre-Salt Oil Field	Brazil	2008	Natural gas processing
Snohvit CO2 Storage	Norway	2008	Natural gas processing
Arkalon CO2 Compression Facility	USA	2009	Ethanol production
Century Plant	USA	2010	Natural gas processing
Bonanza BioEnergy	USA	2012	Ethanol production
Yanchang Integrated CCS Demonstration	China	2012	Chemical production
Air Products Steam Methane Reformer	USA	2013	Hydrogen production
Coffeyville Gasification Plant	USA	2013	Fertilizer production
Lost Cabin Gas Plant	USA	2013	Natural gas processing
PCS Nitrogen	USA	2013	Fertilizer production
Boundary Dam Unit 3	Canada	2014	Power plant - coal
Karamay Dunhua Oil Technology	China	2015	Chemical production (Methanol)
Quest	Canada	2015	Hydrogen production
Uthmaniyah CO2-EOR Demonstration	Saudia Arabia	2015	Natural gas processing
Abu Dhabi CCS (Emirates Steel Industries)	UAE	2016	Iron/steel production
Illinois Industrial Carbon Capture and Storage	USA	2017	Ethanol production
Petra Nova Carbon Capture	USA	2017	Power plant - coal
CNPC Jilin Oil Field CO2 EOR	China	2018	Natural gas processing
Gorgon Carbon Dioxide Injection	Australia	2019	Natural gas processing
Qatar LNG	Qatar	2019	Natural gas processing
Alberta Carbon Trunk Line (ACTL) - Nutrien	Canada	2020	Fertilizer production
Alberta Carbon Trunk Line (ACTL) - Sturgeon Refinery	Canada	2020	Hydrogen production
Guohua Jinjie	China	2020	Power plant - coal
Orca	Iceland	2021	Direct air capture
Glacier Gas Plant	Canada	2022	Natural gas processing
Red Trail Energy	USA	2022	Ethanol production
Sinopec Qilu-Shengli CCUS	China	2022	Chemical production

Appendix B.

Commercial and industrial power facilities with CCS in advanced development

Facility Name	Country	Operational	Industry
Stockholm Exergi BECCS	Sweden	2025	BiCRS/BECCS
HeidelbergCement	USA	2023	Cement production (incl. lime)
Norcem Brevik Cement Plant	Norway	2024	Cement production (incl. lime)
Antwerp@C - BASF Antwerp	Belgium	2030	Chemical production
Lake Charles Methanol	USA	2025	Chemical production
Farley DAC	USA		Direct air capture
Mammoth	Iceland	2024	Direct air capture
Occidental, 1PointFive	USA	2024	Direct air capture
Aberdeen Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Atkinson Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Bushmills Biorefinery CCS	USA	2024	Ethanol production
Casselton Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Central City Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Fairmont Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Federated Co-operatives Limited	Canada	2024	Ethanol production
Galva Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Goldfield Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Grand Junction Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Granite Falls Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Heron Lake Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Huron Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Lamberton Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Lawler Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Marcus Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Mason Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Merrill Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Mina Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Nevada Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Norfolk Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
One Earth Energy facility	USA	2025	Ethanol production
Onida Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production

Facility Name	Country	Operational	Industry
Otter Tail Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Plainview Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Project Interseqt - Plainview Ethanol Plant	USA	2024	Ethanol production
Redfield Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Shenandoah Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Sioux Center Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Steamboat Rock Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Superior Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Watertown Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Wentworth Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Wood River Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
York Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Wabash CO2 Sequestration	USA	2022	Fertilizer production
Air Liquide Refinery Rotterdam	Netherlands	2024	Hydrogen production
Air Products Net-Zero Hydrogen Energy Complex	Canada	2024	Hydrogen production
Air Products Refinery Rotterdam	Netherlands	2024	Hydrogen production
Baytown Low Carbon Hydrogen	USA	2027	Hydrogen production
Cliff Head CCS Project (Mid West Clean Energy Project)	Australia	2025	Hydrogen production
ExxonMobil Benelux Refinery	Netherlands	2024	Hydrogen production
Phillips 66 Humber Refinery	UK	2028	Hydrogen production
Polaris Carbon Storage	Norway	2024	Hydrogen production
Shell Refinery Rotterdam CCS	Netherlands	2024	Hydrogen production
Louisiana Clean Energy Complex	USA	2026	Hydrogen production
Federated Co-operatives Limited	Canada	2026	Hydrogen production (Oil refining)
Prax Lindsey Carbon Capture Project	UK	2028	Hydrogen production (Oil refining)
Abu Dhabi CCS (Natural gas processing plant)	UAE	2025	Natural gas processing
Bayu-Undan CCS	Timor-Leste	2027	Natural gas processing
Ghasha Concession Fields	UAE	2025	Natural gas processing
Lang Lebah	Malaysia	2026	Natural gas processing
Northern Delaware Basin	USA	2023	Natural gas processing
PTTEP Arthit	Thailand	2026	Natural gas processing
Guodian Taizhou Power Station	China	2023	Power plant - coal
Cal Capture	USA	Mid-2020's	Power plant - NG
Capital Power Genesee	Canada	2026	Power plant - NG

Facility Name	Country	Operational	Industry
Coyote Clean Power Project	USA	2025	Power plant - NG
Deer Park Energy Centre	USA		Power plant - NG
James M. Barry Electric Generating Plant	USA	2030	Power plant - NG
Mustang Station of Golden Spread Electric Cooperative	USA		Power plant - NG
Peterhead CCS Power Station	United Kingdom	2026	Power plant - NG
Plant Daniel Carbon Capture	USA		Power plant - NG
VPI Immingham power plant	United Kingdom	2027	Power plant - NG
Acorn Storage Site	United Kingdom	2025	Infrastructure
Bayou Bend CCS	USA	2025	Infrastructure
Bridgeport Energy Moonie CCUS Project	Australia	2023	Infrastructure
CODA Shipping	Iceland	2026	Infrastructure
CODA Terminal Onshore Infrastructure	Iceland	2026	Infrastructure
CODA Terminal Pipeline	Iceland	2026	Infrastructure
CODA Terminal Storage	Iceland	2026	Infrastructure
East Coast Cluster	United Kingdom	2025	Infrastructure
East Coast Cluster Humber Pipeline	United Kingdom	2025	Infrastructure
East Coast Cluster Teesside Pipeline	United Kingdom	Mid-2020's	Infrastructure
Endurance Storage Site	United Kingdom	2025	Infrastructure
Porthos - Compressor Station	Netherlands	2024	Infrastructure
Porthos - Offshore Pipeline	Netherlands	2024	Infrastructure
Porthos Storage	Netherlands	2025	Infrastructure
Project Greensand	Denmark	2025	Infrastructure
Prothos - Onshore Pipeline	Netherlands	2024	Infrastructure
Southeast Saskatchewan CCUS Hub - Storage	Canada		Infrastructure
Stockholm Exergi BECCS - Shipping Route	Sweden	2025	Infrastructure
Summit Pipeline	USA	2024	Infrastructure
Viking CCS Pipeline	United Kingdom	2027	Infrastructure
Viking CCS Storage Site	United Kingdom	2027	Infrastructure
Norcem Brevik - Shipping Route	Norway	2024	Infrastructure
Northern Lights - Storage	Norway	2024	Infrastructure
Copenhill (Amager Bakke)	Denmark	2025	Waste-to-energy
Hafslund Oslo Celsio-Truck Route	Norway	2025	Waste-to-energy
Hafslund Oslo Celsio	Norway	2024	Waste-to-energy

Appendix C.

Commercial and industrial power facilities with CCS in early development

Facility Name	Country	Operational	Industry
Clean Energy Systems BiCRS Plant - Madera County	USA	2027	BiCRS/BECCS
Clean Energy Systems Carbon Negative Energy Plant	USA	2025	BiCRS/BECCS
Cyclus Power Generation	USA		BiCRS/BECCS
Drax BECCS Project	UK	2027	BiCRS/BECCS
Mendota BECCS	USA	2025	BiCRS/BECCS
Air Liquide CalCC	France	2028	Cement production
CEMEX	Germany	2026	Cement production
GO4ECOPLANET	Poland		Cement production
HyNet North West - Hanson Cement	UK	2026	Cement production
K6	France		Cement production
LafargeHolcim Cement Carbon Capture	USA	Mid-2020's	Cement production
LafargeHolcim Ste. Genevieve Cement Plant	USA		Cement production
Antwerp@C - Borealis Antwerp	Belgium	2030	Chemical production
Antwerp@C - Exxonmobil Antwerp Refinery	Belgium	2030	Chemical production
Antwerp@C - Ineos Antwerp	Belgium	2030	Chemical production
Hackberry Carbon Sequestration Project (Sempra)	USA		Chemical production
The Illinois Clean Fuels Project	USA	2025	Chemical production
Velocys' Bayou Fuels Negative Emission Project	USA	2026	Chemical production
Nauticol Energy Net Zero Methanol	Canada	Mid-2020's	Chemical production (Methanol)
Acorn Direct Air Capture Facility	UK	2026	Direct air capture
FS Lucas do Rio Verde	Brazil		Ethanol production
Midwest AgEnergy Blue Flint Ethanol	USA	2022	Ethanol production
Project Interseqt - Hereford Ethanol Plant	USA	2023	Ethanol production
Barents Blue	Norway	Mid-2020's	Fertilizer production
CF Fertilisers Billingham Ammonia CCS	UK	2023	Fertilizer production
El Dorado	USA	2024	Fertilizer production
ExxonMobil Donaldsonville	USA	2025	Fertilizer production
PAU Central Sulawesi Clean Fuel Ammonia Production	Indonesia	Mid-2020's	Fertilizer production
Project Pouakai Hydrogen Production	New Zealand	2024	Fertilizer production
Yara Sluiskil	Netherlands	2025	Fertilizer production
Acorn Hydrogen	UK	2025	Hydrogen production
Air Liquide Normandy CCS	France	2025	Hydrogen production
Buxton Lime Net Zero	UK	2024	Hydrogen production
H2NorthEast	UK	2027	Hydrogen production
Hydrogen 2 Magnum	Netherlands	2024	Hydrogen production
Hydrogen to Humber Saltend	UK	2027	Hydrogen production

Facility Name	Country	Operational	Industry
HyNet Hydrogen Production	UK	2025	Hydrogen production
HyNet North West	UK	Mid-2020's	Hydrogen production
Killinholme Power Station	UK	2027	Hydrogen production
L10 Carbon Capture and Storage	Netherlands	2026	Hydrogen production
Net Zero Teesside	UK	2027	Hydrogen production
Northern Gas Network H21	UK	2026	Hydrogen production
Polaris CCS	Canada	Mid-2020's	Hydrogen production
Preem Refinery	Sweden	2025	Hydrogen production
Project Pouakai Hydrogen Production	New Zealand	2024	Hydrogen production
Zeeland Refinery Azur	Netherlands	2026	Hydrogen production
Sukowati CCUS	Indonesia	2028	Hydrogen production (Oil refining)
Vertex Hydrogen	UK	2025	Hydrogen production (Oil refining)
ArcelorMittal Texas (formerly voestalpine Texas)	USA		Iron/steel production
Caroline Carbon Capture Power Complex	Canada	Mid-2020's	Natural gas processing
G2 Net-Zero LNG	USA		Natural gas processing
Grand Forks Blue Ammonia Capture plant	USA		Natural gas processing
INPEX CCS Project Darwin	Australia	2026	Natural gas processing
NextDecade Rio Grande LNG	USA	2025	Natural gas processing
Novatek Yamal LNG	Russia	Late 2020's	Natural gas processing
Otway Natural Gas Plant	Australia	2026	Natural gas processing
Repsol Sakakemang Carbon Capture and Injection	Indonesia	2026	Natural gas processing
South East Australia Carbon Capture Hub	Australia	2025	Natural gas processing
Dave Johnston Plant	USA	2020's	Power plant - coal
Diamond Vault CCS	USA	2028	Power plant - coal
Dry Fork Integrated CCS	USA	2025	Power plant - coal
Korea-CCS 1&2	South Korea	2020's	Power plant - coal
Caledonia Clean Energy	UK	2025	Power plant - NG
Caroline Carbon Capture Power Complex	Canada	Mid-2020's	Power plant - NG
Damhead Powerstation	UK		Power plant - NG
Ervia Cork CCS	Ireland	2028	Power plant - NG
Illinois Allam-Fetvedt cycle power plant	USA	2025	Power plant - NG
Keady 3 CCS Power Station	UK	2027	Power plant - NG
Medway Power Station	UK		Power plant - NG
Net Zero Teesside - NET Power Plant	UK	Mid-2020's	Power plant - NG
Net Zero Teesside CCGT Facility	UK	2025	Power plant - NG
Pembroke Power Station	UK	2030	Power plant - NG
Project Pouakai Hydrogen Production	New Zealand	2024	Power plant - NG
Saskatchewan NET power plant	Canada	Mid-2020's	Power plant - NG
Whitetail Clean Energy	UK		Power plant - NG

Facility Name	Country	Operational	Industry
Cane Run CCS	USA		Power plant - NG
Acorn	UK	Mid-2020's	Infrastructure
Acorn CO2 Pipeline	UK	2026	Infrastructure
Arun CCS Hub	Indonesia	2029	Infrastructure
Borg CO2	Norway		Infrastructure
Burrup CCS Hub	Australia		Infrastructure
Carbon TerraVault I	USA	2025	Infrastructure
Cinfracap - Pipeline	Sweden	2026	Infrastructure
Cinfracap - Shipping Route	Sweden	2026	Infrastructure
Coastal Bend CCS	USA	2026	Infrastructure
Damhead Pipeline	UK		Infrastructure
Delta Corridor Pipeline Network	Netherlands	2026	Infrastructure
Fortum Oslo Varme - Shipping Route	Norway	2025	Infrastructure
Heartland Greenway Storage	USA	2025	Infrastructure
HyNet Pipeline	UK	2025	Infrastructure
Hynet Storage Site	UK	2025	Infrastructure
Isle of Grain LNG Terminal	UK	2026	Infrastructure
Jubail CCS	Saudia Arabia	2027	Infrastructure
Medway Hub - Esmond and Forbes Carbon Storage	UK		Infrastructure
Medway Hub Shipping	UK		Infrastructure
Northern Lights - Pipeline	Norway	2024	Infrastructure
Origins Project Carbon Storage Hub	Canada	2026	Infrastructure
Ravenna CCS Hub	Italy	2027	Infrastructure
River Bend CCS Louisiana Pipeline	USA	2026	Infrastructure
Net Zero Teesside	UK	2027	Waste-to-energy
Runcorn Carbon Capture	UK		Waste-to-energy
Tees Valley Energy Recovery Facility Project	UK	2026	Waste-to-energy

Appendix D.
Comparative analysis of carbon management industries

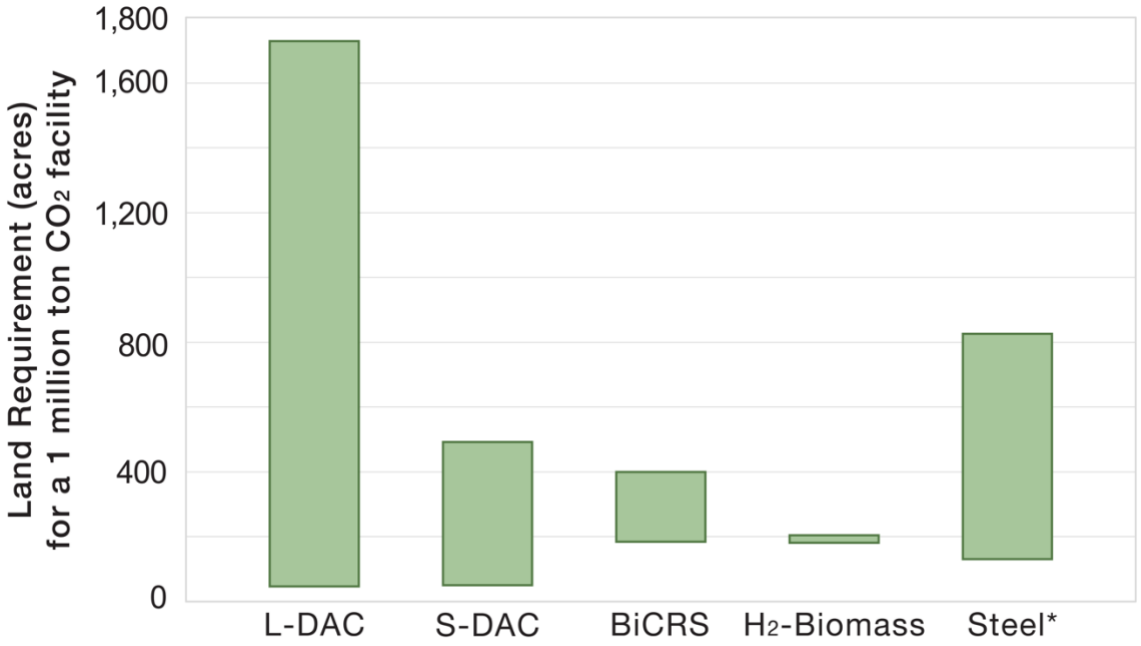

Figure D.1. Land Use. To capture 1 million metric tons of CO_2, the land use requirements of facilities vary considerably. Across the examined industries, estimated footprints range from 0.08 to 2.73 square miles (49-1730 acres). In cases where there is not an operational facility with the capacity to capture carbon at the million ton scale (L-DAC, S-DAC and green hydrogen from biomass) these footprints are industry-provided estimates of needed space. For established industries (steel and BiCRS), the range of values reflects the variability of existing facility footprints, most of which are not actively capturing CO_2. The range in land use is mostly due to availability and affordability of land, and the retrofitting of these types of facilities with carbon capture equipment would likely not result in a significant change in areal footprint. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

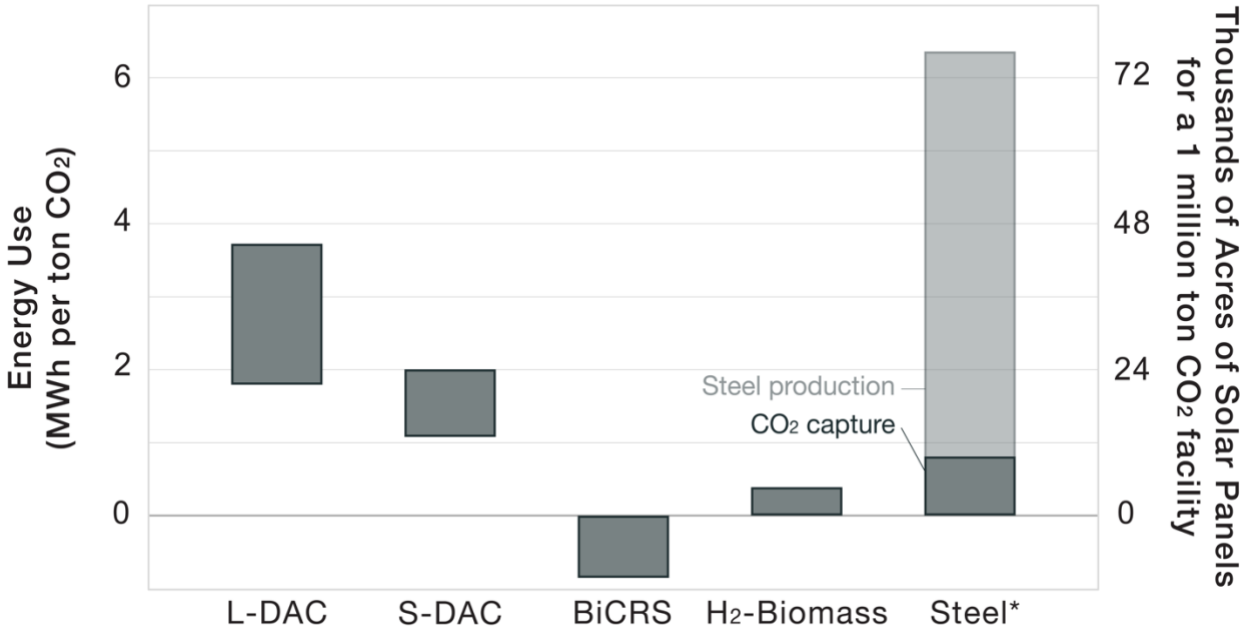

Figure D.2. Energy Use. Most carbon management industries (L-DAC, S-DAC, green hydrogen from biomass, and steel) are energy intensive, requiring both electricity and heat energy. DAC technologies require the largest amounts of energy per ton of CO_2 captured, whereas most of the energy demand for steel goes into steel production (the light shaded region) rather than CO_2 capture (the dark shaded region). Green hydrogen from biomass is less energy-intensive, and like steel, the energy needs also generate a different primary output: production of H_2 gas. Other forms of BiCRS (including BECCS) generate more energy than they consume, and are thus able to power their own production, with some facilities also selling energy to the grid. As a result, BiCRS facilities do not require an external energy supply unless it is more profitable to sell their output (i.e. biofuel, syngas) than to use it to operate the facility. An additional critical factor to note is that any facility using solar PV for their energy needs will also require electricity and heat storage (batteries) to ensure uninterrupted supply of electricity and that heat is provided at the required temperatures (100-1000°C, depending on industry). *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used. The more power supplied by solar energy, the less CO_2 the steel mill would produce.

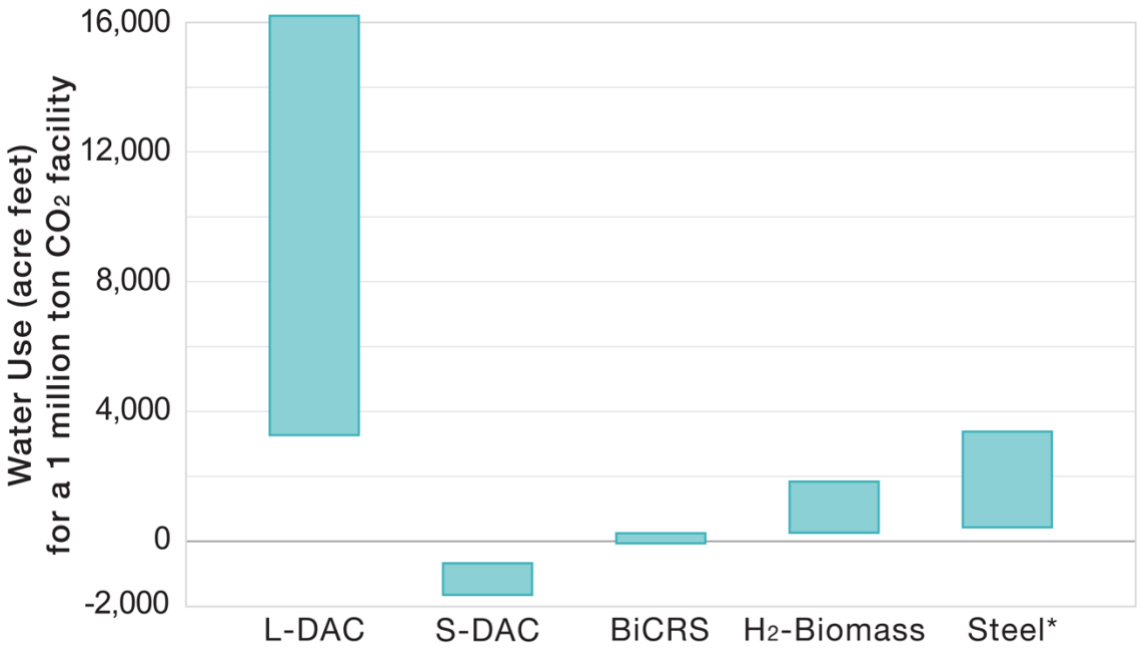

Figure D.3. Water Use. Water use is one of the most variable categories across carbon management industries. Hydrogen production via biomass, steel and particularly L-DAC technologies are water-intensive practices, using as much as 16,200 acre feet of water annually. Meanwhile, BiCRS and S-DAC technologies can actually generate excess water by capturing it from biomass feedstocks or the atmosphere. This water yield depends on the specific process a facility uses, but could be as much as 1,650 acre feet annually. Due to the arid environment in large parts of Kern County, mindfulness about the water intensity of these industries is crucial to ensure supplies can continue to meet a mixture of residential, agricultural, and industrial demands for decades to come. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

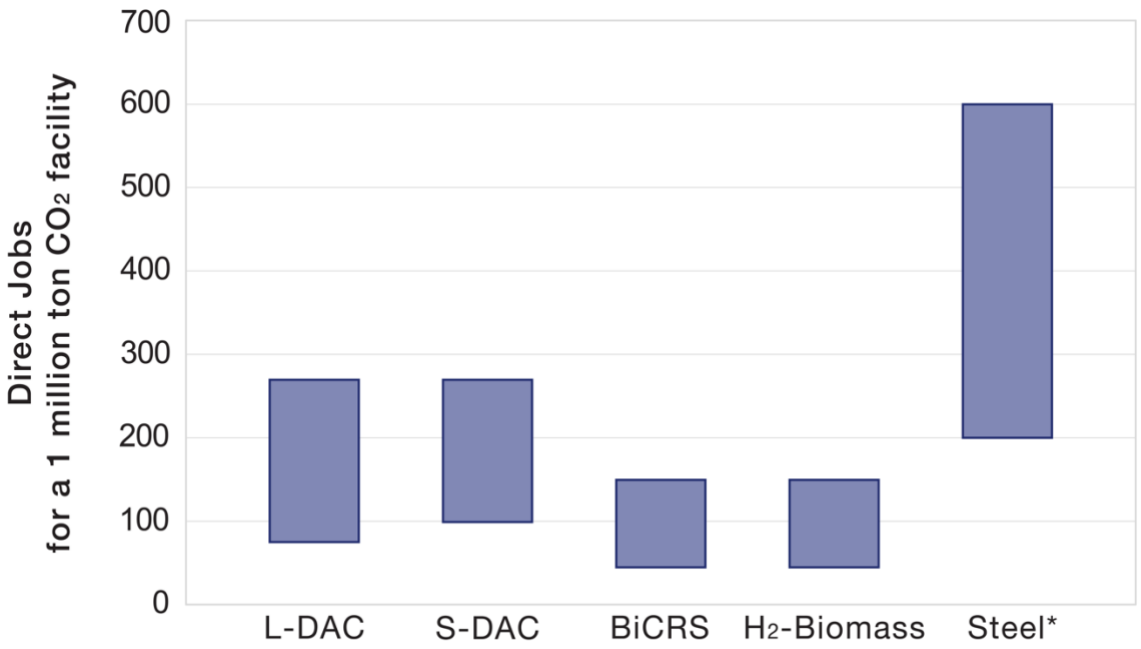

Figure D.4. Job Development Potential. The job growth potential of carbon management facilities can be difficult to quantify, as different companies rely on different processes—even within the same industry—that shapes their labor demands. Industries like BiCRS and hydrogen production via biomass expect to have lower labor demands, similar to that required to operate bioenergy power plants that do not utilize carbon capture. L-DAC and S-DAC have larger expected labor demands, mainly to monitor and maintain contactor units, although it is possible that some of these jobs could be performed remotely, and would not necessarily benefit the host community. Steel is likely to provide the most jobs. It is important to note that job growth potential for many of these industries was determined from the number of jobs at smaller facilities, and because the need for workers does not scale linearly with facility size, these are rough estimates. Furthermore, the possibilities of increased automation and remote monitoring means that steps should be taken in the planning and permitting process to ensure jobs for any new carbon management facility benefits local communities. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

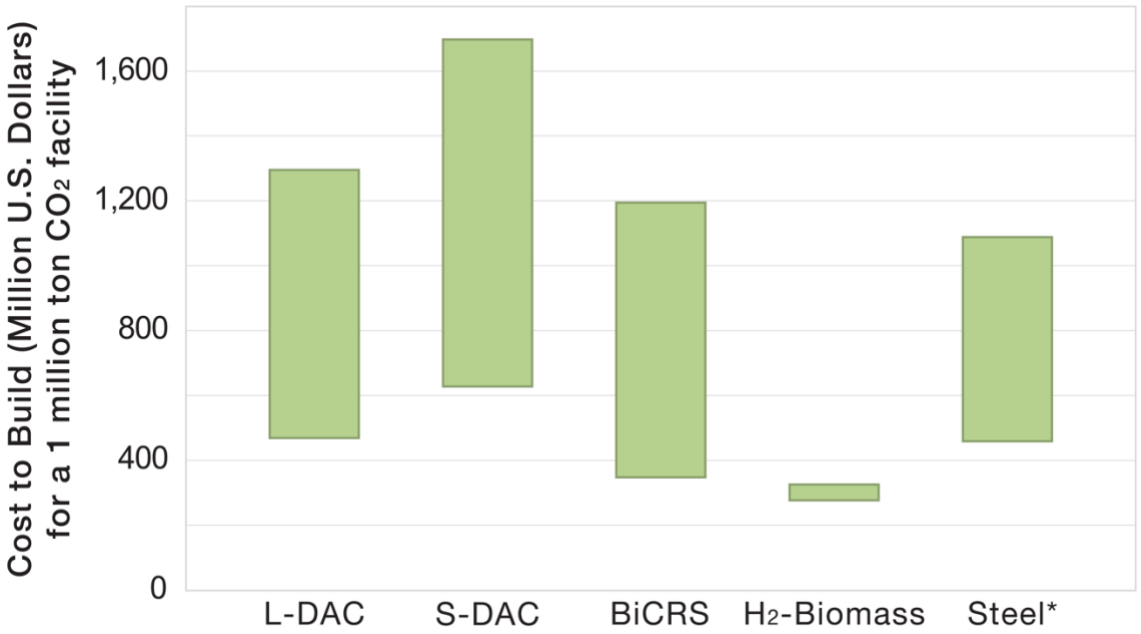

Figure D.5. Cost to Build. Building a new carbon management site comes with considerable expense—securing land, planning, engineering, permitting and zoning, environmental assessments, and other details will need to be handled before construction even begins. Across all of these carbon management industries, upfront costs range from $278 million to 1.7 billion. Costs are generally expected to be higher for the direct air capture industries (L-DAC and S-DAC) than for the biomass-based hydrogen production, BiCRS and steel facilities. However, many of these industries have never been built at a scale that could capture 1 million metric tons of CO_2 per year, which accounts for the large ranges of uncertainty in their upfront costs. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

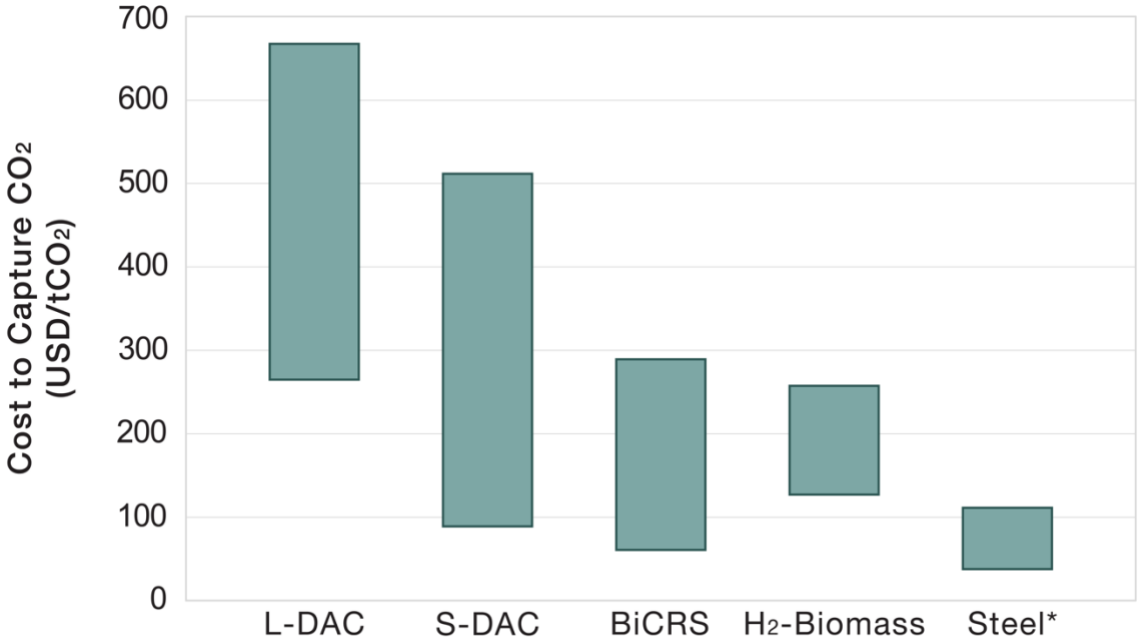

Figure D.6. Cost to Capture. The levelized cost per metric ton of CO_2 is a good way to consider overall costs—it accounts for the cost of building the facility (capital costs), the cost of maintenance and labor (operational costs), and the cost of energy (heat + electricity) over the lifetime of the plant. In these estimates, the plant lifetime has been fixed at 30 years to standardize estimates, though some of these facilities may have longer or shorter lifetimes. The cost of carbon capture is lowest for steel emissions, given the relatively high concentration of CO_2 in exhaust gases from this kind of facility, as well as the maturity of the technology. Biomass-based carbon capture (BiCRS or biomass hydrogen production) also generally have lower levelized cost estimate ranges than direct air capture (L-DAC and S-DAC). However, it is worth noting that 1) all of these costs are likely to decrease as carbon capture technologies mature, and 2) which of these industries is economically viable depends both on the levelized cost and on the potential sources of revenue to recoup that cost, which varies across industries. *The cost to capture CO_2 for the steel facility only considers the cost of building and operating the capture equipment. It does not incorporate the capital and operational costs of the steel mill itself.



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ANALYSIS OF POTENTIAL FISCAL AND ECONOMIC BENEFITS OF KERN COUNTY CARBON MANAGEMENT INDUSTRY

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1.0 INTRODUCTION

This report evaluates the potential fiscal and economic benefits that would be created by the development of a carbon management industry in Kern County. Specifically, the report quantifies the direct fiscal and economic impacts of the proposed Carbon Management Business Park (CMBP), and the indirect impacts that would be generated by related firms that the CMBP would support elsewhere in Kern County.

1.1. Categories of Benefits Evaluated

The study considers the following categories of fiscal and economic benefits:

Fiscal Benefits

- Property tax revenue accruing to the County of Kern General Fund and Fire Fund
- Sales tax revenue accruing to the County of Kern General Fund
- Property tax revenue accruing to city General Funds
- Sales tax revenue accruing to city General Funds

Broader Economic Benefits

- Jobs created
- Payroll created
- Total business activity (the dollar volume of "output") supported

Given the undefined nature of the indirect (offsite) benefits of the CMBP, the study does not attempt to quantify potential benefits to individual/specific cities (since the specific locations of supported businesses are unknown). Instead, potential city-level benefits are shown as aggregate numbers (i.e., for all cities combined).

1.2. Profile of Business Types in CMBP

As conceived by the Kern County Planning and Natural Resources Department, the proposed CMBP would encompass 4,200 acres in unincorporated Kern County. Although a specific site has not been identified yet, it is anticipated that the park would be developed on agricultural land that would be rezoned for industrial uses and the location would generally be west of Interstate 5.

The assumed mix of carbon management and related activities within the CMBP is as follows:

Business Type (Carbon Capture Technology)	Area
Liquid Direct Air Capture (L-DAC)	400 acres
Solid Direct Air Capture (S-DAC)	500 acres
Biomass Carbon Removal and Storage (BiCRS)	600 acres
Green Hydrogen (H2)	600 acres
Steel Micro Mill	600 acres
Research & Development Incubator Site	500 acres
Administrative Offices + Ancillary Clean Energy Industries	1,000 acres
Total (with 31 million square feet of industrial building space)	4,200 acres

1.3. Overview of Study Scope and Methodology

In completing this study, The Natelson Dale Group, Inc. (TNDG) has relied on industry profiles (for each of the above business types) prepared by Blue Engine for the CMBP project. In particular, the Blue Engine team has quantified the following economic variables for each CMBP component:

- Permanent (operational) jobs
- Operations and maintenance costs
- Capital costs

Blue Engine has also provided general descriptions of the types of carbon capture businesses that might be the "tenants" within each component of the park. From these descriptions, TNDG has selected specific industries (i.e., NAICS codes) representative of these business types for purposes of evaluating the projects fiscal and economic impacts.

The direct property tax impacts of the CMBP have been estimated by TNDG based on projected land re-assessment (from converting the underlying land from agricultural and industrial uses) plus anticipated improvement costs (based on the Blue Engine data). Indirect property taxes (i.e., from offsite businesses that would be developed as part of a countywide carbon management industry anchored by the CMBP) have been estimated using the IMPLAN model[1].

The IMPAN model has also been used to estimate direct and indirect sales tax revenue, as well as broader economic impacts such as job creation, payroll, and supported countywide business activity.

Due to the somewhat speculative nature of the CMBP (composed of industries that in many cases are still in early stages of development globally), the Blue Engine research is understood to provide general/

[1] This model was developed by researchers at the University of Minnesota and is widely used in economic impact analysis throughout the Country. This software is classified as an "Input-Output" (IO) model that computes all of the economic impacts of industries in a user-defined region (in this case, Kern County), including the estimated local expenditures of employees of both project-direct and supplier firms. The current version of the IMPLAN model divides the economy into 546 sectors that correspond to 4-digit and 5-digit NAICS codes.

approximate estimates of costs and employment. As such, the Blue Engine numbers are often expressed in broad ranges (e.g., the Liquid Direct Air Capture operation would support 75 to 270 permanent jobs per 1 million in CO2 captured annually). Since TNDG's analysis stems from the Blue Engine estimates, TNDG's numbers are expressed in terms of a "Low Scenario" and a "High Scenario" corresponding the Blue Engine's ranges.

2.0 EXECUTIVE SUMMARY

2.1. Fiscal Benefits of Carbon Management Industry

Table II-1, on the following page, summarizes the potential fiscal benefits of the proposed CMBP and the related countywide carbon management industry. All dollar amounts are expressed in 2023 dollars.

Fiscal Benefits to County of Kern. At full buildout, the CMBP and related offsite industries would generate total property tax income (General Fund plus Fire Fund) of $24.2 million (Low Scenario) to $56.2 million (High Scenario) per year.[2]

Total sales tax income to the County's General Fund is projected to range between $4.2 million and $7.9 million per year.[3]

Fiscal Benefits to Incorporated Cities. Whereas the direct impacts of the CMBP would occur in unincorporated Kern County (where the park would be located), the indirect impacts associated with the overall carbon management industry would potentially be spread throughout the county. Given the undefined nature of these indirect benefits, the study does not quantify potential benefits to individual/ specific cities (since the specific locations of supported businesses are unknown). Instead, potential city-level benefits are shown as aggregate numbers (i.e., for all cities combined).

The CMBP and related offsite industries would generate total property tax income to city General Funds of $4.5 million (Low Scenario) to $8.4 million (High Scenario) per year.

Total sales tax income (to city General Funds) is projected to range between $8.4 million and $15.6 million per year.[4]

[2] The projections of property tax generation are largely driven by the very substantial capital facility investments associated with carbon management projects. For purposes of this study, assessed valuation has been estimated based on total capital investments at the time facilities are completed and put into operation. To the extent these capital facility values are depreciated without offsetting capital reinvestments, property tax revenues from these facilities could decline over time.

[3] The sales tax projections are derived from the IMPLAN model; the IMPLAN estimates for Kern County have been adjusted by TNDG to reflect the recent passage of Measure K, which effectively doubles the County's local sales tax rate.

[4] A significant portion of the sales tax revenue projected in this analysis would be derived from indirect impacts (i.e., CMBP businesses making purchases at other Kern County firms) and induced impacts (i.e., CMBP employees spending their payroll incomes at local businesses). Since many of these indirect/induced expenditures would occur in incorporated cities, the CMBP would create larger sales tax impacts to city General Funds than to the County's General Fund.

Table II-1

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)
INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

LOW SCENARIO

	County		*Cities*	
Project Component	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture	$669,000	$3,163,700	$1,316,700	$709,500
Solid Direct Air Capture	$130,500	$4,326,800	$256,800	$138,400
Biomass Carbon Removal & Storage	$261,300	$1,836,800	$514,300	$277,200
Green Hydrogen	$84,600	$3,148,100	$166,400	$89,700
Steel Micro Mill	$111,800	$1,936,400	$220,000	$118,500
R&D Incubator Site	$581,400	$1,863,300	$1,144,200	$616,600
Ancillary Clean Energy Industries	$2,439,500	$7,895,100	$4,801,200	$2,587,200
Total CMBP and Offsite Support	$4,278,100	$24,170,200	$8,419,600	$4,537,100

HIGH SCENARIO

	County		*Cities*	
Project Component	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture	$1,226,500	$8,599,900	$2,413,900	$1,300,700
Solid Direct Air Capture	$344,000	$11,659,400	$677,000	$364,800
Biomass Carbon Removal & Storage	$1,835,900	$13,841,200	$3,613,300	$1,947,100
Green Hydrogen	$301,200	$4,124,200	$592,900	$319,500
Steel Micro Mill	$168,400	$4,406,800	$331,400	$178,600
R&D Incubator Site	$775,300	$2,681,300	$1,525,800	$822,200
Ancillary Clean Energy Industries	$3,252,600	$10,920,300	$6,401,400	$3,449,500
Total CMBP and Offsite Support	$7,903,900	$56,233,100	$15,555,700	$8,382,400

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Property Tax includes General Fund and County Fire Fund.

2.2. Broader Economic Benefits

Table II-2, on the following page, summarizes the broader economic benefits of the proposed CMBP and the related countywide carbon management industry. All dollar amounts are expressed in 2023 dollars.

Total business activity supported. The potential volume ("output") associated with the CMBP and related offsite activities is projected to range from $4.5 billion (Low Scenario) to $6.9 billion (High Scenario) per year.

Total jobs supported. At full buildout, the CMBP and related offsite activities would directly and indirectly support 13,500 to 22,000 permanent jobs.

Total payroll generated. The total direct and indirect payroll associated with these jobs is projected to range from $1.1 billion to $1.8 billion per year, representing an average annual wage of approximately $80,000.

Table II-2

POTENTIAL ECONOMIC IMPACTS
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

LOW SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture	197	$16,524	$117,945	$184,594
Solid Direct Air Capture	280	23,463	23,004	36,002
Biomass Carbon Removal & Storage	186	20,355	29,577	64,855
Green Hydrogen	368	43,675	32,989	74,886
Steel Micro Mill	500	36,999	30,400	119,439
R&D Incubator Site	325	30,073	47,059	85,755
Ancillary Clean Energy Industries	11,682	888,418	1,564,302	3,975,561
Total CMBP	13,540	$1,059,508	$1,845,277	$4,541,092

HIGH SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture	711	$59,485	$184,714	$338,423
Solid Direct Air Capture	756	63,230	48,574	94,915
Biomass Carbon Removal & Storage	1,368	149,670	149,168	455,611
Green Hydrogen	1,228	145,583	88,822	266,780
Steel Micro Mill	1,501	110,998	37,973	179,934
R&D Incubator Site	876	81,043	99,760	231,094
Ancillary Clean Energy Industries	15,575	1,184,478	1,859,499	5,300,389
Total CMBP	22,014	$1,794,487	$2,468,510	$6,867,148

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

3.0 DETAILED SUMMARY OF FISCAL AND ECONOMIC IMPACTS

This section provides a detailed summary of the ongoing fiscal and economic impacts associated with the CMBP. For fiscal impacts, the analysis shows the ongoing property tax and sales tax revenues that would be generated for the County and incorporated cities in the County. For economic impacts, the analysis shows annually-recurring impacts related to employment, employee compensation, value added, and output (i.e., total dollar volume of business activity).

3.1. CMBP Sales Tax and Property Tax Impacts

Tables III-1 and III-2 (pages 9 and 10) show the direct and indirect sales tax and property tax impacts associated with each proposed CMBP component, along with the total for the entire proposed CMBP. Table III-1 shows the "low" scenario (reflecting more conservative direct employment and operating cost estimates), while Table III-2 shows the "high" scenario (reflecting higher direct employment and operating cost estimates).

3.2. CMBP Economic Impacts

Tables III-3 and III-4 (pages 11 and 12) show the direct and indirect/induced economic impacts associated with each proposed CMBP component, along with the total for the entire proposed CMBP. Table III-1 shows the "low" scenario (reflecting more conservative direct employment and operating cost estimates), while Table III-2 shows the "high" scenario (reflecting higher direct employment and operating cost estimates).

Table III-1

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)
INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

LOW SCENARIO

	County		*Cities*	
Impact Measure	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture				
Direct	$627,912	$3,014,656	$1,235,790	$665,920
Indirect	$41,089	$149,067	$80,867	$43,576
Total	$669,001	$3,163,723	$1,316,657	$709,496
Solid Direct Air Capture				
Direct	$122,465	$4,297,682	$241,023	$129,878
Indirect	$8,014	$29,073	$15,772	$8,499
Total	$130,479	$4,326,755	$256,795	$138,377
Biomass Carbon Removal & Storage				
Direct	$220,881	$1,689,984	$434,714	$234,251
Indirect	$40,461	$146,788	$79,631	$42,910
Total	$261,342	$1,836,772	$514,345	$277,161
Green Hydrogen				
Direct	$36,931	$2,975,317	$72,685	$39,167
Indirect	$47,626	$172,782	$93,732	$50,509
Total	$84,557	$3,148,099	$166,417	$89,676
Steel Micro Mill				
Direct	$58,109	$1,741,749	$114,364	$61,626
Indirect	$53,664	$194,688	$105,616	$56,912
Total	$111,773	$1,936,436	$219,980	$118,539
R&D Incubator Site				
Direct	$393,307	$1,180,952	$774,066	$417,115
Indirect	$188,070	$682,298	$370,140	$199,454
Total	$581,377	$1,863,251	$1,144,206	$616,569
Ancillary Clean Energy Industries				
Direct	$914,321	$2,361,905	$1,799,471	$969,666
Indirect	$1,525,172	$5,533,164	$3,001,683	$1,617,493
Total	$2,439,493	$7,895,069	$4,801,154	$2,587,159
Total Business Park Components				
Direct	$2,373,926	$17,262,245	$4,672,112	$2,517,624
Indirect	$1,904,095	$6,907,860	$3,747,441	$2,019,353
Total	$4,278,021	$24,170,105	$8,419,553	$4,536,977

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Direct Property Tax includes General Fund and County Fire Fund.

Table III-2

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)
INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

HIGH SCENARIO

	County		*Cities*	
Impact Measure	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture				
Direct	$1,151,171	$8,326,656	$2,265,614	$1,220,853
Indirect	$75,330	$273,290	$148,257	$79,890
Total	$1,226,501	$8,599,946	$2,413,871	$1,300,743
Solid Direct Air Capture				
Direct	$322,862	$11,582,788	$635,424	$342,406
Indirect	$21,127	$76,648	$41,581	$22,406
Total	$343,990	$11,659,436	$677,004	$364,812
Biomass Carbon Removal & Storage				
Direct	$1,551,707	$12,809,984	$3,053,907	$1,645,634
Indirect	$284,241	$1,031,197	$559,414	$301,447
Total	$1,835,948	$13,841,181	$3,613,320	$1,947,081
Green Hydrogen				
Direct	$131,568	$3,508,651	$258,939	$139,532
Indirect	$169,667	$615,535	$333,921	$179,937
Total	$301,236	$4,124,185	$592,860	$319,470
Steel Micro Mill				
Direct	$87,540	$4,113,513	$172,288	$92,839
Indirect	$80,845	$293,296	$159,110	$85,738
Total	$168,385	$4,406,809	$331,398	$178,578
R&D Incubator Site				
Direct	$524,473	$1,771,429	$1,032,214	$556,221
Indirect	$250,790	$909,841	$493,579	$265,971
Total	$775,264	$2,681,270	$1,525,793	$822,192
Ancillary Clean Energy Industries				
Direct	$1,219,061	$3,542,857	$2,399,229	$1,292,853
Indirect	$2,033,529	$7,377,432	$4,002,179	$2,156,622
Total	$3,252,590	$10,920,289	$6,401,407	$3,449,475
Total Business Park Components				
Direct	$4,988,384	$45,655,878	$9,817,614	$5,290,339
Indirect	$2,915,530	$10,577,239	$5,738,040	$3,092,012
Total	$7,903,914	$56,233,117	$15,555,654	$8,382,351

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Direct Property Tax includes General Fund and County Fire Fund.

Table III-3

POTENTIAL ECONOMIC IMPACTS
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

LOW SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture				
Direct	150	$12,163	$80,122	$120,000
Indirect/Induced	47	4,361	37,823	64,594
Total	197	$16,524	$117,945	$184,594
Solid Direct Air Capture				
Direct	213	$17,271	$15,627	$23,404
Indirect/Induced	67	6,192	7,377	12,598
Total	280	$23,463	$23,004	$36,002
Biomass Carbon Removal & Storage				
Direct	68	$10,986	$19,849	$46,500
Indirect/Induced	118	9,370	9,729	18,355
Total	186	$20,355	$29,577	$64,855
Green Hydrogen				
Direct	150	$25,978	$21,788	$53,333
Indirect/Induced	218	17,697	11,201	21,552
Total	368	$43,675	$32,989	$74,886
Steel Micro Mill				
Direct	235	$17,259	$14,950	$90,588
Indirect/Induced	265	19,741	15,450	28,851
Total	500	$36,999	$30,400	$119,439
R&D Incubator Site				
Direct	213	$21,587	$31,095	$57,322
Indirect/Induced	112	8,486	15,964	28,433
Total	325	$30,073	$47,059	$85,755
Ancillary Clean Energy Industries				
Direct	7,382	$563,778	$885,833	$2,727,538
Indirect/Induced	4,300	324,640	678,469	1,248,023
Total	11,682	$888,418	$1,564,302	$3,975,561
Total CMBP Components				
Direct	8,411	$669,022	$1,069,264	$3,118,686
Indirect/Induced	5,128	390,486	776,013	1,422,406
Total	13,540	$1,059,508	$1,845,277	$4,541,092

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

Table III-4

POTENTIAL ECONOMIC IMPACTS
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

HIGH SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture				
Direct	540	$43,786	$146,891	$220,000
Indirect/Induced	171	15,698	37,823	118,423
Total	711	$59,485	$184,714	$338,423
Solid Direct Air Capture				
Direct	574	$46,543	$41,198	$61,702
Indirect/Induced	182	16,687	7,377	33,213
Total	756	$63,230	$48,574	$94,915
Biomass Carbon Removal & Storage				
Direct	500	$80,777	$139,439	$326,667
Indirect/Induced	868	68,894	9,729	128,945
Total	1,368	$149,670	$149,168	$455,611
Green Hydrogen				
Direct	500	$86,594	$77,620	$190,000
Indirect/Induced	728	58,989	11,201	76,780
Total	1,228	$145,583	$88,822	$266,780
Steel Micro Mill				
Direct	706	$51,776	$22,523	$136,471
Indirect/Induced	795	59,222	15,450	43,464
Total	1,501	$110,998	$37,973	$179,934
R&D Incubator Site				
Direct	574	$58,174	$83,796	$154,472
Indirect/Induced	302	22,868	15,964	76,622
Total	876	$81,043	$99,760	$231,094
Ancillary Clean Energy Industries				
Direct	9,842	$751,653	$1,181,030	$3,636,471
Indirect/Induced	5,733	432,824	678,469	1,663,918
Total	15,575	$1,184,478	$1,859,499	$5,300,389
Total CMBP Components				
Direct	13,236	$1,119,305	$1,692,497	$4,725,783
Indirect/Induced	8,778	675,182	776,013	2,141,365
Total	22,014	$1,794,487	$2,468,510	$6,867,148

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

K.3 EPA Pamphlelt

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United States Environmental Protection Agency

How EPA's UIC Class VI Regulations Work to Ensure the Protection of Groundwater Resources

What is geologic sequestration?

Geologic sequestration (GS) of carbon dioxide (CO_2) is the injection of CO_2 deep underground to prevent it from entering the atmosphere, thereby helping to mitigate climate change. The CO_2 is injected through specially constructed wells that extend into deep rock formations. These formations have been tested and selected based on geologic characteristics indicating that they can safely contain the CO_2 for long-term storage.

How does the UIC program protect drinking water near geologic sequestration sites?

Under the Safe Drinking Water Act, EPA is tasked with protecting public health by regulating and overseeing the nation's public drinking water supplies. The EPA's Underground Injection Control (UIC) program regulates six classes of wells for the injection of fluids such as water, wastewater, brines, and CO_2 into the subsurface. *UIC regulations are designed to protect underground sources of drinking water (USDWs) by preventing the movement of contaminants out of injection formations and into USDWs. (The diagram on the second side of this pamphlet shows USDWs as the uppermost geologic formations in the figure.) Wells injecting CO_2 for GS are classified as UIC Class VI wells.*

The UIC program regulates all aspects of the injection wells of a GS project including project siting, well construction, injection operations, testing and monitoring, emergency response, financial responsibility, and eventual plugging and closure of the wells and injection sites. The UIC program implements the regulations through permitting, site inspections, required reporting, and compliance reviews to ensure that well owners/operators comply with the regulations. Regulations for Class VI wells are the most rigorous of the UIC program. **The sections below describe how UIC regulations for GS projects protect our underground drinking water resources, with additional details shown in numbered items on the diagram on the second page of this pamphlet.**

How can the public participate?

Public participation and transparency are important components of the UIC regulatory framework. Draft injection well permits for GS projects are published for public review. The public may comment on the draft permits, request and attend public hearings, and in some cases file appeals with the Environmental Appeals Board. Transparency is promoted through communications with communities and providing information from project start through closure.

What are key steps for planning GS projects, and how do they protect USDWs?

The Class VI regulations provide multiple safeguards to protect USDWs, beginning at the initial permitting stage. The owner/operator submitting a permit application for a Class VI well must:

- ***Evaluate the project site*** to document that the geology is suitable for GS and that CO_2 will not leak and migrate to USDWs. This includes identifying both a geologic confining layer to prevent the CO_2 from leaking upward (#1 in diagram on page 2) and an injection formation that can dependably hold and provide long-term storage of the injected CO_2 (see #2). Other geologic features (such as faults) are evaluated to confirm that they will not compromise storage and containment and affect USDWs (#3).
- ***Determine the Area of Review (AoR)***, which is the footprint on the land surface above the subsurface area that could be influenced by CO_2 injection. This is the area where owners/operators will take measures to protect USDWs by identifying other wells, and possibly remediating old or abandoned wells (#9) to ensure that CO_2 does not leak through them.
- ***Meet financial responsibility requirements*** that ensure that the private costs associated with a Class VI well are not passed along to the public and that funding is available to address any problems that could affect USDWs.

How is an injection well constructed and operated to be protective of USDWs?

- ***Construction requirements*** include multiple protective layers of corrosion resistant steel casing and cement (#7 and #8). These requirements help to ensure that CO_2 does not leak out of the well or out of the injection formation along the well itself and migrate to a USDW. The wells are tested for leaks and to confirm proper construction before injection begins. Wells are tested routinely during operations (#14),
- ***Operational requirements***, including safe injection pressure and rate (#6, #13), are established by testing prior to starting injection. Maintaining safe injection pressure and rate avoids fracturing the injection formation. This helps ensure that the injected CO_2 remains where intended and does not migrate to other formations, including those containing USDWs. Safe pressures and rates are set in permit conditions and are continuously monitored at the wellhead during operations (#15).

United States Environmental Protection Agency

What other activities are required for Class VI well operations that help protect USDWs?

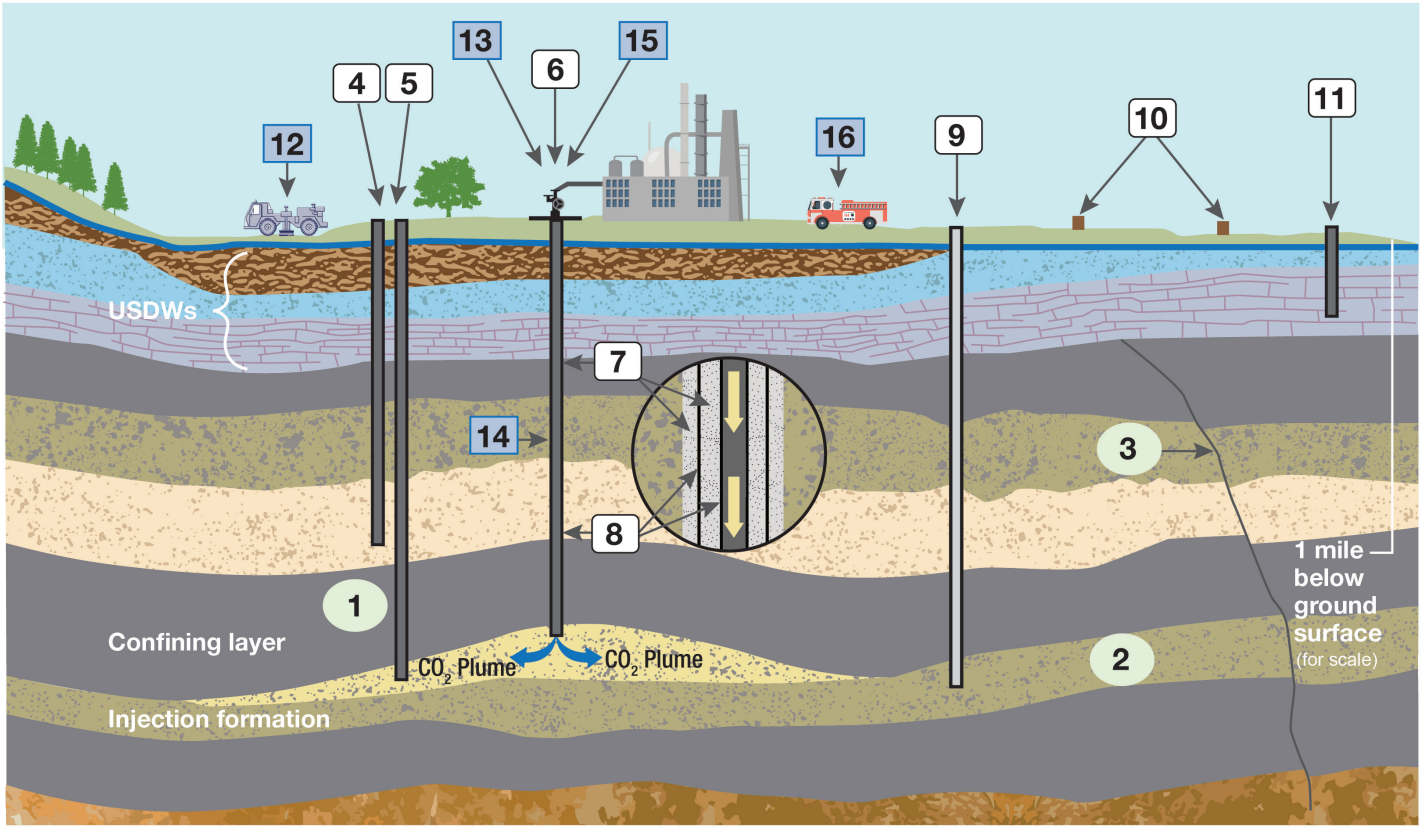
- ***Testing and monitoring*** will provide early warning or evidence in the event of well leaks, unexpected pressure changes, or movement of CO_2 out of the injection formation that could impact USDWs. The injection well is periodically tested for physical integrity and corrosion (#14). The owner/operator uses deep monitoring wells to measure the subsurface pressure and CO_2 in the injection formation (#5). Other monitoring wells are used to monitor groundwater quality above the confining layer (#4). Surface-based seismic surveys (#12) also help track the CO_2 plume.

- ***Emergency response*** requirements require that owners/operators report any evidence of potential dangers to USDWs within 24 hours, including evidence of CO_2 leakage, noncompliance with permit conditions, or malfunction of the injection system (#16).

What activities are required after injection is complete?

- ***Post-injection site care*** begins with well plugging according to an approved well plugging plan. This ensures that CO_2 will not migrate up through the injection well. Testing and monitoring continue according to an approved post-injection site care (PISC) plan. The default period of post-injection site care is 50 years, but the UIC Director can approve a shorter time if the owner/operator demonstrates no danger to USDWs.

- ***Site closure*** can take place when monitoring indicates that the plume and formation pressure are stable and there will be no danger to USDWs. Closure includes removal of surface equipment and site restoration (with grading, planting of vegetation) to conditions approved by the UIC Director. The UIC Director will not authorize the site to be permanently closed until data demonstrate no danger to USDWs.



Through the Underground Injection Control (UIC) program, EPA protects underground sources of drinking water (USDWs) by regulating the construction, operation, permitting, and closure of injection wells that are used for the underground storage or disposal of fluids. Class VI wells are specifically used to inject carbon dioxide (CO_2) into deep rock formations. The UIC permitting authority reviews Class VI permit applications to ensure that injected CO_2 will remain within deep, isolated formations, protecting human health and the environment.

KEY

Site geology
Injection, monitoring, and other wells
Drinking water resource protection practices
Water table

1 Thick, impermeable confining layer prevents CO_2 from leaking upward
2 Permeable injection formation will hold injected CO_2
3 Testing shows that the fault is inactive and sealed against movement of CO_2
4 Water quality is tracked in the permeable formation above the confining layer using a monitoring well
5 Pressure and CO_2 in the injection formation are tracked using a monitoring well
6 CO_2 injection well is permitted for safe operation with many safeguards
7 Cementing prevents CO_2 from moving outside of the well
8 Well materials are corrosion-resistant
9 Properly plugged and abandoned well prevents CO_2 movement between formations
10 Seismic activity is monitored using surface equipment as needed
11 Shallow groundwater well is isolated from the injection formation by multiple impermeable layers
12 Seismic surveys are used to study the geology and track the location of CO_2 through images of the subsurface
13 Safe CO_2 injection pressure avoids damaging the injection formation
14 Regular testing confirms the physical integrity of the well
15 Injection pressure and flow are continually monitored
16 Emergency response plan is in place and ready to be implemented

For general UIC questions, email safewater@epa.gov;
for Class VI questions, email UIC-ClassVI@epa.gov, or send a letter to:

U.S. Environmental Protection Agency
Underground Injection Control Program
Office of Water, Office of Ground Water and Drinking Water
1200 Pennsylvania Avenue, NW Washington, DC 20460